

**Attachment D**

**Coastal Management Program Consistency Determination**

TO BE SUBMITTED AT LATER DATE

## **Federal Consistency Certification for Federal Permit and License Applicants<sup>1</sup>**

This is the Entergy Nuclear Indian Point 2, LLC (IP2) and Entergy Nuclear Indian Point 3, LLC (IP3), here-in-after referred to as “Entergy”, certification to the U.S. Nuclear Regulatory Commission (NRC) that the renewal of the IP2 and IP3 Operating Licenses will 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, New York State Coastal Management Program (NYSCMP) policies, IP2 and IP3 compliance status, and summary findings.

### **CONSISTENCY CERTIFICATION**

Entergy certifies to the NRC that renewal of the IP2 and IP3 Operating Licenses comply with the enforceable policies of New York State’s approved Coastal Management Program (NYSCMP) and will be conducted in a manner consistent with such program. Entergy expects IP2 and IP3 operations during the renewed license terms to be a continuation of current operations as described below, with no physical or operational station alterations that would affect New York State’s coastal zone.

### **NECESSARY DATA and INFORMATION**

#### **Statutory Background**

The Federal Coastal Zone Management Act (CZMA) (16 USC 1451 et seq.) imposes requirements on an applicant for a Federal license to conduct a review of 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 the certification requirement is applicable to renewal of federal licenses for activities not previously reviewed by the state [15 CFR 930.51(b)(1)]. NOAA approved the New York coastal zone management program in 1982. In New York, the approved program is the NYSCMP, and the New York State Waterfront Revitalization of Coastal Areas and Inland Waterways Act, contained in State Executive Law (SEL) Article 42, Department of State regulations in 19 NYCRR Part 600, and State Environmental Quality Review Act (SEQRA) regulations in 6 NYCRR Part 617.

Article 42 SEL 912.9 assures the consistency of federal actions with policies of the New York coastal area and inland waterways and with accepted waterfront revitalization programs of the area. NRC licensing is a federal activity, and the IP2 and IP3 location is within the New York coastal area and inland waterways. IP2 and IP3’s withdrawal from and discharge to coastal areas and inland waterways could reasonably be expected to potentially affect the coastal areas and inland waterways. The state regulation requires certification of compliance with the

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<sup>1</sup> This certification is patterned after the example certification included as Appendix E of NRC LIC-203, 2004.

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NYSCMP policies (19 NYCRR Part 600.3) and the regulation lists the policies (19 NYCRR Part 600.5). Table D-1 identifies the policies and Entergy's justification for certifying compliance.

### **Proposed Action**

Entergy is applying to the NRC for renewal of the IP2 and IP3 Operating Licenses for an additional 20 years beyond the current expiration dates of September 28, 2013 and December 12, 2015, respectively. Entergy expects IP2 and IP3 operations during the license renewal term to be a continuation of current operations as described in the following paragraphs, with no physical or operational changes that would affect the New York State coastal zone. Entergy certifies that the license renewal application complies with the enforceable policies of the NYSCMP and that IP2 and IP3 will continue to be operated in a manner consistent with such policies.

### **Background Information**

IP2 and IP3 are located 24 miles north of New York City on approximately 239 acres of land on the east bank of the Hudson River in upper Westchester County, New York. There are three reactors at the site, Indian Point Units 1, 2, and 3. IP1 was permanently shut down in 1974 and is in SAFSTOR until it is decommissioned. A decommissioning plan for IP1 has been submitted to the NRC and accepted, with plans for decommissioning when IP2 is decommissioned.

Power generation during the license renewal term will consist of IP2 and IP3, with pressurized water reactors and turbine generators licensed for outputs of 3,216 and 3,216 megawatts-thermal (MWt), and electric ratings of 1078 and 1080 megawatts-electric (MWe), respectively. The IP2 Operating License was issued in September 1973 and expires in September 2013. The IP3 Operating License was issued in December 1975 and expires in December 2015. Entergy Nuclear Operations, Inc., a subsidiary of Entergy, operates the facility. The site exclusion area is shown in Figure 2-3 of the license renewal Environmental Report (ER). Approximately 90% of the area within 6 miles of the station is residential housing, parks, and military reservations. The transmission system that ties IP2 and IP3 to the New York grid is in a single right-of-way to Buchanan Substation, located approximately 2,100 feet southeast of the reactors. In areas such as the Hudson River Valley, the inland boundary of the coastal zone may extend inland up to 10,000 feet. In the vicinity of IP2 and IP3, the boundary lies along Washington Street to the east of the Village of Buchanan, and therefore, the area of interest includes the plant property and the Buchanan Substation [NOAA]. Figures 2-1 and 2-2 of the Environmental Report are IP2 and IP3 50-mile and 6-mile vicinity maps, respectively.

IP2 and IP3 are equipped with once-through heat dissipation systems that withdraw cooling water from and discharge to the Hudson River. The details of the plants' cooling systems, intake structures, and discharge system are provided in Chapter 3 of the license renewal ER. IP2 and IP3 each have shoreline-situated intake structures consisting of seven bays (six for circulating water and one for service water). Ristroph screens and fish return systems were timely installed at IP3 and IP2 and completed in 1990 and 1991, respectively. Design features incorporated into the machines were developed and tested in concert with the Hudson River Fishermen's Association [CHGEC]. Modified baskets employing bucket features collect and lift fish to be returned to the river. Additionally, the head section of the screen employs five (5) spray wash headers; three (3) low pressure fish sprays, and two (2) high pressure debris sprays for debris removal. Each screen well is provided with the ability to install stop logs to allow

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dewatering of any individual screen well for maintenance purposes. The water from each individual screenwell flows to a motor-driven, vertical, mixed flow condenser circulating water pump. [IP2 UFSAR, Section 10.2.4; IP3 UFSAR, Section 10.2.4]

Fish are returned to the estuary through a 12-inch diameter pipe that extends 200 feet into the river on the north side of the IP2 intake structure. The pipe is partially buried in the river bottom, and discharges fish at a depth of 35 feet. The location of the discharge was selected after conducting dye and fish release studies to find a location that would minimize re-impingement. [CHGEC, Section IV.B.2.c] Key components of the IP3 screens are identical to those installed at IP2. The IP3 fish return system discharges outside the northwest corner of the station's cooling water discharge canal. [CHGEC, Section V.B.2.c.ii]

For IP2, each of the six dual-speed condenser circulating water pumps provides 140,000 gpm and 21-ft total dynamic head when operating at 254 rpm and 84,000 gpm and 15-ft total dynamic head when operating at 187 rpm. Each pump is located in an individual pump well, thus tying a section of the condenser to an individual pump [IP2 UFSAR, Section 10.2.4]. For IP3, each of the six variable-speed condenser circulating water pumps provides 140,000 gpm at 29 ft total dynamic head when operating at 360 rpm [IP3 UFSAR, Section 10.2.4].

The owners use best reasonable efforts to operate the IP2 and IP3 dual and variable speed circulating pumps to keep the volume of river water drawn into the stations during the relevant entrainment period at the minimum required for efficient operation, considering ambient river water temperature, plant operating status, the need to meet water quality standards and other permit conditions. Flow rates are dependent upon intake water temperature and typically peak between early May and late October. In addition, outages are scheduled, where reasonably practicable, in a manner sensitive to entrainment considerations, typically during the late spring entrainment period, with the result that only one unit is operating during that outage period each year. Further, extensive entrainment survival studies reflect a very high level of entrainment survival among certain species.

After moving through the condensers, cooling water from IP2 and IP3 flows downward from the discharge water boxes by way of six 96-inch down pipes, and exits under the water surface in a 40-foot-wide discharge canal.

The outfall or discharge structure for the IP2 and IP3 facility is designed to enhance mixing of cooling water and river water in such a way as to minimize thermal impact in the river. It can accommodate the combined cooling water flow from both IP2 and IP3 (about 1.75 million gpm, including service water). The cooling water from the discharge channel is released to the Hudson River via an outfall structure located south of IP3. The outfall structure consists of 12 submerged rectangular ports equipped with adjustable gates that are in line and parallel to the river axis. The ports, 4 feet high by 15 feet wide and spaced 21 feet apart (center to center), are submerged to a depth of 12 feet (center to surface) at minimum level water. The first upstream port is approximately 600 ft from the IP3 intake; the length of the total port section is approximately 252 feet. The discharge port gates can be adjusted mechanically to maintain a minimum hydraulic head differential of 1.75 feet across the outfall structure, which assures a discharge velocity of approximately 10 fps. [CHGEC, Section IV.B.2.e]

Entergy holds State Pollutant Discharge Elimination System (SPDES) permits for this and other plant/stormwater discharges (NY-0004472, NY-0234826, NY-0250414, NY-0251135) with

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effluent limitations, monitoring requirements, and other conditions that ensure that all discharges are in compliance with Title 8 of Article 17 of the Environmental Conservation Law (ECL) of New York State and the Clean Water Act (CWA), as amended (33 USC Section 1251 et seq.). In accordance with permit requirements, Entergy monitors discharge characteristics and reports the results to the New York State Department of Environmental Conservation (NYSDEC). Concentrations of radioactivity in effluents are subject to the requirements and limitations of the NRC.

Typically, the temperature increase across the IP3 condenser at 360 RPM is in the range from 14.6°F to 18.0°F (8.1°C to 10°C) and at IP2 with all fast speed pumps from 17°F to 22°F (9.44°C to 12.22°C). Severe fouling due to debris in the Hudson River may cause the water temperature increase across the condensers to go as high as approximately 35°F (19.44°C). The permitted daily average discharge temperature is not to exceed 35°F (34°C) between April 15<sup>th</sup> and June 30<sup>th</sup> for more than 15 days a year during that time period, and at no time is the maximum discharge temperature to exceed 110°F (43.3°C).

IP2 and IP3 do not have an onsite wastewater treatment plant. Sanitary wastewaters from all plant locations is transferred to the Village of Buchanan publicly owned treatment works (POTW) system where it is managed appropriately, except for a few isolated areas which have their own septic tanks which are pumped out by a septic company, as needed, and taken to an offsite facility for appropriate management. Although sanitary wastewaters at the site are nonradioactive, a radiation monitoring system is provided to continuously monitor radiation levels in the effluent from the protected area.

As of June 2006, Entergy employs a permanent workforce of approximately 1,255 employees (including baseline permanent contractors) at IP2 and IP3. The majority of the IP2 and IP3 workforce (approximately 78%) lives in Dutchess, Orange, and Westchester Counties. IP2 and IP3 are on a 24-month alternating refueling cycle. During refueling outages, site employment increases above the 1,255 person permanent workforce by approximately 950 workers for temporary duty (approximately 30 days).

### **Environmental Impacts**

The NRC has prepared a Generic Environmental Impact Statement assessing impacts that nuclear power plant license renewal could have on the environment and has codified its findings in 10 CFR 51, Subpart A, Appendix B, Table B-1 [NRC 1996]. The codification identified 92 potential environmental issues, 69 of which the NRC identified as having small impacts and termed "Category 1 issues." The 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 based its assessment of license renewal impacts on its evaluations of impacts from current plant operations. The NRC codification and the Generic Environmental Impact Statement discuss the following types of Category 1 environmental issues:

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- 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, the NRC relies on its codified findings, as amplified by supporting information in the Generic Environmental Impact Statement, for assessment of environmental impacts from Category 1 issues [10 CFR 51.95(c)(4)]. For plants such as IP2 and IP3 that are located in the coastal zone, many of these issues involve potential impacts to the coastal zone. Entergy has adopted by reference the NRC findings and Generic Environmental Impact Statement analyses for all 43<sup>2</sup> Category 1 issues applicable to IP2 and IP3.

The NRC regulation identified 21 issues as “Category 2,” for which license renewal applicants must submit additional site-specific information.<sup>3</sup> Of these, 11 apply to IP2 and IP3<sup>4</sup>, and like the Category 1 issues, could potentially involve impacts to the coastal zone. The applicable issues and Entergy’s impact conclusions are listed below.

- Aquatic ecology
  - ◆ Entrainment of fish and shellfish in early life stages – This issue addresses mortality of organisms small enough to pass through the plant’s circulating cooling water system. IP2 and IP3 utilize a once-through cooling water system that withdraws

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<sup>2</sup> The remaining Category 1 issues do not apply to IP2 and IP3 either because they are associated with design or operational features that IP2 and IP3 does not have (e.g., cooling towers) or to refurbishment activities, that IP2 and IP3 will not undertake.

<sup>3</sup> 10 CFR 51, Subpart A, Appendix B, Table B-1 also identifies 2 issues as “NA” for which the NRC could not come to a conclusion regarding categorization. Entergy believes that these issues, chronic effects of electromagnetic fields and environmental justice, do not affect “coastal zone” as that phrase is defined by the Coastal Zone Management Act [16 USC 1453(1)].

<sup>4</sup> The remaining Category 2 issues do not apply to IP2 and IP3 either because they are associated with design or operational features that IP2 and IP3 does not have (e.g., cooling towers) or to refurbishment activities that IP2 and IP3 will not undertake.

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cooling water from the Hudson River. The plant holds a State Pollutant Discharge Elimination System (SPDES) permit (NY-0004472) for discharge of cooling waters from the New York State Department of Environmental Conservation [NYSDEC 1987]. More than 30 years of extensive fisheries studies of the Hudson River have been conducted in the vicinity of IP2 and IP3. The results of studies performed from 1974 to the present period have not shown any negative trend in overall aquatic river species populations attributable to plant operations [CHGEC; ASA]. The ongoing studies continue to support these conclusions [ASA]. Entergy uses best reasonable efforts to operate IP2 and IP3 dual and variable speed circulating pumps to keep the volume of river water drawn into the stations during the relevant entrainment period at the minimum required for efficient operation, considering ambient river water temperature, plant operating status, the need to meet water quality standards, and other permit conditions. Flow rates are dependent upon intake water temperature, and typically peak between early May and late October. In addition, outages are scheduled, where reasonably practicable, in a manner sensitive to entrainment considerations, typically during the late spring entrainment period, with the result that only one Station is operating during that outage period each year. Further, extensive entrainment survival studies reflect a very high level of entrainment survival among certain species. Mitigation measures implemented through the Hudson River Settlement Agreement and retained in the four Consent Orders, current agreements with NYSDEC, along with the outcome of current draft SPDES Permit proceedings, will ensure that entrainment impacts remain SMALL during the license renewal term [HRSA; NYSDEC 1997].

- ◆ Impingement of fish and shellfish – 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 plant has installed Ristroph screens and fish return systems on the IP2 and IP3 intake structures to minimize the impact of impingement. Extensive descriptions of more than 23 years of Hudson River fisheries and habitat studies involving trends in key species abundance, diversity, richness, and mortality rates, and impacts from entrainment and impingement at once-through cooling water intakes were provided in a 1999 Draft Environmental Impact Statement (DEIS) submitted on behalf of the owners of the Roseton, Bowline Point, and Indian Point generating stations [CHGEC]. As mentioned above, continuing studies are ongoing, and are submitted annually to the NYSDEC. The DEIS describes sampling study results at Indian Point (IP2 and IP3), and identified 88 species of fish in more than 20 years of impingement studies. Conditional mortality rate (CMR) estimates of the numbers of fish lost to impingement integrated with estimates of the abundance of fish in the river were presented in the DEIS (as a percentage) to estimate the proportional reduction of the population [CHGEC, Section VI.B.1.b]. CMRs and discussion of models to define the CMRs are presented in the DEIS and its appendixes [CHGEC, Section VI.2.A and B]. The estimated average annual CMR due to impingement for American shad is 0.0%, for Atlantic tomcod is 0.62%, for bay anchovy is 0.05%, for blueback herring is 0.22%, for alewife is 0.14%, for spottail shiner is 0.10%, for striped bass is 0.20%, and for white perch is 1.70% [CHGEC, Section V.D]. It should be noted that the impingement percentages included data collected from 1981 to 1990, which was prior to installation of the Ristroph screens on the IP2 and IP3 intakes. Therefore, the impingement mortality during current operations and the license renewal period would be significantly less, based on the

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impingement mortality percentage estimates cited above and anticipating the continued use of the Ristroph screens and fish return systems installed. In the Fact Sheet to the draft permit, NYSDEC noted that the current design, along with seasonable flow reductions and generation outages..., attains an estimated 77% reduction in impingement mortality [NYSDEC 2003]. Currently, more than 30 years of extensive fisheries studies of the Hudson River have been completed in the vicinity of IP2 and IP3. The results of the studies performed from 1974 to 1997, the period of time covered in the DEIS, are referenced and summarized in the DEIS, and have not shown any negative trend in overall aquatic river species populations attributable to plant operations. Ongoing studies continue to support these conclusions [ASA]. In addition, current mitigation measures implemented through the HRSA and retained in the four Consent Orders, the current agreements with NYSDEC, along with the outcome of the draft SPDES Permit proceeding, will ensure that impingement impacts remain SMALL during the license renewal term.

- ◆ Heat shock – This issue addresses mortality of aquatic organisms by exposure to heated plant effluent. The studies discussed above also addresses the impact from heat shock and requirements of 316(a) of the federal Clean Water Act and NYSDEC regulations. Temperature limitations established by the NYSDEC in SPDES permit NY-0004472 to ensure the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife in the Hudson River are being met. In addition, as discussed above, the sites' discharges were designed, and are operated, to minimize potential adverse impacts. Therefore, Entergy concludes that heat discharge from the sites' cooling systems does not cause appreciable harm or interfere with the maintenance of a balanced indigenous aquatic population and that impacts will remain SMALL during the license renewal period.

- Threatened or endangered species

Four animal species currently protected and two candidate species under the Endangered Species Act have geographic ranges which could possibly include the site (see Table D-2). Federally protected and candidate species potentially represented include two fish, two mammals, one reptile, and one bird. These are the shortnose sturgeon (*Acipenser brevirostrum*), Atlantic sturgeon (*Acipenser oxyrinchus*), Indiana bat (*Myotis sodalis*), New England cottontail rabbit (*Sylvilagus transitionalis*), bog turtle (*Clemmys muhlenbergii*), and bald eagle (*Haliaeetus leucocephalus*). Of these species, the Indiana bat and the shortnose sturgeon are listed as endangered, the bog turtle and bald eagle are listed as threatened, and the Atlantic sturgeon and the New England cottontail rabbit are listed as candidate species. There have been no sightings of the Indiana bat or bog turtle either onsite or within the vicinity of the site.

The shortnose sturgeon is the only aquatic species listed as threatened or endangered in the vicinity of IP2 and IP3. Entergy received USFWS and NMFS input on the presence of listed species in the vicinity of Indian Point in January 2007. Both agencies identified the shortnose sturgeon in the vicinity of Indian Point. NMFS also mentioned the presence of the Atlantic sturgeon in the vicinity of Indian Point, which the agency is considering as a Candidate Species, and has initiated a status review for threatened or endangered species listing. However, the NMFS has previously stated in biological assessments involving the shortnose sturgeon that,



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overall, the intakes and discharges of Hudson River power plants are unlikely to jeopardize the recovery of the Hudson River shortnose sturgeon population [NMFS].

Bald eagles have increased in total number, successful nesting pairs, and number of young produced. Alteration of the landscape required by bald eagles continues to be the biggest single threat to this species. Since there are no plans to alter operations, expand existing facilities, or acquire additional land in support of license renewal, therefore no anticipated potential impacts on nesting sites from continued site operations. Even so, Entergy has fleet procedural controls in place to ensure that threatened and endangered species are adequately protected, if present, during site operations and project planning.

Therefore, Entergy concludes that impacts from IP2 and IP3 plant operations to the species discussed above are SMALL and has no plans that would change this conclusion for the license renewal term.

- Human health

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 strictly 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)], Entergy concludes that the issue is not subject to the certification requirement.

- Socioeconomics

- ◆ Housing – This issue addresses impacts that IP2 and IP3 employees required to support license renewal could have on local housing availability. The NRC concluded, and Entergy concurs, that the operation of Indian Point has not considerably affected the housing in the communities neighboring the plants or in the whole of Westchester or Dutchess counties [NRC, 1996, D-2, Section C.4.4.2.1]. Further, the NRC concluded that impacts related to housing value and marketability that occur during the license renewal term are the same as those currently experienced. As Entergy does not intend to add additional permanent employees to the IP2 and IP3 workforce, Entergy has concluded that impacts during the IP2 and IP3 license renewal term would be SMALL.
- ◆ Public services: public utilities – This issue addresses impacts that adding license renewal workers could have on public water supply systems. Entergy has analyzed the availability of public water supplies in candidate locales and has found no limitations that would suggest that the IP2 and IP3 workforce would cause adverse impacts on the public water supply. As Entergy does not intend to add additional permanent employees to the IP2 and IP3 workforce, Entergy has concluded that impacts during the license renewal term would be SMALL.
- ◆ Offsite land use – This issue addresses impacts on land use patterns from local government spending of plant PILOT and property tax dollars. IP2 and IP3 PILOT payments comprise approximately 39 percent of the Village of Buchanan revenues and Entergy expects this to remain generally unchanged during the license renewal term. The NRC concluded, and Entergy concurs, that impacts to offsite land use would be

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small if tax payments continue at approximately the same level. Therefore, Entergy concludes that impacts during the IP2 and IP3 license renewal term would be SMALL.

- ◆ Public services: transportation – This issue addresses impacts that adding license renewal workers could have on local traffic patterns. As Entergy does not intend to add additional employees to the permanent workforce for the license renewal term, this would result in SMALL impacts.
- ◆ Historic and archaeological resources – This issue addresses 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 near the IP2 and IP3 site, none have been identified on plant property. Therefore, since no refurbishment activities are required and there are also no plans to alter operations, expand existing facilities, or disturb additional land in support of license renewal, Entergy concludes that impacts during the license renewal term would be SMALL. Entergy's correspondence with the New York State Historic Preservation Officer (SHPO) also supports this conclusion since the SHPO identified no issues of concern.

### State Program

The New York State Coastal Management Program is administered by the Division of Coastal Resources within the New York State Department of State (NYSDOS). The office maintains a website that describes the program in general terms [NYDS]. The New York State Coastal Management Program [SEL] contains details about the state's enforceable policies and management principles. Table D-1 lists these policies and discusses for each item the applicability to IP2 and IP3 and, where applicable, the status of IP2 and IP3 compliance.

### Findings

1. The NRC has found that the environmental impacts of Category 1 issues are SMALL. Entergy has adopted by reference NRC findings for Category 1 issues applicable to IP2 and IP3.
2. For Category 2 issues applicable to IP2 and IP3, Entergy has determined that the environmental impacts are SMALL.
3. IP2 and IP3 are in compliance with New York State licensing and permitting requirements and are in compliance with its local government-issued licenses and permits.
4. Entergy's license renewal and continued operation of IP2 and IP3 would be consistent with the enforceable policies of the New York State Coastal Management Program.

### STATE NOTIFICATION

By this certification that IP2 and IP3 license renewal is consistent with the New York State Coastal Management Program, the New York State Department of State is notified that it has six months from receipt of this letter and accompanying information in which to concur with or object to Entergy's certification. However, pursuant to the New York State Coastal Management Program and 15 CFR Part 930, if the New York State Department of State has not

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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. The New York State Department of State's concurrence, objection, or notification of review status shall be sent to:

Bo Pham U.S. Nuclear Regulatory Commission One White Flint North 11555 Rockville Pike Rockville, MD 20852-2738	Fred Dacimo Site Vice President Indian Point Energy Center 450 Broadway, Suite 1 Buchanan, NY 10511
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**REFERENCES**

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Council, Inc. et. al. vs. New York State Department of Environmental Conservation and Consolidated Edison Company of New York, Inc, New York Power Authority, Orange and Rockland Utilities, Inc., and Central Hudson Gas and Electric Corp.

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**Table D-1  
New York State Coastal Management Program's  
New York State Coastal Policies**

The New York State Coastal Management Program (NYSCMP) policies are contained in the Article 42 of the State Executive Law (SEL), Department of State regulations in 19 NYCRR Part 600, and the State Environmental Quality Review Act (SEQRA) 6 NYCRR Part 617 and requires persons seeking approval for activities which may impact the Coastal Zone to demonstrate that the activity is consistent with all enforceable policies in 19 NYCRR Part 600 and 6 NYCRR Part 617. Entergy is seeking renewal of the operating licenses for IP2 and IP3. The following table details the NYSCMP policies of 19 NYCRR Part 600 and provides Entergy's demonstration that IP2 and IP3 license renewal would be consistent with 19 NYCRR Part 600.

<b>POLICY</b>	<b>JUSTIFICATION/ CONSISTENCY</b>
<b>DEVELOPMENT POLICIES</b>	
DEVELOPMENT POLICY #1: Restore, revitalize, and redevelop deteriorated and underutilized waterfront areas for commercial, industrial, cultural, recreational, and other compatible uses.	IP2 and IP3 license renewal is not an action involving underutilized waterfront areas. IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
DEVELOPMENT POLICY #2: Facilitate the siting of water dependent uses and facilities on or adjacent to coastal waters.	The renewal of the IP2 and IP3 Operating Licenses would have no effect on the water dependant uses on or adjacent to coastal waters. IP2 and IP3 have no plans for development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
DEVELOPMENT POLICY #3: Further develop the state's major ports of Albany, Buffalo, New York, Ogdensburg, and Oswego as centers of commerce and industry, and encourage the siting, in these port areas, including those under the jurisdiction of state public authorities, of land use and development which is essential to, or in support of, the waterborne transportation of cargo and people.	The renewal of the IP2 and IP3 Operating Licenses would have no impact on the State's major ports. IP2 and IP3 have no plans for additional development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
DEVELOPMENT POLICY #4: Strengthen the economic base of smaller harbor areas by encouraging the development and enhancement of those traditional uses and	IP2 and IP3 are not a small harbor area and license renewal would have no known impact on any smaller harbor areas. In addition, IP2 and IP3 have no plans for additional activities

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activities which have provided such areas with their unique maritime identity.	or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
DEVELOPMENT POLICY #5: Encourage the location of development in areas where public services and facilities essential to such development are adequate.	The renewal of the IP2 and IP3 Operating Licenses would have no identified impact on the development of the existing built environment. In addition, IP2 and IP3 have no plans for additional development as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
DEVELOPMENT POLICY #6: Expedite permit procedures in order to facilitate the siting of development activities at suitable locations.	The renewal of the IP2 and IP3 Operating Licenses would have no identified impact on expediting permit procedures to facilitate siting of development activities. In addition, IP2 and IP3 have no plans for additional activities or development as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
<b>FISH AND WILDLIFE POLICIES</b>	
FISH AND WILDLIFE POLICY #7: Significant coastal fish and wildlife habitats will be protected, preserved, and where practical, restored so as to maintain their viability as habitats.	IP2 and IP3 have not identified any impact that license renewal operations would have on the significant coastal fish and wildlife habitat. In addition, IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
FISH AND WILDLIFE POLICY #8: Protect fish and wildlife resources in the coastal area from the introduction of hazardous wastes and other pollutants which bio-accumulate in the food chain or which cause significant sub-lethal or lethal effects on those resources.	IP2 and IP3 operations are consistent with SPDES permit requirements which are based on federal and state water quality standards. All non-radiological effluent discharges are regulated by the New York State Department of Environmental Conservation (NYSDEC) through the State Pollutant Discharge Elimination System (SPDES) permit program. IP2 and IP3 has four such SPDES permits (NY-0004472, NY-0234826, NY-0250414, NY-0251135) with effluent limitations, monitoring requirements, and other conditions that ensures that all discharges are in compliance

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	<p>with Title 8 of Article 17 of the Environmental Conservation Law (ECL) of New York State and the Clean Water Act (CWA), as amended (33 USC. Section 1251 et seq.). Concentrations of radioactivity in effluents are subject to the requirements of the NRC. IP2 and IP3 are in compliance with its licensing requirements, as well as the requirements and conditions of its SPDES permits. Therefore, it is protecting fish and wildlife resources in the Hudson River area where the plant is located.</p> <p>Pesticide use is regulated by the NYSDEC under 6 NYCRR Part 325. IP2 and IP3 have in place the appropriate NYSDEC Pesticide Business Registrations, submit the required annual reports to the State, and maintain appropriate applicator certifications to ensure that pesticide use and storage on-site are conducted properly and in accordance with regulations. Therefore, it is protecting fish and wildlife resources in the Hudson River area where the plant is located.</p> <p>Petroleum bulk storage on-site is regulated by the NYSDEC under 6 NYCRR Parts 612-614 for IP3, and 6 NYCRR Parts 610-614 and 17 NYCRR Parts 30 and 32 for IP2. IP2 and IP3 facilities have the appropriate registrations and procedures in place for spill prevention, response, and reporting. Onsite chemical bulk storage is regulated by the NYSDEC under 6 NYCRR Parts 595-599. IP2 and IP3 have in place Spill Prevention, Control, and Countermeasures Plans, as required under 40 CFR Part 112, to prevent the discharge of oil to surface waters or surface water tributaries. IP2 and IP3 also have in place Chemical Spill Prevention Plans, as required by 6 NYCRR Part 598, to prevent the discharge of hazardous chemicals to surface waters and their tributaries. IP2 and IP3 facilities have the appropriate registrations and procedures in place for proper materials handling and storage; spill prevention, response, and reporting; and storage systems inspection,</p>



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	<p>maintenance, and repair. IP2 and IP3 have in place processes and procedures to ensure that hazardous chemicals stored and used on-site are handled and stored in accordance with applicable State and Federal regulations. IP2 and IP3 are, therefore, protecting fish and wildlife resources in the Hudson River area.</p> <p>Hazardous and some mixed wastes generated on-site are packaged, temporarily stored, and shipped off-site for processing and disposal. The NYSDEC regulates these activities under 6 NYCRR Parts 370-376. In addition, IP2 has a NYSDEC permit for the storage of mixed wastes and both IP2 and IP3 have EPA permits for the storage of mixed wastes. These activities are also regulated under 6 NYCRR Parts 370–376, as well as 40 CFR Parts 260-268. IP2 and IP3 have in place processes and procedures to ensure that mixed and hazardous wastes are packaged, stored, and shipped so as to comply with the applicable State and Federal regulations, thus ensuring that fish and wildlife resources are protected. Therefore, fish and wildlife resources in the Hudson River area are protected and the proposed activity is consistent with this policy.</p>
<p>FISH AND WILDLIFE POLICY #9: Expand recreational use of fish and wildlife resources in coastal areas by increasing access to existing resources, supplementing existing stocks, and developing new resources.</p>	<p>Water-dependent and water-enhanced recreation along the IP2 and IP3 waterfront cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.</p>

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FISH AND WILDLIFE POLICY #10: Further develop commercial finfish, shellfish, and crustacean resources in the coastal area by encouraging the construction of new, or improvement of existing on-shore commercial fishing facilities, increasing marketing of the states seafood products, maintaining adequate stocks, and expanding aquaculture facilities.	Water-dependent and water-enhanced development along the IP2 and IP3 waterfront cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.
<b>FLOODING AND EROSION HAZARDS POLICIES</b>	
FLOODING AND EROSION HAZARDS POLICY #11: Buildings and other structures will be sited in the coastal area so as to minimize damage to property and the endangering of human lives caused by flooding and erosion.	Entergy is aware of no IP2 and IP3 impacts on coastal areas that damage property or endanger human lives due to flooding or erosion. IP2 and IP3 have no plans for refurbishment or development as a part of the proposed activity, and therefore the proposed activity is consistent with this policy.
FLOODING AND EROSION HAZARDS POLICY #12: Activities or development in the coastal area will be undertaken so as to minimize damage to natural resources and property from flooding and erosion by protecting natural protective features including beaches, dunes, barrier islands, and bluffs.	The shoreline within the IP2 and IP3 protected area has been evaluated according to its geological characteristics. The area is one in which severe natural phenomena such as tornados and flooding are uncommon. The continued operation of IP2 and IP3 during the license renewal period would not involve any activities that would disturb the shoreline along the IP2 and IP3 property. In addition, IP2 and IP3 have no plans for refurbishment or development along the shoreline as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
FLOODING AND EROSION HAZARDS POLICY #13: The construction or reconstruction of erosion protection structures shall be undertaken only if they have a reasonable probability of controlling erosion for at least thirty years as demonstrated in design and construction standards and/or assured maintenance or replacement programs.	IP2 and IP3 license renewal will not necessitate any construction or refurbishment activities. Therefore, the proposed activity is consistent with this policy.

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<p>FLOODING AND EROSION HAZARDS POLICY #14: Activities and development, including the construction or reconstruction of erosion protection structures, shall be undertaken so that there will be no measurable increase in erosion or flooding at the site of such activities or development, or at other locations.</p>	<p>IP2 and IP3 are aware of no impacts that would result from the renewal of the IP2 and IP3 Operating Licenses on erosion hazard areas. In addition, IP2 and IP3 have no plans for additional development as a part of the proposed activity; therefore the proposed activity is consistent with this policy.</p>
<p>FLOODING AND EROSION HAZARDS POLICY #15: Mining, excavation or dredging in coastal waters shall not significantly interfere with the natural coastal processes which supply beach materials to land adjacent to such waters and shall be undertaken in a manner which will not cause an increase in erosion of such land.</p>	<p>The renewal of the IP2 and IP3 Operating Licenses would have no impact on coastal waters due to dredging, mining, or excavation. Any potential dredging to remove sediment build-up in the vicinity of IP2 and IP3 intake or discharge structures would be completed in compliance with state and federal regulations that will ensure the action does not significantly interfere with natural coastal processes. Therefore, the proposed activity is consistent with this policy.</p>
<p>FLOODING AND EROSION HAZARDS POLICY #16: Public funds shall only be used for erosion protective structures where necessary to protect human life, and new development which requires a location within or adjacent to an erosion hazard area to be able to function, or existing development; and only where the public benefits outweigh the long term monetary and other costs including the potential for increasing erosion and adverse effects on natural protective features.</p>	<p>IP2 and IP3 are privately owned facilities and renewal of their Operating Licenses are not a state or federally funded project.</p>
<p>FLOODING AND EROSION HAZARDS POLICY #17: Non-structural measures to minimize damage to natural resources and property from flooding and erosion shall be used whenever possible.</p>	<p>The shoreline within the IP2 and IP3 protected area has been evaluated according to its geological characteristics. The area is one in which severe natural phenomena such as tornados and flooding is uncommon. The continued operation of IP2 and IP3 during the license renewal period will not involve any activities that would disturb the shoreline along the IP2 and IP3 property. In addition, IP2 and IP3 have no plans for additional activities or development along the shoreline as a part of the proposed activity; therefore the proposed</p>

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	activity is consistent with this policy.
<b>GENERAL POLICY</b>	
GENERAL POLICY #18: To safeguard the vital economic, social, and environmental interests of the state and of its citizens, proposed major actions in the coastal area must give full consideration to those interests, and to the safeguards which the state has established to protect valuable coastal resource areas.	IP2 and IP3 license renewal will have significant positive impact on the economic and social interest of New York State and its citizens from contributions to the tax base, education funding, support of public services infrastructure, and workforce. Entergy is aware of no negative impacts that continued operations would have on valuable coastal resource areas.
<b>PUBLIC ACCESS POLICIES</b>	
PUBLIC ACCESS POLICY #19: Protect, maintain, and increase the level and types of access to water-related recreation resources and facilities.	Water-dependent and water-enhanced recreation along the IP2 and IP3 waterfront cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.
PUBLIC ACCESS POLICY #20: Access to the publicly-owned foreshore and to lands immediately adjacent to the foreshore or the water's edge that are publicly owned shall be provided and it shall be provided in a manner compatible with adjoining uses.	Water-dependent and water-enhanced recreation along the IP2 and IP3 waterfront cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.
<b>RECREATION POLICIES</b>	
RECREATION POLICY #21: Water-dependent and water-enhanced recreation will be encouraged and facilitated, and will be given priority over non-water-related uses along the coast.	Water-dependent and water-enhanced recreation cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.

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RECREATION POLICY #22: Development, when located adjacent to the shore, will provide for water-related recreation, whenever such is compatible with reasonably anticipated demand for activities, and is compatible with the primary purpose of the development.	Water-dependent and water-enhanced recreation cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.
<b>HISTORIC AND SCENIC RESOURCES POLICIES</b>	
HISTORIC AND SCENIC RESOURCES POLICY #23: Protect, enhance, and restore structures, districts, areas, or sites that are of significance in the history, architecture, archaeology, or culture of the state, its communities, or the nation.	The renewal of the IP2 and IP3 Operating Licenses will have no impact on historic and cultural resources. In addition, IP2 and IP3 have no plans for refurbishment or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
HISTORIC AND SCENIC RESOURCES POLICY #24: Prevent impairment of scenic resources of statewide significance.	The renewal of the IP2 and IP3 Operating Licenses will have no impairment impact on the significant scenic resources. In addition, IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
HISTORIC AND SCENIC RESOURCES POLICY #25: Protect, restore, or enhance natural and man-made resources which are not identified as being of statewide significance, but which contribute to the overall scenic quality of the coastal area.	The renewal of the IP2 and IP3 Operating Licenses will have no additional impact on the scenic resources in the coastal area. In addition, IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
<b>AGRICULTURAL LANDS POLICY</b>	
AGRICULTURAL LANDS POLICY #26: Conserve and protect agricultural lands in the state's coastal area.	IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.

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<b>ENERGY AND ICE MANAGEMENT POLICIES</b>	
ENERGY AND ICE MANAGEMENT POLICY #27: Encourage energy conservation and the use of alternative sources such as solar and wind power in order to assist in meeting the energy needs of the State.	IP2 and IP3 are important power generation facilities that plays a vital role to assist in meeting the energy needs of the State, without which other sources of energy would be required that could cause environmental or quality of life impacts for the citizens of New York.
ENERGY AND ICE MANAGEMENT POLICY #28: Ice management practices shall not interfere with the production of hydroelectric power, damage significant fish and wildlife and their habitats, or increase shoreline erosion or flooding.	IP2 and IP3 operations and license renewal do not involve ice management practices.
ENERGY AND ICE MANAGEMENT POLICY #29: Encourage the development of energy resources on the outer continental shelf, in Lake Erie and in other water bodies, and ensure the environmental safety of such activities.	IP2 and IP3 are important power generation facilities that plays a vital role in meeting the energy needs of the State of New York, without which other sources of energy would be required that could cause environmental or quality of life impacts for the citizens of New York.
<b>WATER AND AIR RESOURCES POLICIES</b>	
WATER AND AIR RESOURCES POLICY #30: Municipal, industrial, and commercial discharge of pollutants, including but not limited to, toxic and hazardous substances, into coastal waters will conform to state and national water quality standards.	The effluent discharges from IP2 and IP3 are regulated by the NYSDEC through the SPDES permit program. IP2 and IP3 have been issued four SPDES permits (NY-0004472, NY-0234826, NY-0250414, NY-0251135) with effluent limitations, monitoring requirements, and other conditions that ensure that all discharges are in compliance with Title 8 of Article 17 of the ECL of New York State and the CWA, as amended (33 USC Section 1251 et seq.). Concentrations of radioactivity in effluents are subject to the requirements of the NRC. IP2 and IP3 are in compliance with its licensing requirements, as well as the requirements and conditions of its SPDES permits. Therefore, the proposed activity is consistent with this policy.

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<p>WATER AND AIR RESOURCES POLICY #31: State coastal area policies and management objectives of approved local waterfront revitalization programs will be considered while reviewing coastal water classifications and while modifying water quality standards; however those waters already overburdened with contaminants will be recognized as being a development constraint.</p>	<p>The effluent discharges from IP2 and IP3 are regulated by the NYSDEC through the SPDES permit program. IP2 and IP3 have been issued four SPDES permits (NY-0004472, NY-0234826, NY-0250414, NY-0251135) with effluent limitations, monitoring requirements, and other conditions that ensure that all discharges are in compliance with Title 8 of Article 17 of the ECL of New York State and the CWA, as amended (33 USC Section 1251 et seq.). Concentrations of radioactivity in effluents are subject to the requirements of the NRC. IP2 and IP3 are in compliance with its licensing requirements, as well as the requirements and conditions of its SPDES permits. Therefore, the proposed activity is consistent with this policy.</p>
<p>WATER AND AIR RESOURCES POLICY #32: Encourage the use of alternative or innovative sanitary waste systems in small communities where the costs of conventional facilities are unreasonably high, given the size of the existing tax base of these communities.</p>	<p>IP2 and IP3 provide approximately 39 percent of the tax revenue for the Village of Buchanan, and is a major contributor to the tax base of Westchester County. IP2 and IP3 license renewal will have significant positive impact on the economic and social impact from contributions to the tax base, education funding, support of public services infrastructure, and workforce.</p>
<p>WATER AND AIR RESOURCES POLICY #33: Best management practices will be used to ensure the control of stormwater runoff and combined sewer overflows draining into coastal waters.</p>	<p>IP2 and IP3 have in place four SPDES permits (NY-0004472, NY-0234826, NY-0250414, and NY-0251135) that incorporate best management practices to control storm water runoff. The NYSDEC regulates storm water management under 6 NYCRR Part 750, ECL 17-0808, and GP-06-002. IP2 and IP3 have programs and processes in place to ensure compliance with applicable NYSDEC storm water management requirements. Therefore, the proposed activity is consistent with this policy.</p>

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<p>WATER AND AIR RESOURCES POLICY #34: Discharge of waste materials into coastal waters from vessels subject to state jurisdictions will be limited so as to protect significant fish and wildlife habitats, recreational areas and water supply areas.</p>	<p>IP2 and IP3 operations and license renewal do not involve discharge of waste materials into coastal waters from vessels. Therefore, the proposed activity is consistent with this policy.</p>
<p>WATER AND AIR RESOURCES POLICY #35: Dredging and filling coastal waters and disposal of dredged material will be undertaken in a manner that meets existing state permit requirements, and protects significant fish and wildlife habitats, scenic resources, natural protective features, important agricultural lands and wetlands.</p>	<p>IP2 and IP3 have no plans for mining, excavation, filling activities, or development along the waterfront as a part of license renewal operations. Any potential dredging to remove sediment build-up in the vicinity of IP2 and IP3 intake or discharge structures would be completed in compliance with state and federal regulations that will ensure the action does not significantly interfere with fish or wildlife habitats, scenic resources, important agricultural lands, or wetlands. Therefore, the proposed activity is consistent with this policy.</p>
<p>WATER AND AIR RESOURCES POLICY #36: Activities related to the shipment and storage of petroleum and other hazardous materials will be conducted in a manner that will prevent or at least minimize spills into coastal waters; all practicable efforts will be undertaken to expedite the cleanup of such discharges; and restitution for damages will be required when these spills occur.</p>	<p>IP2 and IP3 has in place procedures to ensure that petroleum and other hazardous materials used on-site are safely handled and stored. The NYSDEC regulates petroleum bulk storage under the authority of 6 NYCRR Parts 610-614 and 17 NYCRR Parts 30 and 32. IP2 and IP3 facilities have the appropriate registrations, licenses, and procedures in place to prevent and report spills. Onsite chemical bulk storage is regulated by the NYSDEC under 6 NYCRR Parts 595-599. IP2 and IP3 have in place Spill Prevention, Control, and Countermeasures Plans as required under 40 CFR 112 to prevent the discharge of oil to surface waters or surface water tributaries. IP2 and IP3 also have in place Chemical Spill Prevention Plans, as required by 6 NYCRR Part 598, to prevent the discharge of hazardous chemicals to surface waters and their tributaries. IP2 and IP3 facilities have the appropriate registrations and procedures in place for proper materials handling and storage; spill prevention, response, and reporting; and storage systems inspection, maintenance, and repair. IP2 and IP3 also have in place processes and</p>



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	<p>procedures to ensure that hazardous chemicals stored and used on-site are managed in accordance with applicable State and Federal regulations so as to prevent the release of these materials to coastal waters. Therefore, the proposed activity is consistent with this policy.</p>
<p><b>WATER AND AIR RESOURCES POLICY #37:</b> Best management practices will be utilized to minimize the non-point discharge of excess nutrients, organics, and eroded soils into coastal waters.</p>	<p>IP2 and IP3 have in place four SPDES permits (NY-0004472, NY-0234826, NY-0250414, and NY-0251135) that incorporate best management practices to control storm water runoff. The NYSDEC regulates storm water management under 6 NYCRR Part 750, ECL 17-0808, and GP-06-002. IP2 and IP3 have programs and processes in place to ensure compliance with applicable NYSDEC storm water management requirements. The EPA has authority under 40 CFR 122. Therefore, the proposed activity is consistent with this policy.</p>
<p><b>WATER AND AIR RESOURCES POLICY #38:</b> The quality and quantity of surface water and groundwater supplies will be conserved and protected particularly where such waters constitute the primary or sole source of water supply.</p>	<p>IP2 and IP3 do not use groundwater as a resource for any plant operations or as a potable water source. Processes and procedures are in place for the handling and storage of hazardous materials on-site to prevent spills and to respond to any that occur so as to minimize impacts to groundwater or surface water resources. Effluents from plant operations are regulated under IP2 and IP3's SPDES permits so as to minimize the impacts to surface water supplies (Hudson River) and minimize water use. SPCC Plans are in place to protect surface water resources as required under 40 CFR 112, to prevent the discharge of oil to surface waters or surface water tributaries. IP2 and IP3 have in place processes and procedures that conserve and protect both groundwater and surface water resources. Radiological effluents are regulated in accordance with NRC regulations, policies, and guidance. Therefore, the proposed activity is consistent with this policy.</p>

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<p>WATER AND AIR RESOURCE S POLICY #39: The transport, storage, treatment, and disposal of solid wastes, particularly hazardous wastes, within coastal areas will be conducted in such a manner so as to protect groundwater and surface water supplies, significant fish and wildlife habitats, recreation areas, important agricultural land, and scenic resources.</p>	<p>IP2 and IP3 do not dispose of solid waste on-site. Hazardous and some mixed wastes generated on-site are packaged, temporarily stored, and shipped off-site for processing and disposal. The NYSDEC regulates these activities under 6 NYCRR Parts 370-376. In addition, IP2 has a NYSDEC permit for the storage of mixed wastes and both IP2 and IP3 have EPA permits for the storage of mixed wastes. These activities are also regulated under 6 NYCRR Parts 370-376, as well as 40 CFR Parts 260-268. IP2 and IP3 have in place processes and procedures to ensure that mixed and hazardous wastes are packaged, stored, and shipped in compliance with the applicable State and Federal regulations, thus ensuring that groundwater and surface water supplies, significant fish and wildlife habitats, recreation areas, important agricultural land, and scenic resources are protected. The proposed activity is, therefore, consistent with this policy.</p>
<p>WATER AND AIR RESOURCES POLICY #40: Effluent discharged from major steam electric generating and industrial facilities into coastal waters will not be unduly injurious to fish and wildlife and shall conform to state water quality standards.</p>	<p>The effluent discharges from IP2 and IP3 are regulated by the NYSDEC through the SPDES permit program. The site has been issued four SPDES permits (NY-0004472, NY-0234826, NY-0250414, NY-0251135) with effluent limitations, monitoring requirements, and other conditions that ensure that all discharges are in compliance with Title 8 of Article 17 of the ECL of New York State and the CWA, as amended (33 USC Section 1251 et seq.). IP2 and IP3 are in compliance with its SPDES permits and are meeting all requirements and conditions set forth in the permits, and it is minimizing impacts to fish and wildlife. The proposed activity is, therefore, consistent with this policy.</p>

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<p><b>WATER AND AIR RESOURCES POLICY #41:</b> Land use or development in the coastal area will not cause national or state air quality standards to be violated.</p>	<p>The air discharges from IP2 and IP3 are regulated under the Westchester County Department of Health (WCDOH), Chapter 873, Article XIII of the Laws of Westchester County, the ECL of New York State, and 6 NYCRR Parts 200-201 and 227. IP2 and IP3 have been issued Air State Facility permits (3-5522-00011/00026 and 3-5522-00105/00009) with permissible emissions, monitoring requirements, and other conditions that ensure that all emissions are in compliance with Article XIII of the WCDOH and Article 19: Air Pollution Control – Air State Facility Permit under the ECL. IP2 and IP3 are in compliance with its Air State Facility permit and are meeting all requirements and conditions set forth in the permit, and it is minimizing impacts to the air quality within the coastal area. The proposed activity is therefore consistent with this policy.</p>
<p><b>WATER AND AIR RESOURCES POLICY #42:</b> Coastal management policies will be considered if the state reclassifies land areas pursuant to the prevention of significant deterioration regulations of the federal Clean Air Act.</p>	<p>The renewal of the IP2 and IP3 Operating Licenses would have no known impact if the state reclassifies land areas pursuant to the PSD regulations of the federal Clean Air Act. IP2 and IP3 have no plans for refurbishment or development as a part of the proposed activity; therefore the proposed activity is consistent with this policy.</p>
<p><b>WATER AND AIR RESOURCES POLICY #43:</b> Land use or development in the coastal areas must not cause the generation of significant amounts of acid rain precursors: nitrates and sulfates.</p>	<p>IP2 and IP3 license renewal provides a vital role to meeting the power generation and energy needs of the State, and does so without the production of acid rain precursors, nitrates, or sulfates.</p>
<b>WETLANDS POLICY</b>	
<p><b>Wetlands Policy #44:</b> Preserve and protect tidal and freshwater wetlands and preserve the benefits derived from these areas.</p>	<p>IP2 and IP3 operations do not degrade the tidal wetlands in the area of the IP2 and IP3 facilities, no state or federal jurisdictional tidal or freshwater wetlands exist on the IP2 and IP3 property, and IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of license renewal.</p>

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<b>Table D-2                      Federally-Listed Threatened or Endangered Species                      Possibly Occurring at IP2 and IP3,                      Westchester County, New York</b>			
<b>Common Name</b>	<b>Scientific Name</b>	<b>Federal Status*</b>	<b>State Status</b>
Shortnose sturgeon	<i>Acipenser brevirostrum</i>	E	E
Bog turtle	<i>Clemmys muhlenbergii</i>	T	E
Bald eagle	<i>Haliaeetus leucocephalus</i>	T	T
Indiana bat	<i>Myotis sodalis</i>	E	E
Atlantic Sturgeon	<i>Acipenser oxyrinchus</i>	C	
New England cottontail rabbit	<i>Sylvilagus transitionalis</i>	C	
* E = Endangered; T = Threatened; C = Candidate species Source: USFWS, NYSDEC 2000, NYNHP 2006a, NYNHP 2006b, and NMFS.			

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<b>Table D-3 Environmental Authorizations for Current IP2 and IP3 Operations</b>					
<b>Agency</b>	<b>Authority</b>	<b>Requirement</b>	<b>Number</b>	<b>Expiration Date</b>	<b>Authorized Activity</b>
NRC	Atomic Energy Act, 10 CFR 50	IP1 License to Possess	DPR-5	September 28, 2013	Maintain IP1 in SAFSTOR condition.
NRC	Atomic Energy Act, 10 CFR 50	IP2 License to Operate	DPR-26	September 28, 2013	Operation of IP2.
NRC	Atomic Energy Act, 10 CFR 50	IP3 License to Operate	DPR-64	December 12, 2015	Operation of IP3.
DOT	49 CFR 107, Subpart G	IP2 DOT Hazardous Materials Certificate of Registration	0627065520610Q	June 30, 2009	Radioactive and hazardous materials shipments.
DOT	49 CFR 107, Subpart G	IP3 DOT Hazardous Materials Certificate of Registration	0627065520690Q	June 30, 2009	Radioactive and hazardous materials shipments.
NYSDEC	6 NYCRR Part 325	IP2 Pesticide Application Business Registration	12696	April 30, 2009	Pesticide application.
NYSDEC	6 NYCRR Part 325	IP3 Pesticide Application Business Registration	13163	April 30, 2009	Pesticide application.
NYSDEC	6 NYCRR Parts 704 and 750	IP1, 2, and 3 SPDES Permit	NY 000 4472	October 1, 1992 <sup>1</sup>	Discharge of wastewaters and stormwaters to waters of the State.

<sup>1</sup> Timely renewal application was submitted; therefore, permit is administratively continued under New York State Administrative Procedures Act.

TO BE SUBMITTED AT LATER DATE

**Table D-3  
Environmental Authorizations for Current IP2 and IP3 Operations**

<b>Agency</b>	<b>Authority</b>	<b>Requirement</b>	<b>Number</b>	<b>Expiration Date</b>	<b>Authorized Activity</b>
NYSDEC	6 NYCRR Part 704	Simulator Transformer Vault SPDES Permit	NY 025 0414	March 1, 2008	Discharge of wastewaters to waters of the State.
NYSDEC	6 NYCRR Part 704	Tank Farm SPDES Permit	NY 025 1135	February 1, 2010	Discharge of wastewaters to waters of the State.
NYSDEC	6 NYCRR Part 704	Buchanan Gas Turbine SPDES Permit	NY 022 4826	March 1, 2008	Discharge of wastewaters to waters of the State.
NYSDEC	6 NYCRR Part 750	ISFSI Stormwater SPDES General Permit for Construction Activities	NYR 10H166	Not Applicable	Stormwater Discharge during Construction of the Dry Fuel Cask Storage.
NYSDEC	6 NYCRR Parts 200 and 201	IP2 Air Permit	3-5522-00011/00026	Not Applicable	Operation of air emission sources (boilers, turbines, and generators).
NYSDEC	6 NYCRR Parts 200 and 201	IP3 Air Permit	3/5522-00105/00009	Not Applicable	Operation of air emission sources (boilers, turbines, and generators).
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Gas Turbine 1 Air Permit	#00021	December 31, 2006 <sup>2</sup>	Operation of an air contamination source

<sup>2</sup> Timely renewal application was submitted; therefore permit is administratively continued by WCDOH.

TO BE SUBMITTED AT LATER DATE

<b>Table D-3 Environmental Authorizations for Current IP2 and IP3 Operations</b>					
<b>Agency</b>	<b>Authority</b>	<b>Requirement</b>	<b>Number</b>	<b>Expiration Date</b>	<b>Authorized Activity</b>
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Gas Turbine 2 Air Permit	#00022	December 31, 2006 <sup>2</sup>	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Gas Turbine 3 Air Permit	#00023	December 31, 2006 <sup>2</sup>	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Boiler Permit	52-4493	Not Applicable	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Vapor Extractor Air Permit	52-5682	December 31, 2006 <sup>2</sup>	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP3 Boiler Permit	52-6497	Not Applicable	Operation of an air contamination source

TO BE SUBMITTED AT LATER DATE

<b>Table D-3 Environmental Authorizations for Current IP2 and IP3 Operations</b>					
<b>Agency</b>	<b>Authority</b>	<b>Requirement</b>	<b>Number</b>	<b>Expiration Date</b>	<b>Authorized Activity</b>
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP3 Training Center Boiler Permit	52-6498	Not Applicable	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP3 Vapor Extractor Air Permit	-- <sup>3</sup>	-- <sup>3</sup>	Operation of an air contamination source
NYSDEC	6 NYCRR Part 596	IP2 Hazardous Substance Bulk Storage Registration Certificate	3-000107	September 4, 2007	Onsite bulk storage of hazardous substances.
NYSDEC	6 NYCRR Part 596	IP3 Hazardous Substance Bulk Storage Registration Certificate	3-000071	August 16, 2008	Onsite bulk storage of hazardous substances.
NYSDEC	6 NYCRR Part 610	IP2 Major Oil Storage Facility	3-2140	-- <sup>4</sup>	Onsite bulk storage of > 400K gallons of petroleum products.
WCDOH	Westchester County Sanitary Code, Article XXV	IP3 Petroleum Bulk Storage Registration Certificate	3-166367	September 7, 2010	Onsite bulk storage of petroleum products.

<sup>3</sup> Application has been submitted to WCDOH, but a permit has not been issued

<sup>4</sup> Application has been submitted to NYSDEC, but a permit has not been issued



TO BE SUBMITTED AT LATER DATE

<b>Table D-3 Environmental Authorizations for Current IP2 and IP3 Operations</b>					
<b>Agency</b>	<b>Authority</b>	<b>Requirement</b>	<b>Number</b>	<b>Expiration Date</b>	<b>Authorized Activity</b>
NYSDEC	6 NYCRR Part 372	IP2 Hazardous Waste Generator Identification	NYD000765073	Not Applicable	Hazardous waste generation
NYSDEC	6 NYCRR Part 372	IP3 Hazardous Waste Generator Identification	NYD000765073	Not Applicable	Hazardous waste generation
NYSDEC	6 NYCRR Part 373	IP2 Hazardous Waste Part 373 Permit	NYD991304411	February 28, 2007	Accumulation and temporary onsite storage of mixed waste for > 90 days.
EPA	40 CFR 264	IP2 Hazardous Solid Waste Amendment Permit	NYD991304411	October 14, 2002 <sup>5</sup>	Accumulation and temporary onsite storage of mixed waste for > 90 days.
EPA	40 CFR 264	IP3 Hazardous Solid Waste Amendment Permit	NYD085503746	October 17, 2001 <sup>5</sup>	Accumulation and temporary onsite storage of mixed waste for > 90 days.
SCDHEC	Act No. 429 of 1980, South Carolina Radioactive Waste Transportation and Disposal Act	IP2 Radioactive Waste Transport Permit	0019-31-07	December 31, 2007	Transportation of radioactive waste into the State of South Carolina
		IP3 Radioactive Waste Transport Permit	0072-31-07	December 31, 2007	

<sup>5</sup> Permit has been administratively continued based on conditional mixed waste exemption.

TO BE SUBMITTED AT LATER DATE

**Table D-3  
Environmental Authorizations for Current IP2 and IP3 Operations**

<b>Agency</b>	<b>Authority</b>	<b>Requirement</b>	<b>Number</b>	<b>Expiration Date</b>	<b>Authorized Activity</b>
TDEC	Tennessee Department of Environment and Conservation Regulations	IP2 Radioactive Waste- License-for-Delivery	T-NY-010-L07	December 31, 2007	Shipment of radioactive material into Tennessee to a disposal/processing facility
		IP3 Radioactive Waste- License-for-Delivery	T-NY-005-L07	December 31, 2007	
		IP3 Radioactive Waste Disposal Permit	0072-31-07-X	December 31, 2007	
DOT: U.S. Department of Transportation EPA: Environmental Protection Agency NRC: U.S. Nuclear Regulatory Commission NYSDEC: New York State Department of Environmental Conservation SCDHEC: South Carolina Department of Health and Environmental Control TDEC: Tennessee Department of Environment and Conservation (Division of Radiological Health) WCDOH: Westchester County Department of Health					

## **Attachment E**

### **Severe Accident Mitigation Alternatives Analysis**

Attachment E contains the following sections.

- [E.1](#) – Evaluation of IP2 PSA Model
- [E.2](#) – Evaluation of IP2 SAMA Candidates
- [E.3](#) – Evaluation of IP3 PSA Model
- [E.4](#) – Evaluation of IP3 SAMA Candidates

## ATTACHMENT E

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## **ATTACHMENT E.1**

### **EVALUATION OF IP2 PSA MODEL**

## **E.1 EVALUATION OF IP2 PROBABILISTIC SAFETY ANALYSIS MODEL**

The severe accident risk was estimated using the Probabilistic Safety Analysis (PSA) model and a Level 3 model developed using the most recent version (version 1.13.1) of the MELCOR Accident Consequences Code System version 2 (MACCS2) code. The CAFTA code was used to develop the Indian Point Unit 2 (IP2) PSA Level 1 and Level 2 models. This section provides the description of IP2 PSA Level 1, 2, and 3 analyses, core damage frequency (CDF) uncertainty, Individual Plant Examination of External Events (IPEEE) analyses, and PSA model peer review.

### **E.1.1 PSA Model - Level 1 Analysis**

The PSA model (Level 1 and Level 2) used for the Severe Accident Mitigation Alternatives (SAMA) analysis is the most recent internal events risk model for IP2 (Revision 1, April 2007) [Reference E.1-3]. This model is an updated version of the model used in the 1992 Individual Plant Examination (IPE) [Reference E.1-1], converted from the RISKMAN platform to the CAFTA platform. It reflects the IP2 configuration and design as of December 2005 and uses component failure and unavailability data as of December 2005. The Revision 1 model resolves all findings and observations from the industry peer reviews conducted in May 2002 and July 2005. The IP2 PSA model adopts the small event tree / large fault tree approach and uses the CAFTA code for quantifying CDF.

The PSA model has been updated three times since the original IPE due to the following.

- Equipment performance: As data collection progresses, estimated failure rates and system unavailability data change.
- Plant configuration changes: Plant configuration changes are incorporated into the PSA model.
- Modeling changes: The PSA model is refined to incorporate the latest state of knowledge and recommendations from internal and industry peer reviews. The IP2 model was converted from RISKMAN to CAFTA platform for consistency with other Entergy sites.

The PSA model contains the major initiators leading to core damage with baseline CDFs listed in [Table E.1-1](#).

The IP2 Revision 1 PSA model was reviewed to identify those potential risk contributors that made a significant contribution to CDF. CDF-based Risk Reduction Worth (RRW) rankings were reviewed down to 1.005. Events below this point would influence the CDF by less than 0.5% and are judged to be highly unlikely contributors for the identification of cost-beneficial enhancements. These basic events; including component failures, operator actions, and initiating events; were reviewed to determine if additional SAMA actions may need to be considered.

[Table E.1-2](#) provides a correlation between the Level 1 RRW risk significant events (component failures, operator actions, and initiating events) down to 1.005 identified from the IP2 PSA model and the SAMAs evaluated in [Section E.2](#).



**Table E.1-1  
 IP2 PSA Model CDF Results by Major Initiators**

Accident Type	Point Estimate CDF (/ry)	% Contribution to Point Estimate CDF
Loss of offsite power <sup>1</sup>	$6.73 \times 10^{-6}$	37.56
Internal flooding	$4.69 \times 10^{-6}$	26.19
Loss of coolant accident (LOCA)	$1.49 \times 10^{-6}$	8.31
Transients <sup>1</sup>	$1.21 \times 10^{-6}$	6.77
Anticipated transient without a scram (ATWS)	$9.89 \times 10^{-7}$	5.52
Station blackout (SBO)	$8.51 \times 10^{-7}$	4.75
Steam generator tube rupture (SGTR)	$7.16 \times 10^{-7}$	4.00
Loss of component cooling water	$5.83 \times 10^{-7}$	3.26
Loss of non-essential service water	$3.00 \times 10^{-7}$	1.68
LOCAs outside containment (ISLOCA)	$1.52 \times 10^{-7}$	0.85
Vessel rupture	$1.00 \times 10^{-7}$	0.56
Loss of 125 VDC Power	$5.77 \times 10^{-8}$	0.32
Total loss of service water	$4.40 \times 10^{-8}$	0.25
Loss of essential service water <sup>1</sup>	$1.93 \times 10^{-10}$	0.0011
Total	$1.79 \times 10^{-5}$	100.00

1. Contributions to CDF from SBO and ATWS are listed separately and thus not included in the contributions shown for other accident types.

**Table E.1-2  
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**

Event Name	Probability	RRW	Description	Disposition
IE-T1	8.21E-02	1.716	Loss of offsite power	This term represents the loss of offsite power initiating event. Phase I SAMAs to enhance offsite power availability and coping with SBO events, including cross-tying diesel fuel oil supply lines, cross-tying AC and DC buses, and adding additional onsite power sources, have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-ENG-FR-DG23R	1.55E-02	1.194	Diesel generator 23 fails to run	This term represents failure of (EDG) EDG 23 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-AOV-CC-P1139	8.98E-03	1.185	AFW turbine-driven pump 22 steam control valve PCV-1139 does not open	This term represents failure of steam control valve PCV-1139, leading to unavailability of auxiliary feedwater (AFW) turbine-driven pump 22 to provide water to the steam generators. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
AFW-MAI-MA-TDP22	6.70E-03	1.123	AFW turbine-driven pump 22 out for testing and maintenance	This term represents AFW turbine-driven pump 22 out for testing and maintenance. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
EDG-MAI-MA-EDG23	1.31E-02	1.117	Diesel generator 23 out for maintenance	This term represents EDG 23 out for maintenance. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
IE-TC15FP1	6.04E-05	1.109	Rupture of 10 inch fire protection piping in the deluge room adjacent to control building switchgear room	This term represents an internal flooding event due to rupture of a 10 inch fire protection piping deluge valve station adjacent to the control building switchgear room. Phase II SAMAs 054, 061, 062, and 065, providing a flood alarm, adding protection against flood propagation, providing a hard-wired connection to a SI pump from an alternate safe shutdown system (ASSS) power supply, and upgrading the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
IE-T3	1.87E+00	1.094	Turbine trip with feedwater available initiator (T3)	This term represents an initiating event caused by a transient due to turbine trip with feedwater available. Industry efforts over the last twenty years have led to a significant reduction of plant scrams from all causes. A Phase I SAMA to replace the solenoids and air operators of the main steam isolation valves (MSIVs) to enhance reliability of the MSIVs has been implemented. Phase II SAMA 025, to improve the MSIV design to reduce the frequency of the initiator, was evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
EDG-ENG-FR-DG22R	1.55E-02	1.09	Diesel generator 22 fails to run	This term represents failure of EDG 22 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-TDP-FS-TDP22	4.18E-03	1.078	AFW turbine-driven pump 22 fails to start on demand	This term represents failure of AFW turbine-driven pump 22 to start on demand. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
EDG-ENG-FS-DG23S	5.71E-03	1.063	Diesel generator 23 fails to start	This term represents failure of EDG 23 to start on demand. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-MAI-MA-EDG22	1.67E-02	1.062	Diesel generator 22 out for maintenance	This term represents EDG 22 out for maintenance. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

**Table E.1-2  
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)  
(Continued)**

Event Name	Probability	RRW	Description	Disposition
IE-TC15SW1	3.42E-05	1.059	Rupture of 3 inch service water line in the control building switchgear room flood zone CB 15-1	This term represents an internal flooding event due to rupture of a 3 inch service water line in control building switchgear room flood zone CB 15-1. Phase II SAMAs 054, 062 and 065, providing a flood alarm, providing a hard-wired connection to a SI pump from an ASSS power supply, and upgrading the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
C	1.57E-05	1.057	Reactor protection system failure	This term represents failure of the reactor protection system. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an ATWS mitigating system actuation circuitry (AMSAC) system, have already been implemented. Phase II SAMAs 047, 048, 049, and 050, adding an independent boron injection system, adding relief valves to prevent equipment damage from pressure spikes, installing motor generator set trip breakers in the control room, and providing capability to remove power from the bus powering the control rods, were evaluated.
IE-T2	3.86E-01	1.051	Loss of main feedwater initiator	This term represents an initiating event caused by loss of feedwater. Industry efforts over the last twenty years have led to a significant reduction of plant scrams from all causes. Phase II SAMAs 041 and 043, to install a digital feedwater upgrade and to add a motor-driven feedwater pump, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
OAFWT	6.97E-03	1.051	Failure to manually control turbine-driven AFW pump 22 after battery depletion	This term represents operator failure to control turbine-driven AFW pump 22 after battery depletion, leading to unavailability of AFW turbine-driven pump 22 to provide water to the steam generators. Phase I SAMAs to improve operator response, install pneumatic pressure and level indications, and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. In addition, Phase II SAMAs 029, 043 and 044, improving DC load shedding, adding an additional motor-driven pump, and installing a fire water backup supply to the steam generators, were evaluated.
IE-TC15FP2	2.78E-05	1.048	Rupture of 4 inch fire protection line in the control building stairwell elevation 53-foot flood zone CB 53-1	This term represents an internal flooding event due to rupture of a 4 inch fire protection line in control building stairwell flood zone CB 53-1. Phase I SAMAs have been implemented to improve procedures to reduce CDF contributions due to internal flooding. Phase II SAMAs 054, 062 and 065, providing a flood alarm, providing protection against flood propagation from the stairwell to the switchgear room, and providing a hard-wired connection to a SI pump from an ASSS power supply, were evaluated.
MWS-XHE-FO-CVCS	2.72E-02	1.047	Failure to align backup city water cooling to charging pumps	This term represents operator failure to align city water to the charging pumps for reactor coolant pump (RCP) seal cooling during transients. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 67, providing hardware connections to allow the primary water system to be used to cool charging pumps to mitigate the impact of this event, was evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
AFW-TDP-FR-TDP22	2.34E-03	1.042	AFW turbine-driven pump 22 fails to continue to run	This term represents failure of AFW turbine-driven pump 22 to continue to run. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
IE-T7	7.03E-03	1.042	SGTR initiator	This term represents a SGTR initiating event. Many Phase I SAMAs have been implemented to mitigate this event including improving detection and isolation capabilities, improving makeup capabilities to the reactor pressure vessel, improving primary side depressurization reliability, improving secondary side heat removal capability, and enhancing training. Phase II SAMAs 018, 019, and 020, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, and routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products to mitigate the impact of this event, were evaluated.
AFW-CBR-OO-52AF1	6.58E-03	1.038	AFW motor-driven pump 21 circuit breaker 52/AF1 does not operate	This term represents failure of AFW motor-driven pump 21 circuit breaker 52/AF1 to operate on demand, causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
AC0-RCK-NO-MDBK4	2.50E-03	1.037	Failure of mode switch BK-4 control circuit	This term represents failure of mode switch BK-4 control circuit, causing loss of offsite power. Phase I SAMAs for coping with SBO events, including cross-tying diesel fuel oil supply lines, cross-tying AC and DC buses, and adding additional diesel generators, have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
IE-TCCW	1.05E-03	1.035	Loss of component cooling water initiator	This term represents the loss of component cooling water (CCW) initiating event. Many Phase I SAMAs have been implemented to mitigate this event including providing more reliable or diverse high or low pressure injection cooling, improving RCP seal cooling systems, and enhancing procedures for coping with loss of CCW. Phase II SAMAs 003, 005 and 064, to provide an additional CCW pump, to improve the ability to cool the residual heat removal (RHR) heat exchangers, and to provide a backup cooling water source for the CCW heat exchangers, were evaluated.
IE-TT15	7.35E-03	1.034	Rupture of condenser water boxes and 84 inch circulating water piping in the turbine building elevation 15-foot flood zone TB 15-1	This term represents an internal flooding event due to rupture of condenser water boxes and 84 inch circulating water piping in turbine building flood zone TB 15-1. This event causes damage to the 6.9kV switchgear. A Phase I SAMA has been implemented to improve inspection of circulating water system expansion joints to reduce the CDF contribution from this event. Phase II SAMAs 062 and 065, providing a hard-wired connection to a SI pump from an ASSS power supply and upgrading the ASSS power supply, were evaluated.



**Table E.1-2  
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)  
(Continued)**

<b>Event Name</b>	<b>Probability</b>	<b>RRW</b>	<b>Description</b>	<b>Disposition</b>
EDG-CCF-FR-DG223	2.25E-04	1.031	Common cause failure of diesel generators 22 & 23 fail to run	This term represents common cause failure of diesel generators 22 & 23 to continue to run. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-ENG-FS-DG22S	5.71E-03	1.031	Diesel generator 22 fails to start	This term represents failure of EDG 22 to start on demand. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-FCV-CC-F406A	5.78E-03	1.03	AFW motor-driven pump 21 FCV-406A fails to open	This term represents failure of AFW motor-driven pump 21 flow control valve FCV-406A to open, causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
AFW-FCV-CC-F406B	5.78E-03	1.03	AFW motor-driven pump 21 FCV-406B fails to open	This term represents failure of AFW motor-driven pump 21 flow control valve FCV-406B to open, causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
MRI	1.23E-01	1.027	Failure of manual rod insertion during ATWS	This term represents operator failure to insert control rods during an ATWS event. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 047, 048, 049, and 050, adding an independent boron injection system, adding relief valves to prevent equipment damage from pressure spikes, installing motor generator set trip breakers in the control room, and providing capability to remove power from the bus powering the control rods, were evaluated.
AFW-MDP-FS-PM21	4.60E-03	1.027	AFW motor-driven pump 21 fails to start on demand	This term represents failure of AFW motor-driven pump 21 to start on demand. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
CVC-MAI-MA-PM23	1.56E-02	1.025	Charging pump 23 out for testing and maintenance	This term represents charging pump 23 out for testing and maintenance, causing loss of RCP seal cooling and emergency boration. Phase II SAMAs 001 and 002, providing an independent RCP seal injection system with and without a dedicated diesel, were evaluated.

**Table E.1-2  
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)  
(Continued)**

<b>Event Name</b>	<b>Probability</b>	<b>RRW</b>	<b>Description</b>	<b>Disposition</b>
AC4-CCF-HW-480VS	2.15E-07	1.024	Common cause failure of 480V switchgears 21& 22	This term represents common cause failure of 480V switchgears 21& 22. Phase I SAMAs to improve the availability of the AC bus and coping with SBO events, including cross-tying and repairing or replacing circuit breakers, cross-tying diesel fuel oil supply lines, cross-tying AC and DC buses, and adding additional onsite power sources, have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
OASSS-HHI	1.58E-02	1.023	Failure to align SI pump to ASSS (192 gpm total RCP seal leak rate)	This term represents operator failure to align a SI pump to its ASSS power supply to mitigate a RCP seal LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 062 to provide a hard-wired connection to a SI pump from ASSS was evaluated.
IE-S2	5.00E-04	1.022	Small break LOCA initiator	This term represents the small LOCA initiating event. Phase I SAMAs improving emergency core cooling system (ECCS) sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 039, 040, 055, 056, 058, and 068 to enhance high and low pressure injection and recirculation systems, and provide an independent source of cooling for the recirculation pump motors to reduce the CDF contribution from small break LOCA, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
ORCS-L	2.17E-04	1.022	Failure to perform late RCS cooldown & depressurization during SGTR	This term represents operator failure to perform late cooling and depressurization to cold shutdown following a SGTR to terminate leakage from the reactor coolant system (RCS) into the secondary prior to depleting refueling water storage tank (RWST) inventory. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 018, 019, and 020, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, and routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products to mitigate the impact of this event, were evaluated.
OLHIR-S2	5.74E-04	1.021	Failure to initiate low-head internal recirculation during small LOCA	This term represents operator failure to align low-head ECCS internal recirculation following the injection phase of ECCS to deliver flow to RCS cold legs during a small LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 036, to create an automatic swap-over to recirculation on low RWST level, was evaluated.

**Table E.1-2  
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)  
(Continued)**

<b>Event Name</b>	<b>Probability</b>	<b>RRW</b>	<b>Description</b>	<b>Disposition</b>
OLHER-S2	1.01E-03	1.021	Failure to initiate low-head external recirculation during small LOCA	This term represents operator failure to align low-head ECCS external recirculation following the injection phase of ECCS to deliver flow to RCS cold legs during a small LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 036, to create an automatic swap-over to recirculation on low RWST level, was evaluated.
IE-RCPSL	2.50E-03	1.019	RCP seal LOCA initiator	This term represents the RCP seal LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 038, 040, 055, 056, 058, and 068, to enhance high and low pressure injection and recirculation systems and to provide an independent source of cooling for the recirculation pump motors, were evaluated.
CVC-XHE-FO-BORAT	1.50E-02	1.018	Failure to initiate emergency boration during ATWS	This term represents operator failure to initiate emergency boration during ATWS. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 047, 048, 049, and 050, adding an independent boron injection system, adding relief valves to prevent equipment damage from pressure spikes, installing motor generator set trip breakers in the control room, and providing capability to remove power from the bus powering the control rods, were evaluated.

**Table E.1-2  
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)  
(Continued)**

Event Name	Probability	RRW	Description	Disposition
IE-TSWN	6.86E-04	1.018	Loss of non-essential service water system initiator	This term represents the loss of non-essential service water initiating event. Phase I SAMAs have been implemented to improve service water system reliability by providing additional service water pumps, enhancing screen wash, and replacing strainers. Phase II SAMAs 004 and 064, to provide procedural guidance to cross-tie service water pumps and provide backup cooling water for the CCW heat exchangers, were evaluated.
EDG-ENG-FR-DG21R	1.55E-02	1.018	Diesel generator 21 fails to run	This term represents failure of EDG 21 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-MAI-MA-PM21	4.02E-03	1.017	AFW motor-driven pump 21 out for testing and maintenance	This term represents AFW motor-driven pump 21 out for testing and maintenance. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
ORCS-E	2.56E-02	1.017	Failure to perform early RCS cooldown & depressurization during SGTR	This term represents operator failure to perform early cooling and depressurization to cold shutdown following a SGTR to terminate leakage from the RCS into the secondary prior to depleting RWST inventory. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 018, 019, and 020, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, and routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products to mitigate the impact of this event, were evaluated.
CWBKUP	7.27E-03	1.016	Failure to align backup city water cooling to RHR and SI pumps	This term represents operator failure to align city water to the RHR and safety injection (SI) pumps to prevent and mitigate LOCAs. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
PWS-XHE-FO-RHR1	1.20E-02	1.016	Failure to align primary water backup cooling to RHR and SI pumps	This term represents operator failure to align primary water to the RHR and SI pumps to prevent and mitigate LOCAs. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
IE-TPFPCR	2.60E-05	1.014	Rupture of the fire protection piping in PAB 80-foot elevation flood zone PAB 80-1 impacting CCW & RHR pumps	This term represents an internal flooding event due to rupture of fire protection piping in primary auxiliary building (PAB) flood zone PAB 80-1 impacting CCW and RHR pumps. Phase I SAMAs have been implemented to improve procedures to reduce CDF contribution due to internal flooding. Phase II SAMA 063, providing a water-tight door for additional protection of the RHR pumps against the flooding event, was evaluated.
AFW-RCK-NO-PM21	2.50E-03	1.014	AFW motor-driven pump 21 control circuit no output	This term represents failure of AFW motor-driven pump 21 control circuit causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
SWS-CCF-FR-ALL	2.03E-06	1.014	Common cause failure of all 6 service water pumps to run	This term represents common cause failure of all 6 service water pumps to run, leading to loss of service water cooling to supported components. Phase I SAMAs were implemented to improve service water system reliability by providing additional service water pumps, enhancing screen wash, and replacing strainers. Phase II SAMAs 031, 032 and 063, provide a backup source for diesel cooling, use the fire protection system as a backup source for diesel cooling, and provide backup cooling water for the CCW heat exchangers, were evaluated.



**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
PPR-AOV-OO-455C	8.53E-04	1.013	PORV PCV-455C fails to re-close	This term represents failure of pressure-operated relief valve (PORV) PCV-455C to re-close, causing a small LOCA. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 039, 040, 055, 056, 058, and 068 to enhance high and low pressure injection and recirculation systems, and providing independent source of cooling for the recirculation pump motors, to reduce the CDF contribution from stuck open PORV induced small LOCA, were evaluated.
CCW-XHE-FO-RCPSL	1.19E-02	1.013	Failure to manually restart CCW pumps given inadvertent trip	This term represents operator failure to manually restart CCW pumps, leading to seal LOCA. Phase I SAMAs, providing more reliable or diverse high or low pressure injection cooling, providing additional RCP seal cooling, and enhancing loss of CCW procedures, have been implemented to mitigate this event. Phase II SAMAs 005 and 064, improving the ability to cool the RHR heat exchangers and providing a backup cooling water source for the CCW heat exchangers, were evaluated.
PPR-AOV-OO-456	8.53E-04	1.013	PORV PCV-456 fails to re-close	This term represents failure of PORV PCV-456 to re-close, causing a small LOCA. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 039, 040, 055, 056, 058, and 068 to enhance high and low pressure injection and recirculation systems, and providing independent source of cooling for the recirculation pump motors, to reduce the CDF contribution from stuck open PORV induced small LOCA, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
OHHHER-S2	1.45E-03	1.013	Failure to align high-head external recirculation during small LOCA	This term represents operator failure to align high-head ECCS external recirculation following the injection phase of ECCS to deliver flow to RCS cold legs during a small LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 036, to create an automatic swap-over to recirculation on low RWST level, was evaluated.
EDG-MAI-MA-EDG21	1.45E-02	1.012	Diesel generator 21 out for maintenance	This term represents EDG 21 out for maintenance. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-CCF-FR-3EDGS	3.27E-04	1.012	Common cause failure of 3 diesel generators to continue to run	This term represents common cause failure of three diesel generators to continue to run. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-CCF-FS-AFWPM	5.75E-04	1.011	Common cause failure of AFW motor-driven pumps 21 and 23 to start	This term represents common cause failure of AFW motor-driven pumps 21 and 23 to start. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
EDG-CCF-FS-DG223	8.37E-05	1.011	Common cause failure of diesel generators 22 & 23 to start	This term represents common cause failure of diesel generators 22 & 23 to start on demand. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
HHI-CBR-OO-1T	6.72E-03	1.011	SI pump 21 circuit breaker 52/SI1 does not operate	This term represents failure of SI pump 21 circuit breaker 52/SI1 to operate on demand, causing unavailability of the pump following an SBO. Phase II SAMAs 035, 037 and 039, providing an additional high pressure injection pump with independent diesel, providing injection via the diesel driven fire pump, and adding diesel engines to some high pressure injection pumps, were evaluated.
AFW-XHE-RE-AFW22	6.49E-04	1.011	Failure to restore AFW turbine-driven pump 22 path components after maintenance	This term represents failure to restore AFW turbine-driven pump 22 after testing and maintenance. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
IE-S3	3.40E-03	1.01	Small-small break LOCA initiator	This term represents the small-small LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 039, 040, 055, 056, 058, and 068 to enhance high and low pressure injection and recirculation systems, and provide an independent source of cooling for the recirculation pump motors, to reduce the CDF contribution from small-small LOCA, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
CVC-CBR-OO-1M	6.52E-03	1.01	Charging pump 23 circuit breaker 1M on panel 12FD3 does not operate	This term represents failure of charging pump 23 circuit breaker 1M on panel 12FD3 to operate, causing loss of ASSS supply to the charging pump. Phase II SAMAs 001, 002, 065, providing an independent RCP seal injection system with and without a dedicated diesel, and upgrading the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
HHI-MDP-FS-SI21	5.60E-03	1.009	SI pump 21 fails to start on demand	This term represents failure of SI pump 21 to start on demand, causing unavailability of the pump to mitigate a seal LOCA and to perform the feed and bleed function during transients. Phase II SAMAs 035, 037 and 039, providing an additional high pressure injection pump with independent diesel, providing injection via the diesel-driven fire pump, and adding diesel engines to some high pressure injection pumps, were evaluated.
LHI-CCF-CC-7467	2.48E-05	1.009	Common cause failure of MOV 746 & 747 to open	This term represents common cause failure of motor-operated valves (MOVs) 746&747 to open, causing loss of the low-head injection and recirculation paths during LOCAs and transients. Phase II SAMAs 055 and 056, allowing high-head recirculation from either RHR heat exchanger and keeping the valves normally open were evaluated.
MSS-CCF-CC-4ADVS	2.18E-05	1.009	Common cause failure of all four steam generators' atmospheric dump valves to open	This term represents common cause failure of all four steam generators' atmospheric dump valves to open during a SGTR event. Phase II SAMAs 018 and 020, to install a steam generator shell side heat removal system and to install a water spray over the steam generator safety valves, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
AFW-CCF-CC-3149	1.14E-05	1.009	Common cause failure of check valves BFD-31, 34 & 39	This term represents common cause failure of check valves BFD-31, 34 and 39, leading to failure of all AFW pumps to deliver sufficient flow to the steam generators. Phase II SAMAs 043, 044, 45 and 57 adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, replacing PORVs with larger ones and providing DC power backup for the PORVs, were evaluated.
IE-TPNESW	1.58E-05	1.009	Rupture of the non-essential service water line in the PAB 80-foot elevation	This term represents an internal flooding event due to rupture of the non-essential service water line in the PAB 80-foot elevation, resulting in loss of cooling water to CCW and RHR heat exchangers, charging pumps and RCP seals. Phase I SAMAs have been implemented to improve procedures to reduce CDF contribution due to internal flooding. Phase II SAMAs 005 and 064, improving the ability to cool the RHR heat exchangers and providing a backup cooling source for the CCW heat exchangers, were evaluated.
OASSS-CHG	5.17E-03	1.008	Failure to align charging pump to ASSS	This term represents operator failure to align a charging pump to its ASSS power supply to mitigate a RCP seal LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 001, 002, and 065, providing an independent RCP seal injection system with and without a dedicated diesel, and upgrading the ASSS to allow timely restoration of seal injection and cooling, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
MSS-XHE-FO-SGISO	1.86E-02	1.008	Failure to perform early isolation of ruptured steam generator during SGTR	This term represents operator failure to isolate the ruptured steam generator early during a SGTR event. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 018, 019, and 020, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, and routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products to mitigate the impact of this event, were evaluated.
ODEP-LCCW	4.21E-02	1.007	Failure to perform rapid depressurization of RCS for low-head injection during loss of CCW	This term represents operator failure to depressurize the RCS for low-head injection following loss of CCW and failure of high-head SI. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 040 and 045, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.
CVC-PDP-FS-PM23	4.57E-03	1.007	Charging pump 23 fails to start on demand	This term represents failure of charging pump 23 to start on demand, causing loss of RCP seal cooling and emergency boration. Phase II SAMAs 001, 002, 047, and 067, providing an independent RCP seal injection system with and without a dedicated diesel, providing an independent boron injection system, and adding a hardware connection to allow primary water to cool the charging pumps, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
ODEPR-TC	4.80E-03	1.007	Failure to perform RCS cooldown & depressurization during 480V switchgear room flood	This term represents operator failure to perform RCS cooldown and depressurization during a 480V switchgear room flood to terminate leakage from RCS into the secondary prior to depleting RWST inventory. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 040 and 045, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.
AFW-CBR-OO-52AF3	6.58E-03	1.007	AFW motor-driven pump 23 circuit breaker 52/AF3 does not operate	This term represents failure of AFW motor-driven pump 23 circuit breaker 52/AF3 to operate on demand, causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
IE-S1	4.00E-05	1.007	Intermediate break LOCA initiator	This term represents the intermediate LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 039, 040, 055, 056, 058, and 068 to enhance high and low pressure injection and recirculation systems and provide an independent source of cooling for the recirculation pump motors, were evaluated.

**Table E.1-2  
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)  
(Continued)**

Event Name	Probability	RRW	Description	Disposition
AFW-XHE-RE-AFW21	1.15E-03	1.006	Failure to restore AFW motor-driven pump 21 path components after testing and maintenance	This term represents failure to restore AFW motor-driven pump 21 after testing and maintenance. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
EDG-ENG-FS-DG21S	5.71E-03	1.006	Diesel generator 21 fails to start	This term represents failure of EDG 21 to start on demand. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-XHE-FO-HC405	2.26E-04	1.006	Failure to align AFW turbine-driven pump 22	This term represents operator failure to align AFW turbine-driven pump 22, leading to unavailability of the pump to provide water to the steam generator. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. In addition, Phase II SAMA 043, adding an additional motor-driven pump, was evaluated.
DC1-CCF-HW-2122B	1.05E-06	1.006	Common cause failure of DC batteries 21 & 22	This term represents common cause failure of DC batteries 21 & 22. Phase II SAMAs 026, 027, 028, and 029, for enhancing DC system availability and reliability, were evaluated.



**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
OHHIR-S1	2.50E-03	1.006	Failure to align high-head internal recirculation during medium LOCA	This term represents operator failure to align high-head ECCS internal recirculation following the injection phase of ECCS to deliver flow to RCS cold legs during a medium LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 036, to create an automatic swap-over to recirculation on low RWST level, was evaluated.
IE-R	1.00E-07	1.006	Catastrophic reactor vessel rupture	This term represents an initiating event caused by reactor vessel rupture. Phase II SAMAs 012 and 016, using fire protection system as a backup source for containment spray system, and providing redundant containment spray systems to mitigate the consequence of a reactor vessel rupture, were evaluated.
OHHHER-S1	4.19E-03	1.006	Failure to align high-head external recirculation during medium LOCA	This term represents operator failure to align high-head ECCS external recirculation following the injection phase of ECCS to deliver flow to RCS cold legs during a medium LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 036, to create an automatic swap-over to recirculation on low RWST level, was evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
CDS-XHE-FO-CDPM	3.01E-02	1.006	Failure to align condensate for secondary heat removal	This term represents operator failure to align the condensate system for secondary heat removal during transients. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMA 044, using the fire water system as backup for steam generator inventory, was evaluated.
LHI-RCK-NO-746	2.50E-03	1.005	MOV 746 control circuit no output	This term represents control circuit failure of MOV 746, causing one of the low-head injection and recirculation paths to be unavailable during LOCAs and transients. Phase II SAMA 056, keeping the valve normally open to improve availability of low-head injection and recirculation modes of operation, was evaluated.
LHI-RCK-NO-747	2.50E-03	1.005	MOV 747 control circuit no output	This term represents control circuit failure of MOV 747, causing one of the low-head injection and recirculation paths to be unavailable during LOCAs and transients. Phase II SAMA 056, keeping the valve normally open to improve availability of low-head injection and recirculation modes of operation, was evaluated.
ODEP-S2	4.21E-02	1.005	Failure to rapidly depressurize RCS for low-head injection during small LOCA	This term represents operator failure to depressurize the RCS for low-head injection during a small break LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 040 and 045, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.

**Table E.1-2  
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)  
(Continued)**

Event Name	Probability	RRW	Description	Disposition
AC4-CBR-CC-52-6A	5.00E-04	1.005	480V circuit breaker 52/6A fails to trip on demand	This term represents failure of 480V circuit breaker 52/6A to trip on demand, causing unavailability of the 480Vbus 6A power supply. Phase I SAMAs to improve the availability of the AC bus by cross-tying and repairing or replacing circuit breakers have already been implemented. Phase II SAMA 030, creating AC power cross-tie capability with the other unit, was evaluated.
AC4-CBR-OO-52EG3	5.00E-04	1.005	480V circuit breaker 52/EG3 fails to close	This term represents failure of 480V circuit breaker 52/EG3 to close on demand, causing unavailability of the EDG power supply to 480Vbus 6A. Phase I SAMAs to improve the availability of the AC bus by cross-tying and repairing or replacing circuit breakers have already been implemented. Phase II SAMA 030, creating AC power cross-tie capability with the other unit, was evaluated.
AFW-ORF-PG-TDP22	3.00E-04	1.005	AFW turbine-driven pump 22 min-flow break down orifice plugged	This term represents plugging of the AFW turbine-driven pump 22 min-flow break down orifice, causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
RHR-CCF-CO-2MOVS	4.47E-06	1.005	Common cause failure of 2 MOVs fails to remain closed	This term represents common cause failure of 2 MOVs to remain closed in the RCS shutdown cooling line, causing an ISLOCA event. Phase II SAMA 021, providing additional pressure or leak monitoring instrumentation for ISLOCAs to decrease ISLOCA frequency, was evaluated.

**Table E.1-2  
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)  
(Continued)**

Event Name	Probability	RRW	Description	Disposition
EDG-CCF-FS-3EDGS	1.36E-04	1.005	Common cause failure of diesel generators 21, 22 & 23 fail to start	This term represents common cause failure of diesel generators 21, 22 & 23 to start on demand. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
DGV-CCF-FS-FAN	1.33E-04	1.005	Common cause failure of 4/6 EDG ventilation fans to start	This term represents common cause failure of 4 out of 6 diesel generator ventilation fans to start on demand, eventually causing the loss of 2 out 3 diesel generators. Phase II SAMA 006, adding a diesel generator building high temperature alarm, was evaluated.
RHR-MOV-RP-746	9.00E-03	1.005	RHR heat exchanger 22 outlet MOV 746 rupture	This term represents RHR heat exchanger 22 outlet MOV 746 rupture, causing an ISLOCA event. Phase II SAMAs 021 and 023, providing additional pressure or leak monitoring instrumentation for ISLOCAs and increasing valve leak testing to decrease ISLOCA frequency, were evaluated.
RHR-MOV-RP-747	9.00E-03	1.005	RHR heat exchanger 22 outlet MOV 747 rupture	This term represents RHR heat exchanger 21 outlet MOV 747 rupture, causing an ISLOCA event. Phase II SAMAs 021 and 023, providing additional pressure or leak monitoring instrumentation for ISLOCAs and increasing valve leak testing to decrease ISLOCA frequency, were evaluated.
AFW-MDP-FS-PM23	4.60E-03	1.005	AFW motor-driven pump 23 fails to start on demand	This term represents failure of AFW motor-driven pump 23 to start on demand. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

**Table E.1-2**  
**Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Description	Disposition
SWS-XHE-RE-29/30	1.30E-04	1.005	Failure to properly align SWN-29/ SWN-30 during header swap	This term represents operator failure to properly align SWN-29/SWN-30 during header swap, leading to loss of service water cooling to the EDGs. Phase II SAMAs 031 and 032, providing backup cooling water for the EDGs, were evaluated.
IE-TPESW	2.07E-05	1.005	Rupture of the essential service water line in the PAB 98-foot elevation	This term represents an internal flooding event due to rupture of an essential service water line in the PAB 98-foot elevation, resulting in loss of EDG jacket cooling and containment cooling. Phase I SAMAs have been implemented to improve procedures to reduce CDF contribution due to internal flooding. Phase II SAMAs 005, 016, 031, 032, 062, 064, and 065, providing a redundant containment spray system, providing backup sources for EDG cooling, improving the ability to cool the RHR heat exchangers, providing a hard-wired connection to an SI pump from an ASSS power supply, providing backup cooling to the CCW heat exchangers, and upgrading the ASSS power supply, were evaluated.

## CDF Uncertainty

The uncertainty associated with CDF was estimated using Monte Carlo techniques implemented in CAFTA for the base case mode. The results are shown in Table E.1-3.

**Table E.1-3  
CDF Uncertainty**

Confidence	CDF (/ry)
Mean value	1.89E-5
5 <sup>th</sup> percentile	8.73E-6
50 <sup>th</sup> percentile	1.52E-5
95 <sup>th</sup> percentile	3.96E-5

The values in Table E.1-3 reflect the uncertainties associated with the data distributions used in the analysis. The ratio of the 95th percentile to the mean is about 2.10. This uncertainty factor is included in the factor of 8 used to determine the "baseline benefit with uncertainty" described in [Section 4.21.5.4](#).

### **E.1.2 PSA Model - Level 2 Analysis**

#### **E.1.2.1 Containment Performance Analysis**

The IP2 Level 2 PSA model used for the SAMA analysis is the most recent internal events risk model, which is an updated version of the model used in the IPE [\[Reference E.1-1\]](#). The Level 2 PSA model used for the SAMA analysis, Revision 1 [\[Reference E.1-3\]](#) reflects the IP2 operating configuration and design changes as of December 2005.

The IP2 Level 2 model includes two types of considerations: (1) a deterministic analysis of the physical processes for a spectrum of severe accident progressions, and (2) a probabilistic analysis component in which the likelihood of the various outcomes are assessed. The deterministic analysis examines the response of the containment to the physical processes during a severe accident. This response is performed by

- utilization of the Modular Accident Analysis Program (MAAP) code [\[Reference E.1-4\]](#) to simulate severe accidents that have been identified as dominant contributors to core damage in the Level 1 analysis, and
- reference MAAP calculations of several hydrodynamic and heat transfer phenomena that occur during the progression of severe accidents. Examples include debris coolability, pressure spikes due to ex-vessel steam explosions, scoping calculation of direct

containment heating (DCH), molten debris filling the reactor pit, containment bypass, deflagration and detonation of hydrogen, thrust forces at reactor vessel failure, and thermal attack of containment penetrations.

The Level 2 analysis examined the dominant accident sequences and the resulting plant damage states (PDS) defined in Level 1. The Level 1 analysis involves the assessment of those scenarios that could lead to core damage.

A full Level 2 model was developed for the IP2 PSA and completed at the same time as the Level 1 model. The Level 2 model consists of a single containment event tree (CET) with functional nodes that represent phenomenological events and containment protection system status. The nodes were quantified using subordinate trees and logic rules. A list of the CET functional nodes and descriptions, used for the Level 2 analysis is presented in [Table E.1-4](#).

The Large Early Release Frequency (LERF) is an indicator of containment performance from the Level 2 results because the magnitude and timing of these releases provide the greatest potential for early health effects to the public. The frequency calculated is approximately  $6.50E-7/ry$  [[Reference E.1-3](#)]. [Figure E.1-1](#) and [Figure E.1-2](#) summarize the Level 2 results. Radionuclide release categories are described in [Section E.1.2.2.3](#).

LERF represents a small fraction (~4%) of all release end states. Three types of accidents dominate the internal large early release: accidents initiated by SGTRs, ISLOCAs, and accidents initiated by internal floods impacting vital power buses. (Internal floods impacting vital power buses contribute to LERF because they result in SBO and core damage without power available to the 480 VAC safeguard buses for the duration of the event. A large release occurs due to early containment rupture at vessel breach from either containment overpressurization or hydrogen burns.)

[Table E.1-5](#) provides a correlation between the Level 2 RRW risk significant events (severe accident phenomenon, initiating events, component failures and operator actions) identified from the current IP2 PSA LERF model [[Reference E.1-3](#)] and the SAMAs evaluated in [Section E.2](#).

**Table E.1-4  
 Notation and Definitions for IP2 CET Functional Nodes**

CET Node	CET Functional Node Description
Plant Damage State Event (PDS_EVNT)	This top event represents the initiators considered in the containment performance analysis.
RCS Pressure at Vessel Failure (RCS@VF)	This top event identifies the status of the RCS pressure. RCS@VF is set to success when RCS pressure is low. RCS@VF is set to failure when RCS pressure is high.

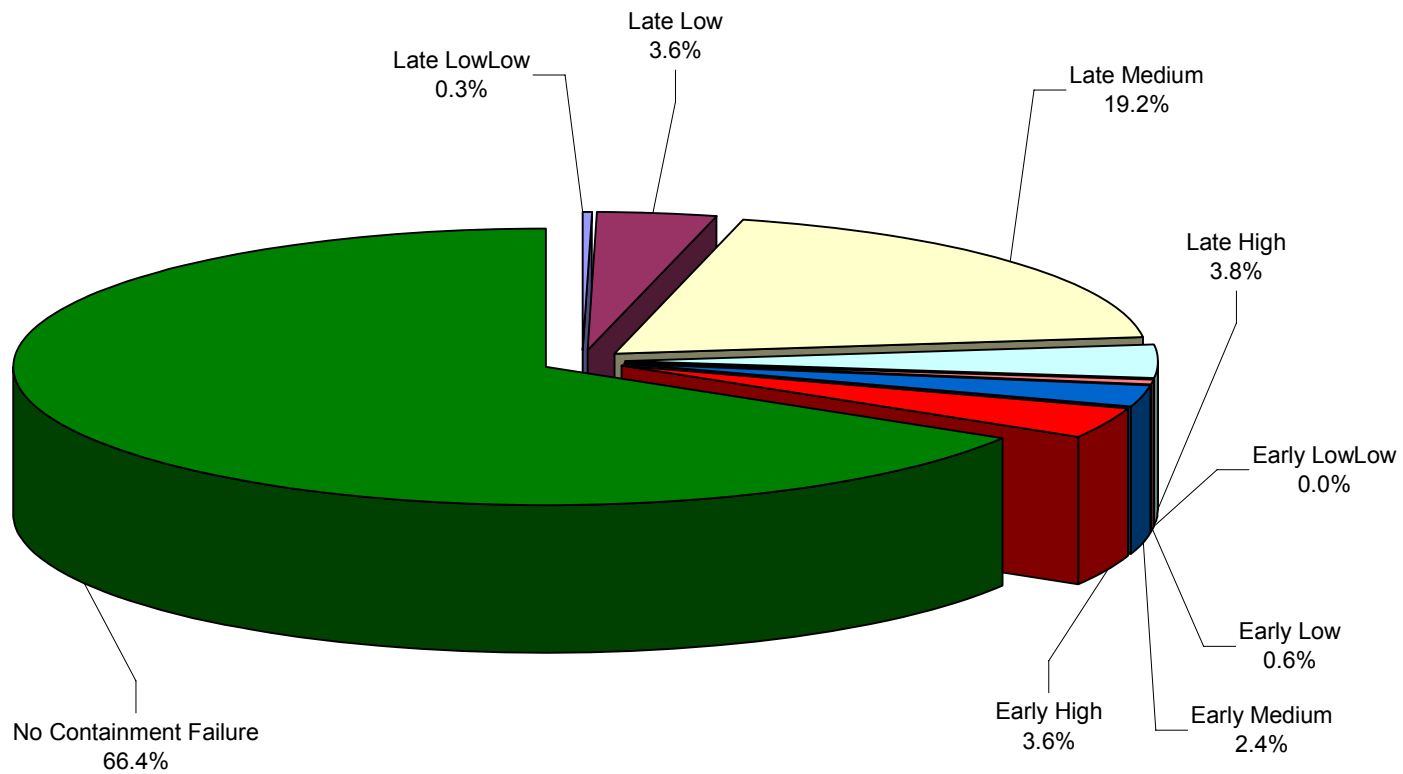
**Table E.1-4  
 Notation and Definitions for IP2 CET Functional Nodes  
 (Continued)**

CET Node	CET Functional Node Description
In-vessel Cooling Recovery (IN-REC)	This top event addresses the recovery of coolant injection into the vessel after core degradation but prior to vessel breach. This top event considers the possibility of low-pressure injection systems working once the RCS is depressurized.
Vessel Failure (VF)	This top event addresses recovery from core degradation within the vessel and the prevention of vessel head thermal attack. Core melt recovery requires the recovery of core cooling prior to core blocking or relocation of molten debris to the lower plenum and thermal attack of the vessel head.
Early Containment Failure (CFE)	This top event node considers the potential loss of containment integrity at, or before, vessel failure. Several phenomena are considered credible mechanisms for early containment failure. They may occur alone or in combination. The phenomena are containment isolation failure; containment bypass; containment overpressure failure at vessel breach; hydrogen deflagration or detonation; fuel-coolant interactions (steam explosions); and high pressure melt ejection (HPME) with subsequent DCH.
Debris Cooled Ex-vessel (DCOOL)	This top event considers the delivery of water to the reactor pit (sump), via containment sprays, or via injection to the vessel and drainage out a vessel breach into the reactor pit/sump area. Success implies the availability of water and the formation of a coolable debris bed such that concrete attack is precluded. Failure implies that the molten core attacks concrete in the reactor pit, that core debris remains hot, and sparging of the concrete decomposition products through the melt releases the less volatile fission products to the containment atmosphere.
Late Containment Failure (CFL)	This top event addresses the potential loss of containment integrity in the long-term. Late containment failure may result from base mat melt-through or from long-term steam and non-condensable gas generation from the attack of molten core debris on concrete.
Fission Product Removal (FPR)	This top event addresses fission product releases from the fuel into the containment and airborne fission product removal mechanisms within the containment structure to characterize potential magnitude of fission product releases to the environment should the containment fail. Failure implies that most of the fission products from the fuel and containment are ultimately released to the environment without mitigation.

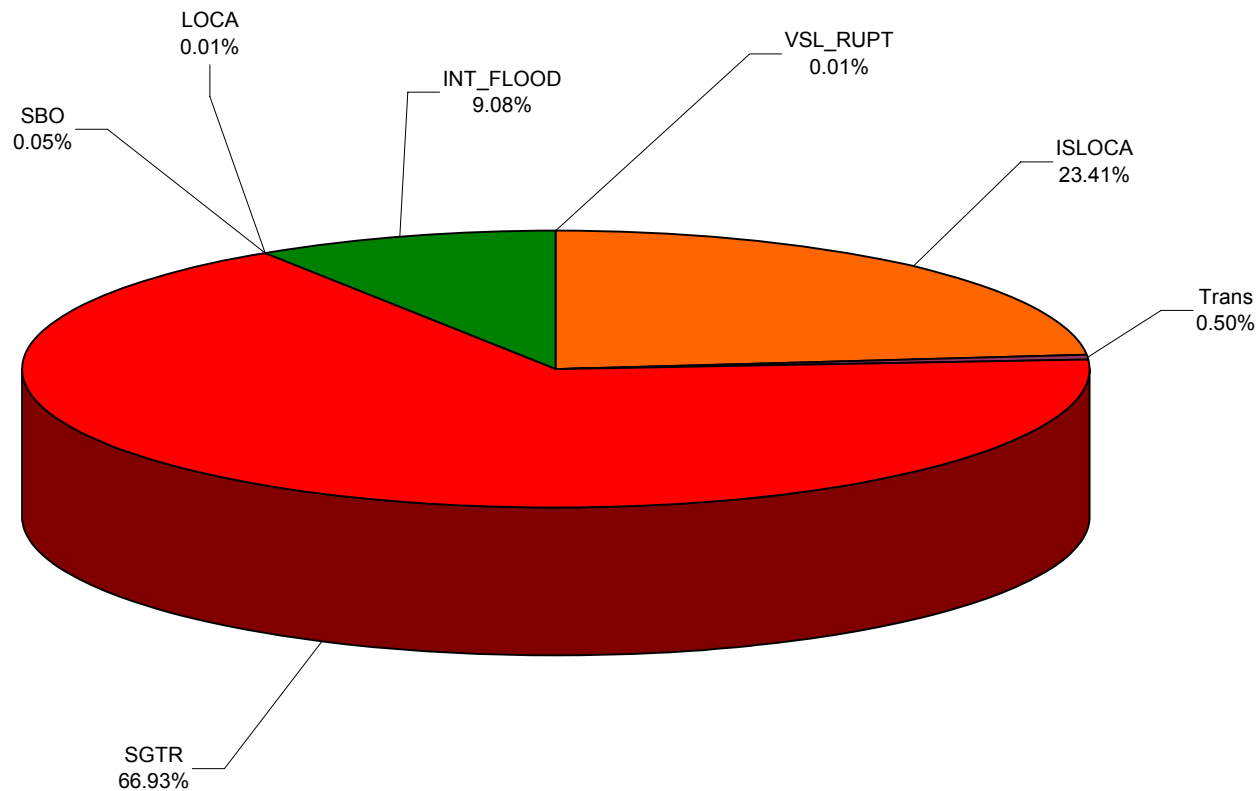


**Table E.1-4**  
**Notation and Definitions for IP2 CET Functional Nodes**  
**(Continued)**

<b>CET Node</b>	<b>CET Functional Node Description</b>
Containment Failure Mode (CFM)	This top event is used to characterize the impact of the timing of containment failure and the break size on the duration and mitigation of the fission product source terms.



**Figure E.1-1**  
**IP2 Radionuclide Release Category Summary**



**Figure E.1-2**  
**IP2 Contributions to Large Early Release Frequency**

**Table E.1-5  
 IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)**

Event Name	Probability	RRW	Event Description	Disposition
NO-FPR_BYPASS	1.0	10.198	No fission product removal due to containment bypass event	<p>This term represents the probability that fission product removal does not occur because containment is bypassed by either an ISLOCA or a SGTR with a stuck-open relief valve. Phase II SAMAs 021, 022, 023, and 024, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.</p> <p>For SGTR sequences, numerous Phase I SAMAs have been implemented to increase reliability of the steam generator via enhanced maintenance practices, improved detection and isolation capabilities, improved makeup capabilities to the RCS, improved primary side depressurization reliability, improved secondary side heat removal capability, installation of new steam generators in 2000 and enhanced SGTR training. Phase II SAMAs 018, 019 and 020 were evaluated to mitigate SGTR events.</p>

**Table E.1-5  
 IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
 (Continued)**

Event Name	Probability	RRW	Event Description	Disposition
PDS_FRAC-51	2.41E-02	2.940	Long-term SGTR with stuck-open safety relief valve	This term is the plant damage state split fraction for a long-term SGTR scenario involving failure to isolate the ruptured steam generator and subsequent stuck-open steam generator safety relief valve. Phase I SAMAs were implemented providing procedures to enhance the likelihood of success of operator action in response to SGTR accident conditions and increasing the reliability of the steam generator via enhanced maintenance practices. Phase II SAMAs 018, 019 and 020 were evaluated to mitigate SGTR events.
NO_SAG-2	1.0	2.629	RCS depressurization failure-post core melt	This term represents the probability that RCS depressurization as described in severe accident guideline SAG-2, "Depressurize the RCS," is not performed during a high pressure core melt accident. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated. In addition, Phase II SAMA 029, to improve DC bus load shedding to extend DC power availability, was evaluated.

**Table E.1-5  
 IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
 (Continued)**

Event Name	Probability	RRW	Event Description	Disposition
NO_HLSL_1	0.9	2.600	RCS hot leg or pressurizer surge line remains intact during medium pressure accident scenario	This term represents the probability that either the RCS hot leg or pressurizer surge line remains intact during an accident in which the RCS system pressure is between 675 psig and 2235 psig. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.
DP-45	1.0	1.280	RCS pressure is low at vessel breach given a large ISLOCA event	This term represents the probability that RCS depressurization occurs during a short-term large-break ISLOCA outside containment. Phase II SAMAs 021, 022, 023, and 024, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.
PDS_FRAC-50	7.96E-03	1.280	Short-term large ISLOCA outside containment event	This term is the plant damage state split fraction for a short-term large-break ISLOCA outside containment. Phase II SAMAs 021, 022, 023, and 024, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.

**Table E.1-5  
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
(Continued)**

<b>Event Name</b>	<b>Probability</b>	<b>RRW</b>	<b>Event Description</b>	<b>Disposition</b>
NO_SAG-4	1.0	1.108	Containment injection post core melt does not occur	This term represents the probability that injection into containment as described in SAG-4, "Inject Into Containment," is not performed to cool the lower head of the reactor vessel. Additional benefit of flooding the containment is that water will be available for ECCS recirculation and to flood core debris in the reactor pit area after vessel breach. Phase II SAMAs 008 and 009, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.
AC_SBO_FLOOD	1.0	1.104	Internal flooding induced SBO event fails AC power supply	This flag event indicates that AC power to the normal offsite supply buses and vital AC safeguard buses is disabled following an internal flooding event that impacts the control building switchgear room at the 15-foot elevation. Phase II SAMAs 054, 060, 061, 062 and 065, to install a flood alarm in the 480VAC switchgear room, to provide added protection against flood propagation into the 480VAC switchgear room, to provide a hard-wired connection to a SI pump from the ASSS power supply, and to upgrade the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
NO-INVESSEL-COOL	1.0	1.100	In-vessel cooling failure post-core damage	This flag event indicates that in-vessel cooling fails during a core melt progression. Phase II SAMAs 034, 035, 036, 037, 038, and 039, for enhancing reactor vessel injection during transients, small LOCA and SBO, were evaluated.

**Table E.1-5  
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
NO_EXVESSEL-COOL	0.8	1.096	No ex-vessel cooling due to internal flooding event	This term represents failure of ex-vessel cooling following a flood in the control building switchgear room. Phase II SAMAs 008 and 009 were evaluated to consider the benefits of containing molten core debris in the reactor pit area or installing a reactor cavity flooding system. Phase II SAMAs 034, 035, 037, 038 and 039 to provide a diesel-driven pump for enhancing reactor vessel injection, and Phase II SAMAs 054, 060, 061, 062 and 065, to install a flood alarm in the 480VAC switchgear room, to provide added protection against flood propagation into the 480VAC switchgear room, to provide a hard-wired connection to a SI pump from the a ASSS power supply, and to upgrade the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
SLUMP_3	0.1	1.089	Core slump probability given CM > 20% and no injection	This term represents the probability of core slump to the lower head as a large mass, given no in-vessel injection. Phase II SAMAs 034, 035, 036, 037, 038, and 039, for enhancing reactor vessel injection and recirculation cooling, were evaluated.
VF_SIZE_PEN	0.9	1.084	Vessel penetration failure occurs debris thermal attack	This term represents the probability of vessel failure due to a single lower head penetration failure. Phase II SAMA 009 was evaluated to consider the benefit of a reactor cavity flooding system with the potential to cool a molten core before it causes vessel failure.



**Table E.1-5**  
**IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
DCH_OCCURS	0.5	1.081	DCH occurs given HPME phenomena	This term represents the probability that DCH occurs following HPME. Phase II SAMAs 040, 045, 053, and 057 to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated. In addition, Phase II SAMA 017, to erect a barrier to provide enhanced protection of the containment shell from ejected core debris following a core melt scenario at high pressure, and SAMA 029, to improve DC bus load shedding to extend DC power availability, were evaluated.
HPME_1	0.5	1.079	HPME occurs at high RCS pressure	This term represents the probability that HPME occurs at high RCS pressure. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.
DP-46	0.1	1.071	RCS pressure is low at vessel breach given a long-term SGTR with stuck-open safety relief valve	This term represents the probability that RCS depressurization occurs during a long-term SGTR with a stuck-open safety relief valve. Phase II SAMAs 018 and 019 to provide shell side heat removal and increase secondary pressure capacity, were evaluated. In addition, Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.

**Table E.1-5  
 IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
 (Continued)**

Event Name	Probability	RRW	Event Description	Disposition
PDS_FRAC-47	7.66E-02	1.062	Long-term internal flood induced SBO sequence at medium RCS pressure	This term is the PDS split fraction for a long-term internal flood event that entails failure of normal offsite supply buses, vital AC safeguard buses and the occurrence of a RCP seal LOCA with the AFW turbine-driven pump available. Phase II SAMAs 054, 060, 061, 062 and 065, to install a flood alarm in the 480VAC switchgear room, to provide added protection against flood propagation into the 480VAC switchgear room, to provide a hard-wired connection to a SI pump from the ASSS power supply, and to upgrade the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
DP-42	0.975	1.071	RCS pressure is medium at vessel breach given a long-term internal flood induced SBO sequence at medium RCS pressure	This term represents the probability that RCS depressurization occurs during a long-term internal flood induced SBO sequence in which a RCP seal LOCA occurs with the AFW turbine-driven pump available. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.
ELK5-P42	0.859	1.059	Small containment failure during a long-term internal flood induced SBO sequence at medium RCS pressure	This term represents the probability that a small containment failure occurs following a long-term internal flood induced SBO sequence in which a RCP seal LOCA occurs with the AFW turbine-driven pump available. Phase II SAMAs 009, 010, 011, 012, 013, 014, 015, and 016 for enhancing containment integrity, were evaluated.

**Table E.1-5**  
**IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
H2_EARLY2_MED	0.5	1.058	In-vessel hydrogen production is medium (between 600 lbm and 2200 lbm)	This term represents the probability that the amount of hydrogen produced is between 600 lbm and 2200 lbm during accidents with 20% core melt, no early injection, and no late recirculation cooling. Phase II SAMA 011, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated.
NO_QUENCH-3	1.0	1.047	No debris quench, given dry reactor pit and no late water supply after vessel breach	This term represents the probability that debris is not quenched immediately after vessel failure, with no water inside the reactor pit at vessel breach and no late water supply for debris cooling after vessel breach. Phase II SAMAs 008 and 009, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.
BURN_VF1-E_DEF	0.5	1.042	Hydrogen burn occurs under medium hydrogen conditions	This term represents the probability of a hydrogen burn occurring at vessel failure, given a medium hydrogen concentration early, no prior early burns, and DCH. Phase II SAMA 011, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated.

**Table E.1-5  
 IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
 (Continued)**

Event Name	Probability	RRW	Event Description	Disposition
CFE@VF_2	0.997	1.039	Containment failure given containment pressure > 23 psig, dry reactor pit, H2 burn and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given containment pressure greater than 23 psig, no water in the reactor pit, DCH, and hydrogen burn. Phase II SAMAs 009, 010, 011, 012, 013, 014, 015, and 016, for enhancing containment integrity, were evaluated. In addition, Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.
CFE@VF_9	0.24	1.037	Containment failure given containment pressure > 23 psig, dry reactor pit, and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given containment pressure greater than 23 psig, no water in the reactor pit, and DCH. Phase II SAMAs 009, 010, 011, 012, 013, 014, 015, and 016 for enhancing containment integrity, were evaluated. In addition, Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.

**Table E.1-5**  
**IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
NO_DISPERSAL	0.9	1.031	Core debris is not dispersed into containment atmosphere at vessel breach	This term represents the probability that debris is not dispersed and cooled following an HPME or an in-vessel or ex-vessel steam explosion event. Phase II SAMAs 040, 045, 053, and 057 to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.
PDS_FRAC-45	3.13E-02	1.025	Long-term internal flood induced SBO sequence	This term is the plant damage state split fraction for a long-term internal flood event that entails failure of normal offsite supply buses, vital AC safeguard buses and loss of the AFW turbine-driven pump. With no secondary-side heat removal, core damage results at high RCS pressure. Phase II SAMAs 054, 060, 061, 062 and 065, to install a flood alarm in the 480VAC switchgear room, to provide added protection against flood propagation into the 480VAC switchgear room, to provide a hard-wired connection to a SI pump from the ASSS power supply, and to upgrade the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
DP-40	0.975	1.024	RCS pressure is low at vessel breach given a long-term internal flood induced SBO sequence	This term represents the probability that RCS depressurization occurs during a long-term internal flood induced SBO sequence. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.

**Table E.1-5  
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
(Continued)**

<b>Event Name</b>	<b>Probability</b>	<b>RRW</b>	<b>Event Description</b>	<b>Disposition</b>
ELK4-P40	0950	1.024	Small containment failure during a long-term internal flood induced SBO sequence at high RCS pressure	This term represents the probability that a small containment failure occurs following a long-term internal flood induced SBO sequence at high RCS pressure. Phase II SAMAs 009, 010, 011, 012, 013, 014, 015, and 016, for enhancing containment integrity, were evaluated.
NO_QUENCH-2	0.5	1.023	No debris quench, given dry reactor pit and late water supply after vessel breach	This term represents the probability that debris is not quenched immediately after vessel failure, without water inside the reactor pit at vessel breach, but with a late water supply for debris cooling after vessel breach. Phase II SAMAs 008 and 009, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.
PDS_FRAC-49	5.58E-04	1.016	Long-term small ISLOCA outside containment event	This term is the plant damage state split fraction for a long-term small break ISLOCA outside containment. Phase II SAMAs 021, 022, 023, and 024, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.
BURN_EARLY1_DEF	0.1	1.015	Hydrogen deflagration burn occurs	This term represents the probability that an early hydrogen burn occurs. Phase II SAMA 011, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated. In addition, Phase II SAMAs 009, 010, 012, 013, 014, 015, and 016, for enhancing containment integrity, were evaluated.

**Table E.1-5  
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
(Continued)**

<b>Event Name</b>	<b>Probability</b>	<b>RRW</b>	<b>Event Description</b>	<b>Disposition</b>
CFE_BURN2-H2_CFE	7.0E-02	1.015	Early hydrogen burn fails containment	This term represents the probability that an early hydrogen burn fails containment due to overpressure. Phase II SAMA 011, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated. In addition, Phase II SAMAs 009, 010, 012, 013, 014, 015, and 016, for enhancing containment integrity, were evaluated.
PDS_FRAC-48	1.02E-02	1.008	Long-term internal flood induced SBO sequence at medium RCS pressure	This term is the plant damage state split fraction for a long-termed internal flood event that entails failure of normal offsite supply buses, vital AC safeguard buses and the occurrence of a RCP seal LOCA occurs with no AFW turbine-driven pump available. Phase II SAMAs 054, 060, 061, 062 and 065, to install a flood alarm in the 480VAC switchgear room, to provide added protection against flood propagation into the 480VAC switchgear room, to provide a hard-wired connection to a SI pump from the ASSS power supply, and to upgrade the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
DP-43	0.975	1.008	RCS pressure is medium at vessel breach given a long-term internal flood induced SBO sequence at medium RCS pressure	This term represents the probability that RCS depressurization occurs during a long-term internal flood induced SBO sequence in which a RCP seal LOCA occurs with no AFW turbine-driven pump available. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs, were evaluated.

**Table E.1-5  
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
(Continued)**

<b>Event Name</b>	<b>Probability</b>	<b>RRW</b>	<b>Event Description</b>	<b>Disposition</b>
ELK4-P43	0950	1.008	Small containment failure during a long-term internal flood induced SBO sequence at medium RCS pressure	This term represents the probability that a small containment failure occurs following a long-term internal flood induced SBO sequence in which a RCP seal LOCA occurs with no AFW turbine-driven pump available. Phase II SAMAs 009, 010, 011, 012, 013, 014, 015, and 016, for enhancing containment integrity, were evaluated.
ALPHA	0.1	1.006	Given in-vessel FCI, 'ALPHA' mode failure, fails reactor and containment	This term represents the probability of vessel and containment failure given an in-vessel fuel-coolant interaction (ALPHA mode failure). Phase II SAMAs 034, 035, 036, 037, 038, and 039, for enhancing reactor vessel injection and recirculation cooling, were evaluated.
FCI_IV_3	0.1	1.006	Low pressure fuel coolant interaction occurs	This term represents the probability that a fuel-coolant interaction occurs inside the reactor vessel at low RCS pressure. Phase II SAMAs 034, 035, 036, 037, 038, and 039, for enhancing reactor vessel injection and recirculation cooling, were evaluated.
HPME_2	0.9	1.004	HPME occurs at medium RCS pressure	This term represents the probability that HPME occurs at RCS pressure between 675 psig and 2235 psig. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs, were evaluated.



### E.1.2.2 Radionuclide Analysis

This subsection provides the following information regarding characterization of the Level 2 CET end states.

- Overview of PDS
- Overview of radionuclide removal processes and the concept of binning
- Identification of radionuclide release categories
- Release category bin assignments
- Process used to group the numerous source terms
- MAAP deterministic calculations to support CET end states definition
- Consequence analysis source terms

#### E.1.2.2.1 Overview of PDS

The interface between the Level 1 Systems Analysis and the Level 2 Containment Performance Analysis consists of a set of PDS. The PDS are defined by a set of functional characteristics for system operation, which are important to accident progression, containment failure and source term definition. Each PDS contains Level 1 sequences with sufficient similarity in system functional characteristics that the containment accident progression for all sequences in the group can be considered to be essentially the same. Each PDS defines a unique set of conditions regarding the state of the plant and containment building systems and the physical state of the core, reactor coolant system and the containment boundary at (approximately) the time of core damage or vessel failure. The important functional characteristics for each PDS were determined by defining the critical parameters (system functions), which impact the key results. The sequence characteristics that are important were defined by the requirements of the containment accident progression analysis. They include the type of accident initiator, the operability or non-operability of important systems, the value of important plant variables (e.g., primary system pressure) which are defined by system operation, and timing of key events.

Based on the above criteria, the Level 1 results were binned into 57 PDS. These PDS define important combinations of system states that can result in distinctly different accident progression pathways and therefore, different containment failure and source term characteristics. [Table E.1-6](#) provides a description of the IP2 PDS that are used to summarize the Level 1 results.

The PDS designators listed in [Table E.1-6](#) represent the core damage end state categories from the Level 1 analyses that are grouped together as entry conditions for the Level 2 analysis. The Level 2 accident progression for each of the PDS is evaluated using a single CET to determine the appropriate release category for each Level 2 sequence. Each end state associated with a Level 2 sequence is assigned to a unique release category.

**Table E.1-6  
Summary of IP2 Internal Events PDS**

<b>Plant Damage State</b>	<b>Description</b>	<b>Frequency/ry</b>
PDS-1	Long-term small-break LOCA event with subsequent loss of secondary cooling. The containment is not bypassed and AC power is available. Core damage proceeds at high RCS pressure (>2350psia). Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	2.12E-09
PDS-2	Same as PDS-1, except random faults fail the containment fan coolers.	1.97E-10
PDS-3	Same as PDS-1, except random faults fail the containment fan coolers and containment injection spray systems.	0.00E+00
PDS-4	Long-term medium or small LOCA scenario with loss of recirculation cooling. Core damage results at medium RCS pressure (>675psia and <2350psia). Containment is not bypassed and AC power is available. Late vessel injection, secondary-side cooling, containment fan coolers and containment spray are available after the onset of core damage.	9.25E-07
PDS-5	Same as PDS-4, except random faults fail the containment fan coolers.	2.51E-08
PDS-6	Same as PDS-4, except random faults fail the containment fan coolers and containment injection spray system.	5.14E-08
PDS-7	Same as PDS-4, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-8	Long-term medium LOCA. Although vessel injection is successful, random faults fail all modes of operation of the high-head recirculation core cooling systems. With no long-term core cooling, core damage proceeds at medium RCS pressure (> 675psia and < 2350psia). Containment is not bypassed and AC power is available. Late vessel injection, containment injection sprays and containment recirculation sprays are not available. However, secondary-side cooling and containment fan coolers are available after the onset of core damage.	1.75E-10
PDS-9	Same as PDS-8, except random faults fail containment fan coolers.	9.42E-09
PDS-10	Long-term medium LOCA with subsequent loss of secondary-side cooling and recirculation cooling. Core damage results at medium RCS pressure (> 675psia and < 2350psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	3.47E-11

**Table E.1-6  
Summary of IP2 Internal Events PDS  
(Continued)**

Plant Damage State	Description	Frequency/ ry
PDS-11	Same as PDS-10, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-12	Same as PDS-10, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-13	Long-term medium LOCA with subsequent random failure of secondary-side cooling and all modes of operation of the high-head recirculation core cooling systems. Core damage results at medium RCS pressure (> 675psia and < 2350psia). Containment is not bypassed and AC power is available. Late vessel injection is not available. Although containment fan coolers are available, both containment injection sprays and containment recirculation sprays are not available after the onset of core damage.	0.00E+00
PDS-14	Same as PDS-13, except random faults fail the containment fan coolers.	0.00E+00
PDS-15	Short-term large LOCA with either a loss of initial injection or loss of recirculation cooling. Core damage results at low RCS pressure (< 675 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment sprays are available after the onset of core damage.	1.90E-07
PDS-16	Same as PDS-15, except random faults fail the containment fan coolers.	2.07E-11
PDS-17	Same as PDS-15, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-18	Same as PDS-15, except random faults fails containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-19	Short-term large LOCA. Although initial injection is successful, random faults fail both the recirculation pumps and RHR pumps for long-term recirculation cooling. Core damage results at low RCS pressure (< 675 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are not available. However, containment fan coolers are available after the onset of core damage.	0.00E+00
PDS-20	Same as PDS-19, except random faults fail the containment fan coolers.	0.00E+00

**Table E.1-6  
Summary of IP2 Internal Events PDS  
(Continued)**

<b>Plant Damage State</b>	<b>Description</b>	<b>Frequency/ry</b>
PDS-21	Short-term ATWS event with AFW available and loss of long-term reactor subcriticality control. RCS pressure remains at the PORV setpoint, precluding high- and low-head safety injection. Therefore, core damage occurs in the short-term at high RCS pressure (> 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	9.77E-07
PDS-22	Long-term transient involving loss of secondary cooling and subsequent loss of primary bleed-and-feed core cooling. Core damage results at high RCS pressure (> 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment sprays are available after the onset of core damage.	3.38E-06
PDS-23	Same as PDS-22, except random faults fail the containment fan coolers.	3.88E-06
PDS-24	Same as PDS-22, except random faults fails the containment fan coolers and containment injection spray system.	2.19E-08
PDS-25	Long-term transient with a subsequent loss of secondary cooling. Following successful bleed-and-feed core cooling, failure to implement long-term recirculation cooling occurs. Core damage results at medium RCS pressure (> 675 psia and < 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	2.47E-08
PDS-26	Same as PDS-25, except random faults fail the containment fan coolers.	1.02E-10
PDS-27	Same as PDS-25, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-28	Same as PDS-25, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-29	Long-term transient with subsequent loss of secondary cooling. Following successful bleed-and-feed core cooling, random faults fail long-term recirculation cooling. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are unavailable after the onset of core damage. However, the containment fan coolers are available.	3.85E-11

**Table E.1-6  
Summary of IP2 Internal Events PDS  
(Continued)**

<b>Plant Damage State</b>	<b>Description</b>	<b>Frequency/ry</b>
PDS-30	Same as PDS-29, except random faults fail the containment fan coolers.	2.47E-07
PDS-31	Long-term RCP seal LOCA caused by loss of CCW to the RCP seals. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	1.81E-06
PDS-32	Same as PDS-31, except random faults fail the containment fan coolers.	4.44E-07
PDS-33	Same as PDS-31, except random faults fails containment fan coolers and containment injection spray system.	3.08E-07
PDS-34	Same as PDS-31, except random faults fails containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-35	Stuck open PORV with loss of long-term recirculation cooling. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are unavailable after the onset of core damage. However, the containment fan coolers are available.	6.42E-09
PDS-36	Same as PDS-35, except random faults fail the containment fan coolers.	4.21E-07
PDS-37	SBO sequence in which a loss of all DC power occurs in the long term. No PORVs stick open. Secondary cooling by the AFW system is unavailable because the SBO renders both motor-driven AFW pumps inoperable, and the steam-turbine-driven AFW pump fails because of battery depletion or random faults. Without primary and secondary cooling, core damage occurs at high RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	7.41E-09
PDS-38	Short-term SBO sequence with immediate loss of secondary cooling. Core damage results at high RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	1.06E-07
PDS-39	Same as PDS-37, except RCS depressurization results from either operator action or a single PORV sticking open. Core damage results at medium RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	3.95E-07

**Table E.1-6  
Summary of IP2 Internal Events PDS  
(Continued)**

Plant Damage State	Description	Frequency/ ry
PDS-40	Short-term SBO sequence with immediate loss of secondary cooling and subsequent RCP seal LOCA or stuck-open PORV. Core damage results at medium RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	0.00E+00
PDS-41	Short-term large LOCA induced by vessel rupture. The LOCA is beyond the capability of the ECCS. Core damage occurs in the short term with the RCS at low pressure. Vessel injection and all forms of containment heat removal (containment fan coolers, RHR heat exchangers, and containment sprays) are available. Containment is not bypassed and AC power is available.	1.28E-07
PDS-42	Same as PDS-41, except random faults fail the containment fan coolers.	0.00E+00
PDS-43	Same as PDS-41, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-44	Same as PDS-41, except random faults fail the containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-45	Long-term internal flood induced SBO sequence in which loss of AFW steam-turbine-driven pump occurs. With no secondary-side heat removal, core damage results at high RCS pressure. Because of the flood, core cooling and containment heat removal systems are unavailable after the onset of core damage. Containment is not bypassed.	9.36E-07
PDS-46	Short-term internal flood induced SBO sequence in which loss of secondary heat removal occurs. Core damage results at high RCS pressure. Because of the flood, core cooling and containment heat removal systems are not available after the onset of core damage.	1.02E-07
PDS-47	Long-term internal flood induced SBO with a subsequent stuck-open PORV or RCP seal LOCA. Core damage ensues at medium RCS pressure. The steam-turbine-driven AFW pump is available after core damage. However, core cooling and containment heat removal systems are unavailable because of the internal flooding event. The containment is not bypassed.	2.31E-06
PDS-48	Short-term internal flood induced SBO sequence in which loss of secondary heat removal occurs and a subsequent breach of RCS integrity occurs because of a stuck-open PORV or RCP seal LOCA. Core damage results at medium RCS pressure. Because of the flood, core cooling and containment heat removal systems are not available after the onset of core damage.	3.06E-07

**Table E.1-6  
Summary of IP2 Internal Events PDS  
(Continued)**

Plant Damage State	Description	Frequency/ ry
PDS-49	Long-term small break ISLOCA occurs outside containment. Core damage results at medium RCS pressure with a bypassed containment. While vessel injection and all modes of containment spray are unavailable, containment fan coolers are available after core damage.	9.97E-09
PDS-50	Short-term large break ISLOCA occurs outside containment. Core damage results at low RCS pressure with a bypassed containment. While vessel injection and all modes of containment spray are unavailable, containment fan coolers are available after core damage.	1.42E-07
PDS-51	SGTR and a failure to isolate the ruptured steam generator. Because RCS pressure remains above the ruptured steam generator pressure, water lost from the RCS does not return to the containment sump and recirculation core cooling is unavailable. Core damage results at medium RCS pressure with a bypassed containment. While vessel injection and all modes of containment sprays are unavailable, containment fan coolers are available after core damage.	4.30E-07
PDS-52	Same as PDS-51, except random faults fail containment fan coolers.	2.76E-09
PDS-53	Same as PDS-51, except random faults fail AFW to the steam generators and the containment fan coolers.	2.33E-09
PDS-54	Same as PDS-51, except the ruptured steam generator is isolated.	2.60E-07
PDS-55	Same as PDS-51 except the ruptured steam generator is isolated and random faults fail the containment fan coolers.	6.55E-09
PDS-56	Same as PDS-51, except the ruptured steam generator is isolated and random faults fail AFW to the steam generators.	8.88E-09
PDS-57	Same as PDS-51, except the ruptured steam generator is isolated, random faults fail AFW to the steam generators and the containment fan coolers.	1.49E-09
Total		1.79E-05

#### E.1.2.2.2 Overview of Radionuclide Removal Processes and Concept of Binning

A major feature of a Level 2 analysis is the estimation of the source term for every possible outcome of the CET. The CET end points represent the outcomes of possible in-containment accident progression sequences. These end points represent complete severe accident sequences from initiating event to release of radionuclides to the environment. The Level 1 and plant system information is passed through to the CET evaluation in discrete PDS. An atmospheric source term may be associated with each of these CET sequences. Because of the large number of postulated accident scenarios considered, mechanistic calculations (i.e., MAAP calculations) are not performed for every end-state in the CET. Rather, accident sequences produced by the CET are grouped or "binned" into a limited number of release categories, each of which represents all postulated accident scenarios that would produce a similar fission product source term.

The criteria used to characterize the release are the estimated magnitude of total release and the timing of the first significant release of radionuclides. The predicted source term associated with each release category, including both the timing and magnitude of the release, is determined using the results of MAAP calculations.

#### E.1.2.2.3 Identification of Radionuclide Release Categories

##### E.1.2.2.3.1 Timing of Release

Timing completely governs the extent of radioactive decay of short-lived radioisotopes prior to an offsite release and, therefore, has a first-order influence on immediate health effects. IP2 characterizes the release timing relative to the time at which the release begins, measured from the time of accident initiation. Two timing categories are used, as follows.

- (1) Early: rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of offsite emergency response and protective actions. This involves CET endstates in which containment failure occurs within 0 to 12 hours from the initiating event.
- (2) Late: mitigated release of airborne fission products from the containment to the environment occurring after effective implementation of offsite emergency response and protective actions. This involves CET endstates in which containment failure occurs after 12 hours from the initiating event.

The definition of the release category timing takes into consideration the compensatory measures available to reduce or prevent dose to the public and the characteristics of the radionuclide release. Compensatory measures are prescribed in the emergency response plan. These actions, which are routinely practiced, are geared to mobilizing utility resources to implement emergency procedures, assess the potential offsite consequence of an accident, and recommend to government officials appropriate action for protecting the public (evacuate or shelter).



An evacuation time estimates study performed for the Indian Point Energy Center (IPEC) site [Reference E.1-7], examined fourteen evacuation scenarios under which evacuation times are calculated to successfully evacuate 100 percent of the general public. The ranges of times for those 14 scenarios for the following emergency planning zone rings (shortest to longest in hours: minutes) are as follows:

2 miles: 4:30 to 6:50;  
5 miles: 5:25 to 8:00;  
10 miles: 7:10 to 12:00.

Since the 10-mile emergency planning zone may not be evacuated for 12 hours from the initiating event, 12 hours is the upper bound time in which an early release can occur.

#### E.1.2.2.3.2 Magnitude of Release

Source term results from previous risk studies suggest that categorization of release magnitude based on cesium iodide (CsI) release fractions alone are appropriate [Reference E.1-5]. The CsI release fraction indicates the fraction of in-vessel radionuclides escaping to the environment. (Noble gas release levels are non-informative since release of the total core inventory of noble gases is essentially complete given containment failure).

The source terms were grouped into five distinct radionuclide release categories or bins according to release magnitude as follows.

- (1) High: A radionuclide release of sufficient magnitude to have the potential to cause early fatalities. This implies a total integrated release of >10% of the initial core inventory of CsI [Reference E.1-5].<sup>1</sup>
- (2) Medium: A radionuclide release of sufficient magnitude to cause near-term health effects. This implies a total integrated release of between 1% and 10% of the initial core inventory of CsI [Reference E.1-5].<sup>2</sup>
- (3) Low: A radionuclide release with the potential for latent health effects. This implies a total integrated release of between 0.1% and 1% of the initial core inventory of CsI.
- (4) Low-Low: A radionuclide release with undetectable or minor health effects over most of the population. This implies a total integrated release of between 0.01% and 0.1% of the initial core inventory of CsI.

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1. Once the CsI source term exceeds 0.1, the source term is large enough that doses above the early fatality threshold can sometimes occur within a population center a few miles from the site.

2. The reference document indicates that for CsI release fractions of 1 to 10 percent, the number of latent fatalities is found to be at least 10% of the latent fatalities for the highest release.

- (5) Negligible or no containment failure (NCF): A radionuclide release that is less than or equal to the containment design base leakage. This implies total integrated release of < 0.01% of the initial core inventory of Csl.

**E.1.2.2.4 Release Category Bin Assignments**

The combination of release magnitude and timing produce nine distinct release categories. [Table E.1-7](#) summarizes the scheme used to bin CET sequences with respect to magnitude of release, based on the predicted Csl release fraction and release timing.

**Table E.1-7  
 IP2 Release Severity and Timing Classification Scheme Summary**

Release Severity		Release Timing	
Classification Category	Percent Csl Release	Classification Category	Time of Initial Release From Accident Initiation
High	Greater than 10	Early (E)	Less than 12 hours
Medium	1 to 10		
Low	0.1 to 1	Late (L)	Greater than 12 hours
Low-Low	0.01 to 0.1		
NCF	Less than < 0.01		

**E.1.2.2.5 Process Used to Group the Source Terms**

The approach used to evaluate radionuclide releases and develop release categories is similar to that applied in the NUREG-1150 analysis; i.e., a source term was associated with each CET end-state that was found to have a significant frequency. The objectives were to establish the timing of the first significant release of radionuclides and estimate the magnitude of the total release.

The first step in the source term assessment effort was to identify the sequence characteristics that are most important for defining the source term. These characteristics were identifiable from the PDS characteristics and from the CET sequence characteristics since one of the primary objectives in the PDS grouping and CET evaluation was to define those events and conditions most important for source term assessment. The set of sequence characteristics important to source term assessment was used as grouping criteria to define the release categories and the associated source term magnitude, composition and timing.

The containment sequence characteristics selected for use in definition of the IP2 source term release categories are

- vessel breach,
- containment failure,
- core-concrete interactions (CCI),
- fission product removal,
- PAB retention.

The goal of the grouping process was to develop the minimum number of release categories necessary to distinguish the important combinations of sequence characteristics that can result in distinctly different atmospheric source terms.

The second step was to classify the various progressions paths in the IP2 CET as unique release end states based on the sequence characteristics. The release modes were categorized into the following general classifications:

- end states recovered in-vessel (no vessel breach);
- end states recovered ex-vessel (vessel breach, but no CCI);
- end states that are late containment failures;
- end states that are early containment failures.

Each CET end state represents a particular release event or a recovered, degraded core state that may be characterized according to its potential for fission product release to the atmosphere, its timing of release initiation relative to time of incipient core damage, and its release duration.

[Table E.1-8](#) summarizes the possible CET release categories for the spectrum of core melt accident sequences. This table defines the various CET release modes as early or late release events and containment damage states (i.e., failure modes), including recovered states and release mechanisms (i.e., no CCI). Each release mode represents a release path from the fuel through the primary coolant system and the containment atmosphere to the environment, should the containment ultimately fail or be bypassed. The release path (including the associated removal mechanism) is related to a particular environmental source term.

The consolidation of source term results for the CET release categories presented in [Table E.1-8](#) was accomplished by "binning" or grouping releases into release categories that represent all postulated accident scenarios that produce a similar fission product source term. The criteria used to characterize the release are the estimated magnitude of total release and the timing of the first significant release of radionuclides.

Based on the above binning methodology, the salient Level 2 results are summarized in [Table E.1-9](#). This table identifies the total annual release frequency for each Level 2 release category.

**Table E.1-8  
 Description of IP2 CET Release Modes**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-1	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-2	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-3	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early Medium
APB-4	Vessel breach at low pressure, recovered ex-vessel, no containment failure	NA	Negligible	NCF
APB-5	Vessel breach at low pressure, recovered ex-vessel, late containment leak failure, in-vessel fission product release mitigated	Late	Low-Low	Late Low-Low
APB-6	Vessel breach at low pressure, recovered ex-vessel, late containment leak failure, in-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-7	Vessel breach at low pressure, recovered ex-vessel, late containment rupture failure, in-vessel fission product release not mitigated	Late	High	Late High
APB-8	Vessel breach at low pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-9	Vessel breach at low pressure, CCI occurs, late containment leak failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release mitigated by sprays	Late	Low-Low	Late Low-Low

**Table E.1-8  
Description of IP2 CET Release Modes**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-10	Vessel breach at low pressure, CCI occurs, late containment rupture failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release mitigated by sprays	Late	Low	Late Low
APB-11	Vessel breach at low pressure, CCI occurs, late containment leak failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release not mitigated	Late	Medium	Late Medium
APB-12	Vessel breach at low pressure, CCI occurs, late containment rupture failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release not mitigated	Late	High	Late High
APB-13	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-14	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release mitigated	Early	Medium	Early Medium
APB-15	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-16	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-17	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, in- and ex-vessel fission product release mitigated	Early	Low	Early Low

**Table E.1-8  
Description of IP2 CET Release Modes**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-18	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, in- and ex-vessel fission product release mitigated	Early	Medium	Early Medium
APB-19	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, ex-vessel fission product release mitigated by overlying pool, in-vessel fission product release not mitigated	Early	High	Early High
APB-20	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, ex-vessel fission product release mitigated by overlying pool, in-vessel fission product release not mitigated	Early	High	Early High
APB-21	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-22	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early-Low
APB-23	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early-Medium
APB-24	Vessel breach at low pressure, recovered ex-vessel, no containment failure	NA	Negligible	NCF
APB-25	Vessel breach at low pressure, no CCI, late containment leak failure, in-vessel fission product release mitigated by sprays	Late	Low-Low	Late Low-Low
APB-26	Vessel breach at low pressure, no CCI, late containment rupture failure, in-vessel fission product release mitigated by sprays	Late	Low	Late Low

**Table E.1-8  
 Description of IP2 CET Release Modes**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-27	Vessel breach at low pressure, no CCI, late containment leak failure, in-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-28	Vessel breach at low pressure, no CCI, late containment rupture failure, in-vessel fission product release not mitigated	Late	High	Late High
APB-29	Vessel breach at low pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-30	Vessel breach at low pressure, significant CCI occurs, late containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Late	Low-Low	Late Low-Low
APB-31	Vessel breach at low pressure, significant CCI occurs, late containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Late	Low	Late Low
APB-32	Vessel breach at low pressure, significant CCI occurs, late containment leak failure, in- and ex-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-33	Vessel breach at low pressure, significant CCI occurs, late containment rupture failure, in- and ex-vessel fission product release not mitigated	Late	High	Late High
APB-34	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-35	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release mitigated	Early	Medium	Early Medium
APB-36	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release not mitigated	Early	High	Early High

**Table E.1-8  
Description of IP2 CET Release Modes**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-37	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-38	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Early	Low	Early Low
APB-39	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-40	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, fission product not mitigated	Early	High	Early High
APB-41	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, fission product not mitigated	Early	High	Early High
APB-42	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-43	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-44	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early Medium
APB-45	Vessel breach at high pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-46	Vessel breach at high pressure, no CCI, late containment leak failure, in-vessel and late fission product release mitigated by sprays	Late	Low	Late Low



**Table E.1-8  
Description of IP2 CET Release Modes**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-47	Vessel breach at high pressure, no CCI, late containment rupture failure, in-vessel and late fission product release mitigated by sprays	Late	Low	Late Low
APB-48	Vessel breach at high pressure, no CCI, late containment leak failure, in-vessel and late fission product release not mitigated	Late	Medium	Late Medium
APB-49	Vessel breach at high pressure, no CCI, late containment rupture failure, in-vessel and late fission product release not mitigated	Late	High	Late High
APB-50	Vessel breach at high pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-51	Vessel breach at high pressure, moderate CCI occurs, late containment leak failure, in- and ex-vessel fission product release mitigated by Sprays	Late	Low	Late Low
APB-52	Vessel breach at high pressure, moderate CCI occurs, late containment rupture failure, in- and ex-vessel fission product release mitigated by Sprays	Late	Low	Late Low
APB-53	Vessel breach at high pressure, moderate CCI occurs, late containment leak failure, in- and ex-vessel, fission product release not mitigated	Late	Medium	Late Medium
APB-54	Vessel breach at high pressure, moderate CCI occurs, late containment rupture failure, in- and ex-vessel, fission product release not mitigated	Late	High	Late High
APB-55	Vessel breach at high pressure, no CCI, early containment leak failure, in-vessel and late fission product release mitigated	Early	Medium	Early Medium
APB-56	Vessel breach at high pressure, no CCI, early containment rupture failure, in-vessel and late fission product release mitigated	Early	Medium	Early Medium

**Table E.1-8  
Description of IP2 CET Release Modes**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-57	Vessel breach at high pressure, no CCI, early containment leak failure, in-vessel and late fission product release not mitigated	Early	Medium	Early Medium
APB-58	Vessel breach at high pressure, no CCI, early containment rupture failure, in-vessel and late fission product release not mitigated	Early	High	Early High
APB-59	Vessel breach at high pressure, moderate CCI occurs, early containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-60	Vessel breach at high pressure, moderate CCI occurs, early containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-61	Vessel breach at high pressure, moderate CCI occurs, early containment leak failure, ex-vessel and late fission product release not mitigated	Early	Medium	Early Medium
APB-62	Vessel breach at high pressure, moderate CCI occurs, early containment rupture failure, ex-vessel and late fission product release not mitigated	Early	High	Early High

**Table E.1-9  
 Summary of CET Quantification  
 IP2 PSA Model Revision 1**

<b>Release Category (Timing/Magnitude)</b>	<b>Release Frequency (Per year)</b>
Late Low-Low	5.82E-08
Late Low	6.43E-07
Late Medium	3.43E-06
Late High	6.88E-07
Early Low-Low	0.00E+00
Early Low	1.11E-07
Early Medium	4.23E-07
Early High	6.50E-07
No Containment Failure (NCF)	1.19E-05
<b>Total</b>	<b>1.79E-05</b>

**Nomenclature**

Timing:

Late - Greater than 12 hours

Early - Less than 12 hours

**Magnitude**

NCF (Little to no release) - Less than 0.01% Csl

Low-Low - 0.01% to 0.1% Csl

Low - 0.1% to 1% Csl

Medium - 1% to 10% Csl

High - Greater than 10% Csl

#### E.1.2.2.6 MAAP Deterministic Calculations to Support CET End States Definition

The MAAP computer code is used to assign both the radionuclide release magnitude and timing based on the accident progression characterization. Specifically, MAAP provides the following information:

- containment pressure and temperature (time of containment failure is determined by comparing these values with the nominal containment capability);
- radionuclide release timing and magnitude for a large number of radioisotopes; and
- release fractions for twelve radionuclide species.

#### E.1.2.2.7 Consequence Analysis Source Terms

Input to the Level 3 IP2 model from the Level 2 model is a combination of radionuclide release fractions, timing of radionuclide releases, and frequencies at which the releases occur. This combination of information is used in conjunction with IP2 site characteristics in the Level 3 model to evaluate the offsite consequences of a core damage event.

Source terms were developed for the nine release categories identified in [Table E.1-9](#). The MAAP computer code was used to generate the radionuclide release magnitude for the MACCS2 consequence analysis [[Reference E.1-6](#)]. The MAAP calculations are representative deterministic thermal hydraulic calculations that portray dominant CET scenarios.

[Table E.1-10](#) provides a summary of the Level 2 results that were used as Level 3 input for the IP2 SAMA analysis.

The source terms presented in [Table E.1-10](#) and used in the consequence analysis were determined as follows.

1. The appropriate MAAP case source terms were selected and assigned to a particular CET accident progression endstate.
2. Based on the source terms from Step 1, the source terms for each plant damage state CET accident progression endstate were determined.
3. The frequency of each release category was determined by summing the individual plant damage state CET accident progression endstates contained in the particular release category (i.e., no containment failure, early high release, etc.).
4. The release category individual fractional contributions for each CET accident progression were determined by dividing the result from Step 3 by the individual PDS frequencies.

5. Each PDS accident progression CET endpoint source terms, release timing, release energy and release elevation was multiplied by the value determine in Step 4.
6. The individual results of Step 5 were summed to arrive at the total final values contained in [Table E.1-10](#).

**Table E.1-10  
IP2 Release Category Source Terms**

	Release Characterization	Frequency (/ry)	Warning Time (sec)	Elevation (m)	Release Start (Hours)	Release Duration (Hours)	Release Energy (W)
1	NCF	1.19E-05	1.66E+04	3.00E+01	0.00E+00	3.55E+01	9.20E+05
2	Early High	6.50E-07	1.36E+04	3.00E+01	3.66E+00	2.29E+01	1.08E+06
3	Early Medium	4.23E-07	1.00E+04	3.00E+01	3.46E+00	2.70E+01	1.33E+06
4	Early Low	1.11E-07	1.09E+04	3.00E+01	4.81E+00	3.22E+01	1.60E+06
5	Early Low-Low	0.0	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
6	Late High	6.88E-07	5.58E+03	3.00E+01	2.05E+01	3.60E+01	9.20E+05
7	Late Medium	3.43E-06	8.94E+03	3.00E+01	2.23E+01	3.60E+01	9.20E+05
8	Late Low	6.43E-07	2.19E+04	3.00E+01	2.75E+01	3.60E+01	9.20E+05
9	Late Low-Low	5.82E-08	2.56E+04	3.00E+01	3.14E+01	3.60E+01	9.20E+05

**Table E.1-10  
IP2 Release Category Source Terms (continued)**

	Release Fractions								
	NG	I	Cs	Te	Sr	Ru	La	Ce	Ba
1	9.27E-05	3.94E-06	1.61E-06	1.21E-06	3.74E-08	2.37E-07	2.11E-09	1.77E-08	1.05E-07
2	7.01E-01	2.43E-01	2.29E-01	2.26E-01	2.47E-02	9.13E-02	7.95E-04	4.84E-03	4.56E-02
3	9.87E-01	2.02E-02	1.75E-02	2.66E-02	8.33E-04	2.03E-02	4.92E-05	3.28E-04	1.33E-02
4	7.55E-01	5.93E-03	4.06E-03	3.89E-03	1.04E-04	1.97E-03	4.58E-06	3.31E-05	7.75E-04
5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

**Table E.1-10**  
**IP2 Release Category Source Terms (continued)**

	Release Fractions								
	NG	I	Cs	Te	Sr	Ru	La	Ce	Ba
6	9.89E-01	1.17E-01	2.26E-02	4.81E-03	2.08E-04	3.74E-03	1.32E-05	1.22E-04	9.06E-04
7	8.23E-01	1.53E-02	4.30E-03	1.49E-03	8.01E-05	1.44E-03	5.11E-06	4.72E-05	3.50E-04
8	6.98E-01	1.06E-03	7.91E-04	1.23E-03	8.69E-05	3.47E-06	2.59E-06	2.38E-05	7.42E-05
9	9.09E-01	8.14E-04	6.96E-04	7.55E-04	3.63E-05	2.08E-06	1.14E-06	1.20E-05	3.33E-05

### **E.1.3 IPEEE Analysis**

#### **E.1.3.1 Seismic Analysis**

The seismic portion of the IPEEE was completed in conjunction with the SQUG program [References E.1-8 and E.1-9]. IP2 performed a seismic probabilistic risk assessment (PRA) following the guidance of NUREG-1407 [Reference E.1-10] and NUREG/CR-2300 [Reference E.1-11]. The seismic PRA logic model was developed using a support state modeling approach similar to the IPE internal events model. The primary model difference is that a seismic event tree was developed to delineate the potential combinations of seismic-induced failures, and resulting seismic scenarios, which were termed "seismic damage states." Traditional event tree techniques were used to identify each of the top seismic-induced events and to formulate the nodal branching logic. The frequencies of these seismic damage states were quantified by convolving the site-specific mean earthquake hazard curve with the structure and equipment seismic fragility curves. This quantification included dependent and correlated failures, as well as random failures of equipment and operator actions. The seismic IPEEE containment performance analysis followed the guidance provided in NUREG-1407 to identify vulnerabilities that involve early failure of containment functions, including containment integrity, containment isolation and prevention of bypass functions. Although some seismic scenarios result in initial loss of containment pressure suppression and heat removal functions, no vulnerabilities which could cause early failures of containment, or containment bypass were identified.

The seismic PRA provides quantitative, but conservative, results. Therefore, its results should not be compared directly with the best-estimate internal events results.

Conservative assumptions in the seismic PRA include the following.

- Sequences in the seismic PSA involving loss of offsite power were assumed to be unrecoverable. If offsite power was recovered following a seismic event, there would be many more systems available to maintain core cooling and containment integrity than were credited for those sequences.
- A single, conservative, surrogate element whose failure leads directly to core damage was used in the seismic risk quantification to model the most seismically rugged components.
- Seismic-induced ATWS was considered in the analysis, but no credit was included for manual scram or mitigation of ATWS using the boration system. This conservatively resulted in most seismic-induced ATWS events leading to consequential core damage.
- Redundant components were conservatively assumed to be completely correlated by treating them as if they were one component for the purpose of determining the probability of seismic induced failures.

- Several systems were assumed to be unavailable during a seismic event, including
  - a. the city water system, which can be used to supply backup cooling to the charging pumps if CCW is lost, as an alternate source of suction to the AFW pumps and to provide alternate cooling to the RHR and SI pumps;
  - b. the primary water system, which can also be used as a backup to CCW to supply cooling to the RHR and SI pumps; and
  - c. the onsite and offsite gas turbine generators, which can provide alternate station power.
- No credit was taken for recovery of power through the ASSS.
- Lawrence Livermore National Laboratory seismic hazard data was used. Use of EPRI seismic hazard data would result in a 10% reduction in overall seismic CDF.

The seismic CDF in the IPEEE was originally estimated to be  $1.46 \times 10^{-5}$  per year. As a result of an IPEEE recommendation, the CCW surge tank hold-down bolts were upgraded, reducing the seismic CDF to  $1.06 \times 10^{-5}$  per year. No other seismic improvements were recommended.

The conclusions of the IP2 seismic PRA are as follows.

- The total seismic CDF for IP2 is  $1.06 \times 10^{-5}$  per year.
- No unique decay heat removal vulnerabilities to seismic events were found because the safety-related systems provide effective and reliable means for reactor reactivity control, electrical power, RCS pressure control, decay heat removal, and containment pressure control.
- Seismic-induced flooding and fires do not pose major risks.
- No unique seismic-induced containment failure mechanisms were identified.

With the upgrade of the surge tank hold down bolts, the major contributors to seismic risk at IP2 are major structural failures rather than component failures. As a result, no further cost-effective changes to reduce seismic risk were identified in this effort.

Although the CDF due to seismic induced scenarios is a conservative value and the performance of mitigating systems and components has improved since the IPEEE was performed, the seismic risk contribution of  $1.06 \times 10^{-5}$  per year was used to determine the external event multiplier described in [Section 4.21.5.4](#).



### E.1.3.2 Fire Analysis

The IP2 internal fire risk model was performed in 1995 as part of the IPEEE submittal report [Reference E.1-8]. The IP2 fire analysis was performed using EPRI's Fire PRA Implementation Guide [Reference E.1-13]. The EPRI Fire Induced Vulnerability Evaluation method was used for the initial screening, and along with the EPRI Fire Events Database as the source of fire frequency data [References E.1-14 and E.1-23]. Unscreened fire zones were then analyzed in more detail using a fire PRA approach.

Table E.1-11 presents the results of the IP2 IPEEE fire analysis and the updated values used in this SAMA evaluation. The IPEEE values presented in Table E.1-11 are the same as those listed in NUREG-1742, [Reference E.1-12].

Conservative assumptions in the IP2 IPEEE fire analysis include the following.

- The frequency and severity of fires were generally conservatively overestimated in the generic IPEEE fire analysis methods. A revised Nuclear Regulatory Commission (NRC) fire events database indicates a trend toward lower frequency and less severe fires. This trend reflects improved housekeeping, reduction in transient fire hazards, and other improved fire protection steps at utilities.
- Cable failure due to fire damage was assumed to arise from open circuits, hot short circuits, and short circuits to ground. In damaging a cable, the analysis addressed the ability of the fire to induce the conductor failure mode of concern. Hot shorts were conservatively assigned a probability of 0.1, which was applied to all single phase, AC control circuit or DC power and control circuit cases regardless of whether the wires were in the same multi-conductor.
- A plant trip was assumed for all fires, including those for which immediate operator actions are not specified in emergency response procedures.
- The main feedwater and condensate systems were assumed to be unavailable in all scenarios, even when their power source was not impacted by the fire scenario. Use of these systems for recovery, following a failure of AFW, is addressed in current plant procedures.
- PORV block valves were assumed to be in the more limiting position (open or closed) to maximize the impact of the fire. As a result, risk important scenarios that included the potential for spurious LOCAs through the PORVs were also assumed to preclude the ability to close the PORV block valve, which was assumed, for those scenarios, to be in the open position (the PORV block valves at IP2 are currently maintained normally closed).
- All sequences involving induced RCP seal LOCAs were assumed to lead to complete seal failure. Although casualty cables exist for powering ECCS pumps from the ASSS

power source, the ASSS was assumed to be ineffective in mitigating induced LOCAs. The currently accepted RCP seal LOCA methodology is more detailed and provides sequences with varying leakage rates. Under that current methodology, a majority of seal LOCAs remain within the capability of a charging pump (which has hardwired ASSS transfer capability) to provide makeup.

The dominant IPEEE fire sequences (sequences with CDF contributions  $> 1 \times 10^{-7}$ ) were re-evaluated to reduce the conservatisms associated with main feedwater and condensate unavailability, PORV block valves, and RCP seal LOCAs. Sequences with contributions of less than  $1 \times 10^{-7}$  were conservatively left as is. Also, the fire ignition frequency for the central control room main control board cabinets was reduced in accordance with current guidance provided in NUREG/CR-6850 [Reference E.1-24]. This re-evaluation resulted in a revised fire CDF of  $9.11 \times 10^{-6}$  per reactor-year, which represents a reduction of 2.02. Therefore, a reduction factor of two was applied in determining the external event multiplier described in Section 4.21.5.4.

Table E.1-11 lists the fire zones with the largest contribution to fire induced CDF at IP2. Although no specific hardware changes were recommended as a result of the IPEEE, a number of procedural and administrative improvements have been made, including:

- enhancing the controls for use, staging and storage of transient combustible materials;
- upgrading the fire protection training requirements for fire brigade members, personnel performing welding and hot work activities, and other plant personnel; and
- improving pre-fire plans and procedures for safely shutting down the plant from outside the control room, including use of the ASSS.

The CDF contribution from fires assumed in the SAMA analysis has not been adjusted for these procedural and administrative improvements.

All of the fire zones shown in Table E.1-11, with the exception of the service water and circulating water pump areas, contain fire detection and manual fire suppression capability (i.e., through hose stations and portable fire extinguishers). In addition, the cable spreading room is equipped with a manually actuated total flooding Halon fire suppression system and the adjacent cable tunnel contains a closed head, pre-action, sprinkler system. All zones are regularly inspected by operations personnel who are trained fire brigade members, as well as by plant security officers. Given the procedural and administrative enhancements already implemented and the inherent complexity, substantial cost and competing risks associated with retrofitting possible fire suppression system designs, no further cost-effective changes were identified to reduce CDF in these zones.

### E.1.3.3 Other External Hazards

The IP2 IPEEE submittal, in addition to the internal fires and seismic events, examined a number of other external hazards:

- high winds and tornadoes;
- external flooding; and
- ice, hazardous chemical, transportation, and nearby facility incidents.

The examination of IP2 utilized the NUREG-1407-recommended progressive screening approach for high winds, external flood, and transportation and nearby facility accidents. With the exception of high winds, these events were screened from further consideration using the NUREG-1407 guidance. Therefore, these other external event hazards are not included in this attachment and are not expected to impact the conclusions of this SAMA evaluation.

The IPEEE also applied and evaluated Generic Letter 89-22 probable maximum precipitation criterion as requested by NUREG-1407 to address Generic Issue 103. Although the evaluation did not result in quantification of the risk associated with these events, several suggested enhancements were implemented, including addition of a drain flapper valve to the surveillance program, addition of weather stripping to an exterior door, and placement of screens on 480V switchgear room hub drains.

#### E.1.3.3.1 High Wind Analysis

IP2 structures and systems were designed to the wind loading requirements of the building codes in effect in the early 1970s. They pre-date and do not meet the 1975 Standard Review Plan criteria. Therefore, utilizing the NUREG-1407 screening approach, it was concluded that a detailed probabilistic risk assessment was needed to address the impact of high wind events at IP2.

The wind hazard and building fragility analysis performed for the Indian Point Probabilistic Safety Study [[Reference E.1-25](#)] was reviewed and updated as necessary. An event tree was used to define a set of unique wind induced PDS. The CDF resulting from each wind induced PDS was quantified by modifying the internal event plant logic model, accounting for the frequency of each damage state and the wind-induced equipment damage.

Conservative assumptions in the high wind PSA analysis included the following.

- Offsite power was assumed to be lost for all high wind events.
- Building frame failures were assumed to cause failure of all equipment within the building.
- Missile (high wind projectile) impact on a structure was assumed to cause failure of all equipment within that structure.

- Likelihood of missile (high wind projectile) strikes was assumed to be independent of the intensity of the hazard.
- Both onsite and offsite alternate power sources (gas turbines) were assumed to fail given failure of a more robust structure.

The conclusions of the IP2 high wind PRA were as follows.

- The total point estimate wind induced CDF for IP2 is  $3.03 \times 10^{-5}$  per year.
- Sequences associated with structural failures are the dominant contributors to the wind risk profile.
- No vulnerabilities which could cause early failures of containment or containment bypass were identified.

The major contributors to wind risk at IP2 are major structural failures rather than component failures. Thus, as described in [Table E.2-1](#) items 214, 227 and 228, insights from the IPEEE and PSA updates show that IP2 could decrease the CDF following SBO and unavailability of the gas turbines by aligning the IP3 Appendix R diesel, by installing an IP2 Appendix R diesel, by upgrading the EDG building, and by protecting the alternate power source from tornados and high winds. Aligning the IP3 Appendix R diesel, installing an IP2 Appendix R diesel, and hardening the alternate power source were not evaluated in Phase II SAMAs because, as discussed in [Section E.1.4.3](#), a modification to replace the existing gas turbines with an IP2 Appendix R diesel is planned for the near future. This modification includes provisions for aligning the IP3 Appendix R diesel and for protecting the new alternate power source from tornados and high winds. Potential upgrade of the EDG building was evaluated in Phase II [SAMA 066](#). Given the substantial cost and complexity of major structural changes, no further cost-effective changes to reduce wind risk were identified.

Since the time of the high wind PRA, one of the gas turbines has been removed from service. Although this change has been incorporated in the Level 1 PSA model, it is not reflected in the IPEEE wind risk value of  $3.03 \times 10^{-5}$  since the IPEEE is not a living model. Although removal of this gas turbine reduces the probability of recovering power from the offsite gas turbine location, the impact on the IPEEE high wind risk contribution has been off-set by improvement in the availability of the remaining offsite gas turbine. Also, as discussed in [Section 4.21](#), qualitative assessment of conservatism in the high wind model and changes within the Level 1 PSA model that have caused internal event CDF to decrease 43% since the IPE shows that the IPEEE wind risk contribution is conservative. Therefore, the IPEEE wind risk contribution of  $3.03 \times 10^{-5}$  per year was used to determine the external events multiplier described in [Section 4.21.5.4](#).

**Table E.1-11  
 IP2 Fire Updated CDF Results**

<b>Fire Zone</b>	<b>Fire Zone Description</b>	<b>CDF/year</b>	<b>New Estimate CDF/year</b>
1A	electrical tunnel / pipe penetration area	$9.19 \times 10^{-7}$	$6.55 \times 10^{-7}$
2A	primary water makeup area	$1.05 \times 10^{-6}$	$5.13 \times 10^{-7}$
11	cable spreading room	$4.28 \times 10^{-6}$	$2.04 \times 10^{-6}$
14	switchgear room	$3.84 \times 10^{-6}$	$1.40 \times 10^{-6}$
15	control room	$7.07 \times 10^{-6}$	$1.43 \times 10^{-6}$
74A	electrical penetration area	$1.11 \times 10^{-6}$	$2.97 \times 10^{-7}$
6A*	drumming and storage station	$1.53 \times 10^{-9}$	$1.53 \times 10^{-9}$
32A*	cable tunnel	$9.62 \times 10^{-8}$	$9.62 \times 10^{-8}$
1*	CCW pump room	$2.19 \times 10^{-9}$	$2.19 \times 10^{-9}$
22/63A*	service water intake	$7.46 \times 10^{-9}$	$7.46 \times 10^{-9}$
23*	AFW pump room	$6.15 \times 10^{-9}$	$6.15 \times 10^{-9}$

\* Note: These fire zones had no sequences with CDF contribution greater than  $1 \times 10^{-7}$  and were conservatively not re-evaluated.

### E.1.4 PSA Model Revisions and Peer Review Summary

The summary of the IP2 PSA models CDF and LERF is presented in the table below.

<b>Summary of Major PSA Models</b>		
<b>Model</b>	<b>CDF (/ry)</b>	<b>LERF (/ry)</b>
IPE (8/1992)	3.13E-5 <sup>1</sup>	N/A <sup>2</sup>
RISKMAN Model (5/2003)	2.19E-5	1.27E-6
Revision 0 (3/2005)	1.71E-5	1.05E-6
Revision 1 (3/2007)	1.79E-5	6.50E-7

1. The IP2 IPE did not include internal flooding, which was examined as part of the IPEEE
2. The IP2 IPE did not provide a LERF value since the use of LERF as a risk metric post dates the IPE

#### E.1.4.1 Major Differences between the IP2 Revision 0 PSA Model and Original IPE Model

The IP2 risk model has undergone both updates and a change from RISKMAN to CAFTA since the IPE was performed. The changes implemented prior to the change from RISKMAN to CAFTA are described in [Section E.1.4.3](#).

In the IPE model, the contributors in order of dominance were transients (41.40 percent), LOCAs (33.30 percent), SBO (14.26 percent), SGTR (5.98 percent), ATWS (5.78 percent), and ISLOCA (0.09 percent). As noted previously, the internal flooding analysis was done separately in the IPEEE.

In the final RISKMAN model (following the WOG peer review), the contributors in order of dominance were internal flooding (29.71 percent), LOCA (20.08 percent), loss of offsite power (19.37 percent), ATWS (14.09 per cent), transients (5.61 percent), loss of CCW (4.14 percent), SGTR (3.57 percent), vessel rupture (1.37 percent), loss of DC power (1.11 percent), loss of non-essential service water (0.42 percent), ISLOCA (0.32 percent), and total loss of service water (0.20 percent).

The Revision 0 PSA model [[Reference E.1-2](#)] CDF (1.71E-5/ry) represents a slight reduction from the CDF determined from the final RISKMAN model (2.19E-5/ry).

In the Revision 0 PSA model, the contributors in order of dominance were loss of offsite power (31.48 percent), internal flooding (28.96 percent), LOCA (7.53 percent), transients (7.53 percent),

ATWS (5.75 percent), SGTR (4.57percent), total loss of service water (4.01 percent), SBO (3.80 percent), loss of CCW (3.10 percent), loss of non-essential service water (1.83 percent), vessel rupture (0.58 percent), ISLOCA (0.58 percent), and loss of 125 VDC power (0.26 percent).

Significant changes were made during the conversion and development of the Revision 0 PSA model. Changes were made to reflect new data, calculations, and modifications to the plant design and procedures. The major model changes impacting CDF and LERF that were incorporated into the IP2 PSA Revision 0 model can be summarized as follows.

### **Level 1 - Core Damage Model**

- Updated initiating event database, including all IP2 plant trips that occurred between 1/1/1986 and 12/31/2003.
- Updated component failure data base that reflects failures that occurred between 2/1/1991 and 12/31/2003, and unavailability data base occurred between 7/1/1993 and 12/31/2003, more equipment groups in which common-cause failures may occur and current on-line maintenance practices.
- Revised HRA to reflect the EOP changes up to 12/31/2003.
- Revised internal flooding analysis to reflect design and procedure modifications.
- Adopted the linked fault tree approach versus the support-state model used in RISKMAN. While RISKMAN uses a large-event-tree/small-fault-tree approach to quantification, the IP2 PSA Revision 0 uses the CAFTA small-event-tree/large-fault-tree approach.
- Provided a more detailed modeling of instrumentation and control systems.
- Utilized MAAP thermal-hydraulic calculations based on a reactor thermal output power level of 3216 MWt (versus 3071.4 MWt) to reflect the IP2 power uprate obtained in 2003 and the stretch power uprate project.
- Incorporated the Improved Technical Specifications issued in 2003.
- Revised initiating event definitions and grouping to that used for other ENN models.
- Revised common-cause component failure modeling to the Alpha method (versus the Multiple-Greek-Letter method used in the previous update). The Alpha method is a more recent method that has been approved by the NRC and used in the NRC plant Standardized Plant Assessment Risk models.
- Updated HRA method to reflect the most recent version of the EPRI HRA method and incorporate improvements in the performance shaping factors and inter-action dependency.

- Updated generic component failure database based on EGG-SSRE-8875 failure rates. The generic data used in the previous model was based on a proprietary database obtained from PLG.
- Updated RCP seal LOCA model to that documented in WCAP-16141, which was approved for use by NRC and is also referred to as the WOG2000 RCP seal LOCA model. The RCP seal LOCA model used in the previous model was based on a previous version of the WOG RCP seal LOCA model, so some differences existed in failure probabilities and timing. In addition, core uncover times used to model RCP seal LOCAs were revised based on plant-specific MAAP runs.
- Updated offsite power recovery data using information contained in EPRI report 1009889, which contains data through 2003. The previous model was based on NUREG/CR-5496 and only included loss of offsite power events through 1996.
- Added event trees for loss of primary coolant events that remain within the capability of the charging system (i.e. small-small LOCAs), RCP seal LOCAs caused by random mechanical failures, loss of essential service water, and additional ISLOCA break locations.

Specific changes to reflect WOG peer review recommendations included the following.

- Revised internal flooding analysis, including estimates of pipe-break frequencies and human error probabilities.
- Updated ISLOCA analysis to address specific pathways, to specifically address ISLOCAs inside containment, to credit mitigating systems only for small LOCAs outside containment, to remove credit for makeup to the RWST and to reduce the break size screening criterion to one inch or less consistent with the approach in NUREG/CR-5744.

## **Level 2 - Containment Performance Model**

As part of the conversion process, the Level 2 analysis was re-done using the more detailed methodology employed earlier for Indian Point Unit 3 (IP3).

The new containment response analysis entailed the following.

- Identifying and describing key highlights of component, system, and structure data of significance in assessing severe accident progressions.
- Applying MAAP 4.0 plant analytical models and the selection of empirical factor and data inputs.
- Reviewing the PDS that characterize the RCS, containment, and core-cooling systems at the start of core damage.



- Characterizing the containment strength assessment and the magnitude of various loads necessary to fail containment.
- Selecting a CET that models various accident scenarios in terms of system capability and human interaction to arrest core damage and prevent an undesirable outcome, given the sets of initial conditions defined by the various PDS.
- Characterizing radionuclide releases by associating each CET end state that was found to have a significant frequency with a specific source term.
- Developing the LERF model.
- Describing the methods and the results of the CET probabilistic analyses (quantification), and the source term numerical results and insights.
- Performing sensitivity studies to evaluate the effects on containment performance of changes in phenomena and changes to plant hardware and operating procedures.

There were no specific IP2 Level 2 WOG peer review issues, other than the ISLOCA issue discussed above, that needed to be addressed during the conversion to the fault tree linking platform. The major Level 2 issue from the IP3 WOG peer review, consideration of the predicted Csl release fraction in the assignment of sequences to release categories, was resolved in both the IP3 Revision 1 and the IP2 Revision 0 models.

#### **E.1.4.2 Major Differences between the IP2 Revision 1 PSA Model and Revision 0 PSA Model**

Quantification of the IP2 Revision 1 PSA model [[Reference E.1-3](#)] resulted in a slightly higher CDF than Revision 0 (i.e., 1.79E-5/ry for Revision 1 vs. 1.71E-5/yr for Revision 0). Major changes impacting CDF and LERF are summarized as follows.

##### **Level 1 - Core Damage Model**

- Included common cause terms for MOVs associated with hot-leg recirculation.
- Revised model to reflect the fact that normal offsite power feeds to the 480VAC safeguards buses do not trip on a SI signal without a concurrent loss of offsite power.
- Updated several initiating event frequencies including loss of offsite power, turbine trip, loss of main feedwater, main steam line break, and SGTR using data through the end of 2005.
- Updated the frequency for total loss of service water to reflect updated NRC component-specific common cause alpha factors for service water pumps. Previously, the model used generic alpha factors for motor-driven pumps.

- Added common-cause plugging of service water pump strainers.
- Updated common cause treatment of the main steam atmospheric relief valves to incorporate the latest Alpha factors from the NRC website.
- Added credit for Unit 1 station air compressors for non-loss of offsite power scenarios.
- Revised success criterion for the AFW system to require flow to two (rather than one) of four steam generators for normal (non-ATWS) response. In addition, the normal position of motor-driven AFW pump flow control valves was changed from open to closed.
- Updated offsite power recovery model based on data contained in NUREG/CR-6890, which provides loss of offsite power data from 1986 to 2004. The offsite power recovery model used in Rev. 0 was based on data contained in EPRI report 11009889, which only contains data through 2003.

## **Level 2 - Containment Performance Model**

- Introduced ten additional PDS to better facilitate transfer of Level 1 information into the Level 2 containment performance analysis.
- Changed definition of high releases to "greater than 10% Csl released," which is consistent with the current industry definition. The previous definition was based on Csl releases greater than 1%.
- Changed some of the containment event tree release category magnitude endstate values (e.g., a number of endstates previously classified as late medium releases were reclassified as late high releases) based on the updated accident progression analysis.

### **E.1.4.3 PSA Model Peer Review**

The original IPE submittal was based on a DOS version of the IP2 RISKMAN support state PSA model that used an equation format for system modeling. That submittal did not include evaluation of internal flooding events, which were subsequently included in the IPEEE analysis. Subsequent to the IPE, the IP2 internal events model was converted from using system equations to fault trees and a limited number of asymmetries that were conservatively modeled in the IPE were eliminated. As a result, the internal event CDF at the time of the IPEEE was 2.85E-5. The CDF for the original IPE was 3.13E-5/ry. [Reference E.1-1] The CDF contribution from internal flooding, found during the IPEEE, was 6.66E-6/ry. The RISKMAN model was subsequently converted to the WINDOWS platform and modified to reflect plant changes and modeling improvements, including

- credit for feedwater or condensate recovery, where available,
- treatment of cross-header common cause for both the essential and non-essential service water headers,

- update of equipment performance and unavailability data,
- update and upgrade of the human error probabilities based on extensive thermal hydraulic calculations,
- incorporation of a more current RCP seal LOCA model, and
- inclusion of internal flooding events.

The model, including the above changes, was peer reviewed in May 2002 using the process adapted by the Westinghouse Owners Group (WOG) from the review process that was originally developed and used by the Boiling Water Reactor Owners Group and subsequently broadened to be an industry-applicable process, through the Nuclear Energy Institute Risk Applications Task Force. All of the technical elements were graded as sufficient to support applications requiring the capabilities of a grade 2, e.g., risk ranking applications. In addition, most of the elements were further graded as sufficient to support applications requiring the capabilities defined for grade 3, e.g., risk-informed applications supported by deterministic insights. Facts and Observation sheets documented the certification team's insights and potential level of significance. There were no Level A findings (for which immediate model changes would have been appropriate) from the peer review. Although a number of minor model corrections were made following the peer review, no significant changes were made to the model structure or underlying assumptions. The final version of the IP2 RISKMAN model was completed in May 2003. Quantification of that model resulted in a CDF of  $2.19E-5/ry$ , again including internal flooding.

Subsequently, the IP2 model was converted from the support state RISKMAN model to a linked fault tree CAFTA model. That effort also included an update and a number of modeling changes for consistency with other Entergy Nuclear Northeast (ENN) risk models and changes in the state of the art. The conversion addressed the remaining issues and observations from the IP2 WOG Peer Review (i.e., Level B, C, and D observations), where appropriate. In addition, the issues raised during the peer review of the IP3 model were also examined for applicability to IP2. All applicable issues were addressed consistent with the treatment for IP3. Given the conversion of the model to the Entergy standard methodology and approach, and to assure consistency for future updates, the revised model was named the "IP2 PSA Model Revision 0" and issued in March 2005 [[Reference E.1-2](#)].

The individual work packages (event tree, fault tree, human reliability analysis (HRA), data, etc.) and internal flooding analysis developed for the Revision 0 PSA model were circulated to other PSA members for independent peer review. The work packages and internal flooding analyses were also provided to appropriate IPEC plant personnel for review. Additionally, the revised model was subjected to a focused self assessment to demonstrate technical quality in preparation for the Mitigating Systems Performance Indicator program in 2006. Also, the update was subjected to a week-long review by a team of industry peers from outside of the ENN staff in July 2005. All findings and recommendations from this peer review were resolved and incorporated in the IP2 Revision 1 PSA model issued in April 2007.

The model changes in the IP2 Revision 1 PSA model were peer reviewed for accuracy and consistency by members of the ENN staff not directly involved in their implementation. In

addition, cognizant departments at IP2—licensing, operations, maintenance, training, planning & scheduling, system engineering, and design engineering—were provided with the final results and insights derived from the study for review prior to the issuance of the Revision 1 report.

In accordance with plant procedures, potential plant modifications, design change documents and emergency operating procedure changes are reviewed to determine their impact on the PSA model prior to implementation. A PSA model change request database is maintained to track potential changes and assess their degree of impact of the PSA model. As of December 2006, this database shows no outstanding changes since December 2005 due to modifications or procedure changes that could have a significant impact on the results of the PSA or the SAMA analysis.

A modification to replace the existing gas turbines with a diesel generator (IP2 SBO/Appendix R diesel) capable of being used to recover power to the vital buses following a station blackout is planned for the near future. The IP2 SBO/Appendix R diesel is not reflected in the PSA model used for the SAMA analysis. A sensitivity study showed that including the IP2 SBO/Appendix R diesel in the model in place of the gas turbines would decrease the internal events CDF by about 1%. The slight decrease in CDF is due to the increased reliability of the IP2 SBO/Appendix R diesel when compared with that of the gas turbines. The IPEEE external events model is not a living model subject to requantification. However, the increased reliability of the IP2 SBO/Appendix R diesel when compared with that of the gas turbines and the relative ruggedness of the planned location of the IP2 SBO/Appendix R diesel within the turbine building compared to that of the gas turbine location would result in an overall reduction in the external event risk contribution. Since the impact on internal events CDF is so slight, redistribution of the relative importance of failure events in the internal events Level 1 model from this modification is not expected to add events to [Table E.1-2](#) that would be likely contributors for the identification of cost-beneficial SAMAs. Therefore, the Phase I analysis would not be impacted by this modification.

If the model had included the IP2 Appendix R diesel in place of the gas turbines, the benefit estimates for Phase II SAMAs enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events (SAMAs 024 through 031) may have been slightly less due to the difference in reliability. For the same reason, the benefit for SAMA 066 (harden the EDG building and fuel oil transfer pumps against tornados and high winds) may have been slightly less. The conclusion of the SAMA analysis for these SAMAs (except SAMA 028) is that the cost of implementation is greater than the benefit. Lowering the benefit would not alter this conclusion. The conclusion for SAMA 028, "Provide a portable diesel-driven battery charger," is that the benefit with uncertainty is greater than the cost of implementation. Therefore, SAMA 028 is retained for further evaluation. Since the impact on CDF is so slight, the benefit with uncertainty of SAMA 028 is not expected to decrease enough to alter the potentially cost-beneficial conclusion, and SAMA 028 is still retained for further evaluation. Thus, the results of the SAMA analysis would remain unchanged if the model included the IP2 Appendix R diesel in place of the gas turbines.

## **E.1.5 MACCS2 Model: Level 3 Analysis**

### **E.1.5.1 Introduction**

SAMA evaluation relies on Level 3 PRA results to measure the effects of potential plant modifications. A Level 3 PRA model using the most recent version (version 1.13.1) of MACCS2 [Reference E.1-6] was created for IP2. This model, which requires detailed site-specific meteorological, population, and economic data, estimates the consequences in terms of population dose and offsite economic cost. Risks in terms of population dose risk (PDR) and offsite economic cost risk (OECR) were also estimated in this analysis. Risk is defined as the product of consequence and frequency of an accidental release.

This analysis evaluates a base case to provide best-estimate consequences for postulated internal events. Instead of considering various emergency planning scenarios, the base case uses a conservative assumption of no evacuation.

PDR was estimated by summing over all releases the product of population dose and frequency for each accidental release. Similarly, OECR was estimated by summing over all releases the product of offsite economic cost and frequency for each accidental release. Offsite economic cost includes costs that could be incurred during the emergency response phase and costs that could be incurred through long-term protective actions.

### **E.1.5.2 Input**

The following sections describe the site-specific input parameters used to obtain the offsite dose and economic impacts for cost-benefit analyses.

#### **E.1.5.2.1 Projected Total Population by Spatial Element**

The total population within a 50-mile radius of IP2 was estimated for the year 2035 for each spatial element by combining total resident population projections with transient populations. The 2035 county level resident projections were derived from the New York Statistical Information System from 2000 to 2030, the New Jersey Department of Labor and Workforce Development from 2000 to 2025, the Connecticut State Data Center from 2000 to 2020, and the Pennsylvania State Data Center from 2000 to 2020 using regression analysis [References E.1-15 through E.1-18). The 2035 transient population was assumed to be the 2004 transient to permanent population ratio multiplied by the extrapolated permanent population. The 2004 transient data

were obtained from state tourism agencies. Table E.1-12 summarizes the estimated population distribution.

**Table E.1-12  
Estimated Population Distribution within a 50-mile Radius**

<b>Sector</b>	<b>0-10 miles</b>	<b>10-20 miles</b>	<b>20-30 miles</b>	<b>30-40 miles</b>	<b>40-50 miles</b>	<b>50-mile Total</b>
<b>N</b>	12,488	22,955	30,654	39,620	51,057	156,774
<b>NNE</b>	14,952	28,140	39,917	56,226	67,213	206,448
<b>NE</b>	23,377	29,419	53,692	62,559	41,261	210,308
<b>ENE</b>	40,386	74,856	119,073	152,175	176,338	562,828
<b>E</b>	41,290	118,335	156,720	200,581	208,394	725,320
<b>ESE</b>	37,861	121,515	144,267	54,180	34,361	392,184
<b>SE</b>	41,873	111,946	87,735	236,426	379,990	857,970
<b>SSE</b>	12,197	98,326	481,703	1,380,249	1,218,170	3,190,645
<b>S</b>	20,621	135,211	1,164,596	3,732,339	3,164,306	8,217,073
<b>SSW</b>	30,318	202,605	395,389	922,649	1,034,467	2,585,428
<b>SW</b>	30,796	183,372	276,902	197,362	246,076	934,508
<b>WSW</b>	27,723	64,428	209,197	109,102	85,849	496,299
<b>W</b>	16,925	32,026	50,974	61,380	57,384	218,689
<b>WNW</b>	14,036	32,528	54,577	57,977	29,719	188,837
<b>NW</b>	13,421	32,572	54,557	24,046	22,317	146,913
<b>NNW</b>	12,286	31,660	32,569	27,599	34,374	138,488
<b>Total</b>	390,550	1,319,894	3,352,522	7,314,470	6,851,276	19,228,712

**E.1.5.2.2 Land Fraction**

The land fraction for each spatial element was estimated within the 50 mile radius area. The National Hydrography Dataset was used to estimate the extent of land and surface water coverage ([Reference E.1-19](#)).

E.1.5.2.3 Watershed Class

Watershed Index is defined by MACCS2 as areas drained by rivers (Class 1) or large water bodies (Class 2). For IPEC, no spatial elements were treated as large water bodies. Therefore, only one watershed class was assigned for the 50 mile zone surrounding IP2.

E.1.5.2.4 Regional Economic Data

**Region Index**

Each spatial element was assigned to an economic region, defined in this report as a county. Where a spatial element covers portions of more than one county, it was assigned to that county having the most area within the element.

**Regional Economic Data**

County level economic data were obtained from the United States Census of Agriculture for 2002 ([Reference E.1-20](#)).

**VALWF: Value of Farm Wealth**

MACCS2 requires an average value of farm wealth (dollars/hectare) for the 50-mile radius area around IPEC. The county-level farmland property value was used as a basis for deriving this value. VALWF is \$50,071/hectare.

**VALWNF: Value of Non-Farm Wealth**

MACCS2 also requires an average value of non-farm wealth. The county-level non-farm property value was used as a basis for deriving this value. VALWNF is \$163,631/person.

Other economic parameters and their values are shown below. The values were obtained by adjusting the economic data from a past census given as default values in [Reference E.1-6](#) with the consumer price index of 195.3, which is the average value for the year 2005, as appropriate.

Variable	Description	Value
EVACST	Daily cost for a person who has been evacuated (\$/person-day)	46.7
POPCST	Population relocation cost (\$/person)	8640
RELCST	Daily cost for a person who is relocated (\$/person-day)	46.7
CDFRM0	Cost of farm decontamination for the various levels of decontamination (\$/hectare)	972 2160

Variable	Description	Value
CDNFRM	Cost of non-farm decontamination for the various levels of decontamination (\$/person)	5184 13824
DLBCST	Average cost of decontamination labor (\$/person-year)	60480
DPRATE	Property depreciation rate (per year)	0.2
DSRATE	Investment rate of return (per year)	0.12

#### E.1.5.2.5 Agriculture Data

The source of regional crop information is the 2002 Census of Agriculture ([Reference E.1-20](#)). The crops listed for each county within the 50-mile area were summed and mapped into the seven MACCS2 crop categories.

#### E.1.5.2.6 Meteorological Data

The MACCS2 model requires meteorological data for wind speed, wind direction, atmospheric stability, accumulated precipitation, and atmospheric mixing heights. The required data were obtained from the IPEC meteorological monitoring system and regional National Weather Service stations.

#### **Site Specific Data**

IPEC meteorological monitoring system includes both primary and backup systems. The primary meteorological system, which includes a 122 meter instrumented tower located onsite, was the data source for the MACCS2 analysis. Based on a review of annual meteorological data collected at the site between 1995 and 2004, five recent years of data were averaged and used for this study. The five-year data included 43,848 (two leap years) consecutive hourly values of wind speed, wind direction, precipitation, and temperature recorded at the IPEC meteorological tower from January 2000 to December 2004. Missing data were estimated using data substitution methods. These methods include substitution of missing data with valid data from the previous hour and substitution of valid data collected from other elevations on the meteorological tower.

#### **Regional Mixing Height Data**

Mixing height is defined as the height of the atmosphere above ground level within which a released contaminant will become mixed (from turbulence) within approximately one hour. Regional mixing heights were calculated using data collected at National Weather Service (NWS) Station No. 72503 in White Plains, NY (approximately 16 miles southeast of IP2) and NWS Station No. 54775 in Albany, NY (approximately 80 miles north of IP2). These two weather stations were the closest NWS sources of data for local and upper air conditions. Staff meteorologists at the National Climatic Data Center selected these two stations for data used to calculate seasonal mixing height values for the IP2 area.



**E.1.5.2.7 Emergency Response Assumptions**

A detailed analysis of evacuation scenarios in emergency planning zone (EPZ) were addressed in the IP2 evacuation travel time estimate study (Reference E.1-21). The study was conducted in 2004 and provides an analysis of the range and variation of public reaction to the evacuation notification process. Evacuation, which is considered as an effective measure for mitigating accident consequences, would reduce radiation dose received by population within the EPZ. The primary parameters affecting the evacuation consequences are evacuation speed and time elapsed to the start of evacuation. Either a lower speed of evacuation or a delayed evacuation would increase the received radiation dose. In turn, should no evacuation get initiated, the dose would be higher. For this study, a "no evacuation scenario" was assumed to conservatively estimate the population dose.

**E.1.5.2.8 Core Inventory**

The estimated IP2 core inventory (Table E.1-13) used in the MACCS2 input is based on current core configuration and a power level of 3216 MW (t).

**Table E.1-13  
IP2 Core Inventory (Becquerels)<sup>1</sup>**

<b>Nuclide</b>	<b>Inventory</b>	<b>Nuclide</b>	<b>Inventory</b>
Co-58	3.04E+16	Te-131m	4.64E+17
Co-60	2.32E+16	Te-132	4.57E+18
Kr-85	3.84E+16	I-131	3.20E+18
Kr-85m	8.48E+17	I-132	4.64E+18
Kr-87	1.63E+18	I-133	6.56E+18
Kr-88	2.29E+18	I-134	7.19E+18
Rb-86	8.31E+15	I-135	6.11E+18
Sr-89	3.08E+18	Xe-133	6.28E+18
Sr-90	3.05E+17	Xe-135	1.67E+18
Sr-91	3.87E+18	Cs-134	7.19E+17
Sr-92	4.19E+18	Cs-136	2.10E+17
Y-90	3.18E+17	Cs-137	4.15E+17
Y-91	3.98E+18	Ba-139	5.83E+18
Y-92	4.19E+18	Ba-140	5.62E+18

**Table E.1-13  
IP2 Core Inventory (Becquerels)<sup>1</sup> (Continued)**

Nuclide	Inventory	Nuclide	Inventory
Y-93	4.85E+18	La-140	6.04E+18
Zr-95	5.38E+18	La-141	5.34E+18
Zr-97	5.41E+18	La-142	5.17E+18
Nb-95	5.45E+18	Ce-141	5.31E+18
Mo-99	6.11E+18	Ce-143	4.96E+18
Tc-99m	5.34E+18	Ce-144	4.19E+18
Ru-103	4.89E+18	Pr-143	4.78E+18
Ru-105	3.36E+18	Nd-147	2.13E+18
Ru-106	1.71E+18	Np-239	6.56E+19
Rh-105	3.09E+18	Pu-238	1.44E+16
Sb-127	3.47E+17	Pu-239	1.22E+15
Sb-129	1.04E+18	Pu-240	1.83E+15
Te-127	3.43E+17	Pu-241	4.12E+17
Te-127m	4.50E+16	Am-241	4.92E+14
Te-129	1.02E+18	Cm-242	1.23E+17
Te-129m	1.50E+17	Cm-244	1.33E+16

1. Derived from [Reference E.1-22](#) for a power level of 3216 MWth except for Co-58 and Co-60, which were power-scaled from the reference inventory given in [Reference E.1-6](#).

#### E.1.5.2.9 Source Terms

Only eight of nine release categories given in Table E.1-9, corresponding to internal event sequences, were part of the MACCS2 input. The Early Low-Low category has zero release frequency and is not considered. [Section E.1.2.2.7](#) provides details of the source terms for postulated internal events. A linear release rate was assumed between the time the release started and the time the release ended.

### **E.1.5.3 Results**

Risk estimates for the base case were analyzed with MACCS2. The base case assumes no evacuation. [Table E.1-14](#) shows estimated base case mean risk values for each release mode. The estimated mean values of PDR and offsite OECR for IP2 are 22 person-rem/yr and \$44,900/yr, respectively.

**Table E.1-14  
 Base Case Mean PDR and OECR Values**

Release Mode	Frequency (/yr)	Population Dose (person-sv) <sup>1</sup>	Offsite Economic Cost (\$)	Population Dose Risk (PDR) (person-rem/yr)	Offsite Economic Cost Risk (OECR) (\$/yr)
NCF	1.19E-05	2.28E+01	5.16E+04	2.71E-02 <sup>2</sup>	6.13E-01
EARLY HIGH	6.50E-07	1.58E+05	3.42E+10	1.03E+01	2.22E+04
EARLY MEDIUM	4.23E-07	4.86E+04	1.17E+10	2.06E+00	4.95E+03
EARLY LOW	1.11E-07	1.90E+04	3.06E+09	2.11E-01	3.40E+02
LATE HIGH	6.88E-07	4.23E+04	1.05E+10	2.91E+00	7.22E+03
LATE MEDIUM	3.43E-06	1.78E+04	2.84E+09	6.11E+00	9.75E+03
LATE LOW	6.43E-07	5.37E+03	5.25E+08	3.45E-01	3.38E+02
LATE LOW-LOW	5.82E-08	4.64E+03	4.60E+08	2.70E-02	2.68E+01
<b>Totals</b>				<b>2.20E+01</b>	<b>4.49E+04</b>

1. 1 sv = 100 rem

2.  $2.71E-02 \text{ (person-rem/yr)} = 1.19E-05 \text{ (/yr)} \times 2.28E+01 \text{ (person-sv)} \times 100 \text{ (rem/sv)}$

## **E.1.6 References**

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## **ATTACHMENT E.2**

### **EVALUATION OF IP2 SAMA CANDIDATES**

## E.2 EVALUATION OF IP2 SAMA CANDIDATES

This section describes the generation of the initial list of potential SAMA candidates, screening methods, and the analysis of the remaining SAMA candidates.

### E.2.1 SAMA List Compilation

A list of SAMA candidates was developed by reviewing industry documents and considering plant-specific enhancements not identified in published industry documents. Since IP2 is a conventional pressurized water reactor, considerable attention was paid to the SAMA candidates from SAMA analyses for other pressurized water reactor plants. Industry documents reviewed include the following.

- Calvert Cliffs Nuclear Power Plant SAMA Analysis [[Reference E.2-1](#)]
- H.B. Robinson Steam Electric Plant Unit No.2 SAMA Analysis [[Reference E.2-2](#)]
- Virgil C. Summer Nuclear Station SAMA Analysis [[Reference E.2-3](#)]
- Arkansas Nuclear One Unit 2 SAMA Evaluation [[Reference E.2-4](#)]
- Donald C. Cook Nuclear Plant SAMA Analysis [[Reference E.2-5](#)]
- Millstone Units 2 and 3 SAMA Analysis [[Reference E.2-6](#)]
- Joseph M. Farley Nuclear Plant SAMA Analysis [[Reference E.2-7](#)]
- Point Beach Nuclear Plant Units 1 and 2 SAMA Analysis [[Reference E.2-8](#)]
- Palisades Nuclear Plant SAMA Analysis [[Reference E.2-28](#)]

The above documents represent a compilation of most SAMA candidates developed from the industry documents. These sources of other industry documents include the following.

- Quad Cities SAMA Analysis [[Reference E.2-9](#)]
- General Electric ABWR severe accident mitigation design alternative (SAMDA) Analysis [[Reference E.2-10](#)]
- Limerick SAMDA cost estimate report [[Reference E.2-11](#)]
- NUREG-1437 description of Limerick SAMDA [[Reference E.2-12](#)]
- NUREG-1437 description of Comanche Peak SAMDA [[Reference E.2-13](#)]
- Tennessee Valley Authority (TVA) response to NRC's RAI on the Watts Bar SAMDA submittal [[Reference E.2-14](#)]
- TVA response to NRC's RAI on the Watts Bar Generic Letter 88-20 IPE for Severe Accident Vulnerabilities [[Reference E.2-15](#)]
- Westinghouse AP600 SAMDA [[Reference E.2-16](#)]
- NUREG-1462, Final safety evaluation report related to the certification of Combustion Engineering System 80+ design [[Reference E.2-17](#)]
- NUREG-0498, Final Environmental Statement related to the Operation of Watts Bar Nuclear Plant Units 1 and 2, Supplement 1, Section 7 [[Reference E.2-18](#)]
- NUREG-1560, Volume 2, NRC Perspectives on the IPE Program [[Reference E.2-19](#)]
- NUREG/CR-5474, Assessment of Candidate Accident Management Strategies [[Reference E.2-20](#)]



In addition to SAMA candidates from review of industry documents, SAMA candidates were obtained from plant-specific sources, such as the IP2 IPE and updates [References E.2-21, E.2-22 and E.2-23] and IPEEE [Reference E.2-24]. In the original IPE, PSA model updates, and IPEEE, several enhancements related to severe accident insights were recommended and implemented. These enhancements are included in the comprehensive list of Phase I SAMA candidates. Table E.2-1 lists the IPE, PSA model update, and IPEEE Phase I SAMA candidates and indicates which have been implemented, which have been incorporated in the model used for the SAMA analysis, and which have been retained for further evaluation in Phase II of the SAMA analysis. The current PSA was also used to identify plant-specific modifications for inclusion in the comprehensive list of SAMA candidates. The risk significant terms from the current PSA model were reviewed for similar failure modes and effects that could be addressed through a potential enhancement to the plant. The correlation between SAMAs and the risk significant terms are listed in Tables E.1-2 and E.1-5.

The comprehensive list contained a total of 231 Phase I SAMA candidates and is available in onsite documentation.

### **E.2.2 Qualitative Screening of SAMA Candidates (Phase I)**

The purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were not viable for implementation at IP2. Potential SAMA candidates were screened out if they modified features not applicable to IP2, if they had already been implemented at IP2, or if they were similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate. During this process, 58 of the Phase I SAMA candidates were screened out because they were not applicable to IP2, 9 of the Phase I SAMA candidates were screened out because they were similar in nature and could be combined with another SAMA candidate, and 96 of the Phase I SAMA candidates were screened out because they had already been implemented at IP2, leaving 68 SAMA candidates for further analysis. The final screening process involved identifying and eliminating those items whose implementation cost would exceed their benefit as described below. Table E.2-2 provides a description of each of the 68 Phase II SAMA candidates. As described in Section 4.21.5.4, the “baseline benefit” values in this table represent the total SAMA benefits for both internal and external events.

### **E.2.3 Final Screening and Cost Benefit Evaluation of SAMA Candidates (Phase II)**

A cost/benefit analysis was performed on each of the remaining SAMA candidates. If the implementation cost of a SAMA candidate was determined to be greater than the potential benefit (i.e., there was a negative net value) the SAMA candidate was considered not to be cost beneficial and was not retained as a potential enhancement.

The expected cost of implementation of each SAMA was established from existing estimates of similar modifications. Most of the cost estimates were developed from similar modifications considered in previously performed SAMA. In particular, these cost-estimates were derived from the following sources.

- Arkansas Nuclear One Unit 2 SAMA Analysis [[Reference E.2-4](#)]
- Calvert Cliffs SAMA Analysis [[Reference E.2-1](#)]
- Donald C. Cook SAMA Analysis [[Reference E.2-5](#)]
- Fort Calhoun Unit 1 SAMA Analysis [[Reference E.2-25](#)]
- Joseph M. Farley SAMA Analysis [[Reference E.2-7](#)]
- McGuire SAMA Analysis [[Reference E.2-26](#)]

The cost estimates did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs associated with unforeseen implementation obstacles. Estimates based on modifications that were implemented or estimated in the past were presented in terms of dollar values at the time of implementation (or estimation), and were not adjusted to present-day dollars. Therefore, the cost estimates were conservative.

The benefit of implementing a SAMA candidate was estimated in terms of averted consequences. The benefit was estimated by calculating the arithmetic difference between the total estimated costs associated with the four impact areas for the baseline plant design and the total estimated impact area costs for the enhanced plant design (following implementation of the SAMA candidate).

Values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the NUREG/BR-0184 [[Reference E.2-27](#)] conversion factor of \$2,000 per person rem and discounted to present value. Values for avoided offsite economic costs were also discounted to present value.

As this analysis focuses on establishing the economic viability of potential plant enhancement when compared to attainable benefit, detailed cost estimates often were not required to make informed decisions regarding the economic viability of a particular modification. Several of the SAMA candidates were clearly in excess of the attainable benefit estimated from a particular analysis case.

For less clear cases, engineering judgment on the cost associated with procedural changes, engineering analysis, testing, training, and hardware modification was applied to determine if a more detailed cost estimate was necessary to formulate a conclusion regarding the economic viability of a particular SAMA. Based on a review of previous submittals' SAMA evaluations and an evaluation of expected implementation costs at IP2, the following estimated costs for each potential element of the proposed SAMA implementation were used.

<b><u>Type of Change</u></b>	<b><u>Estimated Cost Range</u></b>
Procedural only	\$25K-\$50K
Procedural change with engineering required	\$50K-\$200K
Procedural change with engineering and testing/training required	\$200K-\$300K

**Type of Change**

**Estimated Cost Range**

Hardware modification

\$100K to >\$1000K

In most cases, more detailed cost estimates were not required, particularly if the SAMA called for the implementation of a hardware modification. Nonetheless, the cost of each unscreened SAMA candidate was conceptually estimated to the point where conclusions regarding the economic viability of the proposed modification could be adequately gauged. The cost benefit comparison and disposition of each of the 68 Phase II SAMA candidates is presented in [Table E.2-2](#).

Bounding evaluations (or analysis cases) were performed to address specific SAMA candidates or groups of similar SAMA candidates. These analysis cases overestimated the benefit and thus were conservative calculations. For example, one SAMA candidate suggested installing a digital feedwater upgrade system. The bounding calculation estimated the benefit of this improvement by total elimination of risk due to loss of feedwater events (see analysis of Phase II [SAMA 41](#) in [Table E.2-2](#)). This calculation obviously overestimated the benefit, but if the inflated benefit indicated that the SAMA candidate was not cost beneficial, then the purpose of the analysis was satisfied.

A description of the analysis cases used in the evaluation follows.

**Diesel Powered RCP Seal Injection**

This analysis case was used to evaluate the change in plant risk from providing an independent, diesel powered RCP seal cooling system. The plant modification involves installation of a two-inch pipe inside containment and the PAB, manual isolation valves, control valves, instrumentation to monitor flow, self-contained diesel generator outside the PAB, pump, instrumentation cables, four orifices, power cable to the pump, two filters, water source piping and valves, and containment penetration piping and instrumentation. It also requires revision of standard operating and emergency operating procedures; calculations for piping and support dead weight, electrical load, and instrumentation setpoints; additional procedures; and training. RCP seal cooling enhancements would add redundancy to RCP seal cooling, reducing CDF from loss of component cooling or service water or from a SBO event. A bounding analysis was performed by setting all consequential RCP seal LOCAs from all plant initiators to zero in the level 1 PDS model, which resulted in a baseline benefit of approximately \$198,892. This analysis case was used to model the benefit of Phase II SAMA 001.

**Non-Diesel Powered RCP Seal Injection**

This analysis case was used to evaluate the change in plant risk from providing an independent RCP seal cooling system without dedicated diesel power backup. RCP seal cooling enhancements would add redundancy to RCP seal cooling, reducing CDF from loss of component cooling or service water or from a SBO event. A bounding analysis was performed by setting all consequential RCP seal LOCAs from non-SBO initiators to zero in the level 1 PDS

model, which resulted in a baseline benefit of approximately \$182,710. This analysis case was used to model the benefit of Phase II SAMA 002.

### **Additional CCW Pump**

This analysis case was used to evaluate the change in plant risk from installing an additional CCW pump. An additional CCW pump reduces the probability of loss of component cooling leading to a RCP seal LOCA. A bounding analysis was performed by setting common cause failures of CCW pumps to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 003.

### **Service Water Pumps**

This analysis case was used to evaluate the change in plant risk from providing a procedure to cross-tie service water pumps to reduce the frequency of loss of service water. A bounding analysis was performed by setting the loss of non-essential service water and loss of essential service water initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$44,633. This analysis case was used to model the benefit of Phase II SAMA 004.

### **RHR Heat Exchangers**

This analysis case was used to evaluate the change in plant risk by improving the ability to cool the RHR heat exchangers by implementing procedure and hardware modifications to allow manual alignment of the fire protection system. A bounding analysis was performed by setting the loss of CCW to the RHR heat exchangers to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$56,813. This analysis case was used to model the benefit of Phase II SAMA 005.

### **EDG Building Ventilation**

This analysis case was used to evaluate the change in plant risk by adding a diesel building high temperature alarm to improve diagnosis of loss of diesel building room cooling events. A bounding analysis was performed by setting loss of diesel building ventilation to zero in the level 1 PSA model, which results in a baseline benefit of approximately \$28,451. This analysis case was used to model the benefit of Phase II SAMA 006.

### **Filtered Containment Vent**

This analysis case was used to evaluate the change in plant risk from installing a filtered containment vent to provide fission product scrubbing. A bounding analysis was performed by setting late containment overpressurization failure to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$556,227. This analysis case was used to model the benefit of Phase II SAMA 007.

### **Molten Core Debris Removal**

This analysis case was used to estimate the change in plant risk from providing a molten core debris cooling mechanism. The plant modification for a reactor cavity flooding system involves use of fire water as a supply, a run of 500 feet of 8-inch pipe to a 1000 gpm pump (similar to containment spray pump), and a run of 8-inch pipe from the pump spare piping penetration. A 1-inch mini-flow test line and instrumentation would be required for periodic testing. In addition, calculations would be required for pipe support, pump capacity, electric cable, electrical loading, flow, and instrumentation. Additional procedures and training for alignment would also be required. A bounding analysis was performed by setting containment failure due to core-concrete interaction to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$1,697,309. This analysis case was used to model the benefit of Phase II SAMAs 008, 009, and 010.

### **Inert Containment**

This analysis case was used to estimate the change in plant risk from providing a means to inert containment to prevent combustion of hydrogen and carbon monoxide gases. A bounding analysis was performed by setting containment failures due to hydrogen burns to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$695,283. This analysis case was used to model the benefit of Phase II SAMA 011.

### **Containment Sprays**

This analysis case was used to evaluate the change in plant risk from installing additional containment spray capability to provide containment pressure control. A bounding analysis was performed by setting the events for loss of containment spray to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 012, 013, and 016.

### **Base Mat Melt-Through**

This analysis case was used to evaluate the change in plant risk from increasing the depth of the concrete base mat to ensure base mat melt-through does not occur. A bounding analysis was performed by setting containment failure due to base mat melt-through to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$392,631. This analysis case was used to model the benefit of Phase II SAMA 014.

### **Strengthen Containment**

This analysis case was used to evaluate the change in plant risk from strengthening containment by constructed a building connected to primary containment that is maintained at a vacuum to provide a method to depressurize containment and reduce fission product release. The proposed plant modification involves construction of a building structurally strong enough to sustain an approximately 10 psi pressure differential. Vacuum pumps, piping (600 feet), electrical equipment, instrumentation, and containment penetrations would be required. A

bounding analysis was performed by setting all energetic containment failure modes (DCH, steam explosions, late over-pressurization) to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$1,496,904. This analysis case was used to model the benefit of Phase II SAMA 015.

### **Containment Liner Protection**

This analysis case was used to evaluate the change in plant risk from constructing a barrier that provides containment liner protection from ejected core debris at high RCS pressure. The proposed plant modification involves installation of a 50 foot diameter, 70 foot high barrier made of stainless steel. A bounding analysis was performed by setting the probability of HPME and subsequent DCH at high RCS pressure to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$368,091. This analysis case was used to model the benefit of Phase II SAMA 017.

### **Steam Generator Heat Removal**

This analysis case was used to evaluate the change in plant risk from installing a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources. The proposed plant modification involves installation of two 8-inch penetrations into each steam generator, eight lengths of 8-inch pipe and supports inside containment, eight containment penetrations, piping and supports outside of containment, a water storage tank (about 300,000 gallons), tank heater, and instrumentation. It would also require hydro testing, procedure revisions and training. This SAMA would provide an additional means to scrub fission product releases. A bounding analysis was performed by setting SGTR with loss of secondary-side cooling events to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$16,360. This analysis case was used to model the benefit of Phase II SAMA 018.

### **Secondary Side Pressure Capacity**

This analysis case was used to evaluate the change in plant risk from increasing the secondary side pressure capacity to lower the occurrence of an unisolated SGTR. A bounding analysis was performed by eliminating failure to isolate the ruptured steam generator during a SGTR to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$1,144,727. This analysis case was used to model the benefit of Phase II SAMA 019.

### **SGTR Fission Product Scrubbing**

This analysis case was used to evaluate the change in plant risk from routing the discharge from the main steam safety valves through a structure where water spray would condense the steam and scrub the fission products inventory. The proposed plant medication involves installation of four tanks (50 feet long with 20 spray nozzles) and 400 feet of city water piping and supports. Procedure revisions and training would also be required. A bounding analysis was performed by reducing SGTR accident progression source terms by a factor of 2, which resulted in a baseline

benefit of approximately \$126,787. This analysis case was used to model the benefit of Phase II SAMA 020.

### **ISLOCA Mitigation**

This analysis case was used to evaluate the change in plant risk from installing additional pressure or leak monitoring instrumentation between the pressure isolation valves in ISLOCA pathways or submerging potential ISLOCA break points in water. A bounding analysis was performed by setting all ISLOCA initiators to zero in the level 1 PSA model which resulted in a baseline benefit of approximately \$425,172. This analysis case was used to model the benefit of Phase II SAMAs 021 and 024.

### **ISLOCA Valves**

This analysis case was used to evaluate the change in plant risk from reducing the probability of an ISLOCA by increasing the frequency of valve leak testing or adding redundant and diverse limit switches to each containment isolation valve. The increased valve leak testing involves testing of 24 safety-related valves in containment. To allow for testing of valves located inside containment during power operation, installation of a test connection for each valve with piping outside of containment and double containment isolation valves would be required. In addition, revised procedures and training would need to be developed. A bounding analysis was performed by reducing the ISLOCA initiator 50 percent in the level 1 PSA model, which resulted in a baseline benefit of approximately \$212,586. This analysis case was used to model the benefit of Phase II SAMAs 022 and 023.

### **MSIV Design**

This analysis case was used to evaluate the change in plant risk from improving MSIV design to decrease the likelihood of containment bypass scenarios. A bounding analysis was performed by setting MSIV failures to isolate a faulted or ruptured steam generator to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$28,629. This analysis case was used to model the benefit of Phase II SAMA 025.

### **DC Power**

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of Class 1E DC power (i.e., increasing battery capacity, using fuel cells, or improving DC bus load shedding). It was assumed that battery life could be significantly extended from the existing battery capacity. This enhancement would extend AFW steam-driven pump operability and allow more time for AC power recovery. A bounding analysis was performed by changing the time available to recover offsite power before local operation of the AFW steam-driven pump is required from 2 hours to 24 hours during SBO scenarios in the level 1 PSA model. This resulted in a baseline benefit of approximately \$44,633. This analysis case was used to model the benefit of Phase II SAMAs 026, 027, and 029.

### **Alternate Battery Charger Capability**

This analysis case was used to evaluate the change in plant risk from plant modifications to provide alternate battery charging capability by installing a portable diesel-driven battery charger. The proposed plant modification involves purchasing, installing and maintaining a diesel-driven generator to charge the 130VDC batteries. Safety-related quick disconnects would be used to charge the selected battery. The diesel generator would be installed in a weather enclosure outside the turbine or control building, requiring fire barrier penetration sealing. The location would be as close as possible to the batteries to decrease the power loss along the cable. Calculation of cable size would have to be performed. In addition, procedure development and training would be required. A bounding analysis was performed by setting failure to locally control the turbine-driven AFW pump to zero in the Level 1 PSA model. This resulted in a baseline benefit of approximately \$420,459. This analysis case was used to model the benefit of Phase II SAMA 028.

### **AC Power Cross-Tie with IP3**

This analysis case was used to evaluate the change in plant risk from a plant modification to create an AC power cross-tie with IP3 to improve AC power reliability. The proposed plant modification involves installation of two breakers and 1500 feet of cable, conduit and supports from the 480VAC switchgears. Procedure development and training would also be required. A bounding analysis was performed by setting loss of the gas turbines to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$52,724. This analysis case was used to model the benefit of Phase II SAMA 030.

### **EDG Alternate Engine Cooling**

This analysis case was used to evaluate the change in plant risk from providing a redundant and diverse source of engine cooling for the EDGs, which would contribute to enhanced diesel reliability. A bounding analysis was performed by setting loss of the essential service water supply for diesel cooling to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$36,542. This analysis case was used to model the benefit of Phase II SAMAs 031 and 032.

### **Improve 118VAC System**

This analysis case was used to evaluate the change in plant risk from plant modifications to convert under-voltage AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic. This would reduce the risk associated with inverter failure and would improve the availability of the 118VAC vital bus. A bounding analysis was performed by setting common cause failure of the 118VAC transformers to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 033.



### **Low Pressure Injection System**

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of alternate low pressure injection (i.e., additional diesel-driven low pressure vessel makeup or modification of the diesel-driven fire pump). Use of the diesel-driven fire pump for low pressure injection requires installation of piping, valves and supports. Procedure development and training would also be required. A bounding analysis was performed by eliminating failure of the RHR system in the level 1 PSA model, which resulted in a baseline benefit of approximately \$4,090. This analysis case was used to model the benefit of Phase II SAMAs 034 and 037.

### **High Pressure Injection System**

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of high pressure injection (i.e., installing a diesel-driven high pressure injection system or replacing two of the three motor-driven SI pumps with diesel-powered pumps). A bounding analysis was performed by setting failure of the SI system to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$24,450. This analysis case was used to model the benefit of Phase II SAMAs 035 and 039.

### **Automatic Recirculation Cooling Swap-Over**

This analysis case was used to evaluate the change in plant risk from installing an automatic swap-over to recirculation cooling upon RWST depletion to enhance the reliability of ECCS suction. A bounding analysis was performed by setting failure to align recirculation cooling (internal and external) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$81,086. This analysis case was used to model the benefit of Phase II SAMA 036.

### **Conserve RWST Water Inventory**

This analysis case was used to evaluate the change in plant risk from extending RWST capability by throttling low pressure injection pump flow earlier in medium or large-break LOCAs. A bounding analysis was performed by setting failure to align recirculation cooling (internal and external) in large and medium LOCAs to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$20,360. This analysis case was used to model the benefit of Phase II SAMA 038.

### **Enhance RCS Depressurization**

This analysis case was used to evaluate the change in plant risk from enhancing RCS depressurization to allow successful low pressure ECCS injection following a small LOCA and high pressure SI failure. A bounding analysis was performed by setting common cause failure of the steam generator atmospheric dump valves (ADV) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$142,968. This analysis case was used to model the benefit of Phase II SAMA 040.

### **Main Feedwater System Upgrade**

This analysis case was used to evaluate the change in plant risk from installing a digital feedwater upgrade to reduce the probability of loss of main feedwater following a plant trip or from installing a motor-driven feedwater pump to enhance the availability of feedwater injection subsequent to MSIV closure. A bounding analysis was performed by setting the loss of main feedwater initiator to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$105,536. This analysis case was used to model the benefit of Phase II SAMAs 041 and 043.

### **Steam Generator Atmospheric Steam Dump Valve Enhancement**

This analysis case was used to evaluate the change in plant risk in automating the backup nitrogen supply to the steam generator atmospheric steam dump valve (ADV). This would eliminate the need for local manual action to align nitrogen bottles for control air during a loss of offsite power. A bounding analysis was performed by setting the manual local action to align nitrogen supply for control air supply to the steam generator ADV to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$12,270. This analysis case was used to model the benefit of Phase II SAMA 042.

### **Alternate Water Sources to Steam Generators**

This analysis case was used to evaluate the change in plant risk from providing emergency connections to use the fire water system as backup for steam generator inventory. The proposed modification involves installation of 500 feet of 6-inch pipe from the fire pump house to a new electric 800 gpm pump. The modification would also require heat tracing, valves, supports, breakers and cabling, procedure development and training. A bounding analysis was performed by setting failure of the turbine-driven AFW pump and failure of local operation of AFW during SBO to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$984,503. This analysis case was used to model the benefit of Phase II SAMA 044.

### **Install Large Pressurizer PORVs**

This analysis case was used to evaluate the change in plant risk from installing larger capacity PORVs to allow successful feed and bleed cooling with one valve open. A bounding analysis was performed by modifying the number of PORVs required for RCS feed and bleed from 2-of-2 to 1-of-2 and reducing failure of the operator action for feed and bleed by a factor of 5 in the level 1 PSA model, which resulted in a baseline benefit of approximately \$385,602. This analysis case was used to model the benefit of Phase II SAMA 045.

### **Diesel Power to Instrument Air Compressors**

This analysis case was used to evaluate the change in plant risk from modifying emergency operating procedures to align emergency diesel power to the instrument air compressors. This enhancement allows increased reliability of instrument air following loss of offsite power. A bounding analysis was performed by setting failure of the instrument air system to zero in the

level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 046.

### **Independent Boron Injection System**

This analysis case was used to evaluate the change in plant risk from installing an independent boron injection system to provide a redundant means to shut down the reactor during ATWS. A bounding analysis was performed by setting common cause failure of the boric acid transfer pumps to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 047.

### **ATWS Overpressure Protection**

This analysis case was used to evaluate the change in plant risk from installing a system of relief valves in the RCS to prevent equipment damage from a pressure spike during an ATWS. This enhancement would improve equipment availability after an ATWS. The proposed modification involves installation of additional safety valves, discharge lines to the pressurizer relief tank, acoustic monitoring, and RCS hydro capability. Procedure development and training would also be required. A bounding analysis was performed by setting the CDF contribution from RCS overpressurization during an ATWS to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$48,723. This analysis case was used to model the benefit of Phase II SAMA 048.

### **Control Room ATWS Mitigation**

This analysis case was used to evaluate the change in plant risk from installing motor generator set trip breakers in the control room (SAMA 049) or providing the capability to remove power from the bus powering the control rods (SAMA 050). For SAMA 049, the proposed plant modification involves installation of two additional breakers, 300 feet of cable, conduit and supports. This modification also requires two penetrations of the control room boundary and resealing, procedure development and training. For SAMA 050, procedure changes and training would be required. These enhancements would reduce the CDF due to ATWS. A bounding analysis was performed by setting failure to trip the control rods motor generator sets to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$28,451. This analysis case was used to model the benefit of Phase II SAMAs 049 and 050.

### **Large Break LOCA**

This analysis case was used to evaluate the change in plant risk from installing a digital large break LOCA protection system. The proposed plant modification involves installation of analog to digital converters, digital logic racks, and input into the emergency safeguard system logic relay racks. Procedure modifications and training would also be required. A bounding analysis was performed by setting the large break LOCA initiator to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 051.

### **Main Steam Line Break inside Containment**

This analysis case was used to evaluate the change in plant risk from installing secondary side guard pipes up to the MSIVs. This enhancement would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. This SAMA would also guard against or prevent consequential multiple SGTRs following a main steam line break event. A bounding analysis was performed by setting the main steam line break initiators (inside and outside containment) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$73,529. This analysis case was used to model the benefit of Phase II SAMA 052.

### **Pressurizer PORV Block Valves**

This analysis case was used to evaluate the change in plant risk from changing the pressurizer PORV block valves from closed to open. This enhancement would reduce the CDF contribution from loss of secondary heat sink when bleed and feed is not available. A bounding analysis was performed by setting PORV block valve failure to open to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$377,512. This analysis case was used to model the benefit of Phase II SAMA 053.

### **480VAC Switchgear Room Flood Alarm**

This analysis case was used to evaluate the change in plant risk from installing a flood alarm in the 480VAC switchgear room to reduce CDF following switchgear room flooding. The proposed modification involves installing a single alarm and spare wires from the switchgear room to the control room. Procedure revisions and training would also be required. A bounding analysis was performed by setting control building flooding initiator frequencies to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$1,722,733. This analysis case was used to model the benefit of Phase II SAMA 054.

### **High-Head Recirculation Cooling**

This analysis case was used to evaluate the change in plant risk from hardware modifications to allow high-head recirculation from either RHR heat exchanger or from providing procedural guidance to allow high-head recirculation from either RHR heat exchanger. This enhancement would reduce the CDF contribution from transients and LOCAs. The proposed plant modification for SAMA 055 involves installation of an 8-inch pipe tee on the RHR heat exchanger 22 outlet, piping, a new MOV, controls and indications. A bounding analysis was performed by setting loss of high-head recirculation cooling from RHR heat exchanger 21 hardware failures to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 055 and 058.

### **RHR Heat Exchanger Valves**

This analysis case was used to evaluate the change in plant risk from keeping the RHR heat exchanger discharge MOVs normally open to reduce the CDF contribution from transients and

LOCAs. A bounding analysis was performed by setting RHR heat exchanger discharge MOV failure to open to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$44,633. This analysis case was used to model the benefit of Phase II SAMA 056.

### **Pressurizer PORV DC Power**

This analysis case was used to evaluate the change in plant risk from plant modifications to provide a backup source of DC power for the PORVs. This enhancement would reduce the CDF contribution from loss of secondary heat sink and enhance feed and bleed availability. The proposed plant modification involves installation of an additional battery, inverter, charger and two transfer switches. Procedure revisions and training would also be required. A bounding analysis was performed by setting failure of DC power to the PORVs to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$40,721. This analysis case was used to model the benefit of Phase II SAMA 057.

### **AFW System Changes**

This analysis case was used to evaluate the change in plant risk from re-installing the low pressure suction trip on the AFW pumps and enhancing procedures to respond to loss of the normal suction path. This enhancement would increase system availability following loss of the normal AFW suction path and would reduce the CDF contribution from SBO events. The proposed plant modification involves installing two pressure switches for AFW pumps 21 & 22. Procedure revisions and training would also be required. A bounding analysis was performed by setting the CDF contribution from the loss of normal suction path to the AFW system to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$20,360. This analysis case was used to model the benefit of Phase II SAMA 059.

### **Flood Protection from Stairwell 4 into 480VAC Switchgear Room**

This analysis case was used to evaluate the change in plant risk from adding protection against flood propagation from stairwell 4 into the 480V switchgear room. The proposed plant modification involves installation of a reverse door swing, additional ductwork and a check valve. A bounding analysis was performed by setting the internal flood initiator from a break in fire protection piping in stairwell 4 to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$387,828. This analysis case was used to model the benefit of Phase II SAMA 060.

### **Flood Protection from Deluge Room into 480VAC Switchgear Room**

This analysis case was used to evaluate the change in plant risk from adding protection against flood propagation from the deluge room into the 480V switchgear room. The proposed plant modification involves upgrading the deluge room and the inside door to fire barriers. A bounding analysis was performed by setting the internal flood initiator from a break in the 10-in fire protection piping in elevation 15-ft deluge room to zero in the level 1 PSA model, which resulted

in a baseline benefit of approximately \$853,187. This analysis case was used to model the benefit of Phase II SAMA 061.

### **Alternate Safe Shutdown System (ASSS) Power to SI Pump**

This analysis case was used to evaluate the change in plant risk from plant modifications for a hard-wired connection to an SI pump from an ASSS power supply. This enhancement would reduce the CDF contribution from internal and external events that cause loss of power from the 480V vital buses. The proposed plant modification involves installation of 500 feet of cable and conduit, a breaker and transfer switches. A bounding analysis was performed by setting failure to align ASSS power to the high-head SI pumps and charging pumps subsequent to loss of power from vital 480VAC buses due to control building flooding initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$273,489. This analysis case was used to model the benefit of Phase II SAMA 062.

### **RHR Pump Room Flood Protection**

This analysis case was used to evaluate the change in plant risk from providing a water-tight door for additional protection of the RHR pumps against flooding from sources in the PAB. The proposed plant modification involves installation of a water-tight door, a drain pump and a check valve. A bounding analysis was performed by setting the internal flood initiators inside the PAB to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$36,542. This analysis case was used to model the benefit of Phase II SAMA 063.

### **CCW Heat Exchanger Alternate Cooling Supply**

This analysis case was used to evaluate the change in plant risk from providing a backup cooling water source for the CCW heat exchangers. This enhancement would reduce the CDF contribution from loss of non-essential service water events. The proposed plant change involves use of backup service water pumps to cool the CCW heat exchangers. Piping and valves exist to implement this change; however, additional analysis would be required to ensure adequate cooling flow (electrical load and service water flow). In addition, procedure changes and training would be required. A bounding analysis was performed by setting the loss of non-essential service water initiator to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$36,542. This analysis case was used to model the benefit of Phase II SAMA 064.

### **Upgrade ASSS for RCP Seal Cooling**

This analysis case was used to evaluate the change in plant risk from upgrading the ASSS to allow timely restoration of seal injection and cooling. This enhancement would reduce the CDF contribution from internal and external events that cause loss of power from the 480VAC vital buses. The proposed plant modification involves installation of 500 feet of multi-conductor cable to the control room, along with control room penetration and sealing. In addition, the modification requires control switches mounted in panels, seismic evaluations, and internal wiring. Procedure revisions and training would also be required. A bounding analysis was performed by setting the

control building flooding initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$1,722,733. This analysis case was used to model the benefit of Phase II SAMA 065.

### **Harden EDG Building**

This analysis case was used to evaluate the change in plant risk from plant modifications to harden the EDG building and fuel oil transfer pumps against tornados and high winds. Since external events are not part of the internal event PSA model, a bounding analysis was performed by determining the risk associated with wind induced events that included loss of the EDG building from the IPEEE high wind model. Since these events would result in SBO conditions, that risk was added to the internal event SBO PDS to create a revised baseline CDF specifically for this SAMA. This appropriately accounts for the reduced likelihood of offsite power recovery for the scenario. Removal of this risk results in an 85% reduction from the higher SAMA-specific CDF and a baseline benefit of approximately \$1,577,438. Since this modification mitigates high wind external events, the external event multiplier described in Section 4.21.5.4, which was still applied to this SAMA, provides additional conservatism in the baseline benefit value. This analysis case was used to model the benefit of Phase II SAMA 066.

### **Charging Pump Alternate Cooling**

This analysis case was used to evaluate the change in plant risk from plant modifications to allow the primary water system to cool the charging pumps. This enhancement would reduce the effect of loss of CCW by providing an alternate means to cool the charging pumps and preserve seal injection after a loss of CCW. The proposed plant modification involves installation of two manual valves and 100 feet of piping per charging pump. Procedure revisions and training would also be required. A bounding analysis was performed by setting failure to align city water alignment to the charging pumps to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$8,091. This analysis case was used to model the benefit of Phase II SAMA 067.

### **Recirculation Pump Motor Alternate Cooling**

This analysis case was used to evaluate the change in plant risk from providing an independent source of cooling for the recirculation pump motors to reduce CDF associated with loss of CCW events. The proposed plant modification involves connecting city water or primary water supply to the piping associated with the auxiliary component cooling pumps, including isolation valves and supports (~300 feet of piping). A discharge drain line, procedure development and training would also be required. A bounding analysis was performed by setting loss of CCW to the recirculation pumps to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$12,181. This analysis case was used to model the benefit of Phase II SAMA 068.

## **E.2.4 Sensitivity Analyses**

Three sensitivity analyses were conducted to gauge the impact of assumptions upon the analysis. The benefits estimated for each of these sensitivities are presented in [Table E.2-3](#).

A description of each sensitivity case follows:

### **Sensitivity Case 1: Years Remaining Until End of Plant Life**

The purpose of this sensitivity case was to investigate the sensitivity of assuming a 28-year period for remaining plant life (i.e. eight years on the original plant license plus the 20-year license renewal period). The 20-year license renewal period was used in the base case. The resultant monetary equivalent was calculated using 28 years remaining until end of facility life to investigate the impact on each analysis case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

### **Sensitivity Case 2: Conservative Discount Rate**

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the discount rate. The discount rate of 7.0% used in the base case analyses is conservative relative to corporate practices. Nonetheless, a lower discount rate of 3.0% was assumed in this case to investigate the impact on each analysis case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

### **Sensitivity Case 3: Inclusion of Economic Losses Due to Tourism and Business**

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the inclusion of economic losses due to tourism and business. The MACCS2 economic model used for the base case analysis did not consider such losses. This sensitivity case assumed a loss of \$208,838/person as opposed to \$163,631/person in the affected region following a postulated severe accident. This increased the calculated offsite economic cost risk for the base case and for each SAMA under consideration. Since the benefit for each SAMA is estimated as the difference between the base case and the SAMA, the sensitivity case 3 benefit values ([Table E.2-3](#)) are the same or only slightly higher than the baseline benefit values. Therefore, changing this assumption does not cause additional SAMAs to be cost-beneficial.



## **E.2.5 References**

- E.2-1 Attachment (2), Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Operating License Renewal Stage, Calvert Cliffs Nuclear Power, April 1998.
- E.2-2 Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal Application for the H.B. Robinson Steam Electric Plant Unit No.2, June 2002.
- E.2-3 Appendix E, Environmental Report, Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal Application for the Virgil. C. Summer Nuclear Station, August 2002.
- E.2-4 Appendix E-Attachment E, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Arkansas Nuclear One - Unit 2, October 2003.
- E.2-5 Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for License Renewal, Donald C. Cook Nuclear Plant, October 2003.
- E.2-6 Appendix F and Appendix G - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for Renewed Operating Licenses, Millstone Power Station, Units 2 and 3, January 2004.
- E.2-7 Appendix D - Attachment F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Application for License Renewal, Joseph M. Farley Nuclear Plant, September 2003.
- E.2-8 Appendix E - Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Application for Renewed Operating Licenses, Point Beach Nuclear Plant Units 1 and 2, February 2004.
- E.2-9 Appendix F, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Quad Cities Nuclear Power Plant Units 1 and 2, January 2003.
- E.2-10 General Electrical Nuclear Energy, Technical Support Document for the ABWR, 25A5680, Revision 1, January 18, 1995.
- E.2-11 Cost Estimate for Severe Accident Mitigation Design Alternatives, Limerick Generating Station for Philadelphia Electric Company, Bechtel Power Corporation, June 22, 1989.
- E.2-12 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*, Volume 1, 5.35, Listing of SAMDAs considered for the Limerick Generating Station, U.S. Nuclear Regulatory Commission, May 1996.

- E.2-13 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*, Volume 1, 5.36, Listing of SAMDAs considered for the Comanche Peak Steam Electric Station, U.S. Nuclear Regulatory Commission, May 1996.
- E.2-14 Letter from Mr. D. E. Nunn (TVA) to NRC Document Control Desk dated October 7, 1994, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Severe Accident Mitigation Design Alternatives (SAMDA) - Response to Request for Additional Information (RAI) - (TAC Nos. M77222 and M77223)."
- E.2-15 Letter from Mr. M. O. Medford (TVA) to NRC Document Control Desk dated September 1, 1992, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Generic Letter (GL) 88-20 - Individual Plant Examination (IPE) for Severe Accident Vulnerabilities - Response - (TAC M74488)."
- E.2-16 Letter from N. J. Liparulo (Westinghouse Electric Corporation) to NRC Document Control Desk, dated December 15, 1992, "Submittal of Material Pertinent to the AP600 Design Certification Review."
- E.2-17 NUREG-1462, Final Safety Evaluation Report related to the Certification of CE System 80+ design, U.S. Nuclear Regulatory Commission, August 1994.
- E.2-18 NUREG 0498, *Final Environmental Statement Related to the Operation of Watts Bar Nuclear Plant, Units 1 and 2*, Supplement No. 1, U.S. Nuclear Regulatory Commission, April 1995.
- E.2-19 NUREG-1560, *Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance*, Volume 2, U.S. Nuclear Regulatory Commission, December 1997.
- E.2-20 NUREG/CR-5474, *Assessment of Candidate Accident Management Strategies*, U.S. Nuclear Regulatory Commission, March 1990.
- E.2-21 Indian Point 2 Nuclear Generating Station Individual Plant Examination of Internal Events (IPE) Report, August 1992.
- E.2-22 IP-RPT-04-00230 "Indian Point Unit 2 Nuclear Power Plant Probabilistic Safety assessment Revision 0, March 2005.
- E.2-23 IP-RPT-07-00230 "Indian Point Unit 2 Nuclear Power Plant Probabilistic Safety assessment Revision 1, April 2007.
- E.2-24 Indian Point 2 Nuclear Generating Station Individual Plant Examination of External Events (IPEEE) Report, December 1995.

- E.2-25 Appendix E, Appendix 5 - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for License Renewal, Fort Calhoun Unit 1 Nuclear Station, January 2002.
- E.2-26 Duke Power Company, Applicant's Environmental Report, Operating License Renewal Stage, Attachment K, "McGuire Nuclear Stations Severe Accident Mitigation Alternatives (SAMA) Analysis," Rev. 0, Charlotte, North Carolina, May 2001.
- E.2-27 NUREG/BR-0184, *Regulatory Analysis Technical Evaluation Handbook*, U.S. Nuclear Regulatory Commission, January 1997.
- E.2-28 Appendix E-Attachment E, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Palisades Nuclear Plant, March 2005.

**Table E.2-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
201	Operator action: Trip RCPs following loss of CCW	This SAMA would reduce the potential for RCP seal damage due to pump bearing failure.	Already installed	This operator action is taken to reduce the potential for RCP seal damage due to pump bearing failure following loss of CCW. The IP2 procedure instructs the operators to trip the reactor and the RCPs if flow cannot be re-established within two minutes from the time it was lost. Therefore, this SAMA has already been implemented at IP2.	Yes
202	Operator action: Align backup city water cooling to charging pumps following loss of CCW	This SAMA would reduce the possibility of a large RCP seal LOCA following a loss of CCW.	Already installed	This operator action is taken to align backup city water cooling to charging pumps following a loss of CCW to preclude the possibility of a large RCP seal LOCA. The IP2 procedure instructs the operators to align charging pumps in manual at maximum speed and, if no CCW pumps can be started, align backup cooling from city water. Therefore, this SAMA has already been implemented at IP2.	Yes

**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
203	Operator action: Manually control turbine-driven AFW pump after battery depletion	This SAMA would provide direction to manually control the turbine-driven AFW pump after battery depletion to control steam generator water level during SBO.	Already installed	This operator action is taken to align the turbine-driven AFW pump after battery depletion to control steam generator water level and prevent water from entering the turbine and failing the pump. The IP2 procedure instructs the operators to manually open the turbine-driven AFW pump flow control valves to control flow to the steam generators. Therefore, this SAMA has already been implemented at IP2.	Yes
204	Operator action: Align alternate safe shutdown equipment	This SAMA would align alternate safe shutdown equipment to reduce CDF following switchgear room flooding.	Already installed	This operator action is taken to align ASSS to reduce CDF following switchgear room flooding. The IP2 procedure instructs the operators to manually align 23 charging pump, 21 SI pump and 21 AFW pump to ASSS power. Therefore, this SAMA has already been implemented at IP2.	Yes

**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
205	Operator action: Manually insert control rods (ATWS)	This SAMA would insert control rods to reduce CDF following ATWS.	Already installed	This operator action is taken to manually insert control rods for at least one minute prior to peak RCS pressure during ATWS. The IP2 procedure instructs the operators to manually trip the reactor and enter procedure FR-S.1. If a manual trip of the reactor is not successful, FR-S.1 directs the operator to manually insert control rods. Therefore, this SAMA has already been implemented at IP2.	Yes
206	Operator action: Perform early cooldown and depressurization (SGTR)	This SAMA would terminate leakage from RCS into the secondary prior to overfilling the ruptured steam generator.	Already installed	This operator action is taken to cool and depressurize the RCS following a SGTR to terminate leakage from RCS into the secondary prior to overfilling the ruptured steam generator. The IP2 procedure instructs the operators to perform cooldown and depressurize the RCS following a SGTR. Therefore, this SAMA has already been implemented at IP2.	Yes

**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
207	Operator action: Perform late cooldown and depressurization (SGTR)	This SAMA would terminate leakage from RCS into the secondary prior to depleting RWST inventory following a SGTR.	Already installed	This operator action is taken to cool and depressurize the RCS to cold shutdown following a SGTR to terminate leakage from RCS into the secondary prior to depleting RWST inventory. The IP2 procedure instructs the operators to perform cooldown and depressurize the RCS following a SGTR. Therefore, this SAMA has already been implemented at IP2.	Yes
208	Operator action: Initiate emergency boration	This SAMA would initiate emergency boration to reduce CDF following ATWS.	Already installed	This operator action is taken to initiate emergency boration within 10 minutes following an ATWS event. The IP2 procedure instructs the operators to manually trip the reactor and enter procedure FR-S.1. If a manual trip of the reactor is not successful, FR-S.1 directs the operator to initiate emergency boration of the RCS. Therefore, this SAMA has already been implemented at IP2.	Yes

**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
209	Operator action: Align low head ECCS recirculation	This SAMA would reduce the CDF contribution from LOCAs.	Already installed	This operator action is taken to align low head ECCS recirculation (internal and external) following the injection phase of ECCS to deliver flow to the RCS cold legs during a LOCA. The IP2 procedure instructs the operators to transfer to recirculation if RWST level decreases to less than 9.24 feet. Therefore, this SAMA has already been implemented at IP2.	Yes
210	Operator action: Align city water backup cooling to RHR and SI pumps following loss of CCW	This SAMA would reduce the CDF contribution from loss of CCW.	Already installed	This operator action is to align city water backup cooling to RHR and SI pumps following loss of CCW. The IP2 procedure instructs the operators to establish backup cooling to RHR and SI pumps. Therefore, this SAMA has already been implemented at IP2.	Yes
211	Operator action: Align primary water backup cooling to RHR and SI pumps following loss of CCW	This SAMA would reduce the CDF contribution from loss of CCW.	Already installed	This operator action is to align primary water backup cooling to RHR and SI pumps following loss of CCW. The IP2 procedure instructs the operators to establish backup cooling to RHR and SI pumps. Therefore, this SAMA has already been implemented at IP2.	Yes



**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
212	Keep both pressurizer PORV block valves open	This SAMA would reduce the CDF contribution from loss of secondary heat sink when feed and bleed is not available.	Retain (Phase II SAMA 053)	Investigate the feasibility of operating with both pressurizer PORV block valves open. A significant contribution to CDF is caused by events involving total loss of secondary heat sink in which primary feed-and-bleed cooling is not possible because of the inability to open one of the block valves either due to loss of power or random failure of the valves. Considered for a final cost-benefit evaluation, this SAMA would involve procedure and hardware changes to keep both pressurizer PORV block valves open during normal operation.	No
213	Install flood alarm in the 480VAC switchgear room	This SAMA would reduce CDF following switchgear room flooding.	Retain (Phase II SAMA 054)	Investigate the feasibility of installing a flood alarm in the 480V switchgear room. For rupture of the 10-in fire protection line in the deluge room, credit was not given for operator action to mitigate the flood prior to reaching critical flood heights for the switchgear. Appropriate procedures would have to be modified to alert operations personnel to confirm switchgear room conditions upon a fire pump start without a heat or smoke detector alarm, which would be indicative of a rupture of the fire protection piping.	No

**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
214	Align IP3 Appendix R diesel to provide backup power to 6.9kV bus 5 or 6 following a SBO and unavailability of the gas turbines	This SAMA would reduce CDF following a SBO and unavailability of the gas turbines.	Already underway	The engineering evaluation and associated procedural changes to allow aligning the IP3 Appendix R diesel to provide backup power to IP2 6.9kV bus 5 or 6 following a SBO and unavailability of the IP2 Appendix R power source are already underway as part of the installation of the IP2 Appendix R diesel and replacement of the gas turbines.	No
215	Perform a hardware modification to allow high-head recirculation from either RHR heat exchanger	This SAMA would reduce the CDF contribution from transients and LOCAs.	Retain (Phase II SAMA 055)	Considered for a final cost-benefit evaluation, this modification would involve installing a piping connection from RHR heat exchanger 22 to the high-head recirculation header to enhance high-head recirculation capability during transients and LOCAs.	No
216	Keep RHR heat exchanger discharge MOVs normally open	This SAMA would reduce the CDF contribution from transients and LOCAs.	Retain (Phase II SAMA 056)	Considered for a final cost-benefit evaluation, this modification would involve a design modification to keep the RHR heat exchanger discharge MOVs normally open to enhance high pressure recirculation capability during transients and LOCAs.	No

**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
217	Provide DC power backup for the PORVs	This SAMA would reduce the CDF contribution from loss of secondary heat sink and enhance feed and bleed availability.	Retain (Phase II SAMA 057)	Considered for a final cost-benefit evaluation, this modification would involve installing a DC power backup for the PORVs to improve the availability of the PORVs to perform the feed and bleed function during a loss of secondary heat sink.	No
218	Provide procedural guidance to allow high-head recirculation from either RHR heat exchanger	This SAMA would reduce the CDF contribution from transients and LOCAs.	Retain (Phase II SAMA 058)	Considered for a final cost-benefit evaluation, this SAMA would involve procedural changes to use the 22 RHR heat exchanger for high-head recirculation by opening both discharge MOVs and backfeeding through the 21 RHR heat exchanger outlet line.	No
219	Modify power dependencies to increase likelihood of successful high pressure recirculation	This SAMA would reduce the CDF contribution from transients requiring feed and bleed cooling.	Subsumed in Phase I SAMA 212	Swap the power supplies to the following sets of valves: MOVs 746 and 747, MOV 822A and 822B, HCV-638 & HCV-640. Based on power dependencies for those valves, this will increase the likelihood of successful high-head recirculation with feed and bleed cooling. Implementation of this SAMA would require keeping both pressurizer PORV block valves open. Therefore, this SAMA is subsumed in SAMA 212.	No

**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
220	Provide added protection against flood propagation from stairwell 4 into the 480V switchgear room	This SAMA would reduce the CDF contribution from flood sources within stairwell 4 adjacent to the 480V switchgear room.	Retain (Phase II SAMA 060)	Considered for a final cost-benefit evaluation, this modification would involve installation of a reverse door swing, additional ductwork and a check valve.	No
221	Provide added protection against flood propagation from the deluge room into the 480V switchgear room	This SAMA would reduce the CDF contribution from flood sources within the deluge room adjacent to the 480V switchgear room.	Retain (Phase II SAMA 061)	Considered for a final cost-benefit evaluation, this modification would involve upgrading the deluge room and the inside door to fire barriers.	No

**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
222	Provide a hard-wired connection to an SI pump from ASSS power supply	This SAMA would reduce the CDF contribution from internal and external events that cause loss of power from the 480V vital buses (SBO, control building floods and fires).	Retain (Phase II SAMA 062)	Considered for a final cost-benefit evaluation, this modification would involve installing cabling and a transfer switch to provide power from the ASSS power supply directly to at least one SI pump.	No
223	Provide a water-tight door for additional protection of the RHR pumps against flooding	This SAMA would reduce the CDF contribution from flood sources in the PAB.	Retain (Phase II SAMA 063)	Considered for a final cost-benefit evaluation, this modification would involve installing water-tight half height doors in the entrance to the RHR pump cubicles to allow flood water from PAB pipe ruptures to egress through the transformer yard door louvers at 19' elevation. A drain pipe and check valve would also be required.	No

**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
224	Provide backup cooling water source for the CCW heat exchangers	This SAMA would reduce the CDF contribution from loss of non-essential service water events.	Retain (Phase II SAMA 064)	Considered for a final cost-benefit evaluation, the proposed plant change involves use of backup service water pumps to cool the CCW heat exchangers. Piping and valves exist to implement this change; however, additional analysis would be required to ensure adequate cooling flow (electrical load and service water flow).	No
225	Provide alternate source of water to the fan cooler units following loss of all service water	This SAMA would reduce the CDF associated with loss of essential service water.	Already Installed	Connections have been installed in the fan cooler service water inlet and outlet lines to allow connection of fire water, if available, following loss of the essential service water supply.	No

**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
226	Upgrade the ASSS to allow timely restoration of seal injection and cooling.	This SAMA would reduce the CDF contribution from internal and external events that cause loss of power from the 480V vital buses (SBO, control building floods and fires).	Retain (Phase II SAMA 065)	Considered for a final cost-benefit evaluation, this modification would involve providing an automatic start and load feature (or manual start and load from the control room) for the ASSS power source.	No
227	Harden the EDG building and fuel oil transfer pumps against tornados and high winds	This SAMA would reduce the CDF contribution from high wind events that cause loss of offsite power.	Retain (Phase II SAMA 066)	Considered for a final cost-benefit evaluation, this modification would involve hardening the EDG building to meet 1975 Standard Review Plan design criteria for tornados and high winds.	No

**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
228	Harden the alternate power sources against tornados and high winds	This SAMA would reduce the CDF contribution from high wind events that cause loss of offsite power.	Already underway	The design of the new IP2 alternate power source (Appendix R diesel generator) includes protection against tornados and high wind events.	No
229	Provide hardware connections to allow the primary water system to cool the charging pumps	This SAMA would reduce the effect of loss of CCW by providing an alternate means to cool the charging pumps and preserve seal injection after loss of CCW.	Retain (Phase II SAMA 067)	Considered for a final cost-benefit evaluation, this modification would involve installing the necessary connections and implementing procedure changes to allow primary water to supply cooling to the charging pumps on loss of CCW.	No



**Table E.2-1 (Continued)**  
**Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
230	Provide independent source of cooling for the recirculation pump motors	This SAMA would reduce the CDF associated with loss of CCW.	Retain (Phase II SAMA 068)	Considered for a final cost-benefit evaluation, this modification would involve installing the necessary connections and implementing procedure changes to allow an alternate source (city water or primary water) to supply cooling to the recirculation pumps on loss of CCW.	No
231	Re-install the low pressure suction trip on the AFW pumps and enhance procedures to respond to loss of the normal suction path	This SAMA would reduce the CDF from loss of AFW due to loss of the normal suction path.	Retain (Phase II SAMA 059)	Considered for a final cost-benefit evaluation, this modification would re-install the low pressure suction trip to ensure that the pumps would be protected from loss of the normal suction path.	No

**Table E.2-2  
 Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Diesel Powered RCP Seal Injection  001 - Create an independent RCP seal injection system with a dedicated diesel.	Eliminate consequential RCP seal LOCAs from all plant initiators.  The cost of implementing this SAMA was specifically estimated for IP2.	9.59%	1.82%	1.56%	\$198,892	\$418,719	\$1,137,000	Not cost effective
Non-Diesel Powered RCP Seal Injection  002 - Create an independent RCP seal injection system without a dedicated diesel.	Eliminate consequential RCP seal LOCAs from non-SBO events.  The cost of implementing this SAMA was specifically estimated for Donald C. Cook.	8.29%	1.82%	1.56%	\$182,710	\$384,653	\$1,000,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Additional CCW Pump 003 - Install an additional CCW pump.	Eliminate common cause failure of CCW pumps.  The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.	0.12%	0.00%	0.00%	~\$0	~\$0	\$1,500,000	Not cost effective
Service Water Pumps 004 - Enhance procedural guidance for use of service water pumps.	Eliminate loss of non-essential service water and loss of essential service water initiators.  The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.	1.88%	0.45%	0.22%	\$44,633	\$93,964	\$1,750,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
RHR Heat Exchangers  005 - Improve ability to cool the RHR heat exchangers by allowing manual alignment of the fire protection system.	Eliminate loss of CCW to the RHR heat exchangers.  The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	2.93%	0.45%	0.45%	\$56,813	\$119,607	\$565,000	Not cost effective
EDG Building Ventilation  006 - Add a diesel building high temperature alarm.	Eliminate loss of EDG room ventilation.  The cost of implementing this SAMA was specifically estimated for IP2.	1.13%	0.45%	0.22%	\$28,451	\$59,897	\$274,000	Not cost effective
Filtered Containment Vent  007 - Install a filtered containment vent to provide fission product scrubbing.	Eliminate late containment over-pressurization failures.  The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.00%	17.27%	13.36%	\$556,227	\$1,171,004	\$5,700,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Molten Core Debris Removal	Eliminate containment failure due to CCI.	0.00%	48.18%	45.21%	\$1,697,309	\$3,573,283		
008 - Create a large concrete crucible with heat removal potential under the base mat to contain molten core debris.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						\$108,000,000	Not cost effective
009 - Create a reactor cavity flooding system.	The cost of implementing this SAMA was specifically estimated for IP2.						\$3,714,000	Not cost effective
010 - Create a core melt source reduction system.	The cost of implementing this SAMA was specifically estimated for Joseph M Farley.						\$90,000,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Inert Containment  011 - Provide means to inert containment.	Eliminate containment failures due to hydrogen burns.  The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.00%	17.73%	20.49%	\$695,283	\$1,463,754	\$10,900,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Containment Sprays	Eliminate failure of containment spray.	0.00%	0.00%	0.00%	~\$0	~\$0		
012 - Use the fire protection system as a backup source for the containment spray system.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						\$565,000	Not cost effective
013 - Install a passive containment spray system.	The cost of implementing this SAMA was specifically estimated for Joseph M Farley.						\$2,000,000	Not cost effective
016 - Install a redundant containment spray system.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						\$5,800,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Base Mat Melt-Through  014 - Increase the depth of the concrete base mat or use an alternative concrete material to ensure melt-through does not occur.	Eliminate containment failure due to base mat melt-through.  The cost of implementing this SAMA was specifically estimated for Joseph M Farley.	0.00%	12.27%	9.35%	\$392,631	\$826,591	>\$5,000,000	Not cost effective
Strengthen Containment  015 - Construct a building connected to primary containment that is maintained at a vacuum.	Eliminate energetic containment failure modes (DCH, steam explosion, late over-pressurization).  The cost of implementing this SAMA was specifically estimated for IP2.	0.00%	41.36%	40.98%	\$1,496,904	\$3,151,377	\$61,000,000	Not cost effective



**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Containment Liner Protection  017 - Erect a barrier that provides containment liner protection from ejected core debris at high pressure.	Eliminate HPME and subsequent DCH at high RCS pressure.  The cost of implementing this SAMA was specifically estimated for IP2.	0.00%	10.00%	10.24%	\$368,091	\$774,929	\$2,900,000	Not cost effective
Steam Generator Heat Removal  018 - Install a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources.	Eliminate SGTR with loss of secondary-side cooling.  The cost of implementing this SAMA was specifically estimated for IP2.	0.05%	0.45%	0.45%	\$16,360	\$34,441	\$7,400,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Secondary Side Pressure Capacity  019 - Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift.	Eliminate operator failure to isolate the ruptured steam generator.  The cost of implementing this SAMA was specifically estimated for IP2.	2.42%	29.55%	31.18%	\$1,144,727	\$2,409,952	\$13,000,000	Not cost effective
SGTR Fission Product Scrubbing  020 - Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	Reduce SGTR accident progression source terms by a factor of 2.  The cost of implementing this SAMA was specifically estimated for IP2.	0.00%	3.64%	3.34%	\$126,787	\$266,920	\$9,700,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
ISLOCA Mitigation	Eliminate ISLOCAs.	0.83%	10.91%	11.58%	\$425,172	\$895,098		
021 - Install additional pressure or leak monitoring instrumentation for ISLOCAs.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						\$2,300,000	Not cost effective
024 - Ensure all ISLOCA releases are scrubbed.	The cost of implementing this SAMA was specifically estimated for IP2.						\$9,700,000	Not cost effective
ISLOCA Valves	Reduce ISLOCAs by 50 percent.	0.40%	5.45%	5.79%	\$212,586	\$447,549		
022 - Add redundant and diverse limit switches to each containment isolation valve.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						\$1,000,000	Not cost effective
023 - Increase leak testing of valves in ISLOCA paths.	The cost of implementing this SAMA was specifically estimated for IP2.						\$7,964,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
MSIV Design  025 - Improve MSIV design.	Eliminate MSIV failure to isolate a faulted or ruptured steam generator.  The cost of implementing this SAMA was specifically estimated for IP2.	0.05%	0.91%	0.67%	\$28,629	\$60,272	\$476,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
DC Power	Increase time available to recover offsite power before local operation of AFW is required from 2 hours to 24 hours during SBO scenarios.	1.94%	0.45%	0.22%	\$44,633	\$93,964		
026 - Provide additional DC battery capacity.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						>\$1.875,000	Not cost effective
027 - Use fuel cells instead of lead-acid batteries.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						\$2,000,000	Not cost effective
029 - Increase/improve DC bus load shedding.	The cost of implementing this SAMA was specifically estimated for Fort Calhoun Unit 1.						>\$160,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Alternate Battery Charger Capability  028 - Provide a portable diesel-driven battery charger.	Eliminate operator failure to locally control the turbine-driven AFW pump.  The cost of implementing this SAMA was specifically estimated for IP2.	4.79%	10.00%	9.13%	\$420,459	\$885,176	\$494,000	Retain
AC Power Cross-Tie with IP3  030 - Create AC power cross-tie capability with other unit.	Eliminate loss of the gas turbines.  The cost of implementing this SAMA was specifically estimated for IP2.	2.81%	0.45%	0.22%	\$52,724	\$110,997	\$1,156,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
EDG Alternate Engine Cooling	Eliminate loss of essential service water supply for EDG cooling.	1.69%	0.45%	0.22%	\$36,542	\$76,931		
031 - Create a backup source for diesel cooling (not from existing system).	The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.						\$1,700,000	Not cost effective
032 - Use fire protection system as a backup source for diesel cooling.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						\$497,000	Not cost effective
Improve 118VAC System	Eliminate common cause failure of the 118VAC transformers.	0.00%	0.00%	0.00%	~\$0	~\$0	\$1,254,000	Not cost effective
033 - Convert under-voltage AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic.	The cost of implementing this SAMA was specifically estimated for IP2.							

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Low Pressure Injection System	Eliminate failure of the RHR system.	0.02%	0.00%	0.22%	\$4,090	\$8,610		
034 - Provide capability for diesel-driven, low pressure vessel makeup.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						>\$632,000	Not cost effective
037 - Provide capability for alternate injection via diesel-driven fire pump.	The cost of implementing this SAMA was specifically estimated for IP2.						\$750,000	Not cost effective



**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
High Pressure Injection System	Eliminate failure of the SI system.	0.29%	0.45%	0.45%	\$24,450	\$51,474		
035 - Provide an additional high pressure injection pump with independent diesel.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						\$5,000,000	Not cost effective
039 - Replace two of three motor-driven SI pumps with diesel-powered pumps.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						\$2,000,000	Not cost effective
Automatic Recirculation Cooling Swap-Over	Eliminate operator failure to align internal and external recirculation cooling.	4.08%	0.45%	0.45%	\$81,086	\$170,707	\$>1,000,000	Not cost effective
036 - Create automatic swap-over to recirculation cooling upon RWST depletion.	The cost of implementing this SAMA was specifically estimated for McGuire.							

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Conserve RWST Water Inventory  038 - Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Eliminate operator failure to align internal and external recirculation cooling during a large or medium LOCA.  The cost of implementing this SAMA was specifically estimated for IP2.	0.60%	0.45%	0.22%	\$20,360	\$42,864	\$82,000	Not cost effective
Enhance RCS Depressurization  040 - Create/enhance a reactor coolant depressurization system.	Eliminate common cause failure of the steam generator ADVs.  The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.	0.87%	3.18%	3.79%	\$142,968	\$300,986	\$>1,000,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Main Feedwater System Upgrade	Eliminate loss of feedwater initiator.	4.85%	0.91%	0.89%	\$105,536	\$222,181		
041 - Install a digital feed water upgrade.	The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.						\$900,000	Not cost effective
043 - Add a motor-driven feed water pump.	The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.						\$2,000,000	Not cost effective
Steam Generator Atmospheric Steam Dump Valve Enhancement	Eliminate failure of manual local action to align nitrogen supply for control air supply to the steam generator ADV control valve.	0.05%	0.45%	0.22%	\$12,270	\$25,831	\$214,000	Not cost effective
042 - Provide automatic nitrogen backup to steam generator ADVs.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.							

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Alternate Water Sources to Steam Generators  044 - Use fire water system as backup for steam generator inventory.	Eliminate failure of the turbine-driven AFW pump and failure of local operation of AFW during SBO.  The cost of implementing this SAMA was specifically estimated for IP2.	33.00%	14.55%	13.36%	\$984,503	\$2,072,638	\$1,656,000	Retain
Install Large Pressurizer PORVs  045 - Replace current pilot operated relief valves with larger ones such that only one is required for successful feed and bleed.	Change the number of PORVs required for RCS feed and bleed from 2-of-2 to 1-of-2. In addition, reduce failure of the operator action for feed and bleed by a factor of 5.  The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	18.30%	3.64%	2.90%	\$385,602	\$811,795	\$2,700,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Diesel Power to Instrument Air Compressors  046 - Modify emergency operating procedures for ability to align diesel power to more air compressors.	Eliminate failure of the instrument air system.  The cost of implementing this SAMA was specifically estimated for IP2.	0.00%	0.00%	0.00%	~\$0	~\$0	\$82,000	Not cost effective
Independent Boron Injection System  047 - Add an independent boron injection system.	Eliminate common cause failure of boric acid transfer pumps.  The cost of implementing this SAMA was specifically estimated for Arkansas Unit-2.	0.00%	0.00%	0.00%	~\$0	~\$0	\$300,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
ATWS Overpressure Protection  048 - Add a system of relief valves that prevent equipment damage from a pressure spike during an ATWS.	Eliminate RCS overpressurization during an ATWS.  The cost of implementing this SAMA was specifically estimated for IP2.	1.98%	0.45%	0.45%	\$48,723	\$102,574	\$615,000	Not cost effective
Control Room ATWS Mitigation  049 - Install motor generator set trip breakers in control room.  050 - Provide capability to remove power from the bus powering the control rods.	Eliminate failure to trip the control rod motor generator sets.  The cost of implementing this SAMA was specifically estimated for IP2.  The cost of implementing this SAMA was specifically estimated for IP2.	0.91%	0.45%	0.22%	\$28,451	\$59,897	\$716,000  \$90,000	Not cost effective  Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Large Break LOCA  051- Provide digital large break LOCA protection.	Eliminate large break LOCA initiator.  The cost of implementing this SAMA was specifically estimated for IP2.	0.06%	0.00%	0.00%	~\$0	~\$0	\$2,036,000	Not cost effective
Main Steam Line Break Inside Containment  052 - Install secondary side guard pipes up to the MSIVs.	Eliminate main steam line break initiators (inside and outside containment).  The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.	0.45%	1.82%	1.78%	\$73,529	\$154,798	\$1,100,000	Not cost effective
Pressurizer PORV Block Valves  053 - Keep both pressurizer PORV block valves open.	Eliminate failure of PORV block valves to open.  The cost of implementing this SAMA was specifically estimated for IP2.	17.61%	3.64%	2.90%	\$377,512	\$794,761	\$800,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
480VAC Switchgear Room Flood Alarm  054 - Install flood alarm in the 480VAC switchgear room.	Reduce control building flooding initiator frequencies by a factor of 3.  The cost of implementing this SAMA was specifically estimated for IP2.	19.97%	40.45%	38.31%	\$1,722,733	\$3,626,807	\$200,000	Retain



**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
High-Head Recirculation Cooling	Eliminate loss of high-head recirculation cooling due to RHR heat exchanger 21 hardware failures.	0.02%	0.00%	0.00%	~\$0	~\$0		
055 - Perform a hardware modification to allow high-head recirculation from either RHR heat exchanger.	The cost of implementing this SAMA was specifically estimated for IP2.						\$1,330,000	Not cost effective
058 - Provide procedural guidance to allow high-head recirculation from either RHR heat exchanger.	The cost of implementing this SAMA was specifically estimated for IP2.						\$82,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
RHR Heat Exchanger Valves  056 - Keep RHR heat exchanger discharge MOVs normally open.	Eliminate failure of RHR heat exchanger discharge MOVs to open.  The cost of implementing this SAMA was specifically estimated for IP2.	1.84%	0.45%	0.22%	\$44,633	\$93,964	\$82,000	Retain
Pressurizer PORV DC Power  057 - Provide DC power backup for the PORVs.	Eliminate failure of DC power to the PORVs.  The cost of implementing this SAMA was specifically estimated for IP2.	1.22%	0.91%	0.45%	\$40,721	\$85,728	\$376,000	Not cost effective
AFW System Changes  059 - Re-install the low pressure suction trip on the AFW pumps and enhance procedures to respond to loss of the normal suction path.	Eliminate loss of the normal suction path to the AFW system.  The cost of implementing this SAMA was specifically estimated for IP2.	0.68%	0.45%	0.22%	\$20,360	\$42,864	\$318,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Flood Protection from Stairwell 4  060 - Provide added protection against flood propagation from stairwell 4 into the 480VAC switchgear room.	Eliminate internal flood initiated by a break in fire protection piping in stairwell 4.  The cost of implementing this SAMA was specifically estimated for IP2.	4.52%	9.09%	8.69%	\$387,828	\$816,481	\$216,000	Retain
Flood Protection from Deluge Room  061 - Provide added protection against flood propagation from the deluge room into the 480V switchgear room.	Eliminate internal flood initiated by a break in the 10-in fire protection piping in elevation 15-ft deluge room.  The cost of implementing this SAMA was specifically estimated for IP2.	9.84%	20.00%	18.93%	\$853,187	\$1,796,183	\$192,000	Retain

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
ASSS Power to SI pump  062 - Provide a hard-wired connection to an SI pump from ASSS power supply.	Eliminate failure to align ASSS power to the high-head SI pumps and charging pumps subsequent to a loss of power from vital 480VAC buses due to control building flooding initiators.  The cost of implementing this SAMA was specifically estimated for IP2.	3.08%	6.36%	6.01%	\$273,489	\$575,767	\$722,000	Not cost effective
RHR Pump Room Flood Protection  063 - Provide a water-tight door for additional protection of the RHR pumps against flooding.	Eliminate internal floods initiated inside the PAB.  The cost of implementing this SAMA was specifically estimated for IP2.	1.39%	0.45%	0.22%	\$36,542	\$76,931	\$324,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
CCW Heat Exchanger Alternate Cooling Supply  064 - Provide backup cooling water source for the CCW heat exchangers.	Eliminate loss of non-essential service water initiator.  The cost of implementing this SAMA was specifically estimated for IP2.	1.73%	0.45%	0.22%	\$36,542	\$76,931	\$710,000	Not cost effective
Upgrade ASSS for RCP Seal Cooling  065 - Upgrade the ASSS to allow timely restoration of seal injection and cooling.	Eliminate control building flooding initiators.  The cost of implementing this SAMA was specifically estimated for IP2.	19.97%	40.45%	38.31%	\$1,722,733	\$3,626,807	\$560,000	Retain
Harden EDG Building  066 - Harden the EDG building and fuel oil transfer pumps against tornados and high winds.	Eliminate high wind induced failures of the EDG Building.	85.05%	9.09%	8.37%	\$1,577,438	\$3,320,922	>\$10,000,000	Not cost effective

**Table E.2-2 (Continued)**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Charging Pump Alternate Cooling  067 - Provide hardware connections to allow the primary water system to cool the charging pumps.	Eliminate failure to align city water to the charging pumps.  The cost of implementing this SAMA was specifically estimated for IP2.	0.17%	0.00%	0.00%	\$8,091	\$17,033	\$576,000	Not cost effective
Recirculation Pump Alternate Cooling  068 - Provide independent source of cooling for the recirculation pump motors.	Eliminate loss of CCW to the recirculation pumps.  The cost of implementing this SAMA was specifically estimated for IP2.	0.27%	0.00%	0.22%	\$12,181	\$25,644	\$710,000	Not cost effective

**Table E.2-3  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Diesel Powered RCP Seal Injection  001 - Create an independent RCP seal injection system with a dedicated diesel.	\$198,892	\$246,305	\$236,665	\$202,981	\$1,137,000
Non-Diesel Powered RCP Seal Injection  002 - Create an independent RCP seal injection system without a dedicated diesel.	\$182,710	\$225,356	\$218,908	\$186,800	\$1,000,000
Additional CCW Pump  003 - Install an additional CCW pump.	~\$0	~\$0	~\$0	~\$0	\$1,500,000
Service Water Pumps  004 - Enhance procedural guidance for use of service water pumps.	\$44,633	\$55,546	\$52,660	\$44,633	\$1,750,000

**Table E.2-3 (Continued)  
Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
RHR Heat Exchangers  005 - Improve ability to cool the RHR heat exchangers by allowing manual alignment of the fire protection system.	\$56,813	\$70,570	\$67,254	\$56,813	\$565,000
EDG Building Ventilation  006 - Add a diesel building high temperature alarm.	\$28,451	\$34,596	\$34,903	\$28,451	\$274,000
Filtered Containment Vent  007 - Install a filtered containment vent to provide fission product scrubbing.	\$556,227	\$618,664	\$777,247	\$584,856	\$5,700,000



**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Molten Core Debris Removal  008 - Create a large concrete crucible with heat removal potential under the base mat to contain molten core debris.  009 - Create a reactor cavity flooding system.  010 - Create a core melt source reduction system.	\$1,697,309	\$1,887,836	\$2,371,747	\$1,803,647	\$108,000,000  \$3,714,000  \$90,000,000
Inert Containment  011 - Provide a means to inert containment.	\$695,283	\$773,331	\$971,559	\$744,362	\$10,900,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Containment Sprays  012 - Use the fire protection system as a backup source for the containment spray system.  013 - Install a passive containment spray system.  016 - Install a redundant containment spray system.	~\$0	~\$0	~\$0	~\$0	\$565,000  \$2,000,000  \$5,800,000
Base Mat Melt-Through  014 - Increase the depth of the concrete base mat or use an alternative concrete material to ensure melt-through does not occur.	\$392,631	\$436,704	\$548,645	\$408,990	>\$5,000,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Strengthen Containment  015 - Construct a building connected to primary containment that is maintained at a vacuum.	\$1,496,904	\$1,664,935	\$2,091,709	\$1,599,152	\$61,000,000
Containment Liner Protection  017 - Erect a barrier that provides containment liner protection from ejected core debris at high pressure.	\$368,091	\$409,410	\$514,355	\$396,721	\$2,900,000
Steam Generator Heat Removal  018 - Install a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources.	\$16,360	\$18,196	\$22,860	\$16,360	\$7,400,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Secondary Side Pressure Capacity  019 - Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift.	\$1,144,727	\$1,280,604	\$1,587,458	\$1,234,705	\$13,000,000
SGTR Fission Product Scrubbing  020 - Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	\$126,787	\$141,019	\$177,167	\$130,877	\$9,700,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
ISLOCA Mitigation  021 - Install additional pressure or leak monitoring instrumentation for ISLOCAs.  024 - Ensure all ISLOCA releases are scrubbed.	\$425,172	\$475,850	\$589,263	\$461,981	\$2,300,000  \$9,700,000
ISLOCA Valves  022 - Add redundant and diverse limit switches to each containment isolation valve.  023 - Increase leak testing of valves in ISLOCA paths.	\$212,586	\$237,925	\$294,631	\$228,945	\$1,000,000  \$7,964,000
MSIV Design  025 - Improve MSIV design.	\$28,629	\$31,843	\$40,005	\$28,629	\$476,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
DC Power  026 - Provide additional DC battery capacity.  027 - Use fuel cells instead of lead-acid batteries.  029 - Increase/ improve DC bus load shedding.	\$44,633	\$55,546	\$52,660	\$44,633	>\$1.875,000  \$2,000,000  >\$160,000
Alternate Battery Charger Capability  028 - Provide a portable diesel-driven battery charger.	\$420,459	\$480,938	\$565,689	\$440,908	\$494,000
AC Power Cross-Tie with IP3  030 - Create AC power cross-tie capability with other unit.	\$52,724	\$66,021	\$61,539	\$52,724	\$1,156,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
EDG Alternate Engine Cooling  031 - Create a backup source for diesel cooling (not from existing system).  032 - Use fire protection system as a backup source for diesel cooling.	\$36,542	\$45,071	\$43,782	\$36,542	\$1,700,000  \$497,000
Improve 118VAC System  033 - Convert under-voltage AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic.	~\$0	~\$0	~\$0	~\$0	\$1,254,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Low Pressure Injection System  034 - Provide capability for diesel-driven, low pressure vessel makeup.  037 - Provide capability for alternate injection via diesel-driven fire pump.	\$4,090	\$4,549	\$5,715	\$4,090	\$>632,000  \$750,000
High Pressure Injection System  035 - Provide an additional high pressure injection pump with independent diesel.  039 - Replace two of three motor-driven SI pumps with diesel-powered pumps.	\$24,450	\$28,671	\$31,739	\$24,450	\$5,000,000  \$2,000,000



**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Automatic Recirculation Cooling Swap-Over  036 - Create automatic swap-over to recirculation cooling upon RWST depletion.	\$81,086	\$101,994	\$93,891	\$81,086	>\$1,000,000
Conserve RWST Water Inventory  038 - Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	\$20,360	\$24,122	\$26,024	\$20,360	\$82,000
Enhance RCS Depressurization  040 - Create/enhance a reactor coolant depressurization system.	\$142,968	\$161,969	\$194,924	\$151,148	>\$1,000,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Main Feedwater System Upgrade  041 - Install a digital feed water upgrade.  043 - Add a motor-driven feed water pump.	\$105,536	\$130,665	\$125,630	\$105,536	\$900,000  \$2,000,000
Steam Generator Atmospheric Steam Dump Valve Enhancement  042 - Provide automatic nitrogen backup to steam generator ADVs.	\$12,270	\$13,647	\$17,145	\$12,270	\$214,000
Alternate Water Sources to Steam Generators  044 - Use fire water system as backup for steam generator inventory.	\$984,503	\$1,182,085	\$1,232,516	\$1,017,222	\$1,656,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Install Large Pressurizer PORVs  045 - Replace current pilot operated relief valves with larger ones such that only one is required for successful feed and bleed.	\$385,602	\$477,587	\$458,737	\$393,782	\$2,700,000
Diesel Power to Instrument Air Compressors  046 - Modify emergency operating procedures for ability to align diesel power to more air compressors.	~\$0	~\$0	~\$0	~\$0	\$82,000
Independent Boron Injection System  047 - Add an independent boron injection system.	~\$0	~\$0	~\$0	~\$0	\$300,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
ATWS Overpressure Protection  048 - Add a system of relief valves that prevent equipment damage from a pressure spike during an ATWS.	\$48,723	\$60,095	\$58,375	\$48,723	\$615,000
Control Room ATWS Mitigation  049 - Install motor generator set trip breakers in control room.  050 - Provide capability to remove power from the bus powering the control rods.	\$28,451	\$34,596	\$34,903	\$28,451	\$716,000  \$45,000
Large Break LOCA  051- Provide digital large break LOCA protection.	~\$0	~\$0	~\$0	~\$0	\$2,036,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Main Steam Line Break Inside Containment  052 - Install secondary side guard pipes up to the MSIVs.	\$73,529	\$83,259	\$100,320	\$77,619	\$1,100,000
Pressurizer PORV Block Valves  053 - Keep both pressurizer PORV block valves open.	\$377,512	\$467,112	\$449,858	\$385,691	\$800,000
480VAC Switchgear Room Flood Alarm  054 - Install flood alarm in the 480VAC switchgear room.	\$1,722,733	\$1,969,241	\$2,319,905	\$1,808,621	\$200,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
High-Head Recirculation Cooling  055 - Perform a hardware modification to allow high-head recirculation from either RHR heat exchanger.  058 - Provide procedural guidance to allow high-head recirculation from either RHR heat exchanger.	~\$0	~\$0	~\$0	~\$0	\$1,330,000  \$82,000
RHR Heat Exchanger Valves  056 - Keep RHR heat exchanger discharge MOVs normally open.	\$44,633	\$55,546	\$52,660	\$44,633	\$82,000
Pressurizer PORV DC Power  057 - Provide DC power backup for the PORVs.	\$40,721	\$48,243	\$52,048	\$44,811	\$376,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
AFW System Changes  059 - Re-install the low pressure suction trip on the AFW pumps and enhance procedures to respond to loss of the normal suction path.	\$20,360	\$24,122	\$26,024	\$20,360	\$318,000
Flood Protection from Stairwell 4  060 - Provide added protection against flood propagation from stairwell 4 into the 480VAC switchgear room.	\$387,828	\$443,169	\$522,520	\$408,278	\$216,000
Flood Protection from Deluge Room  061 - Provide added protection against flood propagation from the deluge room into the 480V switchgear room.	\$853,187	\$975,523	\$1,148,523	\$898,176	\$192,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
ASSS Power to SI pump  062 - Provide a hard-wired connection to an SI pump from ASSS power supply.	\$273,489	\$313,044	\$367,601	\$285,759	\$722,000
RHR Pump Room Flood Protection  063 - Provide a water-tight door for additional protection of the RHR pumps against flooding.	\$36,542	\$45,071	\$43,782	\$36,542	\$324,000
CCW Heat Exchanger Alternate Cooling Supply  064 - Provide backup cooling water source for the CCW heat exchangers.	\$36,542	\$45,071	\$43,782	\$36,542	\$710,000



**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Upgrade ASSS for RCP Seal Cooling  065 - Upgrade the ASSS to allow timely restoration of seal injection and cooling.	\$1,722,733	\$1,969,241	\$2,319,905	\$1,808,621	\$560,000
Harden EDG Building  066 - Harden the EDG building and fuel oil transfer pumps against tornados and high winds.	\$1,577,438	\$1,978,824	\$1,835,357	\$1,601,977	>\$10,000,000
Charging Pump Alternate Cooling  067 - Provide hardware connections to allow the primary water system to cool the charging pumps.	\$8,091	\$10,475	\$8,879	\$8,091	\$576,000

**Table E.2-3 (Continued)  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Recirculation Pump Alternate Cooling  068 - Provide independent source of cooling for the recirculation pump motors.	\$12,181	\$15,024	\$14,594	\$12,181	\$710,000

## **ATTACHMENT E.3**

### **EVALUATION OF IP3 PSA MODEL**

### **E.3 EVALUATION OF IP3 PROBABILISTIC SAFETY ANALYSIS MODEL**

The severe accident risk was estimated using the Probabilistic Safety Analysis (PSA) model and a Level 3 model developed using the most recent version (version 1.13.1) of the MELCOR Accident Consequences Code System Version 2 (MACCS2) code. The CAFTA code was used to develop the Indian Point Unit 3 (IP3) PSA Level 1 and Level 2 models. This section provides the description of IP3 PSA Level 1, 2, and 3 analyses, core damage frequency (CDF) uncertainty, Individual Plant Examination of External Events (IPEEE) analyses, and PSA model peer review.

#### **E.3.1 PSA Model - Level 1 Analysis**

The PSA model (Level 1 and Level 2) used for the Severe Accident Mitigation Alternative (SAMA) analysis was the most recent internal events risk model for IP3 (Revision 2, April 2007) [Reference E.3-3]. This model is an updated version of the model used in the 1994 Individual Plant Examination (IPE) and reflects the IP3 configuration and design as of December 2005. It uses component failure and unavailability data as of December 2005 and resolves all findings and observations from the industry peer review of the model conducted in January 2001. The IP3 model adopts the small event tree / large fault tree approach and uses the CAFTA code for quantifying CDF.

The PSA model has been updated two times since the original IPE due to the following.

- Equipment performance: As data collection progresses, estimated failure rates and system unavailability data change.
- Plant configuration changes: Plant configuration changes are incorporated into the PSA model.
- Modeling changes: The PSA model is refined to incorporate the latest state of knowledge and recommendations from internal and industry peer reviews.

The PSA model contains the major initiators leading to core damage with baseline CDFs listed in [Table E.3-1](#).

The IP3 Revision 2 PSA model was reviewed to identify those potential risk contributors that made a significant contribution to CDF. CDF-based Risk Reduction Worth (RRW) rankings were reviewed down to 1.005. Events below this point would influence the CDF by less than 0.5% and are judged to be highly unlikely contributors for the identification of cost-beneficial enhancements. These basic events, including component failures, operator actions, and initiating events, were reviewed to determine if additional SAMA actions may need to be considered.

[Table E.3-2](#) provides a correlation between the Level 1 RRW risk significant events (component failures, operator actions, and initiating events) down to 1.005 identified from the IP3 Revision 2 PSA model and the SAMAs evaluated in Section [E.4](#).

**Table E.3-1  
IP3 PSA Model CDF Results by Major Initiators**

Accident Type	Point Estimate CDF (/ry)	% Contribution to Point Estimate CDF
Internal flooding	2.24E-06	19.66
Loss of coolant accident (LOCA)	2.16E-06	18.95
Steam generator tube rupture (SGTR)	1.57E-06	13.78
Anticipated transient without a scram (ATWS)	1.54E-06	13.51
Loss of 125 VDC power	1.00E-06	8.78
Transients <sup>1</sup>	8.48E-07	7.44
Station blackout (SBO)	7.20E-07	6.32
Total loss of service water system	5.41E-07	4.75
Loss of non-essential service water	2.76E-07	2.42
Interfacing system LOCA (ISLOCA)	1.53E-07	1.34
Loss of offsite power <sup>1</sup>	1.19E-07	1.04
Loss of component cooling water	1.11E-07	0.97
Vessel rupture	1.00E-07	0.88
Loss of essential service water <sup>1</sup>	1.78E-08	0.16
<b>Total</b>	<b>1.15E-05</b>	<b>100.00</b>

1. Contributions to CDF from SBO and ATWS are listed separately and thus not included in the contributions shown for other accident types.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**

Event Name	Probability	RRW	Event Description	Disposition
OLR-S2	6.10E-04	1.205	Failure to initiate low-head internal recirculation during small LOCA	This term represents failure to align low-head emergency core cooling system (ECCS) internal recirculation to deliver flow to reactor coolant system (RCS) cold legs during a small LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 034, to allow automatic swap-over to recirculation upon refueling water storage tank (RWST) low level, was evaluated.
AC4-XHE-FO-M312A	2.40E-01	1.196	Failure to align 6.9kV system to motor control center (MCC) 312A	This term represents failure to align alternate safe shutdown equipment to MCC 312A to establish RCS makeup following switchgear room flooding. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions has already been implemented. Phase II SAMA 61, to upgrade the alternate safe shutdown equipment to allow timely restoration of reactor coolant pump (RCP) seal injection and cooling, was evaluated.
IE-SL	2.50E-03	1.169	RCP seal LOCA initiator	This term represents the RCP seal LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 033, 034, 035, 037, 038 and 060, to enhance high and low pressure injection and recirculation systems and to provide an independent source of cooling for the recirculation pump motors, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
IE-T7	6.84E-03	1.158	SGTR initiator	This term represents a SGTR initiating event. Many Phase I SAMAs have been implemented to mitigate this event including improving detection and isolation capabilities, improving makeup capabilities to the RPV, improving primary side depressurization reliability, improving secondary side heat removal capability, and enhancing training. Phase II SAMAs 016, 017, 018, and 051, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products, and enhancing procedure guidance to align main feedwater for secondary heat removal, were evaluated.
C	1.41E-05	1.152	Reactor protection system failure	This term represents failure of the reactor protection system. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an ATWS mitigating system actuation circuitry (AMSAC) system, have already been implemented. Phase II SAMAs 045, 046, 047 and 048, adding an independent boron injection system, adding relief valves to prevent equipment damage from pressure spikes, installing motor generator set trip breakers in the control room, and providing capability to remove power from the bus powering the control rods, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
IE-T2	2.89E-01	1.133	Loss of main feedwater initiator	This term represents an initiating event caused by loss of feedwater. Industry efforts over the last twenty years have led to a significant reduction of plant scrams from all causes. Phase II SAMAs 039 and 041, to install a digital feedwater upgrade and to add a motor-driven feedwater pump, were evaluated.
IE-3-IN-SW	4.35E-06	1.112	Rupture of 3 inch service water line in the control building switchgear room flood zone CTL15-1	This term represents an internal flooding event due to rupture of a 3 inch service water line in control building switchgear room flood zone CTL15-1. Phase I SAMAs have been implemented to improve procedures to reduce the CDF contribution due to internal flooding. Phase II SAMAs 055 and 062, providing the capability of powering one safety injection (SI) pump or residual heat removal (RHR) pump using the Appendix R bus (MCC 312A) during control building flooding events, and providing a flood alarm in the control building switchgear room, were evaluated.
PR1	2.58E-01	1.086	RCS overpressurization failure during ATWS	This term represents overpressurization of the RCS during ATWS. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 044, 047 and 048, to replace pressure-operated relief valves (PORVs) with larger ones to extend the time available for success of the feed and bleed function, to install motor generator set trip breakers in the control room, and to provide capability to remove power from the bus powering the control rods, were evaluated.



**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
IE-T1	5.86E-02	1.08	Loss of offsite power initiator	This term represents the loss of offsite power initiating event. Phase I SAMAs to enhance offsite power availability and coping with SBO events, including cross-tying diesel fuel oil supply lines, cross-tying alternating current (AC) and direct current (DC) buses, and adding additional diesel generators, have already been implemented. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ORCS-L	1.00E-04	1.063	Failure to perform late RCS cooldown and depressurization during SGTR	This term represents failure to perform late cooling and depressurization to cold shutdown following a SGTR to terminate leakage from the RCS into the secondary prior to depleting RWST inventory. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 016, 017, 018, and 051, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products, and enhancing procedure guidance to align main feedwater for secondary heat removal, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
EDG-ENG-FR-DG31R	3.84E-02	1.059	Diesel generator 31 fails to run	This term represents failure of emergency diesel generator (EDG) 31 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
IE-10-IN-FPS	2.22E-06	1.054	Rupture of 10 inch fire protection piping in the deluge room adjacent to control building switchgear room	This term represents an internal flooding event due to rupture of a 10 inch fire protection piping deluge valve station adjacent to the control building switchgear room. Phase I SAMAs have been implemented to improve procedures and to provide seismic support of the fire protection piping to reduce the CDF contribution due to internal flooding. Phase II SAMA 055, providing the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events, was evaluated.
IE-TSWS	5.20E-05	1.049	Total loss of service water system initiator	This term represents the loss of service water initiating event. Phase I SAMAs have been implemented to improve service water system reliability by providing additional service water pumps, enhancing screen wash, and replacing strainers. Phase II SAMAs 028, 029, and 057, to provide backup cooling water for the diesel generators and CCW heat exchangers, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
EDG-CCF-FR-3EDGS	8.09E-04	1.047	Common cause failure of 3 Diesel generators to continue to run	This term represents common cause failure of three diesel generators to continue to run. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
IE-TDC32	3.45E-04	1.047	Loss of 125VDC power panel 32 initiator	This term represents an initiating event caused by loss of 125VDC power panel 32. Phase I SAMAs implemented to enhance DC power availability and coping with SBO events include cross-tying DC buses and providing alternate battery charging capability. Phase II SAMAs 024, 025, 026, and 058, for enhancing DC system availability and reliability, were evaluated.
SL-TCCW	3.09E-02	1.047	Failure to align city water to charging pumps to prevent RCP seal LOCA	This term represents failure to align city water to the charging pumps for RCP seal cooling following loss of component cooling water (CCW). Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 059, to allow primary water to be used as a backup source of cooling, was evaluated.
IE-T5	1.00E-02	1.043	Main steam line break outside containment initiator	This term represents an initiating event caused by a main steam line break outside containment. Phase II SAMA 023, to improve main steam isolation valve (MSIV) design, was evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
IE-TDC3132	6.00E-06	1.043	Common cause failure of 125VDC power panels 31 and 32 initiator	This term represents an initiating event caused by loss of 125VDC power panels 31 and 32. Phase I SAMAs implemented to enhance DC power availability and coping with SBO events include cross-tying DC buses and providing alternate battery charging capability. Phase II SAMAs 024, 025, 026, and 058, for enhancing DC system availability and reliability, were evaluated.
B-DEP	5.45E-03	1.04	Failure to recover AC power given successful RCS depressurization	This term represents failure to recover offsite and onsite AC power following successful RCS depressurization. Phase I SAMAs to improve SBO procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 026, 042 and 056, improving DC bus load shedding, providing an additional power source to the turbine-drive auxiliary feedwater (AFW) pump auxiliaries, and installing pneumatic controls to assist in turbine-driven AFW pump control after battery depletion, were evaluated.
IE-T3	1.67E+00	1.036	Turbine trip with feedwater available initiator (T3)	This term represents an initiating event caused by a transient due to turbine trip with feedwater available. Industry efforts over the last twenty years have led to a significant reduction of plant scrams from all causes. A Phase I SAMA to replace the solenoids and air operators of the MSIVs to enhance reliability of the MSIVs has been implemented. Phase II SAMA 023, to improve the MSIV design to reduce the frequency of the initiator, was evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
AFW-MAI-MA-TDP32	6.92E-03	1.03	AFW turbine-driven pump 32 out for testing and maintenance	This term represents AFW turbine-driven pump 32 out for testing and maintenance. Phase II SAMAs 041 and 043, adding an additional motor-driven pump to enhance AFW system reliability and using fire water as a backup supply to the steam generators, were evaluated.
IE-S2	5.00E-04	1.03	Small break LOCA initiator	This term represents the small LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 033, 034, 035, 037, 038 and 060, to enhance high and low pressure injection and recirculation systems and provide an independent source of cooling for the recirculation pump motors, were evaluated.
WRWST	8.40E-02	1.027	Failure to refill RWST for continuing core cooling during SGTR	This term represents failure to align water from the primary water storage tank to refill the RWST for continuing core cooling during a SGTR event. A Phase I SAMA was implemented providing hardware and a procedure to extend RWST capacity. Phase II SAMAs 016, 017, 018, and 051, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products, and enhancing procedure guidance to align main feedwater for secondary heat removal, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
FB-T7	1.00E+00	1.026	Failure to initiate feed and bleed during SGTR	This term represents failure to establish core cooling using feed and bleed following loss of main feedwater and AFW during a SGTR event. Phase I SAMAs to improve operator response, install computer aided instrumentation and keep pressurizer PORV block valves open have already been implemented. Phase II SAMA 044, to replace current PORVs with larger ones to extend the time available for success of the bleed and feed function, was evaluated.
IE-TSWS-NE	1.67E-03	1.025	Loss of non-essential service water system initiator	This term represents the loss of non-essential service water initiating event. Phase I SAMAs have been implemented to improve service water system reliability by providing additional service water pumps, cross-tying service water pumps, enhancing screen wash, and replacing strainers. Phase II SAMA 057, to provide backup cooling water for the CCW heat exchangers, was evaluated.
MRI	1.70E-01	1.025	Failure of manual rod insertion during ATWS	This term represents failure to insert control rods during an ATWS event. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 045, 046, 047 and 048, adding an independent boron injection system, adding relief valves to prevent equipment damage from pressure spikes, installing motor generator set trip breakers in the control room, and providing capability to remove power from the bus powering the control rods, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
PR2	3.74E-01	1.024	ATWS RCS overpressurization failure (manual rod insertion failure)	This term represents overpressurization of the RCS during ATWS (manual rod insertion failure). Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 044, 047 and 048, to replace PORVs with larger ones to extend the time available for success of the feed and bleed function, to install motor generator set trip breakers in the control room, and to provide capability to remove power from the bus powering the control rods, were evaluated.
SGISO	6.70E-03	1.024	Failure to isolate ruptured steam generator during SGTR	This term represents failure to isolate the ruptured steam generator during a SGTR event. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 016, 017, 018, and 051, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products, and enhancing procedure guidance to align main feedwater for secondary heat removal, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
AFW-XHE-RE-AFW32	5.00E-03	1.023	Failure to restore AFW turbine-driven pump 32 path components after maintenance	This term represents failure to restore AFW turbine-driven pump 32 after testing and maintenance. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 041 and 043, adding a motor-driven feedwater pump and installing a fire water backup supply to the steam generators, were evaluated.
IE-TT15	3.40E-07	1.022	Rupture of fire protection piping in the turbine building outside the control building switchgear room	This term represents an internal flooding event due to rupture of fire protection piping in the turbine building outside the control building switchgear room. This event causes damage to the 480V switchgear. Phase I SAMAs have been implemented to improve procedures to reduce the CDF contribution due to internal flooding. Phase II SAMA 062, providing a flood alarm in the control building switchgear room, was evaluated.
SL-DEP	2.57E-03	1.018	RCP seal LOCA induced core uncover	This term represents failure to recover offsite AC power before RCP seal LOCA causes core uncover. Phase I SAMAs to improve SBO procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 033, 034, 035, 037, 038 and 060, to enhance high and low pressure injection and recirculation systems and to provide an independent source of cooling for the recirculation pump motors, were evaluated.



**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
RCS-XHE-MC-PT402	8.00E-03	1.017	RCS pressure transmitter PT-402 miscalibration	This term represents failure to properly calibrate RCS pressure transmitter PT-402, leading to failure of a motor-operated valve (MOV) in the RCS shutdown cooling line to open on demand. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. No Phase II SAMAs were recommended for this subject.
RCS-XHE-MC-PT403	8.00E-03	1.017	RCS pressure transmitter PT-403 miscalibration	This term represents failure to properly calibrate RCS pressure transmitter PT-403, leading to failure of an MOV in the RCS shutdown cooling line to open on demand. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. No Phase II SAMAs were recommended for this subject.
IE-4-IN-FPS	6.19E-07	1.015	Rupture of 4 inch fire protection piping in the control building switchgear room flood zone CTL15-3	This term represents an internal flooding event due to rupture of a 4 inch fire protection pipe in control building switchgear room flood zone CTL15-3. Phase I SAMAs have been implemented to improve procedures and to provide seismic support for the fire protection piping to reduce the CDF contribution due to internal flooding. Phase II SAMAs 055 and 062, providing the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events, and providing a flood alarm in the control building switchgear room, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
AFW-TDP-FS-TDP32	3.07E-03	1.014	AFW turbine-driven pump 32 fails to start on demand	This term represents failure of AFW turbine driven pump 32 to start on demand. Phase II SAMAs 041 and 043, adding an additional motor-driven pump to enhance AFW system reliability and using fire water as a backup supply to the steam generators, were evaluated.
EDG-MAI-MA-EDG31	9.60E-03	1.013	Diesel generator 31 out for maintenance	This term represents EDG 31 out for maintenance. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-CCF-CC-3149	1.14E-05	1.011	Common cause failure of check valves BFD-31, 34 & 39	This term represents common cause failure of check valves BFD-31, 34 and 39, leading to failure of all AFW pumps to deliver sufficient flow to the steam generators. Phase II SAMAs 041, 043, 044, and 054, adding an additional motor-driven pump to enhance AFW system reliability, using fire water as a backup supply to the steam generators, replacing PORVs with larger ones and providing DC power backup for the PORVs, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
AFW-XHE-RE-AFW31	4.70E-03	1.011	Failure to restore AFW motor-driven pump 31 path components after testing and maintenance	This term represents failure to restore AFW motor-driven pump 31 after testing and maintenance. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 041, 042, 043, and 054, adding an additional motor-driven pump, providing a portable generator to support the turbine-driven pump auxiliaries, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine driven pump 32, were evaluated.
ORCS-MSLB	8.10E-03	1.011	Failure to depressurize RCS during main steam line break	This term represents failure to depressurize the RCS during a main steam line break. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 038 and 044, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.
AFW-CCF-FS-AFWPM	3.12E-04	1.01	Common cause failure of AFW motor-driven pumps 31 and 33 to start	This term represents common cause failure of AFW motor-driven pumps 31 and 33 to start. Phase II SAMAs 041, 043, and 056, adding an additional motor-driven pump, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine-driven pump 32, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
EDG-ENG-FR-DG32R	3.84E-02	1.01	Diesel generator 32 fails to run	This term represents random failure of EDG 32 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
FB-T3	1.70E-02	1.01	Failure to initiate feed and bleed cooling during turbine trip (T3)	This term represents failure to establish core cooling using feed and bleed following a turbine trip and loss of main feedwater and AFW. Phase I SAMAs to improve operator response, install computer aided instrumentation and keep pressurizer PORV block valves open to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 043, 044 and 054, to use fire water as a backup supply to the steam generators, to improve the availability of the feed and bleed function by replacing the current PORVs with larger capacity valves and to provide DC power backup for the PORVs, were evaluated.
IE-TCCW	3.28E-04	1.01	Loss of CCW initiator	This term represents the loss of CCW system initiating event. Many Phase I SAMAs have been implemented to provide more reliable or diverse high or low pressure injection, RCP seal cooling systems and enhancements to loss of CCW procedures to mitigate this event. Phase II SAMAs 003, 004 and 057, to provide an additional CCW pump, improve the ability to cool the RHR heat exchangers and provide a backup cooling water source for the CCW heat exchangers, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
IE-V1	3.51E-05	1.01	Interfacing LOCA (<6") with isolation	This term represents the ISLOCA initiating event. Phase I SAMAs to improve procedures to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 019 and 021, to install additional pressure or leak monitoring instrumentation for ISLOCAs and increase leak testing of valves in ISLOCA pathways, were evaluated.
ODEPR-S2	2.00E-03	1.01	Failure to depressurize RCS for post-LOCA cooldown during small break LOCA	This term represents failure to depressurize the RCS following a small break LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 038 and 044, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.
OHR-S2	7.10E-04	1.01	Failure to initiate high-head internal recirculation during small LOCA	This term represents failure to align high-head ECCS internal recirculation to deliver flow to the RCS cold legs during a small LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 034, to allow automatic swap-over to recirculation upon RWST low level, was evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
AFW-XHE-RE-AFWCC	9.60E-06	1.009	Failure to restore all AFW pumps after testing and maintenance	This term represents failure to restore all AFW pumps after testing and maintenance, leading to failure of all AFW pumps to deliver sufficient flow to the steam generators. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. In addition, Phase II SAMAs 043, 044 and 054, to use fire water as a backup supply to the steam generators, to improve the availability of the feed and bleed function by replacing the current PORVs with larger capacity valves and to provide DC power backup for the PORVs, were evaluated.
IE-R	1.00E-07	1.009	Catastrophic reactor vessel rupture	This term represents an initiating event caused by reactor vessel rupture. Phase II SAMAs 010 and 014, using fire protection system as a backup source for the containment spray system and providing redundant containment spray systems to mitigate the consequence of a reactor vessel rupture, were evaluated.
OHR-TCCW	1.01E-03	1.009	Failure to initiate low-head internal recirculation given loss of CCW system	This term represents failure to align low-head ECCS internal recirculation to deliver flow to the RCS cold legs following loss of CCW. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 034, to allow automatic swap-over to recirculation upon RWST low level, was evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
RHR-SD	9.60E-04	1.009	Failure to align RHR for shutdown cooling mode	This term represents failure to align RHR shutdown cooling mode during a SGTR event. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 016, 017, 018, and 051, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products, and enhancing procedure guidance to align main feedwater for secondary heat removal, were evaluated.
EDG-ENG-FR-DG33R	3.84E-02	1.008	Diesel generator 33 fails to run	This term represents failure of EDG 33 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
IE-S1	4.00E-05	1.008	Intermediate break LOCA initiator	This term represents the intermediate LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 033, 034, 035, 036, 037, 038, and 060, to enhance high and low pressure injection and recirculation systems and provide an independent source of cooling for the recirculation pump motors, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
VISO-S2	2.50E-02	1.008	Failure to isolate ISLOCA resulting in intermediate LOCA	This term represents failure to isolate an intermediate size ISLOCA. Phase I SAMAs to improve procedures to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 20, adding redundant and diverse limit switches to each containment isolation valve to reduce the frequency of unrecognized containment isolation failure and ISLOCAs through enhanced isolation valve position indication, was evaluated.
VL-OUTSIDE	1.00E-01	1.008	ISLOCA outside containment	This term represents the ISLOCA outside containment initiating event. Phase II SAMAs 019 and 021, to install additional pressure or leak monitoring instrumentation for ISLOCAs and increase leak testing of valves in ISLOCA pathways, were evaluated.
AFW-AOV-CC-P1139	1.68E-03	1.007	AFW turbine-driven pump 32 steam control valve PCV-1139 does not open	This term represents failure of steam control valve PCV-1139, leading to unavailability of AFW turbine-driven pump 32. Phase II SAMAs 041 and 043, adding an additional motor-driven pump to enhance AFW system reliability and using fire water as a backup supply to the steam generators, were evaluated.



**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
AFW-XHE-FO-HC405	9.00E-04	1.007	Failure to operate AFW turbine-driven pump 32 flow control valves HC-405A,B,C & D	This term represents failure of control valves 405A/B/C/D, leading to unavailability of AFW turbine-driven pump 32. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 041, 043, and 056, adding an additional motor-driven pump to enhance AFW system reliability, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine-driven pump 32, were evaluated.
IE-3-IN-SW-AC1	2.88E-06	1.007	Rupture of 3 inch service water line in the control building switchgear room flood zone CTL15-2	This term represents an internal flooding event due to rupture of a 3 inch service water line in control building switchgear room flood zone CTL15-2. Phase I SAMAs have been implemented to improve procedures to reduce the CDF contribution due to internal flooding. Phase II SAMAs 055 and 062, providing the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events, and providing a flood alarm in the control building switchgear room, were evaluated.
AFW-MDP-FR-PM31	2.81E-03	1.006	AFW motor-driven pump 31 fails to continue to run	This term represents failure of AFW motor-driven pump 31 to continue to run. Phase II SAMAs 041, 043, and 056, adding an additional motor-driven pump to enhance AFW system reliability, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine-driven pump 32, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
AFW-RCK-NO-PM31	2.50E-03	1.006	AFW motor-driven pump 31 switchgear control circuit no output	This term represents failure of AFW motor-driven pump 31 control circuit, causing unavailability of the pump. Phase II SAMAs 041, 043, and 056, adding an additional motor-driven pump to enhance AFW system reliability, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine-driven pump 32, were evaluated.
CVC-RCK-NO-CH333	2.50E-03	1.006	Emergency boration valve CH-MOV-333 control circuit no output	This term represents failure of MOV-333, resulting in failure of emergency boration during an ATWS. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 045, 047 and 048, to add an independent boron injection system, install motor generator set trip breakers in the control room, and provide capability to remove power from the bus powering the control rods, were evaluated.
FB-T2	1.70E-02	1.006	Failure to initiate feed and bleed cooling during transient	This term represents failure to establish core cooling using feed and bleed following a transient and loss of main feedwater and AFW. Phase I SAMAs to improve operator response, install computer aided instrumentation and keep pressurizer PORV block valves open to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 043, 044 and 054, to use fire water as a backup supply to the steam generators, to improve availability of the feed and bleed function by replacing the PORVs with larger capacity valves, and to provide DC power backup for the PORVs, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
IE-TA18	2.73E-05	1.006	Rupture of condensate line in AFW pump room flood zone AFW18-1	This term represents an internal flooding event due to rupture of a condensate line in AFW pump room flood zone AFW18-1. This event causes loss of the AFW system and potential loss of the MFW system. Phase II SAMAs 043, 044, and 054, to use fire water as a backup supply to the steam generators, to improve the availability of the feed and bleed function by replacing the PORVs with larger capacity valves, and to provide DC power backup for the PORVs, were evaluated.
IE-TAC6A	1.05E-03	1.006	Loss of 480V bus 6A initiator	This term represents an initiating event caused by loss of 480V bus 6A. A Phase I SAMA to proceduralize repair or replacement of failed 480V breakers has already been implemented. Phase II SAMAs 024, 025, 026, 027, and 030, for enhancing AC or DC system reliability, were evaluated.
LTS	2.50E-03	1.006	Failure to establish long-term shutdown during ATWS	This term represents failure to establish long term shutdown via emergency boration during an ATWS. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 045, 047 and 048, to add an independent boron injection system, install motor generator set trip breakers in the control room, and provide capability to remove power from the bus powering the control rods, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
AFW-MAI-MA-PM31	3.06E-03	1.005	AFW motor-driven pump 31 out for testing and maintenance	This term represents AFW motor-driven pump 31 out for testing and maintenance. Phase II SAMAs 041, 043, and 056, adding an additional motor-driven pump to enhance AFW system reliability, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine-driven pump 32, were evaluated.
FB-TAC6A	1.70E-01	1.005	Failure to initiate feed and bleed cooling during loss of 480V bus 6A	This term represents failure to establish core cooling using feed and bleed following loss of 480V bus 6A and loss of main feedwater and AFW. Phase I SAMAs to improve operator response, install computer aided instrumentation and keep pressurizer PORV block valves open to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 043, 044 and 054, to use fire water as a backup supply to the steam generators, to improve the availability of the feed and bleed function by replacing the PORVs with larger capacity valves, and to provide DC power backup for the PORVs, were evaluated.
IE-T4	4.63E-04	1.005	Main steam line break inside containment initiator	This term represents the main steam line break inside the containment initiating event. Phase II SAMAs 011, 014, 023, and 050, providing a passive and redundant containment spray system, improving MSIV design, and installing guard pipes up to the MSIVs, were evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
LHI-RCK-NO-744	2.50E-03	1.005	AC-MOV-744 control circuit no output	This term represents failure of MOV 744 control circuit, leading to loss of external recirculation capability during LOCAs and transients. Phase II SAMA 060, providing an independent source of cooling for the recirculation pump motors, was evaluated.
LHI-RCK-NO-885A	2.50E-03	1.005	SI-MOV-885A control circuit no output	This term represents failure of MOV 885A control circuit, leading to loss of external recirculation capability during LOCAs and transients. Phase II SAMA 060, providing an independent source of cooling for the recirculation pump motors, was evaluated.
LHI-RCK-NO-885B	2.50E-03	1.005	SI-MOV-885B control circuit no output	This term represents failure of MOV 885B control circuit, leading to loss of external recirculation capability during LOCAs and transients. Phase II SAMA 060, providing an independent source of cooling for the recirculation pump motors, was evaluated.
MSGI-T4	3.30E-02	1.005	Failure to isolate faulted steam generator	This term represents failure to isolate the affected steam generator during a main steam line break event. Phase II SAMAs 011, 014, 023, and 050, providing a passive and redundant containment spray system, improving MSIV design, and installing guard pipes up to the MSIVs, were evaluated.
OCOND	5.30E-03	1.005	Failure to align condensate system for secondary cooling	This term represents failure to align the condensate system for secondary cooling during transients. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMA 043, using the fire water system as backup for steam generator inventory, was evaluated.

**Table E.3-2**  
**IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
ODEP-TCCW	4.00E-03	1.005	Failure to depressurize during loss of CCW	This term represents failure to depressurize the RCS following loss of the CCW system. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 038 and 044, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.
RV-T4	6.70E-03	1.005	Reactor vessel rupture during main steam line break inside containment	This term represents failure to terminate SI following a main steam line break inside containment, causing reactor vessel rupture due to pressurized thermal shock. Phase II SAMAs 011, 014, 023, and 050, providing a passive and redundant containment spray system, improving MSIV design, and installing guard pipes up to the MSIVs, were evaluated.

### CDF Uncertainty

The uncertainty associated with CDF was estimated using Monte Carlo techniques implemented in CAFTA for the base case mode. The results are shown in Table E.3-3.

**Table E.3-3  
CDF Uncertainty**

<b>Confidence</b>	<b>CDF (/ry)</b>
Mean value	1.23E-5
5 <sup>th</sup> percentile	8.45E-6
50 <sup>th</sup> percentile	1.11E-5
95 <sup>th</sup> percentile	1.72E-5

The values in Table E.3-3 reflect the uncertainties associated with the data distributions used in the analysis. The ratio of the 95th percentile to the mean CDF is about 1.40. This uncertainty factor is included in the factor of 8 used to determine the "baseline benefit with uncertainty" described in [Section 4.21.5.4](#).

## **E.3.2 PSA Model - Level 2 Analysis**

### **E.3.2.1 Containment Performance Analysis**

The IP3 Level 2 PSA model used for the SAMA analysis is the most recent internal events risk model, which is an updated version of the model used in the IPE [Reference E.3-1]. The Level 2 PSA model used for the SAMA analysis, Revision 2 [Reference E.3-3] reflects the IP3 operating configuration and design changes as of December 2005.

The IP3 Level 2 model includes two types of considerations: (1) a deterministic analysis of the physical processes for a spectrum of severe accident progressions, and (2) a probabilistic analysis component in which the likelihood of the various outcomes are assessed. The deterministic analysis examines the response of the containment to the physical processes during a severe accident. This response is performed by

- utilization of the Modular Accident Analysis Program (MAAP) code [Reference E.3-4] to simulate severe accidents that have been identified as dominant contributors to core damage in the Level 1 analysis, and
- reference MAAP calculations of several hydrodynamic and heat transfer phenomena that occur during the progression of severe accidents. Examples include debris coolability, pressure spikes due to ex-vessel steam explosions, direct containment heating (DCH), molten debris filling the reactor pit, containment bypass, deflagration and detonation of hydrogen, thrust forces at reactor vessel failure, and thermal attack of containment penetrations.

The Level 2 analysis examined the dominant accident sequences and the resulting plant damage states (PDS) defined in Level 1. The Level 1 analysis involves the assessment of those scenarios that could lead to core damage.

A full Level 2 model was developed for the IP3 PSA and completed at the same time as the Level 1 model. The Level 2 model consists of a single containment event tree (CET) with functional nodes that represent phenomenological events and containment protection system status. The nodes were quantified using subordinate trees and logic rules. A list of the CET functional nodes and descriptions used for the Level 2 analysis is presented in Table E.3-4.

The Large Early Release Frequency (LERF) is an indicator of containment performance from the Level 2 results because the magnitude and timing of these releases provide the greatest potential for early health effects to the public. The frequency calculated is approximately  $9.43\text{E-}7/\text{ry}$  [Reference E.3-3]. Figures E.3-1 and E.3-2 summarize the Level 2 results. Radionuclide release categories are described in Section E.3.2.2.3.

LERF represents a small fraction (8%) of all release end states. Three types of accidents dominate the internal large early release: accidents initiated by SGTRs, ISLOCAs, and accidents initiated by internal floods impacting vital power buses. (Internal floods impacting vital power buses contribute to LERF because they result in SBO and core damage without power available



to the 480 VAC safeguard buses for the duration of the event. A large release occurs due to early containment rupture at vessel breach from either containment overpressurization or hydrogen burns.)

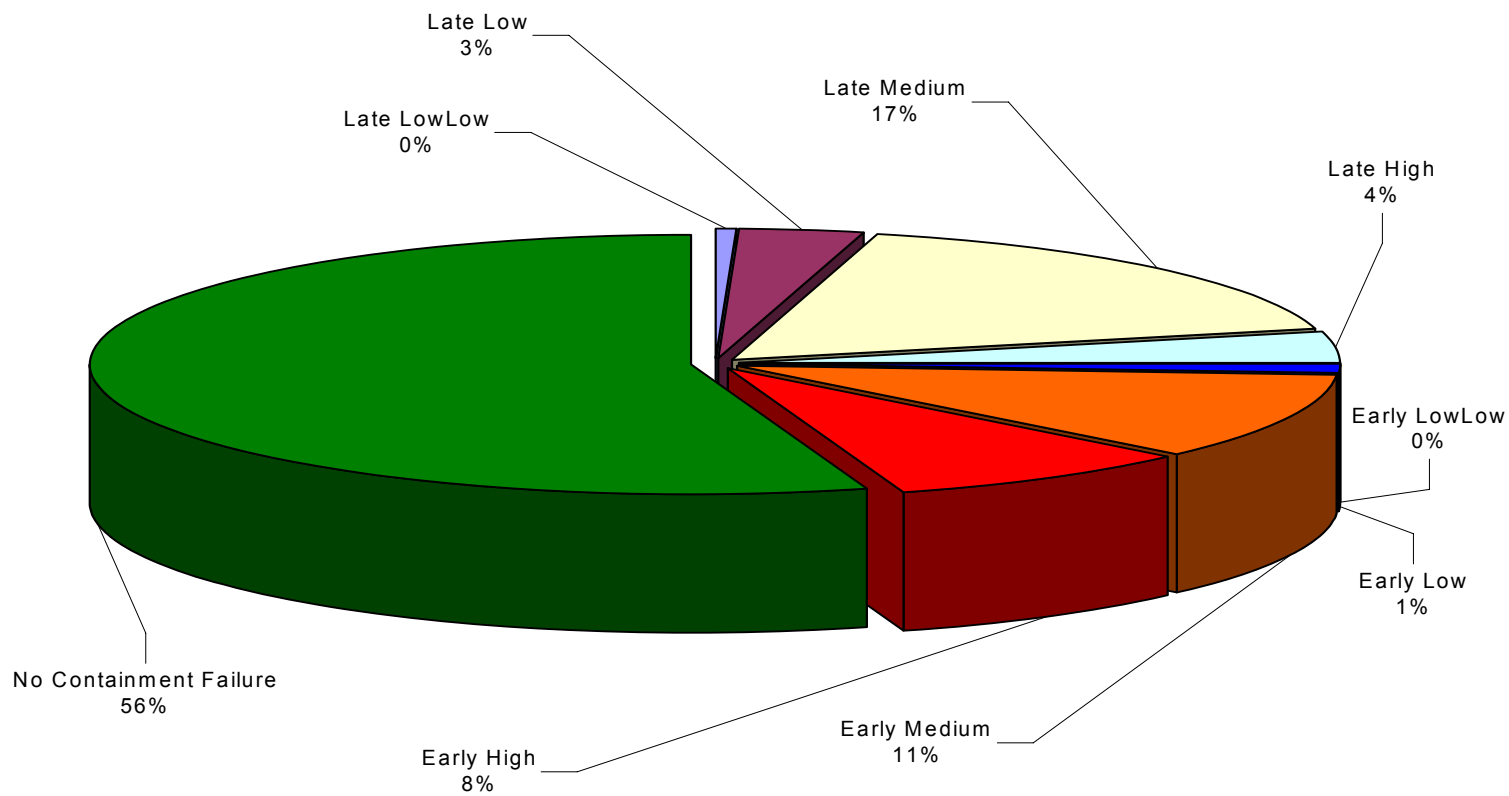
Table E.3-5 provides a correlation between the Level 2 RRW risk significant events (severe accident phenomenon, initiating events, component failures and operator actions) down to 1.005 identified from the current IP3 Revision 2 PSA LERF model [Reference E.3-3] and the SAMAs evaluated in Section E.4.

**Table E.3-4  
Notation and Definitions for IP3 CET Functional Nodes**

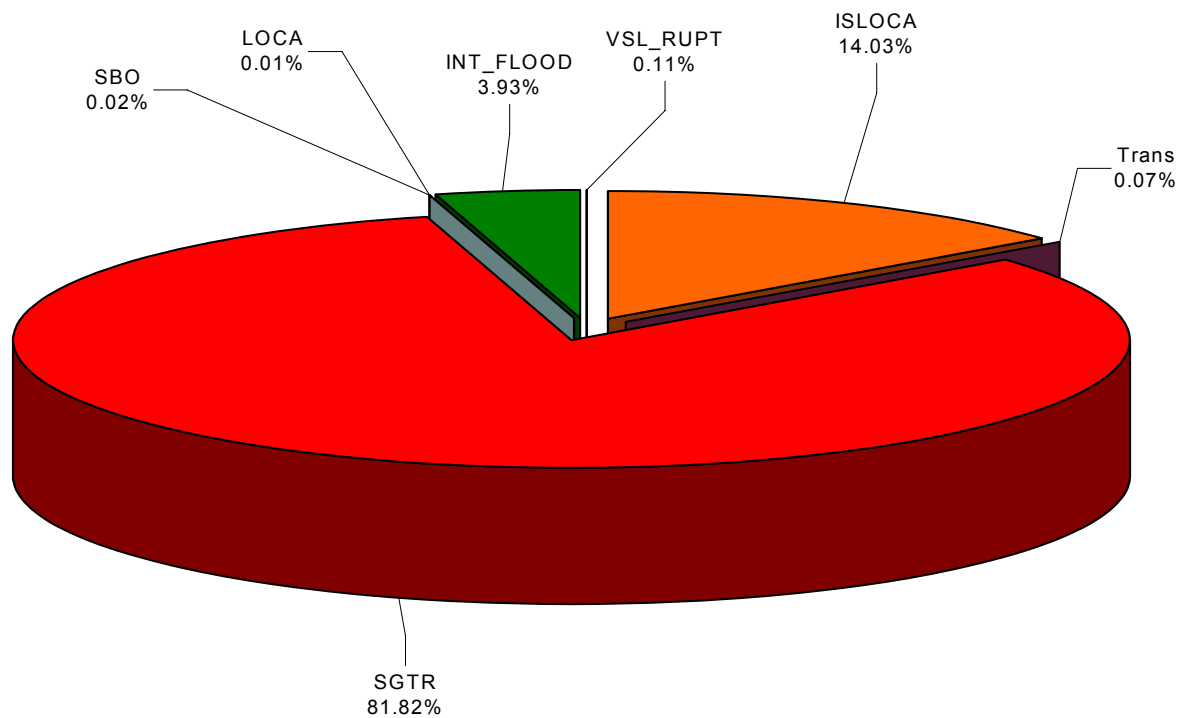
CET Node	CET Functional Node Description
Plant Damage State Event (PDS_EVNT)	This top event represents the initiators considered in the containment performance analysis.
RCS Pressure at Vessel Failure (RCS@VF)	This top event identifies the status of the RCS pressure. RCS@VF is set to success when RCS pressure is low. RCS@VF is set to failure when RCS pressure is high.
In-vessel Cooling Recovery (IN-REC)	This top event addresses the recovery of coolant injection into the vessel after core degradation, but prior to vessel breach. This top event considers the possibility of low-pressure injection systems working once the RCS is depressurized.
Vessel Failure (VF)	This top event addresses recovery from core degradation within the vessel and the prevention of vessel head thermal attack. Core melt recovery requires the recovery of core cooling prior to core blocking or relocation of molten debris to the lower plenum and thermal attack of the vessel head.
Early Containment Failure (CFE)	This top event node considers the potential loss of containment integrity at, or before, vessel failure. Several phenomena are considered credible mechanisms for early containment failure. They may occur alone or in combination. The phenomena are containment isolation failure; containment bypass; containment overpressure failure at vessel breach; hydrogen deflagration or detonation; fuel-coolant interactions (steam explosions); and high pressure melt ejection (HPME) with subsequent DCH.

**Table E.3-4  
 Notation and Definitions for IP3 CET Functional Nodes  
 (Continued)**

<b>CET Node</b>	<b>CET Functional Node Description</b>
Debris Cooled Ex-vessel (DCOOL)	This top event considers the delivery of water to the reactor pit (sump), via containment sprays, or via injection to the vessel and drainage out a vessel breach into the reactor pit area. Success implies the availability of water and the formation of a coolable debris bed such that concrete attack is precluded. Failure implies that the molten core attacks concrete in the reactor pit, that core debris remains hot, and sparing of the concrete decomposition products through the melt releases the less volatile fission products to the containment atmosphere.
Late Containment Failure (CFL)	This top event addresses the potential loss of containment integrity in the long-term. Late containment failure may result from base mat melt-through or from long-term steam and non-condensable gas generation from the attack of molten core debris on concrete.
Fission Product Removal (FPR)	This top event addresses fission product releases from the fuel into the containment and airborne fission product removal mechanisms within the containment structure to characterize potential magnitude of fission product releases to the environment should the containment fail. Failure implies that most of the fission products from the fuel and containment are ultimately released to the environment without mitigation.
Containment Failure Mode (CFM)	This top event is used to characterize the impact of the timing of containment failure and the break size on the duration and mitigation of the fission product source terms.



**Figure E.3-1**  
**IP2 Radionuclide Release Category Summary**



**Figure E.3-2**  
**IP2 Contributions to Large Early Release Frequency**

**Table E.3-5  
 IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)**

Event Name	Probability	RRW	Event Description	Disposition
NO-FPR_BYPASS	1.0	24.124	No fission product removal due to containment bypass event	<p>This term represents the probability that fission product removal does not occur because containment is bypassed by either an ISLOCA or a SGTR with a stuck-open relief valve. Phase II SAMAs 019, 020, 021 and 022, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.</p> <p>For SGTR sequences, numerous Phase I SAMAs have been implemented to increase reliability of the steam generator via enhanced maintenance practices, improved detection and isolation capabilities, improved makeup capabilities to the RCS, improved primary side depressurization reliability, improved secondary side heat removal capability, by installation of new steam generators in 1989, and enhanced SGTR training. Phase II SAMAs 016, 017 and 018 were evaluated to mitigate SGTR events.</p>
NO_SAG-2	1.0	5.873	RCS depressurization failure-post core melt	<p>This term represents the probability that RCS depressurization as described in severe accident guideline SAG-2, "Depressurize the RCS," is not performed during a high pressure core melt accident. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated. In addition, Phase II SAMA 026, to improve DC bus load shedding to extend DC power availability, was evaluated.</p>

**Table E.3-5**  
**IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
NO_HLSL_1	0.90	5.731	RCS hot leg or pressurizer surge line remains intact during medium pressure accident scenario	This term represents the probability that either the RCS hot leg or pressurizer surge line remains intact during an accident in which the RCS system pressure is between 675 psig and 2235 psig. A Phase I SAMA to keep pressurizer PORV block valves open to increase PORV availability has already been implemented. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
PDS_FRAC-51	6.73E-02	5.496	Long-term SGTR with stuck-open safety relief valve	This term is the PDS split fraction for a long-term SGTR scenario involving failure to isolate the ruptured steam generator and subsequent stuck-open steam generator safety relief valve. Phase I SAMAs were implemented providing procedures to enhance the likelihood of success of operator action in response to SGTR accident conditions and increasing the reliability of the steam generator via enhance maintenance practices. Phase II SAMAs 016, 017 and 018 were evaluated to mitigate SGTR events.
PDS_FRAC-49	7.66E-03	1.103	Long-term small ISLOCA outside containment event	This term is the PDS split fraction for a long-term small break ISLOCA outside containment. Phase II SAMAs 019, 020, 021, and 022, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.

**Table E.3-5  
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
DP-46	0.1	1.089	RCS pressure is low at vessel breach given a long-term SGTR with stuck-open safety relief valve	This term represents the probability that RCS depressurization occurs during a long-term SGTR with stuck-open safety relief valve. Phase II SAMAs 016 and 017 to provide shell side heat removal and increase secondary pressure capacity to improve secondary heat removal, were evaluated. In addition, Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
PDS_FRAC-50	3.87E-03	1.050	Short -term large ISLOCA outside containment event	This term is the PDS split fraction for a short-term large break ISLOCA outside containment. Phase II SAMAs 019, 020, 021, and 022, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.
DP-45	1.0	1.050	RCS pressure is low at vessel breach given a large ISLOCA event	This term represents the probability that RCS depressurization occurs during a short-term large break ISLOCA outside containment. Phase I SAMAs to improve procedures to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 019, 020, 021, and 022, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.

**Table E.3-5**  
**IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
NO_SAG-4	1.00	1.042	Containment injection post core melt does not occur	This term represents the probability that injection into containment as described in severe accident guideline SAG-4, "Inject Into Containment," is not performed to cool the lower head of the reactor vessel. An additional benefit of flooding the containment is that water will be available for ECCS recirculation and to flood core debris in the reactor pit area after vessel breach. Phase II SAMAs 006 and 007, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.
SLUMP_3	0.10	1.036	Core slump probability given CM>20% and no injection	This term represents the probability of core slump to the lower head as a large mass, given no in-vessel injection. Phase II SAMAs 032, 033, 034, 035, 036, and 037, for enhancing reactor vessel injection and recirculation cooling, were evaluated.
VF_SIZE_PEN	0.90	1.035	Vessel penetration failure occurs debris thermal attack	This term represents the probability of vessel failure due to a single lower head penetration failure. Phase II SAMA 007 was evaluated to consider the benefit of a reactor vessel exterior cooling system with the potential to cool a molten core before it causes vessel failure.
NO-INVESSEL-COOL	1.0	1.035	In-vessel cooling failure post core damage	This flag event indicates that in-vessel cooling fails during a core melt progression. Phase II SAMAs 032, 033, 034, 035, 036, and 037, for enhancing reactor vessel injection during transients, small LOCA and SBO, were evaluated.



**Table E.3-5  
 IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
 (Continued)**

Event Name	Probability	RRW	Event Description	Disposition
DCH_OCCURS	0.50	1.035	DCH occurs given HPME phenomena	This term represents the probability that DCH occurs following HPME. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated. In addition, Phase II SAMA 015, to erect a barrier to provide enhanced protection of the containment shell from ejected core debris following a core melt scenario at high pressure, and SAMA 026, to improve DC bus load shedding to extend DC power availability, were evaluated.
AC_SBO_FLOOD	1.032	1.135	Internal flooding induced SBO event fails ac power supply	This flag event indicates that AC power to the normal offsite supply buses and vital AC safeguard buses is disabled following an internal flooding event that impacts the control building switchgear room at the 15-foot elevation. Phase II SAMAs 055, 061, and 062, to upgrade the ASSS to allow timely restoration of seal injection and cooling, to install a flood alarm in the 480VAC switchgear room, and to provide the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events, were evaluated.

**Table E.3-5  
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
PDS_FRAC-45	8.35E-02	1.030	Long-term internal flood induced SBO sequence	This term is the PDS split fraction for a long-term internal flood event that entails failure of normal offsite supply buses, vital AC safeguard buses and loss of the AFW turbine-driven pump. With no secondary-side heat removal, core damage results at high RCS pressure. Phase II SAMAs 055, 061, and 062, to upgrade the ASSS to allow timely restoration of seal injection and cooling, to install a flood alarm in the 480VAC switchgear room, and to provide the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events, were evaluated.
NO_EXVESSEL-COOL	0.80	1.030	No ex-vessel cooling due to internal flooding event	This term represents failure of ex-vessel cooling following a flood in the control building switchgear room. Phase II SAMAs 006 and 007, to contain molten core debris in the reactor pit area and create a reactor cavity flooding system; Phase II SAMAs 032, 033, 035, and 037, to provide a diesel-driven pump for enhancing reactor vessel injection; Phase II SAMA 055, to provide the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events; and Phase II SAMAs 061 and 062, to upgrade the ASSS to allow timely restoration of seal injection and cooling and to install a flood alarm in the 480VAC switchgear room, were evaluated.

**Table E.3-5  
 IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
 (Continued)**

Event Name	Probability	RRW	Event Description	Disposition
DP-40	0.975	1.029	RCS pressure is low at vessel breach given a long-term internal flood induced SBO sequence	This term represents the probability that RCS depressurization occurs during a long-term internal flood induced SBO sequence. Phase I SAMAs to improve procedures to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
H2_EARLY2_MED	0.50	1.026	In-vessel hydrogen production is medium (between 600 lbm and 2200 lbm)	This term represents the probability that the amount of hydrogen produced is between 600 lbm and 2200 lbm during accidents with 20% core melt, no early injection, and no late recirculation cooling. Phase II SAMA 009, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated.
HPME_1	0.50	1.025	HPME occurs at high RCS pressure	This term represents the probability that HPME occurs at high RCS pressure. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.

**Table E.3-5**  
**IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
BURN_VF1-E_DEF	0.50	1.021	Hydrogen burn occurs under medium hydrogen conditions	This term represents the probability of a hydrogen burn occurring at vessel failure, given a medium hydrogen concentration early, no prior early burns, and DCH. Phase II SAMA 009, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated.
NO_QUENCH-3	1.0	1.019	No debris quench, given dry reactor pit and no late water supply after vessel breach	This term represents the probability that debris is not quenched immediately after vessel failure, with no water inside the reactor pit at vessel breach and no late water supply for debris cooling after vessel breach. Phase II SAMAs 006 and 007, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.
NO_DISPERSAL	0.9	1.013	Core debris is not dispersed into containment atmosphere at vessel breach	This term represents the probability that debris is not dispersed and cooled following an HPME or an in-vessel or ex-vessel steam explosion event. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.

**Table E.3-5  
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
CFE@VF_2	0.997	1.013	Containment failure given containment pressure >23 psig, dry reactor pit, H2 burn and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given containment pressure greater than 23 psig, no water in the reactor pit, DCH, and hydrogen burn. Phase II SAMAs 007, 008, 009, 010, 011, 012, 013, and 014, for enhancing containment integrity, were evaluated. In addition, Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
CFE@VF_9	0.24	1.0132	Containment failure given containment pressure >23 psig, dry reactor pit, and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given containment pressure greater than 23 psig, no water in the reactor pit, and DCH. Phase II SAMAs 007, 008, 009, 010, 011, 012, 013, and 014, for enhancing containment integrity, were evaluated. In addition, Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
NO_QUENCH-2	0.50	1.010	No debris quench, given dry reactor pit and late water supply after vessel breach	This term represents the probability that debris is not quenched immediately after vessel failure, without water inside the reactor pit at vessel breach, but with a late water supply for debris cooling after vessel breach. Phase II SAMAs 006 and 007, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.

**Table E.3-5  
 IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)  
 (Continued)**

Event Name	Probability	RRW	Event Description	Disposition
DP-44	0.10	1.009	RCS pressure is low at vessel breach given a small ISLOCA event.	This term represents the probability that RCS depressurization occurs during a small ISLOCA event. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
HPME_2	0.9	1.009	HPME occurs at medium RCS pressure	This term represents the probability that HPME occurs at RCS pressure between 675 psig and 2235 psig. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
CFE@VF_4	0.9	1.008	Containment failure given containment pressure < 23 psig, dry reactor pit, H2 burn and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given containment pressure less than 23 psig, no water in the reactor pit, DCH, and hydrogen burn. Phase II SAMAs 007, 008, 009, 010, 011, 012, 013, and 014, for enhancing containment integrity, were evaluated. In addition, Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.

**Table E.3-5**  
**IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
CFE_BURN2-H2_CFE	7.00E-02	1.005	Early hydrogen burn fails containment	This term represents the probability that an early hydrogen burn fails containment due to overpressure. Phase II SAMA 009, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated. In addition, Phase II SAMAs 007, 008, 011, 012, 013, and 014, for enhancing containment integrity, were evaluated.
PDS_FRAC-31	9.17E-02	1.005	Long-term plant transient at medium RCS pressure	This term is the PDS split fraction for a long-term plant transient with secondary-side cooling available and RCS pressure between 675 psig and 2235 psig. The medium RCS pressure is a result of either a stuck-open PORV or RCP seal LOCA. Many Phase I SAMAs have been implemented to provide more reliable or diverse high or low pressure injection systems, enhance RCP seal cooling systems, and enhance procedures to cope with loss of CCW for RCP seal cooling. Phase II SAMAs 001, 002, and 003, to provide redundant RCP seal cooling, were evaluated.
NO-INVL-COOL-DEB	0.1	1.005	Coolable debris bed not formed in-vessel	This term represents the probability that a coolable debris bed is not formed in the reactor vessel, given that reactor vessel coolant injection has been recovered. Phase II SAMAs 032, 033, 034, 035, 036, and 037, for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.

**Table E.3-5**  
**IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)**  
**(Continued)**

Event Name	Probability	RRW	Event Description	Disposition
BURN_EARLY1_DEF	0.1	1.005	Hydrogen deflagration burn occurs	This term represents the probability that an early hydrogen burn occurs. Phase II SAMA 009, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated. In addition, Phase II SAMAs 007, 008, 010, 011, 012, 013, and 014, for enhancing containment integrity, were evaluated.
REACTOR_PIT_WET	1.0	1.005	Water is present in the reactor pit	This flag event indicates that water is present in the reactor pit prior to vessel breach. The presence of water provides debris cooling and reduces the likelihood of DCH and core-concrete interactions (CCI). Phase II SAMA 007 was evaluated to provide cooling of the molten core before it causes vessel failure, enhance debris coolability, reduce CCI, and provide fission product scrubbing.



### E.3.2.2 Radionuclide Analysis

This subsection provides the following information regarding the characterization of the Level 2 CET end states.

- Overview of PDS
- Overview of radionuclide removal processes and the concept of binning
- Identification of radionuclide release categories
- Release category bin assignments
- Process used to group the numerous source terms
- MAAP deterministic calculations to support CET end states definition
- Consequence analysis source terms

#### E.3.2.2.1 Overview of PDS

The interface between the Level 1 Systems Analysis and the Level 2 Containment Performance Analysis consists of a set of PDS. The PDS are defined by a set of functional characteristics for system operation, which are important to accident progression, containment failure and source term definition. Each PDS contains Level 1 sequences with sufficient similarity in system functional characteristics that the containment accident progression for all sequences in the group can be considered to be essentially the same. Each PDS defines a unique set of conditions regarding the state of the plant and containment building systems and the physical state of the core, reactor coolant system and the containment boundary at (approximately) the time of core damage or vessel failure. The important functional characteristics for each PDS were determined by defining the critical parameters (system functions), which impact the key results. The sequence characteristics that are important were defined by the requirements of the containment accident progression analysis. They include the type of accident initiator, the operability or non-operability of important systems, the value of important plant variables (e.g., primary system pressure) which are defined by system operation, and timing of key events.

Based on the above criteria, the Level 1 results were binned into 57 PDS. These PDS define important combinations of system states that can result in distinctly different accident progression pathways and therefore, different containment failure and source term characteristics. [Table E.3-6](#) provides a description of the IP3 PDS that are used to summarize the Level 1 results.

The PDS designators listed in [Table E.3-6](#) represent the core damage end state categories from the Level 1 analyses that are grouped together as entry conditions for the Level 2 analysis. The Level 2 accident progression for each of the PDS is then evaluated using a single CET to determine the appropriate release category for each Level 2 sequence. Each end state associated with a Level 2 sequence is assigned to a unique release category.

**Table E.3-6  
Summary of IP3 Internal Events PDS**

<b>Plant Damage State</b>	<b>Description</b>	<b>Frequency/ry</b>
PDS-1	Long-term small-break LOCA with subsequent loss of secondary cooling. The containment is not bypassed and AC power is available. Core damage proceeds at high RCS pressure (>2350psia). Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	2.12E-09
PDS-2	Same as PDS-1, except random faults fail the containment fan coolers.	0.00E+00
PDS-3	Same as PDS-1, except random faults fail the containment fan coolers and containment injection spray systems.	0.00E+00
PDS-4	Long-term medium or small LOCA with loss of recirculation cooling. Core damage results at medium RCS pressure (>675psia and <2350psia). Containment is not bypassed and AC power is available. Late vessel injection, secondary-side cooling, containment fan coolers and containment spray are available after the onset of core damage.	2.10E-06
PDS-5	Same as PDS-4, except random faults fail the containment fan coolers.	1.30E-10
PDS-6	Same as PDS-4, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-7	Same as PDS-4, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-8	Long-term medium LOCA. Although vessel injection is successful, random faults fail all modes of operation of the high-head recirculation core cooling systems. With no long-term core cooling, core damage proceeds at medium RCS pressure (>675psia and <2350psia). Containment is not bypassed and AC power is available. Late vessel injection, containment injection sprays and containment recirculation sprays are not available. However, secondary-side cooling and containment fan coolers are available after the onset of core damage.	2.95E-08
PDS-9	Same as PDS-8, except random faults fail containment fan coolers.	1.91E-09
PDS-10	Long-term medium LOCA with subsequent loss of secondary-side cooling and recirculation cooling. Core damage results at medium RCS pressure (> 675psia and < 2350psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	3.72E-11

**Table E.3-6  
Summary of IP3 Internal Events PDS  
(Continued)**

Plant Damage State	Description	Frequency/ry
PDS-11	Same as PDS-10, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-12	Same as PDS-10, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-13	Long-term medium LOCA with subsequent random failure of secondary-side cooling and all modes of operation of the high-head recirculation core cooling systems. Core damage results at medium RCS pressure (> 675psia and < 2350psia). Containment is not bypassed and AC power is available. Late vessel injection is not available. Although containment fan coolers are available, both containment injection sprays and containment recirculation sprays are not available after the onset of core damage.	0.00E+00
PDS-14	Same as PDS-13, except random faults fail the containment fan coolers.	8.70E-11
PDS-15	Short-term large LOCA with either a loss of initial injection or loss of recirculation cooling. Core damage results at low RCS pressure (< 675 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment sprays are available after the onset of core damage.	2.19E-08
PDS-16	Same as PDS-15, except random faults fail the containment fan coolers.	0.00E+00
PDS-17	Same as PDS-15, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-18	Same as PDS-15, except random faults fails containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-19	Short-term large LOCA. Although initial injection is successful, random faults fail both the recirculation pumps and RHR pumps for long-term recirculation cooling. Core damage results at low RCS pressure (< 675 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are not available. However, containment fan coolers are available after the onset of core damage.	0.00E+00
PDS-20	Same as PDS-19, except random faults fail the containment fan coolers.	1.09E-08

**Table E.3-6  
Summary of IP3 Internal Events PDS  
(Continued)**

Plant Damage State	Description	Frequency/ry
PDS-21	Short-term ATWS event with AFW available and loss of long-term reactor subcriticality control. RCS pressure remains at the PORV setpoint, precluding high- and low-head safety injection. Therefore, core damage occurs in the short-term at high RCS pressure (> 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	3.64E-07
PDS-22	Long-term transient involving loss of secondary cooling and subsequent loss of primary bleed-and-feed core cooling. Core damage results at high RCS pressure (> 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment sprays are available after the onset of core damage.	3.30E-07
PDS-23	Same as PDS-22, except random faults fail the containment fan coolers.	5.25E-07
PDS-24	Same as PDS-22, except random faults fails the containment fan coolers and containment injection spray system.	0.00E+00
PDS-25	Long-term transient with a subsequent loss of secondary cooling. Following successful bleed-and-feed core cooling, failure to implement long-term recirculation cooling occurs. Core damage results at medium RCS pressure (> 675 psia and < 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	2.42E-08
PDS-26	Same as PDS-25, except random faults fail the containment fan coolers.	3.53E-09
PDS-27	Same as PDS-25, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-28	Same as PDS-25, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-29	Long-term transient with subsequent loss of secondary cooling. Following successful bleed-and-feed core cooling, random faults fail long-term recirculation cooling. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are unavailable after the onset of core damage. However, the containment fan coolers are available.	0.00E+00

**Table E.3-6  
Summary of IP3 Internal Events PDS  
(Continued)**

<b>Plant Damage State</b>	<b>Description</b>	<b>Frequency/ry</b>
PDS-30	Same as PDS-29, except random faults fail the containment fan coolers.	5.54E-07
PDS-31	Long-term RCP seal LOCA caused by loss of CCW to the RCP seals. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	1.05E-06
PDS-32	Same as PDS-31, except random faults fail the containment fan coolers.	1.68E-09
PDS-33	Same as PDS-31, except random faults fails containment fan coolers and containment injection spray system.	3.18E-10
PDS-34	Same as PDS-31, except random faults fails containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-35	Stuck open PORV with loss of long-term recirculation cooling. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are unavailable after the onset of core damage. However, the containment fan coolers are available.	4.57E-10
PDS-36	Same as PDS-35, except random faults fail the containment fan coolers.	5.32E-08
PDS-37	SBO sequence in which a loss of all DC power occurs in the long term. No PORVs stick open. Secondary cooling by the AFW system is unavailable because the SBO renders both motor-driven AFW pumps inoperable, and the steam-turbine-driven AFW pump fails because of battery depletion or random faults. Without primary and secondary cooling, core damage occurs at high RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	1.44E-09
PDS-38	Short-term SBO sequence with immediate loss of secondary cooling. Core damage results at high RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	2.36E-08
PDS-39	Same as PDS-37, except RCS depressurization results from either operator action or a single PORV sticking open. Core damage results at medium RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	6.25E-07

**Table E.3-6  
Summary of IP3 Internal Events PDS  
(Continued)**

Plant Damage State	Description	Frequency/ ry
PDS-40	Short-term SBO sequence with immediate loss of secondary cooling and subsequent RCP seal LOCA or stuck-open PORV. Core damage results at medium RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	2.47E-09
PDS-41	Short-term large LOCA induced by vessel rupture. The LOCA is beyond the capability of the ECCS. Core damage occurs in the short term with the RCS at low pressure. Vessel injection and all forms of containment heat removal (containment fan coolers, RHR heat exchangers, and containment sprays) are available. Containment is not bypassed and AC power is available.	1.34E-06
PDS-42	Same as PDS-41, except random faults fail the containment fan coolers.	1.10E-11
PDS-43	Same as PDS-41, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-44	Same as PDS-41, except random faults fail the containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-45	Long-term internal flood induced SBO sequence in which loss of AFW steam-turbine-driven pump occurs. With no secondary-side heat removal, core damage results at high RCS pressure. Because of the flood, core cooling and containment heat removal systems are unavailable after the onset of core damage. Containment is not bypassed	2.09E-06
PDS-46	Short-term internal flood induced SBO sequence in which loss of secondary heat removal occurs. Core damage results at high RCS pressure. Because of the flood, core cooling and containment heat removal systems are not available after the onset of core damage	1.55E-07
PDS-47	Long-term internal flood induced SBO with a subsequent stuck-open PORV or RCP seal LOCA. Core damage ensues at medium RCS pressure. The steam-turbine-driven AFW pump is available after core damage. However, core cooling and containment heat removal systems are unavailable because of the internal flooding event. The containment is not bypassed	0.00E+00
PDS-48	Short-term internal flood induced SBO sequence in which loss of secondary heat removal occurs and a subsequent breach of RCS integrity occurs because of a stuck-open PORV or RCP seal LOCA. Core damage results at medium RCS pressure. Because of the flood, core cooling and containment heat removal systems are not available after the onset of core damage	0.00E+00

**Table E.3-6  
Summary of IP3 Internal Events PDS  
(Continued)**

<b>Plant Damage State</b>	<b>Description</b>	<b>Frequency/ry</b>
PDS-49	Long-term small break ISLOCA outside containment. Core damage results at medium RCS pressure with a bypassed containment. While vessel injection and all modes of containment sprays are unavailable, containment fan coolers are available after core damage.	8.79E-08
PDS-50	Short-term large break ISLOCA outside containment. Core damage results at low RCS pressure with a bypassed containment. While vessel injection and all modes of containment spray are unavailable, containment fan coolers are available after core damage.	4.45E-08
PDS-51	SGTR and failure to isolate the ruptured steam generator. Because RCS pressure remains above the ruptured steam generator pressure, water lost from the RCS does not return to the containment sump and recirculation core cooling is unavailable. Core damage results at medium RCS pressure with a bypassed containment. While vessel injection and all modes of containment sprays are unavailable, containment fan coolers are available after core damage.	7.72E-07
PDS-52	Same as PDS-51, except random faults fail containment fan coolers.	0.00E+00
PDS-53	Same as PDS-51, except random faults fail AFW to the steam generators and the containment fan coolers.	0.00E+00
PDS-54	Same as PDS-51, except the ruptured steam generator is isolated.	9.84E-07
PDS-55	Same as PDS-51 except the ruptured steam generator is isolated and random faults fail the containment fan coolers.	2.35E-09
PDS-56	Same as PDS-51, except the ruptured steam generator is isolated and random faults fail AFW to the steam generators.	2.71E-07
PDS-57	Same as PDS-51, except the ruptured steam generator is isolated, random faults fail AFW to the steam generators and the containment fan coolers.	2.79E-10
<b>Total</b>		<b>1.15E-5</b>

#### E.3.2.2.2 Overview of Radionuclide Removal Processes and Concept of Binning

A major feature of a Level 2 analysis is the estimation of the source term for every possible outcome of the CET. The CET end points represent the outcomes of possible in-containment accident progression sequences. These end points represent complete severe accident sequences from initiating event to release of radionuclides to the environment. The Level 1 and plant system information is passed through to the CET evaluation in discrete PDS. An atmospheric source term may be associated with each of these CET sequences. Because of the large number of postulated accident scenarios considered, mechanistic calculations (i.e., MAAP calculations) are not performed for every end-state in the CET. Rather, accident sequences produced by the CET are grouped or "binned" into a limited number of release categories, each of which represents all postulated accident scenarios that would produce a similar fission product source term.

The criteria used to characterize the release are the estimated magnitude of total release and the timing of the first significant release of radionuclides. The predicted source term associated with each release category, including both the timing and magnitude of the release, is determined using the results of MAAP calculations.

#### E.3.2.2.3 Identification of Radionuclide Release Categories

##### E.3.2.2.3.1 Timing of Release

Timing completely governs the extent of radioactive decay of short-lived radioisotopes prior to an offsite release and, therefore, has a first-order influence on immediate health effects. IP3 characterizes the release timing relative to the time at which the release begins, measured from the time of accident initiation. Two timing categories are used, as follows.

- (1) Early: rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of offsite emergency response and protective actions. This involves CET endstates in which containment failure occurs within 0 to 12 hours from the initiating event.
- (2) Late: mitigated release of airborne fission products from the containment to the environment occurring after effective implementation of offsite emergency response and protective actions. This involves CET endstates in which containment failure occurs after 12 hours from the initiating event.

The definition of the release category timing takes into consideration the compensatory measures available to reduce or prevent dose to the public and the characteristics of the radionuclide release. Compensatory measures are prescribed in the emergency response plan. These actions, which are routinely practiced, are geared to mobilizing utility resources to implement emergency procedures, assess the potential offsite consequence of an accident, and recommend to government officials appropriate action for protecting the public (evacuate or shelter).



An evacuation time estimates study performed for the Indian Point Energy Center (IPEC) site [Reference E.3-7] examined 14 evacuation scenarios under which evacuation times are calculated to successfully evacuate 100 percent of the general public. The ranges of times for those 14 scenarios for the following emergency planning zone rings (shortest to longest in hours: minutes) are as follows:

2 miles: 4:30 to 6:50;  
5 miles: 5:25 to 8:00;  
10 miles: 7:10 to 12:00.

Since the 10-mile emergency planning zone may not be evacuated for 12 hours from the initiating event, 12 hours is the upper bound time in which an early release can occur.

#### E.3.2.2.3.2 Magnitude of Release

Source term results from previous risk studies suggest that categorization of release magnitude based on cesium iodide (CsI) release fractions alone are appropriate [Reference E.3-5]. The CsI release fraction indicates the fraction of in-vessel radionuclides escaping to the environment. (Noble gas release levels are non-informative since release of the total core inventory of noble gases is essentially complete given containment failure.)

The source terms were grouped into five distinct radionuclide release categories or bins according to release magnitude as follows.

- (1) High: A radionuclide release of sufficient magnitude to have the potential to cause early fatalities. This implies a total integrated release of > 10% of the initial core inventory of Cesium Iodide (CsI) [Reference E.3-5]<sup>1</sup>.
- (2) Medium: A radionuclide release of sufficient magnitude to cause near-term health effects. This implies a total integrated release of between 1% and 10% of the initial core inventory of CsI [Reference E.3-5]<sup>2</sup>.
- (3) Low: A radionuclide release with the potential for latent health effects. This implies a total integrated release of between 0.1% and 1% of the initial core inventory of CsI.
- (4) Low-Low: A radionuclide release with undetectable or minor health effects over most of the population. This implies a total integrated release of between 0.01% and 0.1% of the initial core inventory of CsI.

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1. Once the CsI source term exceeds 0.1, the source term is large enough that doses above the early fatality threshold can sometimes occur within a population center a few miles from the site.

2. The reference document indicates that for CsI release fractions of 1 to 10 percent, the number of latent fatalities is found to be at least 10 percent of the latent fatalities for the highest release.

- (5) Negligible or no containment failure (NCF): A radionuclide release that is less than or equal to the containment design base leakage. This implies total integrated release of < 0.01% of the initial core inventory of Csl.

**E.3.2.2.4 Release Category Bin Assignments**

The combination of release magnitude and timing produce nine distinct release categories. Table E.3-7 summarizes the scheme used to bin CET sequences with respect to magnitude of release, based on the predicted Csl release fraction and release timing.

**Table E.3-7  
 IP3 Release Severity and Timing Classification Scheme Summary**

Release Severity		Release Timing	
Classification Category	Percent Csl Release	Classification Category	Time of Initial Release From Accident Initiation
High	Greater than 10	Early (E)	Less than 12 hours
Medium	1 to 10		
Low	0.1 to 1	Late (L)	Greater than 12 hours
Low-Low	0.01 to 0.1		
NCF	Less than <0.01		

**E.3.2.2.5 Process Used to Group the Source Terms**

The approach used to evaluate radionuclide releases and develop release categories is similar to that applied in the NUREG-1150 analysis; i.e., a source term was associated with each CET end-state that was found to have a significant frequency. The objectives were to establish the timing of the first significant release of radionuclides and estimate the magnitude of the total release.

The first step in the source term assessment effort was to identify the sequence characteristics that are most important for defining the source term. These characteristics were identifiable from the PDS characteristics and from the CET sequence characteristics since one of the primary objectives in the PDS grouping and CET evaluation was to define those events and conditions most important for source term assessment. The set of sequence characteristics important to source term assessment was used as grouping criteria to define the release categories and the associated source term magnitude, composition and timing.

The containment sequence characteristics selected for use in definition of the IP3 source term release categories are

- vessel breach,
- containment failure,
- CCI,
- fission product removal, and
- PAB retention.

The goal of the grouping process was to develop the minimum number of release categories necessary to distinguish the important combinations of sequence characteristics that can result in distinctly different atmospheric source terms.

The second step was to classify the various progressions paths in the IP3 CET as unique release end states based on the sequence characteristics. The release modes were categorized into the following general classifications:

- end states are recovered in-vessel (no vessel breach),
- end states are recovered ex-vessel (vessel breach, but no core-concrete interactions),
- end states are late containment failures, and
- end states are early containment failures.

Each CET end state represents a particular release event or a recovered, degraded core state that may be characterized according to its potential for fission product release to the atmosphere, its timing of release initiation relative to time of incipient core damage, and its release duration.

[Table E.3-8](#) summarizes the possible CET release categories for the spectrum of core melt accident sequences. This table defines the various CET release modes as early or late release events and containment damage states (i.e., failure modes), including recovered states and release mechanisms (i.e., no CCI). Each release mode represents a release path from the fuel through the primary coolant system and the containment atmosphere to the environment, should the containment ultimately fail or be bypassed. The release path (including the associated removal mechanism) is related to a particular environmental source term.

The consolidation of source term results for the CET release categories presented in [Table E.3-8](#) was accomplished by "binning" or grouping releases into release categories that represent all postulated accident scenarios that produce a similar fission product source term. The criteria used to characterize the release are the estimated magnitude of total release and the timing of the first significant release of radionuclides.

Based on the above binning methodology, the salient Level 2 results are summarized in [Table E.3-9](#). This table identifies the total annual release frequency for each Level 2 release category.

**Table E.3-8  
Description of IP3 CET Release Modes**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-1	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-2	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-3	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early Medium
APB-4	Vessel breach at low pressure, recovered ex-vessel, no containment failure	NA	Negligible	NCF
APB-5	Vessel breach at low pressure, recovered ex-vessel, late containment leak failure, in-vessel fission product release mitigated	Late	Low-Low	Late Low-Low
APB-6	Vessel breach at low pressure, recovered ex-vessel, late containment leak failure, in-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-7	Vessel breach at low pressure, recovered ex-vessel, late containment rupture failure, in-vessel fission product release not mitigated	Late	High	Late High
APB-8	Vessel breach at low pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-9	Vessel breach at low pressure, CCI occurs, late containment leak failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release mitigated by sprays	Late	Low-Low	Late Low-Low

**Table E.3-8  
Description of IP3 CET Release Modes  
(Continued)**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-10	Vessel breach at low pressure, CCI occurs, late containment rupture failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release mitigated by sprays	Late	Low	Late Low
APB-11	Vessel breach at low pressure, CCI occurs, late containment leak failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release not mitigated	Late	Medium	Late Medium
APB-12	Vessel breach at low pressure, CCI occurs, late containment rupture failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release not mitigated	Late	High	Late High
APB-13	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-14	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release mitigated	Early	Medium	Early Medium
APB-15	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-16	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-17	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, in- and ex-vessel product release mitigated	Early	Low	Early Low

**Table E.3-8  
Description of IP3 CET Release Modes  
(Continued)**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-18	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, in- and ex-vessel product release mitigated	Early	Medium	Early Medium
APB-19	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, ex-vessel product release mitigated by overlying pool, in-vessel fission product release not mitigated	Early	High	Early High
APB-20	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, ex-vessel product release mitigated by overlying pool, in-vessel fission product release not mitigated	Early	High	Early High
APB-21	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-22	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early-Low
APB-23	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early-Medium
APB-24	Vessel breach at low pressure, recovered ex-vessel, no containment failure	NA	Negligible	NCF
APB-25	Vessel breach at low pressure, no CCI, late containment leak failure, in-vessel fission product release mitigated by sprays	Late	Low-Low	Late Low-Low
APB-26	Vessel breach at low pressure, no CCI, late containment rupture failure, in-vessel fission product release mitigated by sprays	Late	Low	Late Low

**Table E.3-8  
Description of IP3 CET Release Modes  
(Continued)**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-27	Vessel breach at low pressure, no CCI, late containment leak failure, in-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-28	Vessel breach at low pressure, no CCI, late containment rupture failure, in-vessel fission product release not mitigated	Late	High	Late High
APB-29	Vessel breach at low pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-30	Vessel breach at low pressure, significant CCI occurs, late containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Late	Low-Low	Late Low-Low
APB-31	Vessel breach at low pressure, significant CCI occurs, late containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Late	Low	Late Low
APB-32	Vessel breach at low pressure, significant CCI occurs, late containment leak failure, in- and ex-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-33	Vessel breach at low pressure, significant CCI occurs, late containment rupture failure, in- and ex-vessel fission product release not mitigated	Late	High	Late High
APB-34	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-35	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release mitigated	Early	Medium	Early Medium

**Table E.3-8  
Description of IP3 CET Release Modes  
(Continued)**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-36	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-37	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-38	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Early	Low	Early Low
APB-39	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-40	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, fission product not mitigated	Early	High	Early High
APB-41	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, fission product not mitigated	Early	High	Early High
APB-42	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-43	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-44	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early Medium



**Table E.3-8  
Description of IP3 CET Release Modes  
(Continued)**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-45	Vessel breach at high pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-46	Vessel breach at high pressure, no CCI, late containment leak failure, in-vessel and late fission product release mitigated by sprays	Late	Low	Late Low
APB-47	Vessel breach at high pressure, no CCI, late containment rupture failure, in-vessel and late fission product release mitigated by sprays	Late	Low	Late Low
APB-48	Vessel breach at high pressure, no CCI, late containment leak failure, in-vessel and late fission product release not mitigated	Late	Medium	Late Medium
APB-49	Vessel breach at high pressure, no CCI, late containment rupture failure, in-vessel and late fission product release not mitigated	Late	High	Late High
APB-50	Vessel breach at high pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-51	Vessel breach at high pressure, moderate CCI occurs, late containment leak failure, in- and ex-vessel fission product release mitigated by Sprays	Late	Low	Late Low
APB-52	Vessel breach at high pressure, moderate CCI occurs, late containment rupture failure, in- and ex-vessel fission product release mitigated by Sprays	Late	Low	Late Low
APB-53	Vessel breach at high pressure, moderate CCI occurs, late containment leak failure, in- and ex-vessel, fission product release not mitigated	Late	Medium	Late Medium

**Table E.3-8  
 Description of IP3 CET Release Modes  
 (Continued)**

<b>Accident Progression Bin</b>	<b>CET Sequence Description</b>	<b>Release Timing (based on MAAP)</b>	<b>Release Magnitude (based on MAAP)</b>	<b>CET Release Category</b>
APB-54	Vessel breach at high pressure, moderate CCI occurs, late containment rupture failure, in- and ex-vessel, fission product release not mitigated	Late	High	Late High
APB-55	Vessel breach at high pressure, no CCI, early containment leak failure, in-vessel and late fission product release mitigated	Early	Medium	Early Medium
APB-56	Vessel breach at high pressure, no CCI, early containment rupture failure, in-vessel and late fission product release mitigated	Early	Medium	Early Medium
APB-57	Vessel breach at high pressure, no CCI, early containment leak failure, in-vessel and late fission product release not mitigated	Early	Medium	Early Medium
APB-58	Vessel breach at high pressure, no CCI, early containment rupture failure, in-vessel and late fission product release not mitigated	Early	High	Early High
APB-59	Vessel breach at high pressure, moderate CCI occurs, early containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-60	Vessel breach at high pressure, moderate CCI occurs, early containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-61	Vessel breach at high pressure, moderate CCI occurs, early containment leak failure, ex-vessel and late fission product release not mitigated	Early	Medium	Early Medium
APB-62	Vessel breach at high pressure, moderate CCI occurs, early containment rupture failure, ex-vessel and late fission product release not mitigated	Early	High	Early High

**Table E.3-9  
 Summary of CET Quantification  
 IP3 PSA Model Revision 2**

<b>Release Category (Timing/Magnitude)</b>	<b>Release Frequency (Per year)</b>
Late Low-Low	5.66E-08
Late Low	3.75E-07
Late Medium	2.01E-06
Late High	4.23E-07
Early Low-Low	0.00E+00
Early Low	1.46E-07
Early Medium	1.24E-06
Early High	9.43E-07
No Containment Failure (NCF)	6.30E-06
<b>Total</b>	<b>1.15E-05</b>

**Nomenclature**

Timing:

Late - Greater than 12 hours

Early - Less than 12 hours

**Magnitude**

NCF (Little to no release) - Less than 0.01% Cs Iodide

Low-Low - 0.01% to 0.1% Cs Iodide

Low - 0.1% to 1% Cs Iodide

Medium - 1% to 10% Cs Iodide

High - Greater than 10% Cs Iodide

#### E.3.2.2.6 MAAP Deterministic Calculations to Support CET End States Definition

The MAAP computer code is used to assign both the radionuclide release magnitude and timing based on the accident progression characterization. Specifically, MAAP provides the following information:

- containment pressure and temperature (time of containment failure is determined by comparing these values with the nominal containment capability);
- radionuclide release timing and magnitude for a large number of radioisotopes; and
- release fractions for twelve radionuclide species.

#### E.3.2.2.7 Consequence Analysis Source Terms

Input to the Level 3 IP3 model from the Level 2 model is a combination of radionuclide release fractions, timing of radionuclide releases, and frequencies at which the releases occur. This combination of information is used in conjunction with IP3 site characteristics in the Level 3 model to evaluate the offsite consequences of a core damage event.

Source terms were developed for the nine release categories identified in [Table E.3-9](#). The MAAP computer code was used to generate the radionuclide release magnitude for the MACCS2 consequence analysis [[Reference E.3-6](#)]. The MAAP calculations are representative deterministic thermal hydraulic calculations that portray dominant CET scenarios.

[Table E.3-10](#) provides a summary of the Level 2 results that were used as Level 3 input for the IP3 SAMA analysis.

The source terms presented in [Table E.3-10](#) and used in the consequence analysis were determined as follows:

1. The appropriate MAAP case source terms were selected and assigned to a particular CET accident progression endstate.
2. Based on the source terms from Step 1, the source terms for each plant damage state CET accident progression endstate were determined.
3. The frequency of each release category was determined by summing the individual plant damage state CET accident progression endstates contained in the particular release category (i.e., no containment failure, early high release, etc.).
4. The release category individual fractional contributions for each CET accident progression were determined by dividing the result from Step 3 by the individual PDS frequencies.

5. Each PDS accident progression CET endpoint source terms, release timing, release energy and release elevation was multiplied by the value determined in Step 4.
6. The individual results of Step 5 were summed to arrive at the total final values contained in Table E.3-10.

**Table E.3-10  
IP3 Release Category Source Terms**

	Release Characterization	Frequency (/ry)	Warning Time (sec)	Elevation (m)	Release Start (Hours)	Release Duration (Hours)	Release Energy (W)
1	NCF	6.30E-06	1.26E+04	3.00E+01	0.00E+00	3.54E+01	9.20E+05
2	Early High	9.43E-07	1.27E+04	3.00E+01	3.34E+00	2.20E+01	1.03E+06
3	Early Medium	1.24E-06	9.18E+03	3.00E+01	2.56E+00	2.28E+01	1.07E+06
4	Early Low	1.46E-07	9.31E+03	3.00E+01	2.75E+00	2.36E+01	1.11E+06
5	Early Low-Low	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
6	Late High	4.23E-07	5.58E+03	3.00E+01	2.05E+01	3.60E+01	9.20E+05
7	Late Medium	2.01E-06	7.17E+03	3.00E+01	2.14E+01	3.60E+01	9.20E+05
8	Late Low	3.75E-07	2.19E+04	3.00E+01	2.53E+01	3.60E+01	9.20E+05
9	Late Low-Low	5.66E-08	2.56E+04	3.00E+01	3.15E+01	3.60E+01	9.20E+05

**Table E.3-10  
IP3 Release Category Source Terms  
(continued)**

Release Fractions									
	NG	I	Cs	Te	Sr	Ru	La	Ce	Ba
1	9.62E-05	6.51E-06	2.65E-06	2.08E-06	6.09E-08	5.20E-07	3.26E-09	2.72E-08	1.79E-07
2	6.35E-01	1.63E-01	1.48E-01	1.47E-01	1.57E-02	6.48E-02	5.55E-04	3.03E-03	3.07E-02
3	9.87E-01	1.31E-02	1.18E-02	2.65E-02	8.51E-04	2.95E-02	5.17E-05	3.07E-04	1.95E-02
4	2.43E-01	2.03E-03	1.62E-03	2.90E-03	8.98E-05	2.97E-03	5.17E-06	3.11E-05	1.87E-03
5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
6	9.89E-01	1.17E-01	2.26E-02	4.81E-03	2.08E-04	3.74E-03	1.32E-05	1.22E-04	9.06E-04
7	8.23E-01	1.53E-02	4.30E-03	1.49E-03	8.01E-05	1.44E-03	5.11E-06	4.72E-05	3.50E-04
8	6.98E-01	1.06E-03	7.91E-04	1.23E-03	8.69E-05	3.47E-06	2.59E-06	2.38E-05	7.41E-05
9	9.09E-01	8.14E-04	6.96E-04	7.55E-04	3.63E-05	2.08E-06	1.14E-06	1.20E-05	3.33E-05

### **E.3.3 IPEEE Analysis**

#### **E.3.3.1 Seismic Analysis**

The seismic portion of the IPEEE was completed in conjunction with the SQUG program [References E.3-8 and E.3-9]. IP3 performed a seismic probabilistic risk assessment (PRA) following the guidance of NUREG-1407 [Reference E.3-10] and NUREG/CR-2300 [Reference E.3-11]. The seismic PRA logic model was developed using a fault tree linking approach similar to the Level 1 PSA. This approach permits the explicit modeling of system and component dependencies that exist between event tree top events. The seismic PRA also includes a simplified containment performance model, which was developed to address scenarios leading to significant early containment releases during a seismic event. The seismic PRA provides quantitative, but conservative results. Therefore, its results should not be compared directly with the best-estimate internal events results.

Conservative assumptions in the seismic PRA include the following:

- Each of the sequences in the seismic PRA assumes unrecoverable loss of offsite power. If offsite power was maintained, or recovered, following a seismic event, there would be many more systems available to maintain core cooling and containment integrity than are presently credited in the analysis.
- A single, conservative, surrogate element whose failure leads directly to core damage is used in the seismic risk quantification to model the most seismically rugged components.
- Because there is little industry experience with crew actions following seismic events, human actions were conservatively characterized.

The conclusions of the IP3 seismic PRA are as follows.

- The total seismic CDF for IP3 is  $4.4 \times 10^{-5}$ /year.
- No unique decay heat removal vulnerabilities to seismic events were found because the safety-related systems provide effective and reliable means for reactor reactivity control, electrical power, RCS pressure control, decay heat removal, and containment pressure control.
- Seismic-induced flooding and fires do not pose major risks.
- No unique seismic-induced containment failure mechanisms were identified.

The seismic PRA CDF has recently been re-evaluated to reflect updated random component failure probabilities and to model recovery of onsite power and local operation of the turbine-driven AFW pump. The revised seismic CDF of  $2.65 \times 10^{-5}$  per reactor-year represents a

reduction by a factor of 1.67 from the IPEEE. This revised seismic CDF was used to determine the external event multiplier described in [Section 4.21.5.4](#).

One plant improvement is identified in Table 2.4 of NUREG-1742 [[Reference E.3-12](#)]. To address the potential spurious operation of the EDG room carbon dioxide (CO<sub>2</sub>) system and subsequent shutdown of the EDG ventilation system during a seismic event, a plant modification installed a QA category I, seismic class I, actuation permission auxiliary control panel for CO<sub>2</sub> discharge into the EDG building. Since shutdown of EDG ventilation due to spurious operation of the EDG room carbon dioxide (CO<sub>2</sub>) system during a seismic event is not considered in the seismic PRA model, the seismic CDF was not impacted by this modification.

### E.3.3.2 Fire Analysis

The IP3 internal fire risk model was performed in 1997 as part of the IPEEE submittal report [[Reference E.3-8](#)]. The IP3 fire analysis was performed using EPRI's Fire PRA Implementation Guide [[Reference E.3-13](#)]. The EPRI Fire Induced Vulnerability Evaluation method was used for the initial screening, for treatment of transient combustibles, and as the source of fire frequency data [[Reference E.3-14](#)].

[Table E.3-11](#) presents the results of the IP3 IPEEE fire analysis and the updated values used in this SAMA evaluation. The IPEEE values presented in [Table E.3-11](#) are the same as those listed in NUREG-1742 [[Reference E.3-12](#)]. These values reflect the re-evaluation of the IPEEE fire CDF results to include response to Nuclear Regulatory Commission (NRC) questions and issues regarding fire-modeling progression.

A number of plant improvements were identified and are described in NUREG-1742, *Perspectives Gained from the IPEEE Program*, Final Report, April 2002. These improvements have been implemented. In addition, a number of administrative procedures were revised to improve combustible and flammable material control.

The revised fire CDF of  $2.55 \times 10^{-5}$  per reactor-year, which reflects these plant improvements and results in a reduction factor of 2.19, was used to determine the external event multiplier described in [Section 4.21.5.4](#).

#### E.3.3.2.1 Risk Reduction for Dominant Fire Zones

[Table E.3-11](#) lists a number of fire zones with CDF values above 1E-06 per year. The IPEEE recommendations to restore the 480VAC switchgear room carbon dioxide suppression system to automatic actuation, and realign the power supplies and reroute the cables for the EDG fans and engine auxiliaries have been implemented, and are reflected in the revised CDF values in [Table E.3-11](#).

Other improvements implemented include

- restraining flammables or maintaining them in cabinets,



- monitoring and controlling the quantity of combustible materials in critical process areas, and
- monitoring and controlling the pre-staging of outage materials.

Although not explicitly credited in the model, credit for these controls would reduce CDF values for all of the dominant zones.

The following discussion for each dominant zone explains what measures have been taken to reduce risk in that zone and explains why the fire CDF cannot be further reduced in a cost effective manner.

#### **480VAC Switchgear Room (Fire Zone 14)**

The switchgear room is equipped with fire detection, which is annunciated in the control room, and an automatic full flooding CO<sub>2</sub> fire suppression system. This system can also be manually actuated by the fire brigade from the 15-foot elevation of the turbine building. This zone is also regularly inspected by operations personnel who are trained fire brigade members, as well as by plant security officers.

At the time of the IPEEE, the CO<sub>2</sub> system had been placed in "Manual" due to seismic interaction issues. Subsequently, the system was extensively modified and restored to automatic operation. Additionally, a more realistic assessment was made of the standby instrument air compressor run time. The IPEEE analysis assumed both air compressors running at all times. In reality, the standby air compressor will only run during scheduled maintenance of the 33 instrument air compressor (approximately 5 days/year) and rare system perturbations. Therefore, a conservative run time of 10 percent was assigned to the standby air compressor. Accordingly, restoration of automatic fire suppression capability, along with refinements in the updated PSA model, resulted in the revised fire zone CDF in Table E.3-11.

Since the switchgear room is equipped with a detection system that alarms in the control room and an automatic carbon dioxide suppression system, no further cost-effective changes were identified to reduce CDF in this zone.

#### **Cable Spreading Room (Fire Zone 11)**

The cable spreading room is equipped with fire detection, which is annunciated in the control room, and an automatic full flooding CO<sub>2</sub> fire suppression system. This system can also be manually actuated by the fire brigade. This zone is also regularly inspected by operations personnel who are trained fire brigade members, as well as by plant security officers. The reduction in the zone CDF was realized by re-evaluating high CDF scenarios based on a re-assessment of equipment lost as a result of postulated fire induced damage and applicable initiating events.

Based on the above, no further cost-effective changes were identified to reduce CDF in this zone.

### **Central Control Room (Fire Zone 15)**

The main control room is continuously inhabited by operations personnel, who are trained fire brigade members, ensuring prompt fire detection and manual suppression. Therefore, no further cost-effective changes were identified to reduce CDF in this zone.

### **480VAC Switchgear Room / South Turbine Building (Fire Zones 14 / 37A)**

A fire initiating in zone 14 and propagating to zone 37A was the only multiple compartment fire which exceeded the IP3 IPEEE screening criteria. At the time of the IPEEE, the 480VAC switchgear room CO2 suppression system had been placed in "Manual" due to seismic interaction issues. Subsequently, the system was extensively modified and restored to automatic operation. Accordingly, restoration of automatic fire suppression capability, along with refinements in the updated PSA model in fire zone 14, resulted in the revised fire zone CDF in [Table E.3-11](#).

Since the switchgear room is equipped with a detection system that alarms in the control room and an automatic full flooding carbon dioxide suppression system, no further cost-effective changes were identified to reduce CDF in this zone.

### **31, 32, & 33 EDG Cells (Fire Zones 10, 101A, & 102A)**

The EDG cells are equipped with fire detection, which is annunciated in the control room, and an automatic full flooding CO2 fire suppression system. This system can also be manually actuated by the fire brigade. This zone is also regularly inspected by operations personnel who are trained fire brigade members, as well as by plant security officers.

The IPEEE identified vulnerability with the EDG exhaust fans and engine auxiliaries' cable routing which could result in failure of multiple EDGs due to a fire in a single cell. Subsequently, the power supplies and cables for the EDG fans and engine auxiliaries were realigned and re-routed to eliminate this failure mechanism. As reflected in [Table E.3-11](#), this resulted in a significant reduction in the CDF for these fire zones.

EDG cells are equipped with a fire detection system that alarms in the control room and an automatic full flooding carbon dioxide suppression system, and the recommendations of the IP3 IPEEE have been implemented. Therefore, no further cost-effective changes were identified to reduce CDF in these zones.

#### **E.3.3.3 Other External Hazards**

The IP3 IPEEE submittal, in addition to the internal fires and seismic events, examined a number of other external hazards:

- high winds and tornadoes;
- external flooding; and
- ice, hazardous chemical, transportation, and nearby facility incidents.

No risks to the plant occasioned by high winds and tornadoes, external floods, ice, and hazardous chemical, transportation, and nearby facility incidents were identified that might lead to core damage with a predicted frequency in excess of  $10^{-6}$ /year. Therefore, these other external event hazards are not included in this attachment and are not expected to impact the conclusions of this SAMA evaluation.

However, scenarios involving hydrogen explosions within the turbine building, the pipe trench between the PAB and containment, the hydrogen shed area in the containment access facility, and the pipe chase on the 73-ft elevation of the north-east corner of the PAB were identified that, in total, could result in core damage with a conservatively estimated frequency slightly above  $10^{-6}$ /year. Therefore, Phase II SAMA 053 is used to evaluate the change in plant risk from plant modifications to install an excess flow valve to reduce the risk associated with hydrogen explosions inside the turbine building or PAB.

**Table E.3-11  
 IP3 Updated Fire CDF Results**

<b>Fire Zone</b>	<b>Fire Zone Description</b>	<b>CDF/year</b>	<b>Revised CDF/year</b>
14	480V switchgear room	3.51E-05	1.31E-05
11	cable spreading room	6.83E-06	5.26E-06
15	control room	3.65E-06	3.65E-06
14/37A	480V switchgear room / south turbine building	4.49E-06	1.80E-07
10	diesel generator 31	2.13E-06	2.01E-06
102A	diesel generator 33	1.93E-06	4.68E-09
60A	upper electrical tunnel	7.14E-07	7.14E-07
101A	diesel generator 32	3.38E-07	5.15E-09
7A	lower electrical tunnel	2.78E-07	2.78E-07
23	auxiliary feedwater pump room	2.28E-07	2.28E-07
37A	south turbine building elevation 15 ft	3.78E-08	3.78E-08
17A	primary auxiliary building (PAB) corridor	3.17E-8	3.17E-08

### **E.3.4 PSA Model Revisions and Peer Review Summary**

The summary of the IP3 PSA models CDF and LERF is presented in the table below.

<b>Summary of Major PSA Models</b>		
<b>Model</b>	<b>CDF (/ry)</b>	<b>LERF (/ry)</b>
IPE (6/1994)	4.40E-5	N/A <sup>1</sup>
Revision 1 (6/2001)	1.35E-5	5.86E-7
Revision 2 (3/2007)	1.15E-5	9.43E-7

1. The IPE did not provide LERF value since the use of LERF as a risk metric post dates the IPE.

#### **E.3.4.1 Major Differences between the IP3 Revision 1 PSA Model and Original IPE Model**

The draft Revision 1 PSA model was peer reviewed in January 2001 and all Level A and B issues and observations from that peer review were addressed in the final version of the Revision 1 PSA model, which was issued in June 2001. Quantification of the final Revision 1 model yielded a measurably lower CDF (point estimate CDF = 1.35E-5/ry) than the original IPE (point estimate CDF = 4.40E-5/ry) [References [E.3-1](#) and [E.3-2](#)].

In the Revision 1 PSA model, the contributors in order of dominance were transients (44.14 percent), internal flooding (12.91 percent), LOCA (12.56 percent), SGTRs (10.50 percent), ATWS (9.93 percent), SBO (8.66 percent), and ISLOCA (1.30 percent). In the original IPE, the contributors in order of dominance were transient events (28.9 percent), LOCA (20.1 percent), ATWS (19.6 percent), internal flooding (14.7 per cent), SBO (10.8 percent), SGTR (5.5 percent) and ISLOCAs (less than 1 percent).

Significant changes were made to the IPE model in developing the Revision 1 PSA model. These changes were made to reflect new data, calculations, and modifications to the plant design and procedures. The major model changes impacting CDF and LERF that were incorporated into the IP3 PSA Revision 1 model can be summarized as follows.

#### **Level 1: Core Damage Model**

- Updated initiating event database, including all IP3 plant trips that occurred between 1/1/1986 and 12/31/2000.

- Updated component failure data base that reflects failures that occurred between 1/1/1992 and 10/31/1999, and unavailability data base occurred between 1/1/1985 and 10/31/1999, more equipment groups in which common-cause failures may occur and current on-line maintenance practices.
- Revised human reliability analysis to reflect emergency operating procedure changes up to 6/30/2000.
- Revised internal flooding analysis to reflect design and procedure modifications.
- Incorporated Improved Technical Specifications issued in 2001.
- Adopted a more conservative Brookhaven National Laboratory (BNL) RCP seal LOCA model versus Westinghouse model used in original IPE. Revised model reflects installation of qualified high-temperature RCP seals versus "low-temperature" seals in the original IPE analysis.
- Updated offsite power recovery model to reflect loss of offsite power events in NUREG/CR-5496, *Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996*.
- Changed PRA system models and data to reflect various design modifications and procedure changes through October 2000, including those changes associated with recommendations resulting from the original IPE. The major design modifications and procedure changes incorporated in this revision of the model follow.
  - Revision of the maintenance procedure for AFW building exhaust fans, louvers and dampers to improve the availability of AFW building ventilation system.
  - Revision of the emergency procedure for LOCA outside containment, which directs operators to close both SI-899A and SI-747 (or SI-899B and SI-746). This will cope with the potential to create differential pressure in excess of the design capability of SI-1869A or SI-1869B during a LOCA outside containment.
  - Revision of the annunciator response procedure for "Waste Holdup Tank Hi-Lo Level" to mitigate flooding in the PAB. Explicit instructions were added to check whether there is flooding in the PAB on a high-level alarm.
  - Modification of performance test procedures to direct that equipment be restored to the normal position or the position required by the shift manager or control room supervisor. This procedure modification should reduce the likelihood of human performance errors.

- Installation of adequate seismic support for the portion of the fire protection piping deluge valve station located in the control building at 15 ft elevation and installation of a water proof door to the deluge valve station room to reduce overall CDF contribution due to the internal flooding event.
  - Installation of temperature detectors to provide a control room alarm upon detection of high ambient temperature on the 15 and 33 ft elevations of the control building.
  - Replacement of PORVs to eliminate PORV leakage and allow operation with the block valves open to reduce overall CDF contribution due to ATWS and transient events.
  - Reassignment of power supplies to the EDG room exhaust fans eliminating cross-dependencies with other EDGs.
  - Modification of 125VDC back-up battery charger 35 to be able to be powered from 480V MCC 36C, 36D, or 36E. This allows flexibility in use of back-up battery charger 35.
  - Installation of a diesel-driven station air compressor, which can automatically supply back-up, compressed air to the instrument air system in the event of low system pressure.
  - Revision to emergency diesel generator functional test procedures to verify the operational status of each EDG building ventilation system. This procedure modification improves EDG availability since potential failures will be avoided.
- Changed PRA system models and data to reflect WOG peer review recommendations. Specific changes included the following.
    - The small LOCA event tree was modified to include consideration of an RCP seal LOCA due to random mechanical faults during normal plant operation. The RCP seal LOCA initiator frequency ( $2.5E-3/ry$ ) was taken from NUREG/CR-5750.
    - The plant specific frequencies for the turbine trip (T3) and loss of main feedwater (T2) initiators were recalculated using chronological data that more accurately reflected plant operation. A Bayesian update was performed on the generic frequencies and error factors using IP3 trip data for the time period of 1986-2000. Earlier data, which was not considered representative of current operation, was not included.
    - The plant specific frequency for the loss of offsite power (T1) initiator was recalculated using chronological data that more accurately reflected plant operation. The generic frequency for T1 from NUREG/CR-5750, which is used as input for the Bayesian update, was recalculated minus IP3 data for the time period referenced in NUREG/CR-5750. A Bayesian update was performed on the generic frequency and error factor using critical reactor years for IP3 from 1986-2000.

- A common-cause failure basic event was added to the fault trees for the service water system and CCW initiating events, to model common cause failure of the two normally running pumps, assuming a mission time of one year. Revised initiator frequencies for loss of service water system and loss of CCW were incorporated into the accident sequence quantification.
- Common cause failure events involving valve failure to remain closed were removed from the ISLOCA model. In addition, the exposure time for the initial valve failure was changed to 1 year. Thus, the results of the ISLOCA quantification are in units of per reactor-year. Revised ISLOCA initiator frequencies were incorporated into the accident sequence quantification for CDF and into the containment performance analysis.
- Several common cause beta factors were reviewed and recalculated using the common-cause failure program and reference tables presented in NUREG/CR-5497.
- A number of common cause failure probabilities that were significant contributors to CDF were determined to be unnecessarily conservative and were updated using the Multiple Greek Letter methodology.
- Five separate human error probabilities associated with resetting MCCs were incorporated into a single human error probability to reflect the fact that the actions are all directed as part of the same procedural step.
- A screening process was used in which each master cutset was screened for the occurrence of more than one HRA-related event. Multiple HRA cutsets were then reviewed for potential impact to the overall CDF and a rule file created to apply multiplying factors to the dependent post-accident operator actions.

## **Level 2 - Containment Performance Model**

- Transferred the Level 2 model into the same software used for the Level 1 model (changed from Event Progress Analysis Code-EVNTRE to CAFTA).
- Integrated the Level 1 and Level 2 models in one fault tree model; propagation of Level 1 cutsets to the Level 2 CET was developed.
- Developed a detailed LERF model to ensure that LERF calculations are consistent with the PSA Applications Guide [[Reference E.3-15](#)] and NRC requirements for Reg. Guide 1.174.
- Modeled some of IP3 Severe Accident Management Guidelines mitigating strategies for containment flooding and RCS depressurization.



- Revised CET fault tree models to allow credit for AC power recovery following core damage. This ensures that the model does not allow SBO core damage sequences to benefit from AC supported equipment in Level 2 without explicit consideration of AC power recovery.
- As recommended by the WOG peer review, revised assignment of sequences to release categories to include consideration of the predicted cesium-iodide release fraction.

#### **E.3.4.2 Major Differences between the IP3 Revision 2 PSA Model and Revision 1 PSA Model**

Quantification of the Revision 2 PSA model [[Reference E.3-3](#)] resulted in a slightly lower CDF than Revision 1 (i.e.  $1.15\text{E-}5/\text{ry}$  for Revision 2 vs.  $1.35\text{E-}5/\text{yr}$  for Revision 1). Major changes impacting CDF and LERF are summarized as follows.

##### **Level 1: Core Damage Model**

- Changed the common-cause failure (CCF) methodology from the modified Beta method to the Alpha method. The Alpha method is a more recent method that has been approved by the NRC and used in the NRC plant Standardized Plant Assessment Risk models.
- Made more extensive use of the generic component failure rates in the component failure database provided in EGG-SSRE-8875.
- Used the RCP seal LOCA model that is documented in WCAP-16141, which was approved for use by the NRC and is also referred to as the WOG2000 RCP Seal LOCA Model. The RCP seal LOCA model used in the previous PSA model was based on the BNL modeling approach. Although the WOG2000 approach is similar to the BNL approach, some differences exist between the two models in terms of assumptions, failure probabilities and timing.
- Revised success criterion for the AFW system to require flow to two (rather than one) of four steam generators for normal (non-ATWS) response. In addition, the normal position of the motor driven AFW pump flow control valves (FCV-406A through D) was changed from open to close.
- Modeled requirement that the operators trip the reactor coolant pumps within a short time after loss of component cooling water event to protect the pumps from a seal LOCA.
- Updated offsite power recovery model based on data contained in NUREG/CR-6890, which provides loss of offsite power data from 1986 to 2004. The offsite power recovery model used in the previous model was based on NUREG/CR-5496 and only included loss of offsite power events through 1996.

- Removed an asymmetry related to the location of the SGTR by assigning an equal probability of the rupture occurring in any one of the four steam generators. The previous model, which assumed that the SGTR occurred within a specific steam generator, impacted the relative importance of the valves involved in isolating the ruptured steam generator.
- Modified success criteria for cooling of the internal recirculation pumps. The previous model allowed credit for providing cooling from either the component cooling water pumps or the auxiliary component cooling water pumps. Since documentation clearly supporting that position was not available, the updated model does not credit those systems as being redundant for this function.
- Removed credit for the gas turbine which is no longer maintained. In addition to the Appendix R diesel, credit was taken in the previous model for an offsite gas turbine (Gas Turbine No. 2) as a method for restoring AC power following a SBO event.
- Included a total loss of service water initiating event in addition to the loss of essential service water and loss of non-essential service water initiating events.

#### **Level 2: Containment Performance Model**

- Introduced ten additional PDS to better facilitate the transfer of Level 1 information to the Level 2 containment performance analysis.
- Used the MAAP4 code to update the accident progression analysis. The previous update used the MAAP3 code. A total of fifteen MAAP runs were performed to examine thermal-hydraulic behavior of the RCS and containment, and in-vessel and ex-vessel fission product behavior, following core damage. The previous update used only ten MAAP runs.
- Changed definition of high releases to greater than 10% Cesium-Iodine released, which is consistent with the current industry definition. The previous definition was based on Cesium-Iodine releases greater than 1%.
- Updated accident progression analysis, resulting in changes to some of the CET release category magnitude endstate values (e.g., a number of endstates previously classified as late medium releases were reclassified as late high releases).

#### **E.3.4.3 PSA Model Peer Review**

The draft Revision 1 PSA model was peer reviewed in January 2001 using the process adapted by the Westinghouse Owner's Group (WOG) from the process originally developed and used by the Boiling Water Reactor Owners Group and subsequently broadened to be an industry-applicable process, through the Nuclear Energy Institute Risk Applications Task Force. Fact and Observation sheets documented the certification team's insights and their conclusions with

regard to potential level of significance. All Level A and B issues and observations from that peer review were addressed in the final version of the Revision 1 PSA model, which was issued in June 2001. Less significant (Level C&D) issues and observations were addressed, where appropriate. Based on the Westinghouse Owner's Group (WOG) peer review, all of the technical elements were graded as sufficient to support applications requiring risk ranking determination; in addition, most of the elements were further graded as sufficient to support risk-informed applications supported by deterministic insights.

For the Revision 1 PSA model, individual work packages (event tree, fault tree, human reliability analysis (HRA), data, etc.), and internal flooding analysis were circulated to each PSA member for independent peer review. The accident sequence packages, system work packages, HRA, and internal flooding analyses were also assigned to the appropriate IP3 plant personnel for review. For example, event trees, system analyses, and fault tree models were forwarded to the applicable plant system engineers and the HRA was assigned to individuals from the plant Operations Training department for review. In addition, the accident sequence packages, system work packages, HRA report, containment performance analysis, fault tree and event tree models, and Level 2 models were peer reviewed by an outside consultant.

The IP3 Revision 2 PSA model was issued in April 2007. The model changes in this update were reviewed for accuracy and consistency by members of the Entergy Nuclear Systems Analysis Group staff not directly involved in their implementation. Additionally, the revised model was subjected to a focused self assessment to demonstrate technical quality in preparation for implementing the Mitigating Systems Performance Indicator program in 2006. Finally, cognizant departments at IP3q—licensing, operations, maintenance, training, planning & scheduling, system engineering and design engineering—were provided with the final results and insights derived from the study for review prior to issuance of the Revision 2 report.

In accordance with plant procedures, potential plant modifications, design change documents, and emergency operating procedure changes are reviewed to determine their impact on the PSA model prior to implementation. A PSA model change request database is maintained to track potential changes and assess their degree of impact of the PSA model. As of December 2006, this database shows no outstanding changes since December 2005 due to modifications or procedure changes that could have a significant impact on the results of the PSA or the SAMA analysis.

### **E.3.5 MACCS2 Model: Level 3 Analysis**

#### **E.3.5.1 Introduction**

SAMA evaluation relies on Level 3 PRA results to measure the effects of potential plant modifications. A Level 3 PRA model using the most recent version (version 1.13.1) of MACCS2 [Reference E.3-6] was created for IP3. This model, which requires detailed site-specific meteorological, population, and economic data, estimates the consequences in terms of population dose and offsite economic cost. Risks in terms of population dose risk (PDR) and offsite economic cost risk (OECR) were also estimated in this analysis. Risk is defined as the product of consequence and frequency of an accidental release.

This analysis evaluates a base case to provide best-estimate consequences for postulated internal events. Instead of considering various emergency planning scenarios, the base case uses a conservative assumption of no evacuation.

PDR was estimated by summing over all releases the product of population dose and frequency for each accidental release. Similarly, OECR was estimated by summing over all releases the product of offsite economic cost and frequency for each accidental release. Offsite economic cost includes costs that could be incurred during the emergency response phase and costs that could be incurred through long-term protective actions.

### E.3.5.2 Input

The following sections describe the site-specific input parameters used to obtain the offsite dose and economic impacts for cost-benefit analyses.

#### E.3.5.2.1 Projected Total Population by Spatial Element

The total population within a 50-mile radius of IP3 was estimated for the year 2035, the end of the proposed license renewal period, for each spatial element by combining total resident population projections with transient populations. The 2035 county level resident projections were derived from the New York Statistical Information System from 2000 to 2030, the New Jersey Department of Labor and Workforce Development from 2000 to 2025, the Connecticut State Data Center from 2000 to 2020, and the Pennsylvania State Data Center from 2000 to 2020 using regression analysis [References E.3-16 through E.3-19]. The 2035 transient population was assumed to be the 2004 transient to permanent population ratio multiplied by the extrapolated permanent population. The 2004 transient data were obtained from state tourism agencies. Table E.3-12 summarizes the estimated population distribution.

**Table E.3-12  
Estimated Population Distribution within a 50-mile Radius**

<b>Sector</b>	<b>0-10 miles</b>	<b>10-20 miles</b>	<b>20-30 miles</b>	<b>30-40 miles</b>	<b>40-50 miles</b>	<b>50-mile Total</b>
N	12,488	22,955	30,654	39,620	51,057	156,774
NNE	14,952	28,140	39,917	56,226	67,213	206,448
NE	23,377	29,419	53,692	62,559	41,261	210,308
ENE	40,386	74,856	119,073	152,175	176,338	562,828
E	41,290	118,335	156,720	200,581	208,394	725,320
ESE	37,861	121,515	144,267	54,180	34,361	392,184
SE	41,873	111,946	87,735	236,426	379,990	857,970

**Table E.3-12**  
**Estimated Population Distribution within a 50-mile Radius**  
**(Continued)**

<b>Sector</b>	<b>0-10 miles</b>	<b>10-20 miles</b>	<b>20-30 miles</b>	<b>30-40 miles</b>	<b>40-50 miles</b>	<b>50-mile Total</b>
SSE	12,197	98,326	481,703	1,380,249	1,218,170	3,190,645
S	20,621	135,211	1,164,596	3,732,339	3,164,306	8,217,073
SSW	30,318	202,605	395,389	922,649	1,034,467	2,585,428
SW	30,796	183,372	276,902	197,362	246,076	934,508
WSW	27,723	64,428	209,197	109,102	85,849	496,299
W	16,925	32,026	50,974	61,380	57,384	218,689
WNW	14,036	32,528	54,577	57,977	29,719	188,837
NW	13,421	32,572	54,557	24,046	22,317	146,913
NNW	12,286	31,660	32,569	27,599	34,374	138,488
Total	390,550	1,319,894	3,352,522	7,314,470	6,851,276	19,228,712

**E.3.5.2.2 Land Fraction**

The land fraction for each spatial element was estimated within the 50 mile radius area. The National Hydrography Dataset was used to estimate the extent of land and surface water coverage [Reference E.3-20].

**E.3.5.2.3 Watershed Class**

Watershed Index is defined by MACCS2 as areas drained by rivers (Class 1) or large water bodies (Class 2). For IPEC, no spatial elements were treated as large water bodies. Therefore, only one watershed class was assigned for the 50-mile zone surrounding IP3.

**E.3.5.2.4 Regional Economic Data**

**Region Index**

Each spatial element was assigned to an economic region, defined in this report as a county. Where a spatial element covers portions of more than one county, it was assigned to that county having the most area within the element.

### Regional Economic Data

County level economic data were obtained from the United States Census of Agriculture for 2002 [Reference E.3-21].

#### VALWF: Value of Farm Wealth

MACCS2 requires an average value of farm wealth (dollars/hectare) for the 50-mile radius area around IPEC. The county-level farmland property value was used as a basis for deriving this value. VALWF is \$50,071/hectare.

#### VALWNF: Value of Non-farm Wealth

MACCS2 also requires an average value of non-farm wealth. The county-level non-farm property value was used as a basis for deriving this value. VALWNF is \$163,631/person.

Other economic parameters and their values are shown below. The values were obtained by adjusting the economic data from a past census given as default values in Reference E.3-6 with the consumer price index of 195.3, which is the average value for the year 2005, as appropriate.

Variable	Description	Value
EVACST	Daily cost for a person who has been evacuated (\$/person-day)	46.7
POPCST	Population relocation cost (\$/person)	8640
RELCST	Daily cost for a person who is relocated (\$/person-day)	46.7
CDFRM0	Cost of farm decontamination for the various levels of decontamination (\$/hectare)	972 2160
CDNFRM	Cost of non-farm decontamination for the various levels of decontamination (\$/person)	5184 13824
DLBCST	Average cost of decontamination labor (\$/person-year)	60480
DPRATE	Property depreciation rate (per year)	0.2
DSRATE	Investment rate of return (per year)	0.12

#### E.3.5.2.5 Agriculture Data

The source of regional crop information is the 2002 Census of Agriculture [Reference E.3-21]. The crops listed for each county within the 50-mile area were summed and mapped into the seven MACCS2 crop categories.

#### E.3.5.2.6 Meteorological Data

The MACCS2 model requires meteorological data for wind speed, wind direction, atmospheric stability, accumulated precipitation, and atmospheric mixing heights. The required data were obtained from the IPEC meteorological monitoring system and regional National Weather Service stations.

##### **Site Specific Data**

IPEC meteorological monitoring system includes both primary and backup systems. The primary meteorological system, which includes a 122-meter instrumented tower located onsite, was the data source for the MACCS2 analysis. Based on a review of annual meteorological data collected at the site between 1995 and 2004, five recent years of data were averaged and used for this study. The five-year data included 43,848 (two leap years) consecutive hourly values of wind speed, wind direction, precipitation, and temperature recorded at the IPEC meteorological tower from January 2000 to December 2004. Missing data were estimated using data substitution methods. These methods include substitution of missing data with valid data from the previous hour and substitution of valid data collected from other elevations on the meteorological tower.

##### **Regional Mixing Height Data**

Mixing height is defined as the height of the atmosphere above ground level within which a released contaminant will become mixed (from turbulence) within approximately one hour. Regional mixing heights were calculated using data collected at National Weather Service (NWS) Station No. 72503 in White Plains, NY (approximately 16 miles southeast of IP3) and NWS Station No. 54775 in Albany, NY (approximately 80 miles north of IP3). These two weather stations were the closest NWS sources of data for local and upper air conditions. Staff meteorologists at the National Climatic Data Center selected these two stations for data used to calculate seasonal mixing height values for the IP3 area.

#### E.3.5.2.7 Emergency Response Assumptions

A detailed analysis of evacuation scenarios in emergency planning zone (EPZ) were addressed in the IP3 evacuation travel time estimate study [[Reference E.3-22](#)]. The study was conducted in 2004 and provides an analysis of the range and variation of public reaction to the evacuation notification process. Evacuation, which is considered an effective measure for mitigating accident consequences, would reduce radiation dose received by population within the EPZ. The primary parameters affecting evacuation consequences are evacuation speed and time elapsed prior to the start of evacuation. Either a lower speed of evacuation or a delayed evacuation would increase the received radiation dose. In turn, should no evacuation occur, the dose would be higher. For this study, a "no evacuation scenario" was assumed to conservatively estimate the population dose.

E.3.5.2.8 Core Inventory

The estimated IP3 core inventory (Table E.3-13) used in the MACCS2 input is based on current core configuration and a power level of 3216 MW(t).

**Table E.3-13**  
**IP3 Core Inventory (Becquerels)<sup>1</sup>**

<b>Nuclide</b>	<b>Inventory</b>	<b>Nuclide</b>	<b>Inventory</b>
Co-58	3.04E+16	Te-131m	4.64E+17
Co-60	2.32E+16	Te-132	4.54E+18
Kr-85	3.87E+16	I-131	3.18E+18
Kr-85m	8.52E+17	I-132	4.64E+18
Kr-87	1.64E+18	I-133	6.56E+18
Kr-88	2.30E+18	I-134	7.19E+18
Rb-86	8.24E+15	I-135	6.14E+18
Sr-89	3.09E+18	Xe-133	6.25E+18
Sr-90	3.07E+17	Xe-135	1.67E+18
Sr-91	3.87E+18	Cs-134	7.16E+17
Sr-92	4.19E+18	Cs-136	2.08E+17
Y-90	3.20E+17	Cs-137	4.15E+17
Y-91	3.98E+18	Ba-139	5.86E+18
Y-92	4.22E+18	Ba-140	5.58E+18
Y-93	4.85E+18	La-140	5.76E+18
Zr-95	5.38E+18	La-141	5.34E+18
Zr-97	5.41E+18	La-142	5.17E+18
Nb-95	5.45E+18	Ce-141	5.31E+18
Mo-99	6.11E+18	Ce-143	4.99E+18
Tc-99m	5.34E+18	Ce-144	4.19E+18
Ru-103	4.85E+18	Pr-143	4.78E+18



**Table E.3-13**  
**IP3 Core Inventory (Becquerels)<sup>1</sup> (Continued)**

Nuclide	Inventory	Nuclide	Inventory
Ru-105	3.34E+18	Nd-147	2.12E+18
Ru-106	1.69E+18	Np-239	6.53E+19
Rh-105	3.08E+18	Pu-238	1.43E+16
Sb-127	3.45E+17	Pu-239	1.22E+15
Sb-129	1.04E+18	Pu-240	1.82E+15
Te-127	3.43E+17	Pu-241	4.08E+17
Te-127m	4.47E+16	Am-241	5.03E+14
Te-129	1.02E+18	Cm-242	1.21E+17
Te-129m	1.49E+17	Cm-244	1.29E+16

1. Derived from [Reference E.3-23](#) for a power level of 3216 MWth except for Co-58 and Co-60, which were power-scaled from the reference inventory given in [Reference E.3-6](#).

#### E.3.5.2.9 Source Terms

Only eight release categories given in [Table E.3-9](#), corresponding to internal event sequences, were part of the MACCS2 input. The Early Low-Low category has zero release frequency and is not considered. [Section E.3.2.2.7](#) provides details of the source terms for postulated internal events. A linear release rate was assumed between the time the release started and the time the release ended.

#### E.3.5.3 Results

Risk estimates for the base case were analyzed with MACCS2. The base case assumes no evacuation. [Table E.3-14](#) shows estimated base case mean risk values for each release mode. The estimated mean values of PDR and offsite OECR for IP3 are 24.5 person-rem/yr and \$52,800/yr, respectively.

**Table E.3-14  
 Base Case Mean PDR and OECR Values**

Release Mode	Frequency (/yr)	Population Dose (person-sv) <sup>1</sup>	Offsite Economic Cost (\$)	Population Dose Risk (PDR) (person-rem/yr)	Offsite Economic Cost Risk (OECR) (\$/yr)
NCF	6.30E-06	3.85E+01	1.54E+05	2.42E-02 <sup>2</sup>	9.69E-01
EARLY HIGH	9.43E-07	1.31E+05	2.98E+10	1.24E+01	2.81E+04
EARLY MEDIUM	1.24E-06	5.13E+04	1.14E+10	6.35E+00	1.41E+04
EARLY LOW	1.46E-07	1.37E+04	2.15E+09	1.99E-01	3.13E+02
LATE HIGH	4.23E-07	4.24E+04	1.04E+10	1.79E+00	4.40E+03
LATE MEDIUM	2.01E-06	1.78E+04	2.83E+09	3.57E+00	5.68E+03
LATE LOW	3.75E-07	5.36E+03	5.24E+08	2.01E-01	1.96E+02
LATE LOWLOW	5.66E-08	4.63E+03	4.60E+08	2.62E-02	2.60E+01
<b>Totals</b>				<b>2.45E+01</b>	<b>5.28E+04</b>

1. 1 sv = 100 rem

2.  $2.42E-02 \text{ (person-rem/yr)} = 6.30E-06 \text{ (/yr)} \times 3.85E+01 \text{ (person-sv)} \times 100 \text{ (rem/sv)}$

### **E.3.6 References**

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## **ATTACHMENT E.4**

### **EVALUATION OF IP3 SAMA CANDIDATES**

## E.4 EVALUATION OF IP3 SAMA CANDIDATES

This section describes the generation of the initial list of potential SAMA candidates, screening methods, and the analysis of the remaining SAMA candidates.

### E.4.1 SAMA List Compilation

A list of SAMA candidates was developed by reviewing industry documents and considering plant-specific enhancements not identified in published industry documents. Since IP3 is a conventional pressurized water reactor, considerable attention was paid to the SAMA candidates from SAMA analyses for other pressurized water reactor plants. Industry documents reviewed include the following.

- Calvert Cliffs Nuclear Power Plant SAMA Analysis [[Reference E.4-1](#)]
- H.B. Robinson Steam Electric Plant Unit No.2 SAMA Analysis [[Reference E.4-2](#)]
- Virgil. C. Summer Nuclear Station SAMA Analysis [[Reference E.4-3](#)]
- Arkansas Nuclear One Unit 2 SAMA Evaluation [[Reference E.4-4](#)]
- Donald C. Cook Nuclear Plant SAMA Analysis [[Reference E.4-5](#)]
- Millstone Units 2 and 3 SAMA Analysis [[Reference E.4-6](#)]
- Joseph M. Farley Nuclear Plant SAMA Analysis [[Reference E.4-7](#)]
- Point Beach Nuclear Plant Units 1 and 2 SAMA Analysis [[Reference E.4-8](#)]
- Palisades Nuclear Plant SAMA Analysis [[Reference E.4-28](#)]

The above documents represent a compilation of most SAMA candidates developed from the industry documents. These sources of other industry documents include the following.

- Quad Cities SAMA Analysis [[Reference E.4-9](#)]
- General Electric ABWR severe accident mitigation design alternative (SAMDA) Analysis [[Reference E.4-10](#)]
- Limerick SAMDA cost estimate report [[Reference E.4-11](#)]
- NUREG-1437 description of Limerick SAMDA [[Reference E.4-12](#)]
- NUREG-1437 description of Comanche Peak SAMDA [[Reference E.4-13](#)]
- Tennessee Valley Authority (TVA) response to NRC's RAI on the Watts Bar SAMDA submittal [[Reference E.4-14](#)]
- TVA response to NRC's RAI on the Watts Bar Generic Letter 88-20 IPE for Severe Accident Vulnerabilities [[Reference E.4-15](#)]
- Westinghouse AP600 SAMDA [[Reference E.4-16](#)]
- NUREG-1462, Final safety evaluation report related to the certification of Combustion Engineering System 80+ design [[Reference E.4-17](#)]
- NUREG-0498, Final Environmental Statement related to the Operation of Watts Bar Nuclear Plant Units 1 and 2, Supplement 1, Section 7 [[Reference E.4-18](#)]
- NUREG-1560, Volume 2, NRC Perspectives on the IPE Program [[Reference E.4-19](#)]
- NUREG/CR-5474, Assessment of Candidate Accident Management Strategies [[Reference E.4-20](#)]

In addition to SAMA candidates from review of industry documents, SAMA candidates were obtained from plant-specific sources, such as the IP3 IPE and updates [References E.4-21, E.4-22 and E.4-23] and IPEEE [Reference E.4-24]. In the original IPE and IPEEE, several enhancements related to severe accident insights were recommended and implemented. These enhancements are included in the comprehensive list of Phase I SAMA candidates. Table E.4-1 lists the IPE, PSA model update, and IPEEE Phase I SAMA candidates and indicates which have been implemented, which have been incorporated in the model used for the SAMA analysis, and which have been retained for further evaluation in Phase II of the SAMA analysis. The current PSA was also used to identify plant-specific modifications for inclusion in the comprehensive list of SAMA candidates. The risk significant terms from the current PSA model were reviewed for similar failure modes and effects that could be addressed through a potential enhancement to the plant. The correlation between SAMAs and the risk significant terms are listed in Table E.3-2 and Table E.3-5.

The comprehensive list contained a total of 237 Phase I SAMA candidates and is available in onsite documentation.

#### **E.4.2 Qualitative Screening of SAMA Candidates (Phase I)**

The purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were not viable for implementation at IP3. Potential SAMA candidates were screened out if they modified features not applicable to IP3, if they had already been implemented at IP3, or if they were similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate. During this process, 55 of the Phase I SAMA candidates were screened out because they were not applicable to IP3, 6 of the Phase I SAMA candidates were screened out because they were similar in nature and could be combined with another SAMA candidate, and 114 of the Phase I SAMA candidates were screened out because they had already been implemented at IP3, leaving 62 SAMA candidates for further analysis. The final screening process involved identifying and eliminating those items whose implementation cost would exceed their benefit as described below. Table E.4-2 provides a description of each of the 62 Phase II SAMA candidates. As described in Section 4.21.5.4, the “baseline benefit” values in this table represent the total SAMA benefits for both internal and external events.

#### **E.4.3 Final Screening and Cost Benefit Evaluation of SAMA Candidates (Phase II)**

A cost/benefit analysis was performed on each of the remaining SAMA candidates. If the implementation cost of a SAMA candidate was determined to be greater than the potential benefit (i.e. there was a negative net value) the SAMA candidate was considered not to be cost beneficial and was not retained as a potential enhancement.

The expected cost of implementation of each SAMA was established from existing estimates of similar modifications. Most of the cost estimates were developed from similar modifications considered in previously performed SAMA. In particular, these cost-estimates were derived from the following sources.

- Arkansas Nuclear One Unit 2 SAMA Analysis [[Reference E.4-4](#)]
- Calvert Cliffs SAMA Analysis [[Reference E.4-1](#)]
- Donald C. Cook SAMA Analysis [[Reference E.4-5](#)]
- Fort Calhoun Unit 1 SAMA Analysis [[Reference E.4-25](#)]
- Joseph M. Farley SAMA Analysis [[Reference E.4-7](#)]
- McGuire SAMA Analysis [[Reference E.4-26](#)]

The cost estimates did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs associated with unforeseen implementation obstacles. Estimates based on modifications that were implemented or estimated in the past were presented in terms of dollar values at the time of implementation (or estimation), and were not adjusted to present-day dollars. Therefore, the cost estimates were conservative.

The benefit of implementing a SAMA candidate was estimated in terms of averted consequences. The benefit was estimated by calculating the arithmetic difference between the total estimated costs associated with the four impact areas for the baseline plant design and the total estimated impact area costs for the enhanced plant design (following implementation of the SAMA candidate).

Values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the NUREG/BR-0184 [[Reference E.4-27](#)] conversion factor of \$2,000 per person rem and discounted to present value. Values for avoided offsite economic costs were also discounted to present value.

As this analysis focuses on establishing the economic viability of potential plant enhancement when compared to attainable benefit, detailed cost estimates often were not required to make informed decisions regarding the economic viability of a particular modification. Several of the SAMA candidates were clearly in excess of the attainable benefit estimated from a particular analysis case.

For less clear cases, engineering judgment on the cost associated with procedural changes, engineering analysis, testing, training, and hardware modification was applied to determine if a more detailed cost estimate was necessary to formulate a conclusion regarding the economic viability of a particular SAMA. Based on a review of previous submittals' SAMA evaluations and an evaluation of expected implementation costs at IP3, the following estimated costs for each potential element of the proposed SAMA implementation were used.

<b><u>Type of Change</u></b>	<b><u>Estimated Cost Range</u></b>
Procedural only	\$25K-\$50K
Procedural change with engineering required	\$50K-\$200K
Procedural change with engineering and testing/training required	\$200K-\$300K



**Type of Change**

**Estimated Cost Range**

Hardware modification

\$100K to >\$1000K

In most cases, more detailed cost estimates were not required, particularly if the SAMA called for the implementation of a hardware modification. Nonetheless, the cost of each unscreened SAMA candidate was conceptually estimated to the point where conclusions regarding the economic viability of the proposed modification could be adequately gauged. The cost benefit comparison and disposition of each of the 62 Phase II SAMA candidates is presented in [Table E.4-2](#).

Bounding evaluations (or analysis cases) were performed to address specific SAMA candidates or groups of similar SAMA candidates. These analysis cases overestimated the benefit and thus were conservative calculations. For example, one SAMA candidate suggested installing a digital feedwater upgrade system. The bounding calculation estimated the benefit of this improvement by total elimination of risk due to loss of feedwater events (see analysis of Phase II [SAMA 039](#) in [Table E.4-2](#)). This calculation obviously overestimated the benefit, but if the inflated benefit indicated that the SAMA candidate was not cost beneficial, then the purpose of the analysis was satisfied.

A description of the analysis cases used in the evaluation follows.

**Diesel Powered RCP Seal Injection**

This analysis case was used to evaluate the change in plant risk from providing an independent, diesel powered RCP seal cooling system. The plant modification involves installation of a two-inch pipe inside containment and the PAB, manual isolation valves, control valves, instrumentation to monitor flow, self-contained diesel generator outside the PAB, pump, instrumentation cables, four orifices, power cable to the pump, two filters, water source piping and valves, and containment penetration piping and instrumentation. It also requires revision of standard operating and emergency operating procedures; calculations for piping and support dead weight, electrical load, and instrumentation setpoints; additional procedures; and training. The RCP seal cooling enhancements would add redundancy to RCP seal cooling, reducing CDF from loss of component cooling or service water or from a SBO event. A bounding analysis was performed by setting all consequential RCP seal LOCAs from all plant initiators to zero in the Level 1 PDS model, which resulted in a baseline benefit of approximately \$135,611. This analysis case was used to model the benefit of Phase II SAMA 001.

**Non-Diesel Powered RCP Seal Injection**

This analysis case was used to evaluate the change in plant risk from providing an independent RCP seal cooling system without dedicated diesel power backup. RCP seal cooling enhancements would add redundancy to RCP seal cooling, reducing CDF from loss of component cooling or service water or from a SBO event. A bounding analysis was performed by setting all consequential RCP seal LOCAs from all plant initiators to zero in the level 1 PDS

model, which resulted in a baseline benefit of approximately \$100,223. This analysis case was used to model the benefit of Phase II SAMA 002.

### **Additional CCW Pump**

This analysis case was used to evaluate the change in plant risk from installing an additional CCW pump. An additional CCW pump reduces the probability of loss of component cooling leading to a RCP seal LOCA. A bounding analysis was performed by setting common cause failures of CCW pumps to zero in the Level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 003.

### **RHR Heat Exchangers**

This analysis case was used to evaluate the change in plant risk by improving the ability to cool the RHR heat exchangers by implementing procedure and hardware modifications to allow manual alignment of the fire protection system. A bounding analysis was performed by setting loss of CCW to the RHR heat exchangers to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$35,517. This analysis case was used to model the benefit of Phase II SAMA 004.

### **Filtered Containment Vent**

This analysis case was used to evaluate the change in plant risk from installing a filtered containment vent to provide fission product scrubbing. A bounding analysis was performed by setting late containment overpressurization failure to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$504,995. This analysis case was used to model the benefit of Phase II SAMA 005.

### **Molten Core Debris Removal**

This analysis case was used to estimate the change in plant risk from providing a molten core debris cooling mechanism. The plant modification for a reactor cavity flooding system involves use of fire water as a supply, a run of 500 feet of 8-inch pipe to a 1000 gpm pump (similar to containment spray pump) and a run of 8-inch pipe from the pump spare piping penetration. A 1-inch mini-flow test line and instrumentation would be required for periodic testing. In addition, calculations would be required for pipe support, pump capacity, electric cable, electrical loading, flow, and instrumentation. Additional procedures and training for alignment would also be required. A bounding analysis was performed by setting containment failure due to core-concrete interaction to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$1,378,340. This analysis case was used to model the benefit of Phase II SAMAs 006, 007, and 008.

### **Inert Containment**

This analysis case was used to estimate the change in plant risk from providing a means to inert containment to prevent combustion of hydrogen and carbon monoxide gases. A bounding

analysis was performed by setting containment failures due to hydrogen burns to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$552,524. This analysis case was used to model the benefit of Phase II SAMA 009.

### **Containment Sprays**

This analysis case was used to evaluate the change in plant risk from installing additional containment spray capability to provide containment pressure control. A bounding analysis was performed by setting the events for loss of containment spray to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 010, 011, and 014.

### **Base Mat Melt-Through**

This analysis case was used to evaluate the change in plant risk from increasing the depth of the concrete base mat to ensure base mat melt-through does not occur. A bounding analysis was performed by setting containment failure due to base mat melt-through to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$297,056. This analysis case was used to model the benefit of Phase II SAMA 012.

### **Strengthen Containment**

This analysis case was used to evaluate the change in plant risk from strengthening containment by constructed a building connected to primary containment that is maintained at a vacuum to provide a method to depressurize containment and reduce fission product release. The proposed plant modification involves construction of a building structurally strong enough to sustain an approximately 10 psi pressure differential. Vacuum pump, piping (600 feet), electrical equipment, instrumentation, and containment penetrations would be required. A bounding analysis was performed by setting all energetic containment failure modes (DCH, steam explosions, late over-pressurization) to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$1,271,400. This analysis case was used to model the benefit of Phase II SAMA 013.

### **Containment Liner Protection**

This analysis case was used to evaluate the change in plant risk from constructing a barrier that provides containment liner protection from ejected core debris at high RCS pressure. The proposed plant modification involves installation of a 50 foot diameter, 70 foot high barrier made of stainless steel. A bounding analysis was performed by setting the probability of HPME and subsequent DCH at high RCS pressure to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately \$255,468. This analysis case was used to model the benefit of Phase II SAMA 015.

### **Steam Generator Heat Removal**

This analysis case was used to evaluate the change in plant risk from installing a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources. The proposed plant modification involves installation of two 8-inch penetrations into each steam generator, eight lengths of 8-inch pipe and supports inside containment, eight containment penetrations, piping and supports outside of containment, a water storage tank (about 300,000 gallons), tank heater, and instrumentation. It would also require hydro testing, procedure revisions and training. This SAMA would provide an additional means to scrub fission product releases. A bounding analysis was performed by setting SGTR with loss of secondary-side cooling events to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$356,079. This analysis case was used to model the benefit of Phase II SAMA 016.

### **Secondary Side Pressure Capacity**

This analysis case was used to evaluate the change in plant risk from increasing the secondary side pressure capacity to lower the occurrence of an unisolated SGTR. A bounding analysis was performed by eliminating failure to isolate the ruptured steam generator during a SGTR to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$2,909,856. This analysis case was used to model the benefit of Phase II SAMA 017.

### **SGTR Fission Product Scrubbing**

This analysis case was used to evaluate the change in plant risk from routing the discharge from the main steam safety valves through a structure where water spray would condense the steam and scrub the fission products inventory. The proposed plant medication involves installation of four tanks (50 feet long with 20 spray nozzles) and 400 feet of city water piping and supports. Procedure revisions and training would also be required. A bounding analysis was performed by reducing SGTR accident progression source terms by a factor of 2, which resulted in a baseline benefit of approximately \$665,406. This analysis case was used to model the benefit of Phase II SAMA 018.

### **ISLOCA Mitigation**

This analysis case was used to evaluate the change in plant risk from installing additional pressure or leak monitoring instrumentation between the pressure isolation valves in ISLOCA pathways or submerging potential ISLOCA break points in water. A bounding analysis was performed by setting all ISLOCA initiators to zero in the level 1 PSA model which resulted in a baseline benefit of approximately \$457,208. This analysis case was used to model the benefit of Phase II SAMAs 019 and 022.

### **ISLOCA Valves**

This analysis case was used to evaluate the change in plant risk from reducing the probability of an ISLOCA by increasing the frequency of valve leak testing or adding redundant and diverse

limit switches to each containment isolation valve. The increased valve leak testing involves testing of 34 safety-related valves in containment. To allow testing of valves located inside containment during power operation, installation of a test connection for each valve with piping outside of containment and double containment isolation valves would be required. In addition, procedure revisions and training would be required. A bounding analysis was performed by reducing the ISLOCA initiator 50 percent in the level 1 PSA model, which resulted in a baseline benefit of approximately \$219,692. This analysis case was used to model the benefit of Phase II SAMAs 020 and 021.

### **MSIV Design**

This analysis case was used to evaluate the change in plant risk from improving MSIV design to decrease the likelihood of containment bypass scenarios. A bounding analysis was performed by setting MSIV failures to isolate a faulted or ruptured steam generator to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 23.

### **DC Power/ AFW System Changes**

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of Class 1E DC power (i.e., increasing battery capacity, using fuel cells, improving DC bus load shedding, or extending auxiliary feed pump operation after battery depletion). It was assumed that battery life could be significantly extended from the existing battery capacity. The proposed plant modification for extending the AFW steam-driven pump operation after battery depletion involves purchasing, staging and maintaining a portable generator with fuel supply, control station, conduit and cabling. This enhancement would extend AFW steam-driven pump operability and allow more time for AC power recovery.

This analysis case was also used to evaluate the change in plant risk from plant modifications to install pneumatic controls and indication for the turbine-driven AFW pump to reduce the CDF contribution from SBO events. The proposed plant modification for this SAMA involves installation of ten local instruments since the existing system includes some electrical and pneumatic controls. Procedure revisions and training would also be required.

A bounding analysis was performed by changing the time available to recover offsite power before local operation of the AFW steam-driven pump is required from 2 hours to 24 hours during SBO scenarios in the level 1 PSA model. This resulted in a baseline benefit of approximately \$35,259. This analysis case was used to model the benefit of Phase II SAMAs 024, 025, 026, 042 and 056.

### **AC Power Cross-Tie with Indian Point Unit 2 (IP2)**

This analysis case was used to evaluate the change in plant risk from a plant modification to create an AC power cross-tie with IP2 to improve AC power reliability. The proposed plant modification involves installation of two breakers and 1500 feet of cable, conduit and supports from the 480 VAC switchgears. Procedure development and training would also be required. A

bounding analysis was performed by setting loss of the Appendix R diesel to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$58,765. This analysis case was used to model the benefit of Phase II SAMA 027.

### **EDG Alternate Engine Cooling**

This analysis case was used to evaluate the change in plant risk from providing a redundant and diverse source of engine cooling for the EDGs, which would contribute to enhanced diesel reliability. A bounding analysis was performed by setting loss of the essential service water supply for diesel cooling to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$11,753. This analysis case was used to model the benefit of Phase II SAMAs 028 and 029.

### **Alternate Battery Charger Capability**

This analysis case was used to evaluate the change in plant risk from plant modifications to provide alternate battery charging capability by installing a portable diesel-driven battery charger. The proposed plant modification involves purchasing, installing and maintaining a diesel-driven generator to charge the 125VDC batteries. Safety-related quick disconnects would be used to charge the selected battery. The diesel generator would be installed in a weather enclosure outside the turbine or control building, requiring fire barrier penetration sealing. The location would be as close as possible to the batteries to decrease power loss along the cable. Calculation of cable size would have to be performed. In addition, procedure development and training would be required. A bounding analysis was performed by changing the time available to recover offsite power before local operation of AFW is required from 2 hours to 24 hours during SBO scenarios and reducing internal switchgear room floods 5 percent to account for local operation of the turbine-driven AFW pump. This resulted in a baseline benefit of approximately \$509,643. This analysis case was used to model the benefit of Phase II SAMA 030.

### **Improve 118VAC System**

This analysis case was used to evaluate the change in plant risk from plant modifications to convert under-voltage AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic. This would reduce the risk associated with inverter failure and would improve the availability of the 118VAC vital bus. A bounding analysis was performed by setting common cause failure of the 118VAC transformers to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$23,764. This analysis case was used to model the benefit of Phase II SAMA 031.

### **Low Pressure Injection System**

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of alternate low pressure injection (i.e., additional diesel-driven low pressure vessel makeup or modification of the diesel-driven fire pump). Use of the diesel-driven fire pump for low pressure injection requires installation of piping, valves and supports. Procedure development and training would also be required. A bounding analysis was

performed by eliminating failure of the RHR system in the level 1 PSA model, which resulted in a baseline benefit of approximately \$5,941. This analysis case was used to model the benefit of Phase II SAMAs 032 and 035.

### **High Pressure Injection System**

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of high pressure injection (i.e., installing a diesel-driven high pressure injection system or replacing two of the three motor-driven SI pumps with diesel-powered pumps). A bounding analysis was performed by setting failure of the SI system to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$35,517. This analysis case was used to model the benefit of Phase II SAMAs 033 and 037.

### **Automatic Recirculation Cooling Swap-Over**

This analysis case was used to evaluate the change in plant risk from installing an automatic swap-over to recirculation cooling upon RWST depletion to enhance the reliability of ECCS suction. A bounding analysis was performed by setting failure to align recirculation cooling (internal and external) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$340,435. This analysis case was used to model the benefit of Phase II SAMA 034.

### **Conserve RWST Water Inventory**

This analysis case was used to evaluate the change in plant risk from extending reactor water storage tank capability by throttling low pressure injection flow earlier in medium or large-break LOCAs. A bounding analysis was performed by setting failure to align recirculation cooling (internal and external) in large and medium LOCAs to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$11,753. This analysis case was used to model the benefit of Phase II SAMA 036.

### **Enhance RCS Depressurization**

This analysis case was used to evaluate the change in plant risk from enhancing RCS depressurization to allow successful low pressure ECCS injection following a small LOCA and high pressure SI failure. A bounding analysis was performed by setting common cause failure of the steam generator atmospheric dump valves (ADVs) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$65,223. This analysis case was used to model the benefit of Phase II SAMA 038.

### **Main Feedwater System Upgrade**

This analysis case was used to evaluate the change in plant risk from installing a digital feedwater upgrade to reduce the probability of loss of main feedwater following a plant trip or to install a motor-driven feedwater pump to enhance the availability of feed water injection subsequent to MSIV closure. A bounding analysis was performed by setting the loss of main

feedwater initiator to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$206,128. This analysis case was used to model the benefit of Phase II SAMAs 039 and 041.

### **Steam Generator Atmospheric Steam Dump Valve Enhancement**

This analysis case was used to evaluate the change in plant risk in automating the backup nitrogen supply to the steam generator atmospheric steam dump valve (ADV). This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOOP. A bounding analysis was performed by setting the manual local action to align nitrogen supply for control air supply to the steam generator ADV to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$65,223. This analysis case was used to model the benefit of Phase II SAMA 040.

### **Alternate Water Sources to Steam Generators**

This analysis case was used to evaluate the change in plant risk from providing emergency connections to use the fire water system as backup for steam generator inventory. The proposed modification involves installation of 500 feet of 6-inch pipe from the fire pump house to a new electric 800 gpm pump. The modification would also require heat tracing, valves, supports, breakers and cabling, procedure development and training. A bounding analysis was performed by setting failure of the turbine-driven AFW pump and failure to restore AC power given successful AFW operation during SBO to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$183,140. This analysis case was used to model the benefit of Phase II SAMA 043.

### **Install Large Pressurizer PORVs**

This analysis case was used to evaluate the change in plant risk from installing larger capacity power operated relief valves to allow successful feed and bleed cooling with one valve open. A bounding analysis was performed by modifying the number of PORVs required for RCS feed and bleed from 2-of-2 to 1-of-2 and to account for the additional time to aligned bleed and feed, the operator action for bleed and feed is reduced by a factor of 5 in the level 1 PSA model, which resulted in a baseline benefit of approximately \$337,997. This analysis case was used to model the benefit of Phase II SAMA 044.

### **Independent Boron Injection System**

This analysis case was used to evaluate the change in plant risk from installing an independent boron injection system to provide a redundant means to shut down the reactor during ATWS. A bounding analysis was performed by setting common cause failure of the boric acid transfer pumps to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 045.



### **ATWS Overpressure Protection**

This analysis case was used to evaluate the change in plant risk from installing a system of relief valves in the RCS to prevent equipment damage from a pressure spike during an ATWS. This enhancement would improve equipment availability after an ATWS. The proposed modification involves installation of additional safety valves discharge lines to the pressurizer relief tank, acoustic monitoring, and RCS hydro capability. Procedure development and training would also be required. A bounding analysis was performed by setting the CDF contribution from RCS overpressurization during an ATWS to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$176,682. This analysis case was used to model the benefit of Phase II SAMA 046.

### **Control Room ATWS Mitigation**

This analysis case was used to evaluate the change in plant risk from installing motor generator set trip breakers in the control room (SAMA 47) or providing the capability to remove power from the bus powering the control rods (SAMA 48). For SAMA 47, the proposed plant modification involves installation of two additional breakers, 300 feet of cable, conduit and supports. This modification also requires two penetrations of the control room boundary and resealing, procedure development and training. For SAMA 48, procedure changes and training would be required. These enhancements would reduce the CDF due to ATWS. A bounding analysis was performed by setting failure to trip the control rod motor generator sets to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$23,506. This analysis case was used to model the benefit of Phase II SAMAs 047 and 048.

### **Large Break LOCA**

This analysis case was used to evaluate the change in plant risk from installing a digital large break LOCA protection system. The proposed plant modification involves installation of nine analog to digital converters, digital logic racks, and input into the emergency safeguard system logic relay racks. Procedure modifications and training would also be required. A bounding analysis was performed by setting the large break LOCA initiator to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 049.

### **Main Steam Line Break inside Containment**

This analysis case was used to evaluate the change in plant risk from installing secondary side guard pipes up to the MSIVs. This enhancement would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. This SAMA would also guard against or prevent consequential multiple SGTRs following a main steam line break event. A bounding analysis was performed by setting the main steam line break initiators (inside and outside containment) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$611,289. This analysis case was used to model the benefit of Phase II SAMA 050.

### **Main Feedwater Secondary-Side Cooling**

This analysis case was used to evaluate the change in plant risk from aligning the main feedwater for secondary heat removal to reduce the CDF contribution from transients and subsequent loss of AFW secondary-side cooling. A bounding analysis was performed by setting failure of condensate secondary-side cooling to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$11,753. This analysis case was used to model the benefit of Phase II SAMA 051.

### **AFW System Alternate Suction Supply**

This analysis case was used to evaluate the change in plant risk from opening the city water supply valve for alternative AFW pump suction. This SAMA would enhance the availability of AFW. A bounding analysis was performed by setting loss of normal suction path to the AFW system to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$65,223. This analysis case was used to model the benefit of Phase II SAMA 052.

### **Plant Hydrogen Control**

This analysis case was used to evaluate the change in plant risk from plant modifications to install an excess flow valve to reduce the risk associated with hydrogen explosions inside the turbine building or PAB. The proposed plant modification involves installation of a non-electric excess flow valve. Procedure revisions and training would also be required. A bounding analysis was performed by eliminating hydrogen ruptures inside the turbine building, which resulted in a baseline benefit of approximately \$142,328. This analysis case was used to model the benefit of Phase II SAMA 053.

### **Pressurizer PORV DC Power**

This analysis case was used to evaluate the change in plant risk from plant modifications to provide a backup source of DC power for the PORVs. This enhancement would reduce the CDF contribution from loss of secondary heat sink and enhance feed and bleed availability. The proposed plant modification involves installation of an additional battery, inverter, charger and two transfer switches. Procedure revisions and training would also be required. A bounding analysis was performed by setting failure of DC power to the PORVs to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 054.

### **Appendix R Power to SI or RHR Pump**

This analysis case was used to evaluate the change in plant risk from plant modifications for a hard-wired connection to one SI or RHR pump from the Appendix R diesel (MCC-312A) power supply. This enhancement would reduce the CDF contribution from internal and external events that cause loss of power from the 480V vital buses. The proposed plant modification involves installation of 500 feet of cable and conduit, a breaker and transfer switches. Procedure revisions and training would also be required. A bounding analysis was performed by setting

failure to align MCC-312A to power the charging pump to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$11,274,884. This analysis case was used to model the benefit of Phase II SAMA 055.

### **CCW Heat Exchanger Alternate Cooling Supply**

This analysis case was used to evaluate the change in plant risk from providing a backup cooling water source for the CCW heat exchangers. This enhancement would reduce the CDF contribution from loss of non-essential service water events. The proposed plant change involves use of backup service water pumps to cool the CCW heat exchangers. Piping and valves exists to implement this change, however, additional analysis would be required to ensure adequate cooling flow (electrical load and service water flow). In addition, procedure changes and training would be required. A bounding analysis was performed by setting the loss of non-essential service water initiator to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$35,259. This analysis case was used to model the benefit of Phase II SAMA 057.

### **Backup DC Power Supply**

This analysis case was used to evaluate the change in plant risk from providing an automatic backup DC power supply. This enhancement reduces the CDF associated with loss of a DC bus. The proposed plant modification involves installation of four transfer switches and instrumentation. Procedure revisions and training would also be required. A bounding analysis was performed by setting the loss of DC Bus 31 and Bus 32 initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$76,459. This analysis case was used to model the benefit of Phase II SAMA 058.

### **Charging Pump Alternate Cooling**

This analysis case was used to evaluate the change in plant risk from plant modifications to allow the primary water system to cool the charging pumps. This enhancement would reduce the effect of loss of component cooling by providing an alternate means to cool the charging pumps and preserve seal injection after loss of component cooling. The proposed plant modification involves installation of two manual valves and 100 feet of piping per charging pump. Procedure revisions and training would also be required. A bounding analysis was performed by setting failure to align city water to the charging pumps to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 059.

### **Recirculation Pump Motor Alternate Cooling**

This analysis case was used to evaluate the change in plant risk from providing an independent source of cooling for the recirculation pump motors to reduce CDF associated due to loss of CCW events. The proposed plant modification involves connecting city water or primary water supply to the piping associated with the auxiliary component cooling pumps, including isolation valves and supports (~300 feet of piping). A discharge drain line, procedure development and training would also be required. A bounding analysis was performed by setting loss of CCW to

the recirculation pumps to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 060.

### **Upgrade Alternate Safe Shutdown System (ASSS) for RCP Seal Cooling**

This analysis case was used to evaluate the change in plant risk from upgrading the ASSS to allow timely restoration of seal injection and cooling. This enhancement would reduce the CDF contribution from internal and external events that cause loss of power from the 480VAC vital buses. The proposed plant modification involves installation of 500 feet of multi-conductor cable to the control room, along with control room penetration and sealing. In addition, the modification requires control switches mounted in panels, seismic evaluations, and internal wiring. Procedure revisions and training would also be required. A bounding analysis was performed by setting the control building flooding initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$1,365,046. This analysis case was used to model the benefit of Phase II SAMA 061.

### **480VAC Switchgear Room Flood Alarm**

This analysis case was used to evaluate the change in plant risk from installing a flood alarm in the 480VAC switchgear room. The proposed modification involves installation of a single alarm and wiring from the switchgear room to the control room. Procedure revisions and training would also be required. A bounding analysis was performed by setting control building flooding initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately \$1,365,046. This analysis case was used to model the benefit of Phase II SAMA 062.

#### **E.4.4 Sensitivity Analyses**

Three sensitivity analyses were conducted to gauge the impact of assumptions upon the analysis. The benefits estimated for each of these sensitivities are presented in [Table E.4-3](#).

A description of each sensitivity case follows:

##### **Sensitivity Case 1: Years Remaining Until End of Plant Life**

The purpose of this sensitivity case was to investigate the sensitivity of assuming a 28-year period for remaining plant life (i.e. eight years on the original plant license plus the 20-year license renewal period). The 20-year license renewal period was used in the base case. The resultant monetary equivalent was calculated using 28 years remaining until end of facility life to investigate the impact on each analysis case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

##### **Sensitivity Case 2: Conservative Discount Rate**

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the discount rate. The discount rate of 7.0% used in the base case analyses is conservative relative to corporate practices. Nonetheless, a lower discount rate of 3.0% was assumed in this case to

investigate the impact on each analysis case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

#### Sensitivity Case 3: Inclusion of Economic Losses Due to Tourism and Business

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the inclusion of economic losses due to tourism and business. The MACCS2 economic model used for the base case analysis did not consider such losses. This sensitivity case assumed a loss of \$208,838/person as oppose to \$163,631/person in the affected region following a postulated severe accident. This increased the calculated offsite economic cost risk for the base case and for each SAMA under consideration. Since the benefit for each SAMA is estimated as the difference between the base case and the SAMA, the sensitivity case 3 benefit values (Table E.4-3) are the same or only slightly higher than the baseline benefit values. Therefore, changing this assumption does not cause additional SAMAs to be cost-beneficial.

#### **E.4.5 References**

- E.4-1 Attachment (2), Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Operating License Renewal Stage, Calvert Cliffs Nuclear Power, April 1998.
- E.4-2 Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal Application for the H.B. Robinson Steam Electric Plant Unit No.2, June 2002.
- E.4-3 Appendix E, Environmental Report, Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal Application for the Virgil C. Summer Nuclear Station, August 2002.
- E.4-4 Appendix E-Attachment E, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Arkansas Nuclear One - Unit 2, October 2003.
- E.4-5 Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for License Renewal, Donald C. Cook Nuclear Plant, October 2003.
- E.4-6 Appendix F and Appendix G - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for Renewed Operating Licenses, Millstone Power Station, Units 2 and 3, January 2004.
- E.4-7 Appendix D - Attachment F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Application for License Renewal, Joseph M. Farley Nuclear Plant, September 2003.
- E.4-8 Appendix E - Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Application for Renewed Operating Licenses, Point Beach Nuclear Plant Units 1 and 2, February 2004.
- E.4-9 Appendix F, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Quad Cities Nuclear Power Plant Units 1 and 2, January 2003.
- E.4-10 General Electrical Nuclear Energy, Technical Support Document for the ABWR, 25A5680, Revision 1, January 18, 1995.
- E.4-11 Cost Estimate for Severe Accident Mitigation Design Alternatives, Limerick Generating Station for Philadelphia Electric Company, Bechtel Power Corporation, June 22, 1989.
- E.4-12 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, 5.35, Listing of SAMDAs considered for the Limerick Generating Station, U.S. Nuclear Regulatory Commission, May 1996.

- E.4-13 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, 5.36, Listing of SAMDAs considered for the Comanche Peak Steam Electric Station, U.S. Nuclear Regulatory Commission, May 1996.
- E.4-14 Letter from Mr. D. E. Nunn (TVA) to NRC Document Control Desk dated October 7, 1994, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Severe Accident Mitigation Design Alternatives (SAMDA) - Response to Request for Additional Information (RAI) - (TAC Nos. M77222 and M77223)."
- E.4-15 Letter from Mr. M. O. Medford (TVA) to NRC Document Control Desk dated September 1, 1992, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Generic Letter (GL) 88-20 - Individual Plant Examination (IPE) for Severe Accident Vulnerabilities - Response - (TAC M74488)."
- E.4-16 Letter from N. J. Liparulo (Westinghouse Electric Corporation) to NRC Document Control Desk, dated December 15, 1992, "Submittal of Material Pertinent to the AP600 Design Certification Review."
- E.4-17 NUREG-1462, Final Safety Evaluation Report related to the Certification of CE System 80+ design, U.S. Nuclear Regulatory Commission, August 1994.
- E.4-18 NUREG 0498, "Final Environmental Statement Related to the Operation of Watts Bar Nuclear Plant, Units 1 and 2," Supplement No. 1, U.S. Nuclear Regulatory Commission, April 1995.
- E.4-19 NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," Volume 2, U.S. Nuclear Regulatory Commission, December 1997.
- E.4-20 NUREG/CR-5474, "Assessment of Candidate Accident Management Strategies", U.S. Nuclear Regulatory Commission, March 1990.
- E.4-21 IP3-RPT-MULT-01539, "Indian Point 3 Nuclear Power Plant Individual Plant Examination Revision 0, June 1994.
- E.4-22 IP3-RPT-MULT-01539, "Indian Point 3 Nuclear Power Plant Individual Plant Examination Revision 1, June 2001.
- E.4-23 IP-RPT-06-00071 "Indian Point Unit 3 Nuclear Power Plant Probabilistic Safety Assessment, Revision 2," April 2007.
- E.4-24 P3-RPT-UNSPEC-02182, "Indian Point Three Nuclear Power Plant Individual Plant Examination for External Events," September 1997, Revision 0.

- E.4-25 Appendix E, Appendix 5 - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for License Renewal, Fort Calhoun Unit 1 Nuclear Station, January 2002.
- E.4-26 Duke Power Company, Applicant's Environmental Report, Operating License Renewal Stage, Attachment K, "McGuire Nuclear Stations Severe Accident Mitigation Alternatives (SAMA) Analysis," Rev. 0, Charlotte, North Carolina, May 2001.
- E.4-27 NUREG/BR-0184 "Regulatory Analysis Technical Evaluation Handbook," U.S. Nuclear Regulatory Commission, January 1997.
- E.4-28 Appendix E-Attachment E, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Palisades Nuclear Plant, March 2005.



**Table E.4-1  
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
201	Operator Action: Align alternate safe shutdown equipment to MCC-312A	This SAMA would align alternate safe shutdown equipment to reduce core damage frequency following 480VAC switchgear room flooding.	Already installed	This operator action is taken to align alternate safe shutdown equipment to MCC-312A to establish RCS makeup and reduce CDF following switchgear room flooding. The IP3 procedure instructs the operators to manually align 31 or 32 charging pump, 32 CCW pump and 38 service water pump to MCC-312A. Therefore, this SAMA has already been implemented at IP3.	Yes
202	Operator Action: Perform late cooldown and depressurization (SGTR)	This SAMA would terminate leakage from RCS into the secondary prior to depleting RWST inventory following a SGTR.	Already installed	This operator action is taken to cool and depressurize the RCS to cold shutdown following a SGTR to terminate leakage from RCS into the secondary prior to depleting RWST inventory. The IP3 procedure instructs the operators to perform cooldown and depressurize the RCS following a SGTR. Therefore, this SAMA has already been implemented at IP3.	Yes
203	Operator action: Recover AC power following a station blackout given successful RCS cooldown	This SAMA would reduce the CDF contribution from loss of offsite power.	Already installed	This operator action is taken to restore AC power following loss of offsite power and failure of the EDGs. The IP3 procedure instructs the operators to restore power using three sources of power: recovery of offsite power, the Appendix R diesel, and Con Ed's gas turbine No. 2. Therefore, this SAMA has already been implemented at IP3.	Yes

**Table E.4-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
 (Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
204	Operator action: Align low head internal recirculation during a small LOCA	This SAMA would reduce the CDF contribution from small LOCA.	Already installed	This operator action is taken to align low head ECCS internal recirculation following the injection phase of ECCS to deliver flow to the RCS cold legs during a LOCA. The IP3 procedure instructs the operators to transfer to recirculation if RWST level decreases to less than 11.5 feet. Therefore, this SAMA has already been implemented at IP3.	Yes
205	Operator action: Align main feedwater for secondary heat removal	This SAMA would reduce the CDF contribution from transients.	Retain (Phase II SAMA 051)	Because the MSIVs are closed during implementation of the procedure for loss of secondary heat sink, loss of condenser vacuum results. Subsequent restoration of main feedwater is not proceduralized. Considered for a final cost-benefit evaluation, this SAMA would involve a procedure change to credit the operator re-establishing operation of the main feedwater system.	No
206	Operator action: Initiate feed and bleed cooling following loss of 480V bus 6A	This SAMA would reduce the CDF contribution from the loss of 480V bus 6A.	Already installed	This operator action is taken to establish core cooling using feed and bleed upon loss of main feedwater and all AFW pumps. The IP3 procedure instructs the operators to trip RCPs and establish an RCS bleed path. Therefore, this SAMA has already been implemented at IP3.	Yes

**Table E.4-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
 (Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
207	Operator Action: Align backup city water cooling to charging pumps following loss of CCW	This SAMA would preclude the possibility of a large RCP seal LOCA following a loss of CCW.	Already installed	This operator action is taken to align backup city water cooling to charging pumps following a loss of CCW to preclude the possibility of a large RCP seal LOCA. The IP3 procedure instructs the operators to align charging pumps in manual at maximum speed and, if no CCW pumps can be started, align backup cooling from city water. Therefore, this SAMA has already been implemented at IP3.	Yes
208	Operator action: Initiate feed and bleed cooling following a reactor trip	This SAMA would reduce the CDF contribution from transients.	Already installed	This operator action is taken to establish core cooling using feed and bleed upon loss of main feedwater and all AFW pumps. The IP3 procedure instructs the operators to trip RCPs and establish an RCS bleed path. Therefore, this SAMA has already been implemented at IP3.	Yes
209	Operator Action: Manually insert control rods (ATWS)	This SAMA would insert control rods to reduce CDF following ATWS.	Already installed	This operator action is taken to manually insert control rods for at least one minute prior to peak RCS pressure during ATWS. The IP3 procedure instructs the operators to manually trip the reactor and enter procedure FR-S.1. If a manual trip of the reactor is not successful, FR-S.1 directs the operator to manually insert control rods. Therefore, this SAMA has already been implemented at IP3.	Yes

**Table E.4-1  
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
(Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
210	Operator Action: Align alternative switchgear room ventilation	This SAMA would provide capability to provide alternate 480VAC switchgear room ventilation should the normal ventilation system fail.	Already installed	This operator action is taken to establish alternate 480VAC switchgear room cooling during large break LOCA. The IP3 alarm procedure instructs the operators to block open the doors in the 480VAC switchgear room and set up portable fans. Therefore, this SAMA has already been implemented at IP3.	Yes
211	Allow for condenser steam dump capability following an SI signal	This SAMA would reduce the CDF contribution from transients.	Already installed	A recent modification provided a more reliable source of backup cooling to the circulating water pumps following an SI signal, which reduces the likelihood that condenser vacuum will be lost and allows the use of condenser steam dumps for RCS depressurization during an SGTR event or during a LOCA involving a loss of high-head safety injection.	Yes

**Table E.4-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
 (Continued)**

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
212	Open city water supply valve for alternative AFW pump suction	This SAMA would enhance the availability of the AFW system.	Retain (Phase II SAMA 052)	This operator action is taken to recover from the plugging of condensate storage tank isolation valves CT-6 or CT-64. The plugging of these valves subsequent to a reactor trip and loss of main feedwater will cause the AFW pumps to trip on low flow, a major potential cause of loss of secondary-side cooling. The emergency operating procedure instructs the operators to align the backup city water supply to the AFW pumps should the condensate storage tank outlet valves fail, as indicated by a low suction flow alarm. The procedural guidance could be improved to direct the action to align the city water backup in the event of a low AFW suction flow alarm combined with the inability to restore adequate suction from the condensate storage tank.	No

**Table E.4-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
 (Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
213	Provision of alternative AFW pump room ventilation	This SAMA would enhance the availability of the AFW system.	Already installed	The operator is required to establish ventilation to the AFW pump room should normal room ventilation fail. A loss of ventilation to this room while the AFW pumps are running will result in failure of the motor-driven pumps and isolation of the steam supply to the turbine-driven pump. Therefore, to guard against a loss of ventilation and its consequences when the AFW pumps start, the alarm response procedure for high pump room temperature directs the operator to open the roll-up door to the AFW pump room to ventilate the room. Therefore, this SAMA has already been implemented at IP3.	Yes
214	Provide procedural guidance for determining LOCA outside containment	This SAMA would reduce the CDF contribution from LOCA outside containment.	Already installed	IP3 emergency operating procedure for LOCA outside containment was revised to direct the operators to close both SI-899A and SI-747 (or SI-899B and SI-746). This procedural change copes with the potential to create differential pressure in excess of the design capability of SI-1869A or SI-1869B during a LOCA outside containment. Therefore, this SAMA has already been implemented at IP3.	No (although ISLOCA isolation is credited)

**Table E.4-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
 (Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
215	Flush control building 480VAC switchgear room 15 ft elevation floor drains periodically	This SAMA would reduce the CDF contribution from 480VAC switchgear room flooding.	Already installed	IP3 preventive maintenance program has been revised to have the control building 15 ft elevation floor drains flushed during each outage. This procedural change greatly increases the likelihood that the drains at this elevation will be available to mitigate flooding in the control building and switchgear room. Therefore, this SAMA has already been implemented at IP3.	No
216	Keep both pressurizer PORV block valves open	This SAMA would reduce the CDF contribution from loss of secondary heat sink when feed and bleed is not available.	Already installed	Initiation of primary feed and bleed cooling is included in accident sequences that involve total loss of secondary side cooling and, in particular, failure to establish AFW flow. The time available to initiate feed and bleed cooling (and thus the probability of human error in taking this action) is determined by the time at which the RCPs are tripped and whether the PORV block valves are open when the reactor trip occurs. The PORVs have been replaced to eliminate leakage and allow the plant to run with the block valves open, which will enhance the likelihood of successfully initiating feed and bleed cooling. Therefore, this SAMA has already been implemented at IP3.	Yes

**Table E.4-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
 (Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
217	Expand the scope of diesel generator functional tests	This SAMA would enhance the availability of the EDGs.	Already installed	Revision to EDG functional test procedures has been made to verify the operational status of each EDG building ventilation system. This procedure modification improves availability since potential failures will now be monitored. Therefore, this SAMA has already been implemented at IP3.	Yes
218	Revised the maintenance procedure FAN-009-AFW for AFW building ventilation system	This SAMA would improve the availability of the AFW building ventilation system.	Already installed	Maintenance procedure FAN-009-AFW for AFW building exhaust fans, louvers and dampers has been revised to improve the availability of AFW building ventilation system. Therefore, this SAMA has already been implemented at IP3.	Yes
219	Install adequate seismic support for the fire protection piping deluge valve station located in the control building at 15 ft elevation	This SAMA would reduce the CDF contribution from 480VAC switchgear room flooding.	Already installed	Adequate seismic support to the portion of the fire protection piping deluge valve station located in the control building at 15 ft elevation has been installed. In addition, a water proof door to the deluge valve station room has also been installed to reduce the CDF contribution from 480VAC switchgear room flooding. Therefore, this SAMA has already been implemented at IP3.	No (seismic-induced floods not modeled)



**Table E.4-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
 (Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
220	Revise alarm response procedure to mitigate flood	This SAMA would reduce the CDF contribution from the PAB building flooding event.	Already installed	The alarm response procedure for flooding mitigation in the PAB has been revised. Explicit instructions were added to check whether there is flooding in the PAB on a high-level alarm. Therefore, this SAMA has already been implemented at IP3.	No
221	Reassign the power supplies to the EDG room exhaust fans	This SAMA would enhance the availability of the EDGs.	Already installed	EDG room exhaust fan power supplies have been realigned to eliminate cross-dependencies with other EDG's. Therefore, this SAMA has already been implemented at IP3.	Yes
222	Modify the power sources of backup charger 35	This SAMA would enhance the availability of backup 125VDC battery charger 35.	Already installed	Power supply to backup 125V DC battery charger 35 has been modified and is able to be powered from either 480V MCC 36C, 36D, or 36E. This allows flexibility in backup battery charger 35 to power the station batteries. Therefore, this SAMA has already been implemented at IP3.	Yes
223	Provide backup compressed air to the instrument air system	This SAMA would enhance availability of the instrument air system.	Already installed	A diesel-driven station air compressor, which can automatically supply backup, compressed air to the instrument air system in the event of low system pressure, has been installed. Therefore, this SAMA has already been implemented at IP3.	Yes

**Table E.4-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
 (Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
224	Modify fire suppression system within the switchgear room be restored to automatic actuation.	This SAMA would reduce the CDF contribution from a 480VAC switchgear room fire.	Already installed	A modification has been implemented to change the operating mode of the CO <sub>2</sub> fire suppression system in the 480V switchgear room from a manually initiated automatic system to a fully automatic system. Therefore, this SAMA has already been implemented at IP3.	No (Not credited in internal PSA model)
225	Prevent spurious operation of the EDG room CO <sub>2</sub> system during seismic event	This SAMA would reduce the CDF contribution from seismic events.	Already installed	A modification to install a QA category I, seismic class I, actuation permission auxiliary control panel for CO <sub>2</sub> discharge into the EDG building was installed. This modification prevents spurious operation of the EDG room CO <sub>2</sub> system and subsequent shutdown of the EDG ventilation system during a seismic event. Therefore, this SAMA has already been implemented at IP3.	No (spurious CO <sub>2</sub> system not modeled in IPEEE)
226	Eliminate the common cause failure of EDG relays during seismic event	This SAMA would enhance the availability of the EDGs during seismic event.	Already installed	A calculation has been performed demonstrating that seismic capacity of the relays which may result in a common cause failure of all EDGs during a seismic event is adequate to withstand a safe shutdown earthquake. Therefore, this SAMA has already been implemented at IP3.	Yes

**Table E.4-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
 (Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
227	Install an excess flow valve to reduce the risk associated with hydrogen explosions	This SAMA would reduce the risk associated with hydrogen explosions inside the turbine building or PAB.	Retain (Phase II SAMA 053)	Considered for a final cost-benefit evaluation, this modification would reduce the risk associated with hydrogen explosions by installing an excess flow valve at the outside hydrogen storage facility to stop flow in the event of a hydrogen line rupture inside the turbine building or PAB.	No
228	Provide DC power backup for the PORVs	This SAMA would reduce the CDF contribution from loss of secondary heat sink and enhance feed and bleed availability.	Retain (Phase II SAMA 054)	Considered for a final cost-benefit evaluation, this modification would involve installation of a DC power backup for the PORVs to improve the availability of PORVs to perform the feed and bleed function during a loss of secondary heat sink.	No
229	Provide hard-wired connection to one SI or RHR pump from the Appendix R bus (MCC 312A)	This SAMA would reduce the CDF contribution from internal flooding scenarios.	Retain (Phase II SAMA 055)	Considered for a final cost-benefit evaluation, this modification would involve providing a power source for one SI or RHR pump from the Appendix R bus (MCC 312A) during internal flooding scenarios in the control building at 15 ft elevation.	No

**Table E.4-1  
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
(Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
230	Install pneumatic controls and indication for the turbine-driven AFW pump	This SAMA would reduce the CDF contribution from SBO events.	Retain (Phase II SAMA 056)	Considered for a final cost-benefit evaluation, this modification would involve installing pneumatic controls and indication for the turbine-driven AFW pump to reduce the CDF contribution from SBO events.	No
231	Provide backup cooling water source for the CCW heat exchangers	This SAMA would reduce the CDF contribution from loss of non-essential service water events	Retain (Phase II SAMA 057)	Considered for a final cost-benefit evaluation, this would involve using the IP3 backup service water pumps to provide cooling for the CCW heat exchangers on loss of non-essential service water. Currently, the backup service water pumps are only aligned to provide backup to the essential service water header.	No
232	Provide alternate source of water to the fan cooler units following loss of all service water	This SAMA would reduce the CDF associated with loss of essential service water.	Already installed	IP3 has the capability to supply the essential service water loads from the backup service water pumps, which are separate from the normal service water system.	No (Not credited in internal PSA model)
233	Provide automatic DC power backup	This SAMA would reduce the CDF associated with loss of a DC bus.	Retain (Phase II SAMA 058)	Similar to a capability that already exists at IP2, provide DC power backup using transfer switches that would automatically provide alternate DC power from another DC panel in the event of low output from the normal DC supply.	No

**Table E.4-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
 (Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
234	Provide hardware connections to allow the primary water system to be used to cool the charging pumps	This SAMA would reduce the effect of loss of CCW by providing an alternate means to cool the charging pumps and preserve seal injection after a loss of CCW.	Retain (Phase II SAMA 059)	Considered for a final cost-benefit evaluation, this modification would involve installing the necessary connections and implementing procedure changes to allow primary water to supply cooling to the charging pumps on loss of CCW.	No
235	Provide independent source of cooling for the recirculation pump motors	This SAMA would reduce the CDF associated with loss of CCW events	Retain (Phase II SAMA 060)	Considered for a final cost-benefit evaluation, this modification would involve installing the necessary connections and implementing procedure changes to allow an alternate source (city water or primary water) to supply cooling to the recirculation pumps on loss of CCW.	No

**Table E.4-1  
 Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights  
 (Continued)**

<b>Phase I SAMA ID Number</b>	<b>SAMA Title</b>	<b>Result of Potential Enhancement</b>	<b>Screening Criteria</b>	<b>SAMA Disposition</b>	<b>Credited in PSA Model</b>
236	Upgrade the ASSS to allow timely restoration of seal injection and cooling.	This SAMA would reduce the CDF contribution from internal and external events that cause loss of power from the 480V vital buses (SBO, control building floods and fires)	Retain (Phase II SAMA 061)	Considered for a final cost-benefit evaluation, this modification would involve providing an automatic start and load feature for the alternate safe shutdown power source.	No
237	Install flood alarm in the 480VAC switchgear room	This SAMA would reduce CDF from switchgear room flooding.	Retain (Phase II SAMA 062)	Considered for a final cost-benefit evaluation, this SAMA would involve procedure and hardware changes to reduce CDF following control building 480VAC switchgear room flooding.	No

**Table E.4-2  
 Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Diesel Powered RCP Seal Injection  001 - Create an independent RCP seal injection system with a dedicated diesel.	Eliminate consequential RCP seal LOCAs from all plant initiators.  The cost of implementing this SAMA was specifically estimated for IP3.	6.87%	0.82%	0.57%	\$135,611	\$196,538	\$1,137,000	Not cost effective
Non-Diesel Powered RCP Seal Injection  002 - Create an independent RCP seal injection system without a dedicated diesel.	Eliminate consequential RCP seal LOCAs from non-SBO events.  The cost of implementing this SAMA was specifically estimated for Donald C. Cook.	5.05%	0.41%	0.57%	\$100,223	\$145,251	\$1,000,000	Not cost effective

**Table E.4-2  
 Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation  
 (Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Additional CCW Pump  003 - Install an additional CCW pump.	Eliminate common cause failure of CCW pumps.  The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.	0.11%	0.00%	0.00%	~\$0	~\$0	\$1,500,000	Not cost effective
RHR Heat Exchangers  004 - Improve ability to cool the RHR heat exchangers by allowing manual alignment of the fire protection system.	Eliminate loss of CCW to the RHR heat exchangers.  The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.65%	0.41%	0.38%	\$35,517	\$51,474	\$565,000	Not cost effective



**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Filtered Containment Vent  005 - Install a filtered containment vent to provide fission product scrubbing.	Eliminate late containment over-pressurization failures.  The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.00%	9.80%	7.01%	\$504,995	\$731,877	\$5,700,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Molten Core Debris Removal	Eliminate containment failure due to CCI.	0.00%	24.08%	21.59%	\$1,378,340	\$1,997,594		
006 - Create a large concrete crucible with heat removal potential under the base mat to contain molten core debris.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						\$108,000,000	Not cost effective
007 - Create a reactor cavity flooding system.	The cost of implementing this SAMA was specifically estimated for IP2.						\$3,714,000	Not cost effective
008 - Create a core melt source reduction system.	The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.						\$90,000,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Inert Containment  009 - Provide means to inert containment.	Eliminate containment failures due to hydrogen burns.  The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.00%	8.57%	9.66%	\$552,524	\$800,760	\$10,900,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Containment Sprays	Eliminate failure of containment spray.	0.11%	0.00%	0.00%	~\$0	~\$0		
010 - Use the fire protection system as a backup source for the containment spray system.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						\$565,000	Not cost effective
011 - Install a passive containment spray system.	The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.						\$2,000,000	Not cost effective
014 - Install a redundant containment spray system.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						\$5,800,000	Not cost effective

**Table E.4-2  
 Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation  
 (Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Base Mat Melt-Through  012 - Increase the depth of the concrete base mat or use an alternative concrete material to ensure melt-through does not occur.	Eliminate containment failure due to base mat melt-through.  The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.	0.00%	5.71%	4.17%	\$297,056	\$430,516	>\$5,000,000	Not cost effective
Strengthen Containment  013 - Construct a building connected to primary containment that is maintained at a vacuum.	Eliminate energetic containment failure modes (DCH, steam explosion, late over-pressurization).  The cost of implementing this SAMA was specifically estimated for IP3.	0.00%	21.63%	20.45%	\$1,271,400	\$1,842,609	\$61,000,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Containment Liner Protection  015 - Erect a barrier that provides containment liner protection from ejected core debris at high pressure.	Eliminate HPME and subsequent DCH at high RCS pressure.  The cost of implementing this SAMA was specifically estimated for IP3.	0.11%	4.08%	4.36%	\$255,468	\$370,244	\$2,900,000	Not cost effective
Steam Generator Heat Removal  016 - Install a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources.	Eliminate SGTR with loss of secondary-side cooling.  The cost of implementing this SAMA was specifically estimated for IP3.	2.47%	5.31%	5.30%	\$356,079	\$516,057	\$7,400,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Secondary Side Pressure Capacity  017 - Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	Eliminate operator failure to isolate the ruptured steam generator.  The cost of implementing this SAMA was specifically estimated for IP3.	8.57%	44.90%	47.35%	\$2,909,856	\$4,217,182	\$13,000,000	Not cost effective
SGTR Fission Product Scrubbing  018 - Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	Reduce SGTR accident progression source terms by a factor of 2.  The cost of implementing this SAMA was specifically estimated for IP3.	0.00%	11.43%	10.61%	\$665,406	\$964,356	\$9,700,000	Not cost effective

**Table E.4-2  
 Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation  
 (Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
ISLOCA Mitigation	Eliminate ISLOCAs.	1.26%	6.94%	7.39%	\$457,208	\$662,620		
019 - Install additional pressure or leak monitoring instrumentation for ISLOCAs.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						\$2,300,000	Not cost effective
022 - Ensure all ISLOCA releases are scrubbed.	The cost of implementing this SAMA was specifically estimated for IP3.						\$9,700,000	Not cost effective



**Table E.4-2  
 Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation  
 (Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
ISLOCA Valves	Reduce ISLOCAs by 50 percent.	0.68%	3.27%	3.60%	\$219,692	\$318,394		
020 - Add redundant and diverse limit switches to each containment isolation valve.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						\$1,000,000	Not cost effective
021 - Increase leak testing of valves in ISLOCA paths.	The cost of implementing this SAMA was specifically estimated for IP3.						\$10,604,000	Not cost effective

**Table E.4-2  
 Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation  
 (Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
MSIV Design  023 - Improve MSIV design.	Eliminate MSIV failure to isolate a faulted or ruptured steam generator.  The cost of implementing this SAMA was specifically estimated for IP3.	0.11%	0.00%	0.00%	~\$0	~\$0	\$476,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
DC Power/ AFW System Changes	Increase time available to recover offsite power before local operation of AFW is required from 2 hours to 24 hours during SBO scenarios.	2.81%	0.00%	0.00%	\$35,259	\$51,100		
024 - Provide additional DC battery capacity.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						>\$1,875,000	Not cost effective
025 - Use fuel cells instead of lead-acid batteries.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						\$2,000,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
026 - Increase/improve DC bus load shedding.	The cost of implementing this SAMA was specifically estimated for Fort Calhoun Unit 1.						>\$160,000	Not cost effective
042 - Provide hookup for portable generators to power the turbine-driven AFW pump after station batteries are depleted.	The cost of implementing this SAMA was specifically estimated for IP3.						\$1,072,000	Not cost effective
056 - Install pneumatic controls and indication for the turbine-driven AFW pump.	The cost of implementing this SAMA was specifically estimated for IP3.						\$982,000	Not cost effective

**Table E.4-2  
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation  
(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
AC Power Cross-Tie with IP2  027 - Create AC power cross-tie capability with other unit.	Eliminate loss of the Appendix R diesel.  The cost of implementing this SAMA was specifically estimated for IP3.	4.50%	0.00%	0.00%	\$58,765	\$85,166	\$1,156,000	Not cost effective
EDG Alternate Engine Cooling  028 - Create a backup source for diesel cooling (not from existing system).  029 - Use fire protection system as a backup source for diesel cooling.	Eliminate loss of the essential service water supply for EDG cooling.  The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.  The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.56%	0.00%	0.00%	\$11,753	\$17,033	\$1,700,000  \$497,000	Not cost effective  Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Alternate Battery Charger Capability  030 - Provide a portable diesel-driven battery charger.	Reduce internal switchgear room floods 5 percent to account for local operation of the turbine-driven AFW pump; and increase the time available to recover offsite power before local operation of AFW is required from 2 hours to 24 hours during SBO scenarios.  The cost of implementing this SAMA was specifically estimated for IP3.	8.73%	6.94%	6.06%	\$509,643	\$738,613	\$494,000	Retain

**Table E.4-2  
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation  
(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
<p>Improve 118VAC System</p> <p>031 - Convert under-voltage, AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic.</p>	<p>Eliminate common cause failure of the 118VAC transformers.</p> <p>The cost of implementing this SAMA was specifically estimated for IP3.</p>	0.33%	0.41%	0.38%	\$23,764	\$34,441	\$1,254,000	Not cost effective
<p>Low Pressure Injection System</p> <p>032 - Provide capability for diesel-driven, low pressure vessel makeup.</p> <p>035 - Provide capability for alternate injection via diesel-driven fire pump.</p>	<p>Eliminate failure of the RHR system.</p> <p>The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.</p> <p>The cost of implementing this SAMA was specifically estimated for IP3.</p>	0.24%	0.00%	0.19%	\$5,941	\$8,610	<p>\$&gt;632,000</p> <p>\$750,000</p>	<p>Not cost effective</p> <p>Not cost effective</p>

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
High Pressure Injection System	Eliminate failure of the safety injection system.	0.39%	0.41%	0.38%	\$35,517	\$51,474		
033 - Provide an additional high pressure injection pump with independent diesel.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						\$5,000,000	Not cost effective
037 - Replace two of three motor-driven SI pumps with diesel-powered pumps.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						\$2,000,000	Not cost effective



**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Automatic Recirculation Cooling Swap-Over  034 - Create automatic swap-over to recirculation cooling upon RWST depletion.	Eliminate operator failure to align internal and external recirculation cooling.  The cost of implementing this SAMA was specifically estimated for McGuire.	19.86%	1.22%	1.14%	\$340,435	\$493,384	>\$1,000,000	Not cost effective
Conserve RWST Water Inventory  036 - Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Eliminate operator failure to align internal and external recirculation cooling during a large or medium LOCA.  The cost of implementing this SAMA was specifically estimated for IP3.	0.86%	0.00%	0.00%	\$11,753	\$17,033	\$82,000	Not cost effective

**Table E.4-2  
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation  
(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Enhance RCS Depressurization  038 - Create/enhance a reactor coolant depressurization system.	Eliminate common cause failure of the steam generator ADVs.  The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.	0.55%	0.82%	0.95%	\$65,223	\$94,526	\$4,600,000	Not cost effective
Main Feedwater System Upgrade  039 - Install a digital feed water upgrade.  041 - Add a motor-driven feedwater pump.	Eliminate loss of feedwater initiator.  The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.  The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.	11.84%	0.82%	0.57%	\$206,128	\$298,737	\$900,000  \$2,200,000	Not cost effective  Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Steam Generator Atmospheric Steam Dump Valve Enhancement  040 - Provide automatic nitrogen backup to steam generator ADVs.	Eliminate failure of manual local action to align nitrogen supply for control air supply to the steam generator ADV control valve.  The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.51%	0.82%	0.95%	\$65,223	\$94,526	\$214,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Alternate Water Sources to Steam Generators  043 - Use fire water system as backup for steam generator inventory.	Eliminate failure of the turbine-driven AFW pump and failure to restore AC power given successful AFW operation.  The cost of implementing this SAMA was specifically estimated for IP3.	6.75%	1.63%	1.33%	\$183,140	\$265,420	\$1,656,000	Not cost effective

**Table E.4-2  
 Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation  
 (Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Install Large Pressurizer PORVs  044 - Replace current pilot operated relief valves with larger ones such that only one is required for successful feed and bleed.	Change the number of PORVs required for RCS feed and bleed from 2-of-2 to 1-of-2. In addition, reduce failure of the operator action for feed and bleed by a factor of 5.  The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	4.46%	4.49%	4.73%	\$337,997	\$489,851	\$2,700,000	Not cost effective
Independent Boron Injection System  045 - Add an independent boron injection system.	Eliminate common cause failure of boric acid transfer pumps.  The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.	0.16%	0.00%	0.00%	~\$0	~\$0	\$300,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
ATWS Overpressure Protection  046 - Add a system of relief valves that prevent equipment damage from a pressure spike during an ATWS.	Eliminate RCS overpressurization during an ATWS.  The cost of implementing this SAMA was specifically estimated for IP3.	10.28%	0.82%	0.38%	\$176,682	\$256,060	\$615,000	Not cost effective
Control Room ATWS Mitigation  047 - Install motor generator set trip breakers in control room.  048 - Provide capability to remove power from the bus powering the control rods.	Eliminate failure to trip the control rod motor generator sets.  The cost of implementing this SAMA was specifically estimated for IP3.  The cost of implementing this SAMA was specifically estimated for IP3.	1.60%	0.00%	0.00%	\$23,506	\$34,066	\$716,000  \$45,000	Not cost effective  Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Large Break LOCA  049 - Provide digital large break LOCA protection.	Eliminate large break LOCA initiator.  The cost of implementing this SAMA was specifically estimated for IP3.	0.30%	0.00%	0.00%	~\$0	~\$0	\$2,036,000	Not cost effective
Main Steam Line Break Inside Containment  050 - Install secondary side guard pipes up to the MSIVs.	Eliminate main steam line break initiators (inside and outside containment).  The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.	4.67%	8.98%	9.28%	\$611,289	\$885,926	\$1,100,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Main Feedwater Secondary Side Cooling  051 - Operator action: Align main feedwater for secondary heat removal.	Eliminate failure of condensate secondary side cooling.  The cost of implementing this SAMA was specifically estimated for IP3.	0.65%	0.00%	0.00%	\$11,753	\$17,033	\$55,000	Not cost effective
AFW Alternate Suction Supply  052 - Open city water supply valve for alternative AFW pump suction.	Eliminate loss of the normal suction path to the AFW system.  The cost of implementing this SAMA was specifically estimated for IP3.	0.89%	0.82%	0.95%	\$65,223	\$94,526	\$50,000	Retain



**Table E.4-2  
 Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation  
 (Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Plant Hydrogen Control  053 - Install an excess flow valve to reduce the risk associated with hydrogen explosions.	Eliminate hydrogen ruptures inside the turbine building.  The cost of implementing this SAMA was specifically estimated for IP3.	1.79%	2.00%	1.86%	\$142,328	\$206,273	\$228,000	Not cost effective
Pressurizer PORV DC Power  054 - Provide DC power backup for the PORVs.	Eliminate failure of DC power to the PORVs.  The cost of implementing this SAMA was specifically estimated for IP3.	0.20%	0.00%	0.00%	~\$0	~\$0	\$376,000	Not cost effective

**Table E.4-2  
 Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation  
 (Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Appendix R Power SI or RHR Pump  055 - Provide hard-wired connection to one SI or RHR pump from the Appendix R bus (MCC 312A).	Eliminate operator failure to align MCC 312A.  The cost of implementing this SAMA was specifically estimated for IP3.	16.48%	18.37%	16.48%	\$1,274,884	\$1,847,657	\$1,288,000	Retain
CCW Heat Exchanger Alternate Cooling Supply  057 - Provide backup cooling water source for the CCW heat exchangers.	Eliminate loss of non-essential service water initiator.  The cost of implementing this SAMA was specifically estimated for IP3.	2.51%	0.00%	0.00%	\$35,259	\$51,100	\$109,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
Backup DC Power Supply  058 - Provide automatic DC power backup.	Eliminate loss of DC Bus 31 and Bus 32 initiators.  The cost of implementing this SAMA was specifically estimated for IP3.	4.83%	0.00%	0.19%	\$76,459	\$110,809	\$1,868,000	Not cost effective
Charging Pump Alternate Cooling  059 - Provide hardware connections to allow the primary water system to cool the charging pumps.	Eliminate failure to align city water to the charging pumps.  The cost of implementing this SAMA was specifically estimated for IP3.	0.19%	0.00%	0.00%	~\$0	~\$0	\$576,000	Not cost effective

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Recirculation Pump Motor Alternate Cooling  060 - Provide independent source of cooling for the recirculation pump motors.	Eliminate loss of CCW to the recirculation pumps.  The cost of implementing this SAMA was specifically estimated for IP3.	0.20%	0.00%	0.00%	~\$0	~\$0	\$710,000	Not cost effective
Upgrade ASSS for RCP Seal Cooling  061 - Upgrade the ASSS to allow timely restoration of seal injection and cooling.	Eliminate control building flooding initiators.  The cost of implementing this SAMA was specifically estimated for IP3.	17.43%	19.59%	17.80%	\$1,365,046	\$1,978,328	\$560,000	Retain

**Table E.4-2**  
**Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**  
**(Continued)**

<b>Phase II SAMA</b>	<b>Assumptions</b>	<b>CDF Reduction</b>	<b>Offsite Dose Reduction</b>	<b>OECR Reduction</b>	<b>Baseline Benefit</b>	<b>Baseline Benefit With Uncertainty</b>	<b>Estimated Cost</b>	<b>Conclusion</b>
480VAC Switchgear Room Flood Alarm  062 - Install flood alarm in the 480VAC switchgear room.	Eliminate control building flooding initiators.  The cost of implementing this SAMA was specifically estimated for IP3.	17.43%	19.59%	17.80%	\$1,365,046	\$1,978,328	\$196,800	Retain

**Table E.4-3  
 Sensitivity Analysis Results**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Diesel Powered RCP Seal Injection  001 - Create an independent RCP seal injection system with a dedicated diesel.	\$135,611	\$177,227	\$161,294	\$141,552	\$1,137,000
Non-diesel Powered RCP Seal Injection  002 - Create an independent RCP seal injection system without a dedicated diesel.	\$100,223	\$131,227	\$118,895	\$100,223	\$1,000,000
Additional CCW Pump  003 - Install an additional CCW pump.	~\$0	~\$0	~\$0	~\$0	\$1,500,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
RHR Heat Exchangers  004 - Improved ability to cool the RHR heat exchangers by allowing manual alignment of the fire protection system.	\$35,517	\$43,325	\$46,105	\$41,459	\$565,000
Filtered Containment Vent  005 - Install a filtered containment vent to provide fission product scrubbing.	\$504,995	\$575,870	\$705,659	\$534,701	\$5,700,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Molten Core Debris Removal  006 - Create a large concrete crucible with heat removal potential under the base mat to contain molten core debris.  007 - Create a reactor cavity flooding system.  008 - Create a core melt source reduction system.	\$1,378,340	\$1,571,787	\$1,926,033	\$1,467,457	\$108,000,000  \$8,750,000  \$90,000,000
Inert Containment  009 - Provide means to inert containment.	\$552,524	\$630,070	\$772,074	\$594,112	\$10,900,000



**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Containment Sprays  010 - Use the fire protection system as a backup source for the containment spray system.  011 - Install a passive containment spray system.  014 - Install a redundant containment spray system.	~\$0	~\$0	~\$0	~\$0	\$565,000  \$2,000,000  \$5,800,000
Base Mat Melt-Through  012 - Increase the depth of the concrete base mat or use an alternative concrete material to ensure melt-through does not occur.	\$297,056	\$338,747	\$415,093	\$308,938	>\$5,000,000

**Table E.4-3  
Sensitivity Analysis Results  
(Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Strengthen Containment  013 - Construct a building connected to primary containment that is maintained at a vacuum.	\$1,271,400	\$1,449,838	\$1,776,599	\$1,354,576	\$61,000,000
Containment Liner Protection  015 - Erect a barrier that provides containment liner protection from ejected core debris at high pressure.	\$255,468	\$291,323	\$356,980	\$273,292	\$2,900,000
Steam Generator Heat Removal  016 - Install a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources.	\$356,079	\$414,523	\$486,994	\$379,844	\$7,400,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Secondary Side Pressure Capacity  017 - Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	\$2,909,856	\$3,346,478	\$4,030,853	\$3,141,560	\$13,000,000
SGTR Fission Product Scrubbing  018 - Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	\$665,406	\$758,794	\$929,809	\$724,817	\$9,700,000

**Table E.4-3  
Sensitivity Analysis Results  
(Continued)**

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
ISLOCA Mitigation  019 - Install additional pressure or leak monitoring instrumentation for ISLOCAs.  022 - Ensure all ISLOCA releases are scrubbed.	\$457,208	\$527,022	\$631,831	\$498,795	\$2,300,000  \$9,700,000
ISLOCA Valves  020 - Add redundant and diverse limit switches to each containment isolation valve.  021 - Increase leak testing of valves in ISLOCA paths.	\$219,692	\$253,348	\$303,463	\$243,457	\$1,000,000  \$10,604,000
MSIV Design  023 - Improve MSIV Design.	~\$0	~\$0	~\$0	~\$0	\$476,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
DC Power/ AFW System Changes	\$35,259	\$48,676	\$38,693	\$35,259	
024 - Provide additional DC battery capacity.					>\$1,875,000
025 - Use fuel cells instead of lead-acid batteries.					\$2,000,000
026 - Increase/ improve DC bus load shedding.					>\$160,000
042 - Provide hookup for portable generators to power the turbine-driven AFW pump after station batteries are depleted.					\$1,072,000
056 - Install pneumatic controls and indication for the turbine-driven AFW pump.					\$982,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
AC Power Cross-Tie with IP2  027 - Create AC power cross-tie capability with other unit.	\$58,765	\$81,127	\$64,448	\$64,706	\$1,156,000
EDG Alternate Engine Cooling  028 - Create a backup source for diesel cooling (not from existing system).  029 - Use fire protection system as a backup source for diesel cooling.	\$11,753	\$16,225	\$12,898	\$11,753	\$1,700,000  \$497,000
Alternate Battery Charger Capability  030 - Provide a portable diesel-driven battery charger.	\$509,643	\$609,400	\$676,899	\$551,231	\$494,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Improve 118VAC System  031 - Convert under-voltage, AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic.	\$23,764	\$27,100	\$33,207	\$29,706	\$1,254,000
Low Pressure Injection System  032 - Provide capability for diesel-driven, low pressure vessel makeup.  035 - Provide capability for alternate injection via diesel-driven fire pump.	\$5,941	\$6,775	\$8,302	\$5,941	>\$632,000  \$750,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
High Pressure Injection System  033 - Provide an additional high pressure injection pump with independent diesel.  037 - Replace two of three motor-driven SI pumps with diesel-powered pumps.	\$35,517	\$43,325	\$46,105	\$35,517	\$5,000,000  \$2,000,000
Automatic Recirculation Cooling Swap-Over  034 - Create automatic swap-over to recirculation upon RWST depletion.	\$340,435	\$452,860	\$394,978	\$346,376	>\$1,000,000



**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Conserve RWST Water Inventory  036 - Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	\$11,753	\$16,225	\$12,898	\$11,753	\$82,000
Enhance RCS Depressurization  038 - Create/enhance a reactor coolant depressurization system.	\$65,223	\$77,200	\$87,614	\$71,164	\$4,600,000
Main Feedwater System Upgrade  039 - Install a digital feed water upgrade.  041 - Add a motor-driven feedwater pump.	\$206,128	\$274,580	\$238,680	\$212,070	\$900,000  \$2,000,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Steam Generator Atmospheric Steam Dump Valve Enhancement  040 - Provide automatic nitrogen backup to steam generator ADVs.	\$65,223	\$77,200	\$87,614	\$65,223	\$214,000
Alternate Water Sources to Steam Generators  043 - Use fire water system as backup for steam generator inventory.	\$183,140	\$231,427	\$227,709	\$195,022	\$1,656,000
Install Large Pressurizer PORVs  044 - Replace current pilot operated relief valves with larger ones such that only one is required for successful feed and bleed.	\$337,997	\$399,549	\$454,676	\$355,821	\$2,700,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Independent Boron Injection System  045 - Add an independent boron injection system.	~\$0	~\$0	~\$0	~\$0	\$300,000
ATWS Overpressure Protection  046 - Add a system of relief valves that prevent equipment damage from a pressure spike during an ATWS.	\$176,682	\$235,354	\$204,583	\$182,623	\$615,000
Control Room ATWS Mitigation  047 - Install motor generator set trip breakers in control room.  048 - Provide capability to remove power from the bus powering the control rods.	\$23,506	\$32,451	\$25,795	\$23,506	\$716,000  \$45,000

**Table E.4-3  
Sensitivity Analysis Results  
(Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Large Break LOCA  049 - Provide digital large break LOCA protection.	~\$0	~\$0	~\$0	~\$0	\$2,036,000
Main Steam Line Break Inside Containment  050 - Install secondary side guard pipes up to the MSIVs.	\$611,289	\$711,197	\$836,562	\$646,935	\$1,100,000
Main Feedwater Secondary Side Cooling  051 - Operator action: Align main feedwater for secondary heat removal.	\$11,753	\$16,225	\$12,898	\$11,753	\$55,000
AFW Alternate Suction Supply  052 - Open city water supply valve for alternative AFW pump suction.	\$65,223	\$77,200	\$87,614	\$71,164	\$50,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Plant Hydrogen Control  053 - Install an excess flow valve to reduce the risk associated with hydrogen explosions.	\$142,328	\$167,950	\$191,833	\$160,152	\$228,000
Pressurizer PORV DC Power  054 - Provide DC power backup for the PORVs.	~\$0	~\$0	~\$0	~\$0	\$376,000
Appendix R Power to SI or RHR Pump  055 - Provide hard-wired connection to one SI or RHR pump from the Appendix R bus (MCC 312A).	\$1,274,884	\$1,507,447	\$1,714,485	\$1,346,177	\$1,288,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
CCW Heat Exchanger Alternate Cooling Supply  057 - Provide backup cooling water source for the CCW heat exchangers.	\$35,259	\$48,676	\$38,693	\$41,200	\$109,000
Backup DC Power Supply  058 - Provide automatic DC power backup.	\$76,459	\$104,127	\$85,688	\$76,459	\$1,868,000
Charging Pump Alternate Cooling  059 - Provide hardware connections to allow the primary water system to cool the charging pumps.	~\$0	~\$0	~\$0	~\$0	\$576,000

**Table E.4-3  
 Sensitivity Analysis Results  
 (Continued)**

<b>Phase II SAMA</b>	<b>Baseline Benefit 20 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate</b>	<b>Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate</b>	<b>Sensitivity Case 3 Baseline with Loss of Tourism and Business</b>	<b>Estimated Cost</b>
Recirculation Pump Motor Alternate Cooling  060 - Provide independent source of cooling for the recirculation pump motors.	~\$0	~\$0	~\$0	~\$0	\$710,000
Upgrade ASSS for RCP Seal Cooling  061 - Upgrade the ASSS to allow timely restoration of seal injection and cooling.	\$1,365,046	\$1,613,369	\$1,836,597	\$1,436,340	\$560,000
480VAC Switchgear Room Flood Alarm  062 - Install flood alarm in the 480Vac switchgear room.	\$1,365,046	\$1,613,369	\$1,836,597	\$1,436,340	\$196,800