Chapter 10

References

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10.1 References

Note to reader: Some web pages cited in this document may no longer be available, or may no longer be available through the original URL addresses. Hard copies of cited web pages are available in Exelon Generation files. Some sites, for example the census data, cannot be accessed through their given URLs. The only way to access these pages is to follow queries on previous web pages. The complete URLs used by Exelon Generation have been given for these pages, even though the URLs may not provide direct access to the pages.

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Appendix A

NRC NEPA Issues for License Renewal of Nuclear Power Plants

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Exelon Generation has prepared this environmental report in accordance with the requirements of NRC regulation 10 CFR 51.53. NRC included in the regulation the list of 92 National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants that were identified in the 1996 GEIS (Appendix B to Subpart A of 10 CFR Part 51, Table B-1).

Table A-1, below, lists the 92 issues from 10 CFR Part 51, Appendix B, Table B-1 and identifies the section in this environmental report in which Exelon Generation addresses each applicable issue. For organization and clarity, Exelon Generation has assigned a number to each issue and uses the issue numbers throughout the environmental report.

As is explained in Section 4.0.2 of this environmental report, on April 20, 2012, the NRC staff requested Commission approval to publish a final rule amending the environmental protection regulations for the renewal of nuclear power plant operating licenses (SECY-12-0063). The updated GEIS that supports the final rule discussed in SECY-12-0063 reviews the 92 environmental issues that were identified and categorized in the 1996 GEIS. It retains many without change in definition or categorization, but others are combined and redefined, and some have been re-categorized from Category 2 to Category 1. Also, one issue (Environmental Justice) was re-categorized from NA to a new Category 2 issue. According to SECY-12-0063, Enclosure 1, 15 new issues were identified in all, of which 11 were determined to be Category 1 and four were determined to be Category 2 issues.

The revised version of Appendix B to Subpart A of 10 CFR Part 51, Table B, as presented in SECY-12-0063, Enclosure 1, lists a total of 78 NEPA issues for license renewal of nuclear power plants. In the same manner as was done for the 92 issues identified in the 1996 GEIS, Exelon Generation has assigned a number to each of the 78 issues. The issue numbers mentioned in Table A-2 below are based on these numbers. Only the 15 new Category 1 and Category 2 issues are named in Table A-2. For each applicable issue, Table A-2 identifies the sections in this environmental report and in the updated GEIS that address the issue.

Table A-1 Byron Units 1 & 2 Environmental Report Cross-Reference of License Renewal NEPA Issues.

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
Surface Water Quality, Hydrology, and Use (for all plants)			
1. Impacts of refurbishment on surface water quality	1	4.0.1	3.4.1/3-4
2. Impacts of refurbishment on surface water use	1	4.0.1	3.4.1/3-4
3. Altered current patterns at intake and discharge structures	1	4.0.1	4.3.2.2/4-31
4. Altered salinity gradients	1	NA	Issue applies to an activity, discharge to saltwater, which Byron does not do.
5. Altered thermal stratification of lakes	1	NA	Issue applies to a plant feature, discharge to a lake, which Byron does not have.
6. Temperature effects on sediment transport capacity	1	4.0.1	4.3.2.2/4-31
7. Scouring caused by discharged cooling water	1	4.0.1	4.3.2.2/4-31
8. Eutrophication	1	4.0.1	4.3.2.2/4-31
9. Discharge of chlorine or other biocides	1	4.0.1	4.3.2.2/4-31
10. Discharge of sanitary wastes and minor chemical spills	1	4.0.1	4.3.2.2/4-31
11. Discharge of other metals in waste water	1	4.0.1	4.3.2.2/4-31
12. Water use conflicts (plants with once-through cooling systems)	1	NA	Issue applies to a plant feature, a once-through cooling system, which Byron does not have.
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	4.1	4.3.2.2/4-31

Table A-1. Byron Units 1 & 2 Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	4.0.1	3.5/3-5
15. Accumulation of contaminants in sediments or biota	1	4.0.1	4.3.3/4-33
16. Entrainment of phytoplankton and zooplankton	1	4.0.1	4.3.3/4-33
17. Cold shock	1	4.0.1	4.3.3/4-33
18. Thermal plume barrier to migrating fish	1	4.0.1	4.3.3/4-33
19. Distribution of aquatic organisms	1	4.0.1	4.3.3/4-33
20. Premature emergence of aquatic insects	1	4.0.1	4.3.3/4-33
21. Gas supersaturation (gas bubble disease)	1	4.0.1	4.3.3/4-33
22. Low dissolved oxygen in the discharge	1	4.0.1	4.3.3/4-33
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.0.1	4.3.3/4-33
24. Stimulation of nuisance organisms (e.g., shipworms)	1	4.0.1	4.3.3/4-33
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)			
25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	NA	Issue applies to a once-through and cooling pond heat dissipation system, which Byron does not have.
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	NA	Issue applies to a once-through and cooling pond heat dissipation system, which Byron does not have.
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	NA	Issue applies to a once-through and cooling pond heat dissipation system, which Byron does not have.
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)			
28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	4.0.1	4.3.3/4-33
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	4.0.1	4.3/4-33

Table A-1. Byron Units 1 & 2 Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
30. Heat shock for plants with cooling-tower-based heat dissipation systems	1	4.0.1	4.3/4-33
Groundwater Use and Quality			
31. Impacts of refurbishment on groundwater use and quality	1	4.0.1	3.4.2/3-5
32. Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	NA	Issue applies to a feature, use of <100 gpm of groundwater, which Byron does not have.
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	4.5	4.8.1/4-116 4.8.1/4-119
34. Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	4.6	4.8.1/4-117
35. Groundwater use conflicts (Ranney wells)	2	NA	Issue applies to a plant feature, Ranney wells, which Byron does not have.
36. Groundwater quality degradation (Ranney wells)	1	NA	Issue applies to a feature, Ranney wells, that Byron does not have.
37. Groundwater quality degradation (saltwater intrusion)	1	NA	Issue applies to a feature, a coastal location, that Byron does not have.
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	NA	Issue applies to a feature, a coastal location, that Byron does not have.
39. Groundwater quality degradation (cooling ponds at inland sites)	2	NA	Issue applies to a feature, cooling ponds, that Byron does not have.
Terrestrial Resources			
40. Refurbishment impacts to terrestrial resources	2	4.9	3.6/3-6
41. Cooling tower impacts on crops and ornamental vegetation	1	4.0.1	4.3.4/4-34
42. Cooling tower impacts on native plants	1	4.0.1	4.3.4/4-35
43. Bird collisions with cooling towers	1	4.0.1	4.3.5/4-45
44. Cooling pond impacts on terrestrial resources	1	NA	Issue applies to a feature, cooling ponds, which Byron does not have

Table A-1. Byron Units 1 & 2 Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
45. Power line right-of-way management (cutting and herbicide application)	1	4.0.1	4.5.6.1/4-71
46. Bird collisions with power lines	1	4.0.1	4.5.6.2/4-74
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.0.1	4.5.6.3/4-77
48. Floodplains and wetlands on power line right-of-way	1	4.0.1	4.5.7./4-81
Threatened or Endangered Species (for all plants)			
49. Threatened or endangered species	2	4.10	4.1/4-1
Air Quality			
50. Air quality during refurbishment (non-attainment and maintenance areas)	2	4.11	3.3/3-2
51. Air quality effects of transmission lines	1	4.0.1	4.5.2/4-62
Land Use			
52. Onsite land use	1	4.0.1	3.2/3-1
53. Power line right-of-way land use impacts	1	4.0.1	4.5.3/4-62
Human Health			
54. Radiation exposures to the public during refurbishment	1	4.0.1	3.8.1/3-32
55. Occupational radiation exposures during refurbishment	1	4.0.1	3.8.2/3-43
56. Microbiological organisms (occupational health)	1	4.0.1	4.3.6/4-48
57. Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	4.12	4.3.6/4-48
58. Noise	1	4.0.1	4.3.7/4-49
59. Electromagnetic fields, acute effects	2	4.13	4.5.4.1/4-66
60. Electromagnetic fields, chronic effects	NA	4.0.1	4.5.4.2/4-67
61. Radiation exposures to public (license renewal term)	1	4.0.1	4.6.2/4-87
62. Occupational radiation exposures (license renewal term)	1	4.0.1	4.6.3/4-95

Table A-1. Byron Units 1 & 2 Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
	Socioeconomics		
63. Housing impacts	2	4.14	3.7.2/3-10 (refurbishment) 4.7.1/4-101 (renewal term)
64. Public services: public safety, social services, and tourism and recreation	1	4.0.1	Refurbishment 3.7.4/3-14 (public service) 3.7.4.3/3-18 (safety) 3.7.4.4/3-19 (social) 3.7.4.6/3-20 (tour, rec) Renewal Term 4.7.3/4-104 (public safety) 4.7.3.3/4-106 (safety) 4.7.3.44-107 (social) 4.7.3.6/4-107 (tour, rec)
65. Public services: public utilities	2	4.15	3.7.4.5/3-19 (refurbishment) 4.7.3.5/4-107 (renewal term)
66. Public services: education (refurbishment)	2	4.16	3.7.4/3-15
67. Public services: education (license renewal term)	1	4.0.1	4.7.3.1/4-106
68. Offsite land use (refurbishment)	2	4.17.1	3.7.5/3-20
69. Offsite land use (license renewal term)	2	4.17.2	4.7.4/4-107
70. Public services: transportation	2	4.18	3.7.4.2/3-17 (refurbishment) 4.7.3.2/4-106 (renewal term)
71. Historic and archaeological resources	2	4.19	3.7.7/3-23 (refurbishment) 4.7.7/4-114 (renewal term)
72. Aesthetic impacts (refurbishment)	1	4.0.1	3.7.8/3-30
73. Aesthetic impacts (license renewal term)	1	4.0.1	4.7.6/4-111
74. Aesthetic impacts of transmission lines (license renewal term)	1	4.0.1	4.5.8/4-83
	Postulated Accidents		
75. Design basis accidents	1	4.0.1	5.3.2/5-11 (design basis) 5.5.1/5-114 (summary)

Table A-1. Byron Units 1 & 2 Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
76. Severe accidents	2	4.20	5.3.3/5-12 (probabilistic analysis) 5.3.3.2/5-19 (air dose) 5.3.3.3/5-49 (water) 5.3.3.4/5-65 (groundwater) 5.3.3.5/5-95 (economic) 5.4/5-106 (mitigation) 5.5.2/5-114 (summary)
Uranium Fuel Cycle and Waste Management			
77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4.0.1	6.2/6-8
78. Offsite radiological impacts (collective effects)	1	4.0.1	Not in GEIS.
79. Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4.0.1	Not in GEIS.
80. Nonradiological impacts of the uranium fuel cycle	1	4.0.1	6.2.2.6/6-20 (land use) 6.2.2.7/6-20 (water use) 6.2.2.8/6-21 (fossil fuel) 6.2.2.9/6-21 (chemical)
81. Low-level waste storage and disposal	1	4.0.1	6.4.2/6-36 (low-level def) 6.4.3/6-37 (low-level volume) 6.4.4/6-48 (renewal effects)
82. Mixed waste storage and disposal	1	4.0.1	6.4.5/6-63
83. Onsite spent fuel	1	4.0.1	6.4.6/6-70
84. Nonradiological waste	1	4.0.1	6.5/6-86
85. Transportation	1	4.0.1	6.3/6-31, as revised by Addendum 1, August 1999
Decommissioning			
86. Radiation doses (decommissioning)	1	4.0.1	7.3.1/7-15
87. Waste management (decommissioning)	1	4.0.1	7.3.2/7-19 (impacts) 7.4/7-25 (conclusions)
88. Air quality (decommissioning)	1	4.0.1	7.3.3/7-21 (air) 7.4/7-25 (conclusions)
89. Water quality (decommissioning)	1	4.0.1	7.3.4/7-21 (water) 7.4/7-25 (conclusions)
90. Ecological resources (decommissioning)	1	4.0.1	7.3.5/7-21 (ecological) 7.4/7-25 (conclusions)

Table A-1. Byron Units 1 & 2 Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
91. Socioeconomic impacts (decommissioning)	1	4.0.1	7.3.7/7-19 (socioeconomic) 7.4/7-24 (conclusions)
Environmental Justice			
92. Environmental justice	NA	2.6.2	not in GEIS

a. 10 CFR 51, Subpart A, Appendix A, Table B-1. (Issue numbers added to facilitate discussion.)
b. Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437).
NA = not applicable
NEPA = National Environmental Policy Act

Table A-2 Byron Units 1 & 2 Environmental Report Cross-Reference of New License Renewal NEPA Issues Identified in the Updated GEIS.

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section)[a]
Geologic Resources			
8. Geology and soils	1	4.0.2	4.4/4-28
Surface Water Resources			
18. Effects of dredging on surface water quality	1	4.0.2	4.5.1.1/4-38
Groundwater Resources			
27. Radionuclides released to groundwater	2	4.0.2	45.1.2/4-46
Terrestrial Resources			
29. Exposure of terrestrial resources to radionuclides	1	4.0.2	4.6.1.1/4-55
33. Water use conflicts with terrestrial resources (plants with cooling ponds or cooling towers using makeup water from a river)	2	4.0.2	4.6.1.1/4-69
Aquatic Resources			
44. Exposure of aquatic organisms to radionuclides	1	4.0.2	4.6.1.2/4-98
45. Effects of dredging on aquatic organisms	1	4.0.2	4.6.1.2/4-100
46. Water use conflicts with aquatic resources (plants with cooling ponds or cooling towers using makeup from a river)	2	4.0.2	4.6.1.2/4-102
48. Impacts of transmission line right-of-way (ROW) management on aquatic resources	1	4.0.2	4.6.1.2/4-104
Socioeconomics			
52. Employment and income, recreation and tourism	1	4.0.2	4.8.1/4-122
53. Tax revenues	1	4.0.2	4.8.1/4-123
55. Population and housing	1	4.0.2	4.8.1/4-125
Human Health			
59. Human health impact from chemicals	1	4.0.2	4.9.1.1/4-141
63. Physical occupational hazards	1	4.0.2	4.9.1.1/4-151

Table A-2 Byron Units 1 & 2 Environmental Report Cross-Reference of New License Renewal NEPA Issues Identified in the Updated GEIS. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section)[a]
	Environmental Justice		
67. Minority and low-income populations	2	2.6.2 and 4.0.2	4.10.1/4-161
	Cumulative Impacts		
73. Cumulative Impacts	2	4.21	4.13/4-220

a. Issue numbers are based on the revised list of issues in the text for Appendix B to Subpart A of 10 CFR Part 51, Table B-1, as presented in SECY-12-0063, Enclosure 1. For each applicable issue, Table A-2 identifies the sections in this environmental report and in the updated GEIS that address the issue.

NEPA = National Environmental Policy Act

Appendix B

NPDES Permit

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ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 North Grand Avenue East, P.O. Box 19276, Springfield, Illinois 62794-9276 • (217) 782-2829
James R. Thompson Center, 100 West Randolph, Suite 11-300, Chicago, IL 60601 • (312) 814-6026

PAT QUINN, GOVERNOR DOUGLAS P. SCOTT, DIRECTOR

217/782-0610

July 15, 2011

Exelon Generation Company, LLC
Byron Station
445- North German Church Road
Byron, IL 61010-9794

Re: Exelon Generation Company, LLC - Byron Station
NPDES Permit No. IL0048313
Modification of NPDES Permit (Without Public Notice)

Mr. Adams:

The Illinois Environmental Protection Agency received your letters dated January 24, 2011 and February 22, 2011 concerning the use of OPTISPERSE PWR6600 and the permit corrections. Our final determination is to modify the Permit as follows:

The use of OPTISPERSE PWR6600 would not be expected to cause any significant changes in effluent quality, therefore this product has been approved for use as requested.

The page numbers have been corrected.

Special Condition 21 has been corrected.

Enclosed is a copy of the modified Permit. Because the changes made in the Permit were minor, no formal Public Notice of the modification will be issued.

Should you have any questions or comments, please contact Leslie Lowry of my staff at the phone number and address above.

Sincerely,

Alan Keller

Alan Keller, P.E.
Manager, Permit Section
Division of Water Pollution Control

RECEIVED
JUL 2 0 2011
BY: DLS

SAK:LRL:48313mod.wpd

Enclosure: Modified Permit

cc: Rockford Region
Records

Rockford • [illegible] Des Plaines • [illegible]
Elgin • [illegible] Peoria • [illegible]
Bureau of Land – Peoria • [illegible] Champaign • [illegible]
Collinsville • [illegible] Marion • [illegible]

[illegible]

NPDES Permit No. IL0048313

Illinois Environmental Protection Agency

Division of Water Pollution Control

1021 North Grand Avenue East

Post Office Box 19276

Springfield, Illinois 62794-9276

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

Reissued (NPDES) Permit

Expiration Date: December 31, 2015	Issue Date: January 24, 2011 Effective Date: January 24, 2011 Modification Date: July 15, 2011
Name and Address of Permittee: Exelon Generation Company, LLC Environmental Department 4300 Winfield Road Warrenville, Illinois 60555-5701	Facility Name and Address: Exelon Generation Company, LLC Byron Nuclear Power Station 4450 North German Church Road Byron, Illinois 61010 Ogle County
Discharge Number and Name:	Receiving Waters:
001 Cooling System Blowdown	Rock River
A01 Demineralizer Regenerant Waste	
B01 Sewage Treatment Plant Effluent	
C01 Wastewater Treatment Plant Effluent	
D01 Radwaste Treatment System Effluent	
E01 Stormwater Runoff Basin	
F01 Intake Screen Backwash	
002 Stormwater Runoff Basin Overflow	Woodland Creek
003 East Station Area Runoff	Woodland Creek
004 West Station Area Runoff	Unnamed Tributary to Rock River

In compliance with the provisions of the Illinois Environmental Protection Act, Title 35 of Ill. Adm. Code, Subtitle C and/or Subtitle D, Chapter 1, and the Clean Water Act (CWA), the above-named permittee is hereby authorized to discharge at the above location to the above-named receiving stream in accordance with the standard conditions and attachments herein.

Permittee is not authorized to discharge after the above expiration date. In order to receive authorization to discharge beyond the expiration date, the permittee shall submit the proper application as required by the Illinois Environmental Protection Agency (IEPA) not later than 180 days prior to the expiration date.

Alan Keller

Alan Keller, P.E.
Manager, Permit Section
Division of Water Pollution Control

SAK:LRL:07052102.bah

Page 2 Modification Date: July 15, 2011

NPDES Permit No. IL0048313

Effluent Limitations and Monitoring

From the modification date of this permit until the expiration date, the effluent of the following discharge(s) shall be monitored and limited at all times as follows:

PARAMETER	LOAD LIMITS lbs/day DAF (DMF) 30 DAY AVERAGE	LOAD LIMITS lbs/day DAF (DMF) DAILY MAXIMUM	CONCENTRATION LIMITS mg/l 30 DAY AVERAGE	CONCENTRATION LIMITS mg/l DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall 001 – Cooling System Blowdown*
(Average Flow = 20.3 MGD)

The discharge consist of:

1. Cooling Tower Blowdown
2. Non-Essential Service Water Blowdown & Strainer Backwash
3. Essential Service Water Blowdown & Strainer Backwash
4. Demineralizer Regenerant Waste (A01)
5. Sewage Treatment Plant Effluent (B01)
6. Wastewater Treatment Plant Effluent (C01)
7. Radwaste Treatment Plant Effluent (D01)
8. Stormwater Runoff Basin (E01)
9. Intake Screen Backwash
10. Secondary Steam System (Non-Radioactive) Process Water
11. Condenser Drain Discharge
12. Circulating Water Make-Up
13. Miscellaneous Drain Water
    - Chiller Condensate
    - Fire Protection System Drain Water
    - Service Water Drains
    - Closed Cooling System Drain Water

PARAMETER	LOAD 30 DAY AVERAGE	LOAD DAILY MAXIMUM	CONC. 30 DAY AVERAGE	CONC. DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1.				Daily	Continuous
pH	See Special Condition 2.				1/Week	Grab
Temperature	See Special Condition 3 & 12.				Daily	Continuous*****
Total Residual Chlorine/ Total Residual Oxidant**				0.05	1/Week	Grab
Zinc (Total)			0.213	0.433	1/Week	Grab
Hydrazine***			0.011	0.027	Daily When Discharging	Grab
Copper (Total)****				0.071	1/Week	Grab
Chromium (Total)				0.2	1/Week	Grab
Oil/Grease			15	20	1/Week	Grab
126 Priority Pollutants	See Special Condition 8 & 15.					
Total Suspended Solids	See Special Condition 24.		Monitor Only		1/Month	Grab

* - See Special Condition 17.
** - See Special Condition 22.
*** - See Special Condition 13.
**** - See Special Condition 14.
***** - During periods of inoperability of the inline temperature instrument temperature can be measured once per day.

NPDES Permit No. IL0048313

Effluent Limitations and Monitoring

From the modification date of this permit until the expiration date, the effluent of the following discharge(s) shall be monitored and limited at all times as follows:

	LOAD LIMITS lbs/day DAF (DMF)		CONCENTRATION LIMITS mg/l			
PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall A01 – Demineralizer Regenerant Waste*
(Average Flow = 0.019 MGD)

The discharge consist of:

1. Make-Up Demineralizer Regenerant Waste
2. Condensate Polisher Sump Discharge
3. Make-Up Demineralizer Area Drains
4. Well Water Sand Filter Backwash (Alternative Route)
5. Steam Generators Cleaning Process Waste (Once Every 5 – 10 Years)
6. Temporary Demineralizer Regenerant Waste
7. Secondary Steam System (Non-Radioactive) Discharge (Alternative Route)
8. Reverse Osmosis Waste

Flow (MGD)	See Special Condition 1.				Daily	Continuous
Total Suspended Solids			15	30	1/Month	8-hour Composite**

The following metal parameter limitations and monitoring are to apply during steam generator(s) cleaning process periods:

Chromium (Hexavalent)			0.1	0.2	Daily	Grab
Chromium (Total)			1	2	Daily	Grab
Copper			0.5	1	Daily	Grab
Iron (Total)				1	Daily	Grab
Lead			0.2	0.4	Daily	Grab
Nickel			1	2	Daily	Grab
Zinc (Total)			1	2	Daily	Grab

* - See Special Condition 9.
** - Permittee may follow the sampling procedure identified as Byron Station procedure BCP-300-40 or equivalent for determination of total suspended solids by calculation from individual composites.

NPDES Permit No. IL0048313

Effluent Limitations and Monitoring

From the modification date of this permit until the expiration date, the effluent of the following discharge(s) shall be monitored and limited at all times as follows:

	LOAD LIMITS lbs/day DAF (DMF)		CONCENTRATION LIMITS mg/l			
PARAMETER	30 DAY AVERAGE	DAILY MAXIMUM	30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE
Outfall B01 – Sewage Treatment Plant Effluent* (DAF = 0.008 MGD)						
Flow (MGD)	See Special Condition 1.				Daily	Continuous
pH	See Special Condition 2.				2/Month	Grab
Total Suspended Solids	5.3	10.5	30	60	2/Month	24-hour Composite
BOD_5	5.3	10.5	30	60	2/Month	24-hour Composite

* - See Special Condition 6.

NPDES Permit No. IL0048313

Effluent Limitations and Monitoring

From the modification date of this permit until the expiration date, the effluent of the following discharge(s) shall be monitored and limited at all times as follows:

PARAMETER	LOAD LIMITS lbs/day DAF (DMF) 30 DAY AVERAGE	DAILY MAXIMUM	CONCENTRATION LIMITS mg/l 30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall C01 – Wastewater Treatment Plant Effluent *
(Average Flow = 0.028 MGD)

The discharge consist of:

1. Turbine Building Floor Drain Sumps**
2. Turbine Building Fire & Oil Sump**
3. Turbine Building Equipment Drains**
4. Essential Service Water Drain Sumps**
5. Units 1 & 2 Tendon Tunnel Sumps
6. Reactor Building Roof Drains
7. Auxiliary Boiler Blowdown
8. Units 1 & 2 Diesel Fuel Storage Tank Sumps
9. Wastewater Treatment System Sand Filter Backwash
10. Well Water Sand filter Backwash
11. Steam Generator Cleaning Process Waste (Once Every 5 – 10 Years)
12. Condenser Drain Discharge (Alternative Route)
13. Secondary Steam System (Non-Radioactive) Discharge (Alternative Route)
14. Generic Metal Cleaning Activities
15. Waste Treatment Plant Oil Separator
16. Miscellaneous Non-Contaminated Drain Water
    - Chiller Condensate
    - Fire Protection System Drain Water
    - Service Water Drains
    - Closed Cooling System Drain Water

Flow (MGD)	See Special Condition 1.				Daily	Continuous
Total Suspended Solids			15	30	2/Month	24-hour Composite

The following metal parameter limitations and monitoring are to apply during steam generator(s) cleaning process periods:

Chromium (Hexavalent)			0.1	0.2	Daily	Grab
Chromium (Total)			1	2	Daily	Grab
Copper			0.5	1	Daily	Grab
Iron (Total)				1	Daily	Grab
Lead			0.2	0.4	Daily	Grab
Nickel			1	2	Daily	Grab
Zinc (Total)			1	2	Daily	Grab

* - See Special Condition 6 and Special Condition 9.
** - These waste streams may be directed to the radwaste treatment system depending on the results of the process radiation monitors.

NPDES Permit No. IL0048313

Effluent Limitations and Monitoring

From the modification date of this permit until the expiration date, the effluent of the following discharge(s) shall be monitored and limited at all times as follows:

PARAMETER	LOAD LIMITS lbs/day DAF (DMF) 30 DAY AVERAGE	DAILY MAXIMUM	CONCENTRATION LIMITS mg/l 30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall D01 – Radwaste Treatment System Effluent
(Average Flow = 0.022 MGD)

The discharge consist of:

1. Steam Generator Condensate Blowdown
2. Cooling Jacket Blowdown
3. Auxiliary Building Floor Drains
4. Laundry Waste Treatment System Drains
5. Auxiliary Building Equipment Drains
6. Radwaste Demineralizer Filter Backwash
7. Evaporator Wastewater
8. Turbine Building Floor Drain Sumps (Alternative Route)
9. Turbine Building Fire & Oil Sump (Alternative Route)
10. Turbine Building Equipment Drains (Alternative Route)
11. Essential Service Water Drain Sumps (Alternative Route)
12. Boron Recycle System Blowdown
13. Condensate Polisher Sump Discharge (Alternative Route)
14. Generic Non-Chemical Metal Cleaning Activities
15. Portable Demineralizer Discharge
16. Reactor Coolant Letdown
17. Laboratory Drains, Decon Showers, & Sample Sinks
18. Miscellaneous Drain Water
    - Chiller Condensate
    - Fire Protection System Drain Water
    - Service Water Drains
    - Closed Cooling System Drain Water

Flow (MGD)	See Special Condition 1				Daily	Continuous
Total Suspended Solids			15	30	2/Month	Discharge Tank Composite

Modification Date: July 15, 2011

NPDES Permit No. IL0048313

Effluent Limitations and Monitoring

From the modification date of this permit until the expiration date, the effluent of the following discharge(s) shall be monitored and limited at all times as follows:

PARAMETER	LOAD LIMITS lbs/day DAF (DMF) 30 DAY AVERAGE	DAILY MAXIMUM	CONCENTRATION LIMITS mg/l 30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall E01 – Stormwater Runoff Basin*
(Average Flow = 0.119 MGD)

The discharge consist of:

1. Parking Lot Runoff
2. Transformer Area Runoff
3. Station Area Runoff
4. Turbine Building Fire & Oil Sump
5. Steam Generators Cleaning Process Waste (Once Every 5 – 10 Years)
6. Generic Non-Chemical Metal Cleaning Activities
7. Chiller Condensate
8. Fire Protection System Drains
9. Service Water Drains
10. Closed Cooling System Drain Water

Flow (MGD)	See Special Condition 1.				2/Month	Continuous

The following metal parameters limitations and monitoring are to apply during steam generator(s) cleaning process periods:

Chromium (Hexavalent)			0.1	0.2	Daily	Grab
Chromium (Total)			1	2	Daily	Grab
Copper			0.5	1	Daily	Grab
Iron (Total)				1	Daily	Grab
Lead			0.2	0.4	Daily	Grab
Nickel			1	2	Daily	Grab
Zinc (Total)			1	2	Daily	Grab

For each week in which a discharge occurs from numbers 4 – 6 listed above to the stormwater runoff basin, outfall E01 shall be monitored and limited for the following additional parameters:

Total Suspended Solids			15	30	1/Week	Grab

For each week in which a discharge occurs from numbers 8 – 10 listed above to the stormwater runoff basin, outfall E01 shall be monitored and limited for the following additional parameters:

Total Suspended Solids			30	100	1/Week	Grab

* - See Special Condition 9 and 17.

Outfall F01 – Intake Screen Backwash
(Intermittent Discharge)

There shall be no intentional discharge of collected debris.

NPDES Permit No. IL0048313

Effluent Limitations and Monitoring

From the modification date of this permit until the expiration date, the effluent of the following discharge(s) shall be monitored and limited at all times as follows:

PARAMETER	LOAD LIMITS lbs/day DAF (DMF) 30 DAY AVERAGE	DAILY MAXIMUM	CONCENTRATION LIMITS mg/l 30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall 002 – Stormwater Runoff Basin Overflow*
(Intermittent Discharge)

The discharge consist of:
1. Parking Lot Runoff
2. Transformer Area Runoff
3. Station Area Runoff
4. Turbine Building Fire & Oil Sump
5. Steam Generator Cleaning Process Waste (Once Every 5 – 10 Years)
6. Generic Non-Chemical Metal Cleaning Activities
7. Chiller Condensate
8. Fire Protection System Drain Water
9. Service Water Drains
10. Closed Cooling System Drain Water

PARAMETER	30 DAY AVERAGE (lbs/day)	DAILY MAXIMUM (lbs/day)	30 DAY AVERAGE (mg/l)	DAILY MAXIMUM (mg/l)	SAMPLE FREQUENCY	SAMPLE TYPE
Flow (MGD)	See Special Condition 1.				Measure When Discharging	Estimate
Oil/Grease			15	20	1/Day When Discharging	Grab

The following metal parameters limitations and monitoring are to apply during steam generator(s) cleaning process periods:

PARAMETER	30 DAY AVERAGE (lbs/day)	DAILY MAXIMUM (lbs/day)	30 DAY AVERAGE (mg/l)	DAILY MAXIMUM (mg/l)	SAMPLE FREQUENCY	SAMPLE TYPE
Chromium (Hexavalent)			0.011	0.016	Daily	Grab
Chromium (Total)			1	2	Daily	Grab
Copper			0.025	0.041	Daily	Grab
Iron (Total)				1	Daily	Grab
Lead			0.063	0.298	Daily	Grab
Nickel			0.011	0.176	Daily	Grab
Zinc (Total)			0.047	0.26	Daily	Grab

For each week in which a discharge occurs from numbers 4 – 6 listed above to the stormwater runoff basin, outfall 002 shall be monitored and limited for the following parameters:

PARAMETER	30 DAY AVERAGE (lbs/day)	DAILY MAXIMUM (lbs/day)	30 DAY AVERAGE (mg/l)	DAILY MAXIMUM (mg/l)	SAMPLE FREQUENCY	SAMPLE TYPE
Total Suspended Solids			15	30	1/Week	Grab

For each week in which a discharge occurs from numbers 8 – 10 listed above to the stormwater runoff basin, outfall 002 shall be monitored and limited for the following parameters:

PARAMETER	30 DAY AVERAGE (lbs/day)	DAILY MAXIMUM (lbs/day)	30 DAY AVERAGE (mg/l)	DAILY MAXIMUM (mg/l)	SAMPLE FREQUENCY	SAMPLE TYPE
Total Suspended Solids			30	100	1/Week	Grab

* - See Special Condition 9 and 17.

Modification Date: July 15, 2011

NPDES Permit No. IL0048313

Effluent Limitations and Monitoring

From the modification date of this permit until the expiration date, the effluent of the following discharge(s) shall be monitored and limited at all times as follows:

PARAMETER	LOAD LIMITS lbs/day DAF (DMF) 30 DAY AVERAGE	DAILY MAXIMUM	CONCENTRATION LIMITS mg/l 30 DAY AVERAGE	DAILY MAXIMUM	SAMPLE FREQUENCY	SAMPLE TYPE

Outfall 003 – East Station Area Runoff*
(Intermittent Discharge)

* - See Special Condition 16.

Outfall 004 – West Station Area Runoff*
(Intermittent Discharge)

* - See Special Condition 16.

Special Conditions

SPECIAL CONDITION 1. Flow shall be measured in units of Million Gallons per Day (MGD) and reported as a monthly average and a daily maximum on the monthly Discharge Monitoring Report.

SPECIAL CONDITION 2. The pH shall be in the range 6.0 to 9.0. The monthly minimum and monthly maximum values shall be reported on the DMR form.

SPECIAL CONDITION 3. This facility meets the allowed mixing criteria for thermal discharges pursuant to 35 IAC 302.102. No reasonable potential exists for the discharge to exceed thermal water quality standards. This determination is based on a maximum temperature of 120°F. The permittee shall monitor the flow and temperature of the discharge prior to entry into the receiving water body. Monitoring results shall be reported on the monthly Discharge Monitoring Report. This permit may be modified to include formal temperature limitations should the results of the monitoring show that there is reasonable potential to exceed a thermal water quality standard. Modification of this permit shall follow public notice and opportunity for comment.

There shall be no abnormal temperature changes that may adversely affect aquatic life unless caused by natural conditions. The normal daily and seasonal temperature fluctuations which existed before the addition of heat due to other than natural causes shall be maintained.

The monthly maximum value shall be reported on the DMR form

SPECIAL CONDITION 4. The Permittee shall record monitoring results on Discharge Monitoring Report (DMR) Forms using one such form for each outfall each month.

In the event that an outfall does not discharge during a monthly reporting period, the DMR form shall be submitted with no discharge indicated.

The Permittee may choose to submit electronic DMRs (eDMRs) instead of mailing paper DMRs to the IEPA. More information, including registration information for the eDMR program, can be obtained on the IEPA website, http://www.epa.state.il.us/water/edmr/index.html.

The completed Discharge Monitoring Report forms shall be submitted to IEPA no later than the 28th day of the following month, unless otherwise specified by the permitting authority.

Permittees not using eDMRs shall mail Discharge Monitoring Reports with an original signature to the IEPA at the following address:

Illinois Environmental Protection Agency
Division of Water Pollution Control
Attention: Compliance Assurance Section, Mail Code #19
1021 North Grand Avenue East
Post Office Box 19276
Springfield, Illinois 62794-9276

SPECIAL CONDITION 5. Samples taken in compliance with the effluent monitoring requirements shall be taken at a point representative of the discharge, but prior to entry into the receiving stream.

SPECIAL CONDITION 6. The use or operation of this facility shall be by or under the supervision of a Certified Class K operator.

SPECIAL CONDITION 7. If an applicable effluent standard or limitation is promulgated under Sections 301(b)(2)(c) and (d), 304(b)(2), and 307(a)(2) of the Clean Water Act and that effluent standard or limitation is more stringent than any effluent limitation in the permit or controls a pollutant not limited in the NPDES Permit, the Agency shall revise or modify the permit in accordance with the more stringent standard or prohibition and shall so notify the permittee.

SPECIAL CONDITION 8. This permit authorizes the use of water treatment additives that were requested as part of this renewal. The use of any new additives, or change in those previously approved by the Agency, or if the permittee increases the feed rate or quantity of the additives used beyond what has been approved by the Agency, the permittee shall request a modification of this permit in accordance with the Standard Conditions – Attachment H. In connection with any such modification, the permittee must also submit a new letter to the Agency certifying that the facility is not using any additives containing any of the 126 priority pollutants.

The permittee shall submit to the Agency on a yearly basis a report summarizing their efforts with water treatment suppliers to find a suitable alternative to phosphorus based additives.

SPECIAL CONDITION 9. The samples taken in compliance with the steam generator(s) cleaning process monitoring requirements shall be taken at a point representative of the discharge, but prior to mixing with any other wastewater and stormwater runoff. If the permittee requires further treatment within the station's wastewater treatment system in order to comply with limits, the steam generator(s) cleaning wastes shall not be co-treated with other wastewater (except for incidental amounts) unless this permit has been modified to allow for such co-treatment.

SPECIAL CONDITION 10. There shall be no discharge of polychlorinated biphenyl compounds.

SPECIAL CONDITION 11. The "Upset" defense provisions listed under 40 CFR 122.41(n) are hereby incorporated by reference.

SPECIAL CONDITION 12. In the event that the Rock River is less than 2,400 cfs and/or the temperature differential between the main river temperatures and the water quality standard is less than 3°F, daily calculations will be undertaken to demonstrate compliance with the water quality standard. Calculations shall be based upon hourly measurements, averaged over a 24-hour calendar day for river flow, main river temperature (measured as Circ Water Makeup Temperature), blowdown flow, and blowdown temperature values. In the event that a data or points are unavailable due to technical issues, the missing value shall be estimated. Results of the calculations shall be reported with the DMR on a monthly basis.

SPECIAL CONDITION 13. Outfall 001 shall be monitored for hydrazine when there is a discharge of the steam generator chemical cleaning solution and associated rinses containing hydrazine into the cooling water system. On those occasions monitoring shall be performed at outfall 001 on a daily basis using a minimum of three grab samples taken at periodic intervals during the discharge of steam generator chemical cleaning solution and associated rinses containing hydrazine. Sample collection and analysis procedures shall be in accordance with station practice for measuring hydrazine and standard methods. The quantity of hydrazine discharged in steam generator chemical cleaning solution and associated rinses to the cooling water system, the duration of this discharge to the cooling water system, and the analytical results shall be submitted with the monthly Discharge Monitoring Report. The permittee shall submit a letter to the Agency requesting a modification to this permit, if the use of hydrazine during normal steam generator lay-up is at a higher feed rate or quantity than what has been previously approved by the Agency.

SPECIAL CONDITION 14. Copper monitoring of outfall 001 shall be performed during periods when the station's copper ion system is being utilized for Zebra Mussel infestation control. In addition to monitoring the discharge from outfall 001 for copper (Total) the permittee shall measure the total mass of copper used during Zebra Mussel dosing and include that value with the Discharge Monitoring Report filed the month following the cessation of copper ion system discharge. This permit must be modified to accommodate use of the copper ion system for purposes other than Zebra Mussel control.

SPECIAL CONDITION 15. The discharge of 126 priority pollutants except for chromium and zinc (40 CFR 423, Appendix A) is prohibited in detectable amounts from cooling tower discharges if the pollutants come from cooling tower maintenance chemicals.

SPECIAL CONDITION 16.

STORM WATER POLLUTION PREVENTION PLAN (SWPPP) – for outfalls 003 & 004

A. A storm water pollution prevention plan shall be maintained by the permittee for the storm water associated with industrial activity at this facility. The plan shall identify potential sources of pollution which may be expected to affect the quality of storm water discharges associated with the industrial activity at the facility. In addition, the plan shall describe and ensure the implementation of practices which are to be used to reduce the pollutants in storm water discharges associated with industrial activity at the facility and to assure compliance with the terms and conditions of this permit.

B. The owner or operator of the facility shall make a copy of the plan available to the Agency at any reasonable time upon request.

C. The permittee may be notified by the Agency at any time that the plan does not meet the requirements of this condition. After such notification, the permittee shall make changes to the plan and shall submit a written certification that the requested changes have been made. Unless otherwise provided, the permittee shall have 30 days after such notification to make the changes.

D. The discharger shall amend the plan whenever there is a change in construction, operation, or maintenance which may affect the discharge of significant quantities of pollutants to the waters of the State or if a facility inspection required by paragraph G of this condition indicates that an amendment is needed. The plan should also be amended if the discharger is in violation of any conditions of this permit, or has not achieved the general objective of controlling pollutants in storm water discharges. Amendments to the plan shall be made within the shortest reasonable period of time, and shall be provided to the Agency for review upon request.

E. The plan shall provide a description of potential sources which may be expected to add significant quantities of pollutants to storm water discharges, or which may result in non-storm water discharges from storm water outfalls at the facility. The plan shall include, at a minimum, the following items:

Special Conditions

1. A topographic map extending one-quarter mile beyond the property boundaries of the facility, showing: the facility, surface water bodies, wells (including injection wells), seepage pits, infiltration ponds, and the discharge points where the facility's storm water discharges to a municipal storm drain system or other water body. The requirements of this paragraph may be included on the site map if appropriate.

2. A site map showing:

   i. The storm water conveyance and discharge structures;

   ii. An outline of the storm water drainage areas for each storm water discharge point;

   iii. Paved areas and buildings;

   iv. Areas used for outdoor manufacturing, storage, or disposal of significant materials, including activities that generate significant quantities of dust or particulates.

   v. Location of existing storm water structural control measures (dikes, coverings, detention facilities, etc.);

   vi. Surface water locations and/or municipal storm drain locations

   vii. Areas of existing and potential soil erosion;

   viii. Vehicle service areas;

   ix. Material loading, unloading, and access areas.

3. A narrative description of the following:

   i. The nature of the industrial activities conducted at the site, including a description of significant materials that are treated, stored or disposed of in a manner to allow exposure to storm water;

   ii. Materials, equipment, and vehicle management practices employed to minimize contact of significant materials with storm water discharges;

   iii. Existing structural and non-structural control measures to reduce pollutants in storm water discharges;

   iv. Industrial storm water discharge treatment facilities;

   v. Methods of onsite storage and disposal of significant materials;

4. A list of the types of pollutants that have a reasonable potential to be present in storm water discharges in significant quantities.

5. An estimate of the size of the facility in acres or square feet, and the percent of the facility that has impervious areas such as pavement or buildings.

6. A summary of existing sampling data describing pollutants in storm water discharges.

F. The plan shall describe the storm water management controls which will be implemented by the facility. The appropriate controls shall reflect identified existing and potential sources of pollutants at the facility. The description of the storm water management controls shall include:

1. Storm Water Pollution Prevention Personnel - Identification by job titles of the individuals who are responsible for developing, implementing, and revising the plan.

2. Preventive Maintenance - Procedures for inspection and maintenance of storm water conveyance system devices such as oil/water separators, catch basins, etc., and inspection and testing of plant equipment and systems that could fail and result in discharges of pollutants to storm water.

3. Good Housekeeping - Good housekeeping requires the maintenance of clean, orderly facility areas that discharge storm water. Material handling areas shall be inspected and cleaned to reduce the potential for pollutants to enter the storm water conveyance system.

Special Conditions

4. Spill Prevention and Response - Identification of areas where significant materials can spill into or otherwise enter the storm water conveyance systems and their accompanying drainage points. Specific material handling procedures, storage requirements, spill clean up equipment and procedures should be identified, as appropriate. Internal notification procedures for spills of significant materials should be established.

5. Storm Water Management Practices - Storm water management practices are practices other than those which control the source of pollutants. They include measures such as installing oil and grit separators, diverting storm water into retention basins, etc. Based on assessment of the potential of various sources to contribute pollutants, measures to remove pollutants from storm water discharge shall be implemented. In developing the plan, the following management practices shall be considered:

   i. Containment - Storage within berms or other secondary containment devices to prevent leaks and spills from entering storm water runoff;

   ii. Oil & Grease Separation - Oil/water separators, booms, skimmers or other methods to minimize oil contaminated storm water discharges;

   iii. Debris & Sediment Control - Screens, booms, sediment ponds or other methods to reduce debris and sediment in storm water discharges;

   iv. Waste Chemical Disposal - Waste chemicals such as antifreeze, degreasers and used oils shall be recycled or disposed of in an approved manner and in a way which prevents them from entering storm water discharges.

   v. Storm Water Diversion - Storm water diversion away from materials manufacturing, storage and other areas of potential storm water contamination;

   vi. Covered Storage or Manufacturing Areas - Covered fueling operations, materials manufacturing and storage areas to prevent contact with storm water.

6. Sediment and Erosion Prevention - The plan shall identify areas which due to topography, activities, or other factors, have a high potential for significant soil erosion and describe measures to limit erosion.

7. Employee Training - Employee training programs shall inform personnel at all levels of responsibility of the components and goals of the storm water pollution control plan. Training should address topics such as spill response, good housekeeping and material management practices. The plan shall identify periodic dates for such training.

8. Inspection Procedures - Qualified plant personnel shall be identified to inspect designated equipment and plant areas. A tracking or follow-up procedure shall be used to ensure appropriate response has been taken in response to an inspection. Inspections and maintenance activities shall be documented and recorded.

G. The permittee shall conduct an annual facility inspection to verify that all elements of the plan, including the site map, potential pollutant sources, and structural and non-structural controls to reduce pollutants in industrial storm water discharges are accurate. Observations that require a response and the appropriate response to the observation shall be retained as part of the plan. Records documenting significant observations made during the site inspection shall be submitted to the Agency in accordance with the reporting requirements of this permit.

H. This plan should briefly describe the appropriate elements of other program requirements, including Spill Prevention Control and Countermeasures (SPCC) plans required under Section 311 of the CWA and the regulations promulgated thereunder, and Best Management Programs under 40 CFR 125.100.

I. The plan is considered a report that shall be available to the public under Section 308(b) of the CWA. The permittee may claim portions of the plan as confidential business information, including any portion describing facility security measures.

J. The plan shall include the signature and title of the person responsible for preparation of the plan and include the date of initial preparation and each amendment thereto.

Construction Authorization

K. Authorization is hereby granted to construct treatment works and related equipment that may be required by the Storm Water Pollution Prevention Plan developed pursuant to this permit.

Special Conditions

This Authorization is issued subject to the following condition(s).

1. If any statement or representation is found to be incorrect, this authorization may be revoked and the permittee there upon waives all rights thereunder.

2. The issuance of this authorization (a) does not release the permittee from any liability for damage to persons or property caused by or resulting from the installation, maintenance or operation of the proposed facilities; (b) does not take into consideration the structural stability of any units or part of this project; and (c) does not release the permittee from compliance with other applicable statutes of the State of Illinois, or other applicable local law, regulations or ordinances.

3. Plans and specifications of all treatment equipment being included as part of the stormwater management practice shall be included in the SWPPP.

4. Construction activities which result from treatment equipment installation, including clearing, grading and excavation activities which result in the disturbance of one acre or more of land area, are not covered by this authorization. The permittee shall contact the IEPA regarding the required permit(s).

REPORTING

L. The facility shall submit an annual inspection report to the Illinois Environmental Protection Agency. The report shall include results of the annual facility inspection which is required by Part G of the Storm Water Pollution Prevention Plan of this permit. The report shall also include documentation of any event (spill, treatment unit malfunction, etc.) which would require an inspection, results of the inspection, and any subsequent corrective maintenance activity. The report shall be completed and signed by the authorized facility employee(s) who conducted the inspection(s).

M. The first report shall contain information gathered during the one year time period beginning with the effective date of coverage under this permit and shall be submitted no later than 60 days after this one year period has expired. Each subsequent report shall contain the previous year's information and shall be submitted no later than one year after the previous year's report was due.

N. Annual inspection reports shall be mailed to the following address:

Illinois Environmental Protection Agency
Bureau of Water
Compliance Assurance Section
Annual Inspection Report
1021 North Grand Avenue East
Post Office Box 19276
Springfield, Illinois 62794-9276

O. If the facility performs inspections more frequently than required by this permit, the results shall be included as additional information in the annual report.

SPECIAL CONDITION 17. The Agency has determined that the effluent limitations in this permit constitute BAT/BCT for storm water which is treated in the existing treatment facilities for purposes of this permit reissuance, and no pollution prevention plan will be required for such storm water. In addition to the chemical specific monitoring required elsewhere in this permit, the permittee shall conduct an annual inspection of the facility site to identify areas contributing to a storm water discharge associated with industrial activity, and determine whether any facility modifications have occurred which result in previously-treated storm water discharges no longer receiving treatment. If any such discharges are identified the permittee shall request a modification of this permit within 30 days after the inspection. Records of the annual inspection shall be retained by the permittee for the term of this permit and be made available to the Agency on request.

SPECIAL CONDITION 18. Discharge of chemical metal cleaning agents EDTA, Elimin-Ox and/or hydrazine, and associated rinses are allowed once every 5 - 10 years per unit at outfalls A01, C01, and E01.

SPECIAL CONDITION 19. Except as allowed in Special Condition No. 18 of this permit, there shall be no discharge of complexed metal bearing waste streams or associated rinses from chemical metal cleaning unless this permit has been modified to include the new discharge.

SPECIAL CONDITION 20. Exelon Generation Company's demonstration for the Byron Nuclear Power Station in accordance with Section 316(b) of the Clean Water Act was approved by IEPA by a letter dated May 15, 1989. It is determined that no additional intake monitoring or modification is being required for reissuance of this NPDES Permit.

Special Conditions

SPECIAL CONDITION 21. Exelon Generation Company's Byron Nuclear Power Station has been deemed to have met the applicable national performance standards and will not be required to demonstrate further that the Rock River Intake Structure meets the specified impingement mortality and entrainment performance standards pursuant to 40 CFR 125.94(a)(1)(i). This determination was made because of the use and operation of the cooling towers. The Permittee shall request and receive a modification to this permit prior to changing the use or operation of the cooling towers. This determination does not relieve the Permittee of submitting pertinent information regarding the Rock River intake structure and cooling towers operation with the renewal application for this permit as required under 40 CFR 122.21(r)(2), (3), and (5).

SPECIAL CONDITION 22. All samples for Total Residual Chlorine/Total Residual Oxidant shall be analyzed by an applicable method contained in 40 CFR 136, equivalent in accuracy to low-level amperometric titration. Any analytical variability of the method used shall be considered when determining the accuracy and precision of the results obtained.

Discharge Monitoring Reports shall indicate whether chlorine or bromine compounds were used during the month.

SPECIAL CONDITION 23. For copper, zinc, and hydrazine a zone of initial dilution (ZID) is recognized with dimensions of 15.6 feet across the width of the river from the end-of-pipe and 15.5 feet downstream from this point. Within the ZID, 1.42:1 dilution is afforded. A mixing zone is recognized with dimensions extending 148 feet across the width of the river and 229 feet downstream. Within the mixing zone 6.1:1 dilution is afforded.

SPECIAL CONDITION 24. The influent from the Rock River and effluent from Outfall 001 shall be monitored for Total Suspended Solids on a monthly basis for two years from the effective date of this permit. After collection of all required samples, and upon written notification to the Agency the sampling may cease, unless the Agency modifies the permit to require continued sampling at some frequency.

Attachment H

Standard Conditions

Definitions

Act means the Illinois Environmental Protection Act, 415 ILCS 5 as Amended.

Agency means the Illinois Environmental Protection Agency.

Board means the Illinois Pollution Control Board.

Clean Water Act (formerly referred to as the Federal Water Pollution Control Act) means Pub. L 92-500, as amended. 33 U.S.C. 1251 et seq.

NPDES (National Pollutant Discharge Elimination System) means the national program for issuing, modifying, revoking and reissuing, terminating, monitoring and enforcing permits, and imposing and enforcing pretreatment requirements, under Sections 307, 402, 318 and 405 of the Clean Water Act.

USEPA means the United States Environmental Protection Agency.

Daily Discharge means the discharge of a pollutant measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling. For pollutants with limitations expressed in units of mass, the "daily discharge" is calculated as the total mass of the pollutant discharged over the day. For pollutants with limitations expressed in other units of measurements, the "daily discharge" is calculated as the average measurement of the pollutant over the day.

Maximum Daily Discharge Limitation (daily maximum) means the highest allowable daily discharge.

Average Monthly Discharge Limitation (30 day average) means the highest allowable average of daily discharges over a calendar month, calculated as the sum of all daily discharges measured during a calendar month divided by the number of daily discharges measured during that month.

Average Weekly Discharge Limitation (7 day average) means the highest allowable average of daily discharges over a calendar week, calculated as the sum of all daily discharges measured during a calendar week divided by the number of daily discharges measured during that week.

Best Management Practices (BMPs) means schedules of activities, prohibitions of practices, maintenance procedures, and other management practices to prevent or reduce the pollution of waters of the State. BMPs also include treatment requirements, operating procedures, and practices to control plant site runoff, spillage or leaks, sludge or waste disposal, or drainage from raw material storage.

Aliquot means a sample of specified volume used to make up a total composite sample.

Grab Sample means an individual sample of at least 100 milliliters collected at a randomly-selected time over a period not exceeding 15 minutes.

24-Hour Composite Sample means a combination of at least 8 sample aliquots of at least 100 milliliters, collected at periodic intervals during the operating hours of a facility over a 24-hour period.

8-Hour Composite Sample means a combination of at least 3 sample aliquots of at least 100 milliliters, collected at periodic intervals during the operating hours of a facility over an 8-hour period.

Flow Proportional Composite Sample means a combination of sample aliquots of at least 100 milliliters collected at periodic intervals such that either the time interval between each aliquot or the volume of each aliquot is proportional to either the stream flow at the time of sampling or the total stream flow since the collection of the previous aliquot.

(1) **Duty to comply.** The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application. The permittee shall comply with effluent standards or prohibitions established under Section 307(a) of the Clean Water Act for toxic pollutants within the time provided in the regulations that establish these standards or prohibitions, even if the permit has not yet been modified to incorporate the requirements.

(2) **Duty to reapply.** If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must apply for and obtain a new permit. If the permittee submits a proper application as required by the Agency no later than 180 days prior to the expiration date, this permit shall continue in full force and effect until the final Agency decision on the application has been made.

(3) **Need to halt or reduce activity not a defense.** It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

(4) **Duty to mitigate.** The permittee shall take all reasonable steps to minimize or prevent any discharge in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment.

(5) **Proper operation and maintenance.** The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up, or auxiliary facilities, or similar systems only when necessary to achieve compliance with the conditions of the permit.

(6) **Permit actions.** This permit may be modified, revoked and reissued, or terminated for cause by the Agency pursuant to 40 CFR 122.62 and 40 CFR 122.63. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

(7) **Property rights.** This permit does not convey any property rights of any sort, or any exclusive privilege.

(8) **Duty to provide information.** The permittee shall furnish to the Agency within a reasonable time, any information which the Agency may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also furnish to the Agency upon request, copies of records required to be kept by this permit.

(9) **Inspection and entry.** The permittee shall allow an authorized representative of the Agency or USEPA (including an authorized contractor acting as a representative of the Agency or USEPA), upon the presentation of credentials and other documents as may be required by law, to:
- (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;
- (b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;
- (c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and
- (d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance, or as otherwise authorized by the Act, any substances or parameters at any location.

(10) **Monitoring and records.**
- (a) Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.
- (b) The permittee shall retain records of all monitoring information, including all calibration and maintenance records, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least 3 years from the date of this permit, measurement, report or application. Records related to the permittee's sewage sludge use and disposal activities shall be retained for a period of at least five years (or longer as required by 40 CFR Part 503). This period may be extended by request of the Agency or USEPA at any time.
- (c) Records of monitoring information shall include:
  - (1) The date, exact place, and time of sampling or measurements;
  - (2) The individual(s) who performed the sampling or measurements;
  - (3) The date(s) analyses were performed;
  - (4) The individual(s) who performed the analyses;
  - (5) The analytical techniques or methods used; and
  - (6) The results of such analyses.
- (d) Monitoring must be conducted according to test procedures approved under 40 CFR Part 136, unless other test procedures have been specified in this permit. Where no test procedure under 40 CFR Part 136 has been approved, the permittee must submit to the Agency a test method for approval. The permittee shall calibrate and perform maintenance procedures on all monitoring and analytical instrumentation at intervals to ensure accuracy of measurements.

(11) **Signatory requirement.** All applications, reports or information submitted to the Agency shall be signed and certified.
- (a) **Application.** All permit applications shall be signed as follows:
  - (1) For a corporation: by a principal executive officer of at least the level of vice president or a person or position having overall responsibility for environmental matters for the corporation:
  - (2) For a partnership or sole proprietorship: by a general partner or the proprietor, respectively; or
  - (3) For a municipality, State, Federal, or other public agency: by either a principal executive officer or ranking elected official.
- (b) **Reports.** All reports required by permits, or other information requested by the Agency shall be signed by a person described in paragraph (a) or by a duly authorized representative of that person. A person is a duly authorized representative only if:
  - (1) The authorization is made in writing by a person described in paragraph (a); and
  - (2) The authorization specifies either an individual or a position responsible for the overall operation of the facility, from which the discharge originates, such as a plant manager, superintendent or person of equivalent responsibility; and
  - (3) The written authorization is submitted to the Agency.
- (c) **Changes of Authorization.** If an authorization under (b) is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of (b) must be submitted to the Agency prior to or together with any reports, information, or applications to be signed by an authorized representative.
- (d) **Certification.** Any person signing a document under paragraph (a) or (b) of this section shall make the following certification:

  I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

(12) **Reporting requirements.**
- (a) **Planned changes.** The permittee shall give notice to the Agency as soon as possible of any planned physical alterations or additions to the permitted facility. Notice is required when:
  - (1) The alteration or addition to a permitted facility may meet one of the criteria for determining whether a facility is a new source pursuant to 40 CFR 122.29 (b); or
  - (2) The alteration or addition could significantly change the nature or increase the quantity of pollutants discharged. This notification applies to pollutants which are subject neither to effluent limitations in the permit, nor to notification requirements pursuant to 40 CFR 122.42 (a)(1).
  - (3) The alteration or addition results in a significant change in the permittee's sludge use or disposal practices, and such alteration, addition, or change may justify the application of permit conditions that are different from or absent in the existing permit, including notification of additional use or disposal sites not reported during the permit application process or not reported pursuant to an approved land application plan.
- (b) **Anticipated noncompliance.** The permittee shall give advance notice to the Agency of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.
- (c) **Transfers.** This permit is not transferable to any person except after notice to the Agency.
- (d) **Compliance schedules.** Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 14 days following each schedule date.
- (e) **Monitoring reports.** Monitoring results shall be reported at the intervals specified elsewhere in this permit.
  - (1) Monitoring results must be reported on a Discharge Monitoring Report (DMR).

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(2) If the permittee monitors any pollutant more frequently than required by the permit, using test procedures approved under 40 CFR 136 or as specified in the permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

(3) Calculations for all limitations which require averaging of measurements shall utilize an arithmetic mean unless otherwise specified by the Agency in the permit.

(f) **Twenty-four hour reporting**. The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24-hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within 5 days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and time; and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The following shall be included as information which must be reported within 24-hours:

(1) Any unanticipated bypass which exceeds any effluent limitation in the permit.

(2) Any upset which exceeds any effluent limitation in the permit.

(3) Violation of a maximum daily discharge limitation for any of the pollutants listed by the Agency in the permit or any pollutant which may endanger health or the environment.

The Agency may waive the written report on a case-by-case basis if the oral report has been received within 24-hours.

(g) **Other noncompliance**. The permittee shall report all instances of noncompliance not reported under paragraphs (12) (d), (e), or (f), at the time monitoring reports are submitted. The reports shall contain the information listed in paragraph (12) (f).

(h) **Other Information**. Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application, or in any report to the Agency, it shall promptly submit such facts or information.

(13) **Bypass**.

(a) Definitions.

(1) Bypass means the intentional diversion of waste streams from any portion of a treatment facility.

(2) Severe property damage means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

(b) Bypass not exceeding limitations. The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of paragraphs (13)(c) and (13)(d).

(c) Notice.

(1) Anticipated bypass. If the permittee knows in advance of the need for a bypass, it shall submit prior notice, if possible at least ten days before the date of the bypass.

(2) Unanticipated bypass. The permittee shall submit notice of an unanticipated bypass as required in paragraph (12)(f) (24-hour notice).

(d) Prohibition of bypass.

(1) Bypass is prohibited, and the Agency may take enforcement action against a permittee for bypass, unless:

(i) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(ii) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and

(iii) The permittee submitted notices as required under paragraph (13)(c).

(2) The Agency may approve an anticipated bypass, after considering its adverse effects, if the Agency determines that it will meet the three conditions listed above in paragraph (13)(d)(1).

(14) **Upset**.

(a) Definition. Upset means an exceptional incident in which there is unintentional and temporary noncompliance with technology based permit effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

(b) Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with such technology based permit effluent limitations if the requirements of paragraph (14)(c) are met. No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

(c) Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:

(1) An upset occurred and that the permittee can identify the cause(s) of the upset;

(2) The permitted facility was at the time being properly operated; and

(3) The permittee submitted notice of the upset as required in paragraph (12)(f)(2) (24-hour notice).

(4) The permittee complied with any remedial measures required under paragraph (4).

(d) Burden of proof. In any enforcement proceeding the permittee seeking to establish the occurrence of an upset has the burden of proof.

(15) **Transfer of permits**. Permits may be transferred by modification or automatic transfer as described below:

(a) Transfers by modification. Except as provided in paragraph (b), a permit may be transferred by the permittee to a new owner or operator only if the permit has been modified or revoked and reissued pursuant to 40 CFR 122.62 (b) (2), or a minor modification made pursuant to 40 CFR 122.63 (d), to identify the new permittee and incorporate such other requirements as may be necessary under the Clean Water Act.

(b) Automatic transfers. As an alternative to transfers under paragraph (a), any NPDES permit may be automatically transferred to a new permittee if:

(1) The current permittee notifies the Agency at least 30 days in advance of the proposed transfer date;
(2) The notice includes a written agreement between the existing and new permittees containing a specified date for transfer of permit responsibility, coverage and liability between the existing and new permittees; and
(3) The Agency does not notify the existing permittee and the proposed new permittee of its intent to modify or revoke and reissue the permit. If this notice is not received, the transfer is effective on the date specified in the agreement.

(16) All manufacturing, commercial, mining, and silvicultural dischargers must notify the Agency as soon as they know or have reason to believe:
(a) That any activity has occurred or will occur which would result in the discharge of any toxic pollutant identified under Section 307 of the Clean Water Act which is not limited in the permit, if that discharge will exceed the highest of the following notification levels:
(1) One hundred micrograms per liter (100 ug/l);
(2) Two hundred micrograms per liter (200 ug/l) for acrolein and acrylonitrile; five hundred micrograms per liter (500 ug/l) for 2,4-dinitrophenol and for 2-methyl-4,6 dinitrophenol; and one milligram per liter (1 mg/l) for antimony.
(3) Five (5) times the maximum concentration value reported for that pollutant in the NPDES permit application; or
(4) The level established by the Agency in this permit.
(b) That they have begun or expect to begin to use or manufacture as an intermediate or final product or byproduct any toxic pollutant which was not reported in the NPDES permit application.

(17) All Publicly Owned Treatment Works (POTWs) must provide adequate notice to the Agency of the following:
(a) Any new introduction of pollutants into that POTW from an indirect discharge which would be subject to Sections 301 or 306 of the Clean Water Act if it were directly discharging those pollutants; and
(b) Any substantial change in the volume or character of pollutants being introduced into that POTW by a source introducing pollutants into the POTW at the time of issuance of the permit.
(c) For purposes of this paragraph, adequate notice shall include information on (i) the quality and quantity of effluent introduced into the POTW, and (ii) any anticipated impact of the change on the quantity or quality of effluent to be discharged from the POTW.

(18) If the permit is issued to a publicly owned or publicly regulated treatment works, the permittee shall require any industrial user of such treatment works to comply with federal requirements concerning:
(a) User charges pursuant to Section 204 (b) of the Clean Water Act, and applicable regulations appearing in 40 CFR 35;
(b) Toxic pollutant effluent standards and pretreatment standards pursuant to Section 307 of the Clean Water Act; and
(c) Inspection, monitoring and entry pursuant to Section 308 of the Clean Water Act.

(19) If an applicable standard or limitation is promulgated under Section 301(b)(2)(C) and (D), 304(b)(2), or 307(a)(2) and that effluent standard or limitation is more stringent than any effluent limitation in the permit, or controls a pollutant not limited in the permit, the permit shall be promptly modified or revoked, and reissued to conform to that effluent standard or limitation.

(20) Any authorization to construct issued to the permittee pursuant to 35 Ill. Adm. Code 309.154 is hereby incorporated by reference as a condition of this permit.

(21) The permittee shall not make any false statement, representation or certification in any application, record, report, plan or other document submitted to the Agency or the USEPA, or required to be maintained under this permit.

(22) The Clean Water Act provides that any person who violates a permit condition implementing Sections 301, 302, 306, 307, 308, 318, or 405 of the Clean Water Act is subject to a civil penalty not to exceed $25,000 per day of such violation. Any person who willfully or negligently violates permit conditions implementing Sections 301, 302, 306, 307, 308, 318 or 405 of the Clean Water Act is subject to a fine of not less than $2,500 nor more than $25,000 per day of violation, or by imprisonment for not more than one year, or both.
Additional penalties for violating these sections of the Clean Water Act are identified in 40 CFR 122.41 (a)(2) and (3).

(23) The Clean Water Act provides that any person who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit shall, upon conviction, be punished by a fine of not more than $10,000, or by imprisonment for not more than 2 years, or both. If a conviction of a person is for a violation committed after a first conviction of such person under this paragraph, punishment is a fine of not more than $20,000 per day of violation, or by imprisonment of not more than 4 years, or both.

(24) The Clean Water Act provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or non-compliance shall, upon conviction, be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than 6 months per violation, or by both.

(25) Collected screening, slurries, sludges, and other solids shall be disposed of in such a manner as to prevent entry of those wastes (or runoff from the wastes) into waters of the State. The proper authorization for such disposal shall be obtained from the Agency and is incorporated as part hereof by reference.

(26) In case of conflict between these standard conditions and any other condition(s) included in this permit, the other condition(s) shall govern.

(27) The permittee shall comply with, in addition to the requirements of the permit, all applicable provisions of 35 Ill. Adm. Code, Subtitle C, Subtitle D, Subtitle E, and all applicable orders of the Board or any court with jurisdiction.

(28) The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit is held invalid, the remaining provisions of this permit shall continue in full force and effect.

(Rev. 7-9-2010 bah)

Appendix C

Special Status Species Correspondence

Byron Station Environmental Report

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Exelon Generation

Michael P. Gallagher

November 09, 2012

Mr. Todd Rettig
Division Manager
Office of Realty and Environmental Planning
Illinois Department of Natural Resources
1 Natural Resources Way, 2nd Floor
Springfield, Illinois 62702-1271

SUBJECT: Exelon Generation, LLC – Byron Station Units 1 and 2 License Renewal Project. Request for Information on Listed Species and Sensitive Habitats – Ogle County

Dear Mr. Rettig:

Exelon Generation, LLC (Exelon) plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for Byron Station (Byron) Units 1 and 2, in June 2013. The existing operating license for Unit 1 will expire on October 31, 2024, and the existing operating license for Unit 2 will expire on November 6, 2026. Renewed licenses would allow Byron Units 1 and 2 to operate until 2044 and 2046, respectively.

As part of the license renewal process, the NRC requires license renewal applications to include environmental reports assessing the impacts from license renewal activities on threatened or endangered species, listed or proposed for listing in accordance with the Endangered Species Act (ESA) (16 USC 1531, et seq.)(10 CFR 51.53(c)(3)(ii)(E)). This letter seeks input from the Illinois Department of Natural Resources (DNR) regarding such effects in the vicinity of Byron.

Project Features

Byron is in northern Illinois near the center of Ogle County, approximately 90 miles west-northwest of Chicago, 17 miles southwest of Rockford, and 3.7 miles south-southwest of the City of Byron, as shown in Figure 1.

The Byron site property includes approximately 1,782 acres, which consists of the main site area and a right-of-way (ROW) to the Rock River for the cooling tower makeup water intake and blowdown discharge pipelines. The main site area consists of approximately 1,398 acres while the water pipelines ROW consists of the remaining 384 acres. The site is situated on a topographic high in the Rock River Hill Country physiographic province, in an agricultural area.

The nuclear generating facilities at Byron are sited in the approximate center of the main site area and include the two reactor containment buildings and related structures, two natural draft cooling towers, a switchyard, administration buildings, warehouses, and other features. The cooling tower makeup water intake and blowdown discharge pipelines ROW runs from the northwest site boundary approximately 2 miles west to the Rock River. The Rock River is the source of the plant's makeup water and the receiving body for the cooling tower blowdown discharge, which is subject to limitations established by National Pollutant Discharge Elimination System (NPDES) Permit IL0048313.

Three 345-kilovolt (345-kV) electrical transmission line ROWs totaling an additional approximately 1,210 acres, shown on Figures 2 and 3, were constructed with the station to connect it to the electric grid and are considered to be within the scope of the license renewal project. One ROW runs north and then east from Byron approximately 30 miles to the Wempleton Transmission Substation, located approximately 7 miles northwest of Rockford, IL. A second ROW runs northeast from Byron for approximately 21 miles, to the Cherry Valley Transmission Substation. The third ROW goes directly south for a total length of 8.5 miles to its intersection with the Nelson to Cherry Valley transmission line, which existed before Byron was constructed. All three ROWs pass through primarily agricultural land with some areas of forest or lesser value land use categories. These ROWs are owned and maintained Commonwealth Edison Company (ComEd). In locations where a ROW passes through farmland, the land generally continues to be used as farmland.

Identification of Threatened and Endangered Species Resources

In 2011, Exelon conducted mussel surveys in the Rock River up- and down-stream of the Byron intake/discharge pipelines to determine if any federally listed mussel species were present. No federally listed species was found during the survey. According to the USFWS database, there are no records of species that are candidates for federal listing or that are proposed for federal listing in Ogle or Winnebago Counties. Exelon is not aware of any other federally listed species being observed on the Byron site or along the associated ROWs.

The Byron license renewal project information was submitted to the Illinois DNR through the EcoCAT system. Attached for your review are the Illinois DNR reports listing the Natural Resource Review results of the Illinois Natural Heritage database for (1) the Byron Station; (2) the Byron Station Blowdown Area on Rock River; (3) the Byron Station to Cherry Valley Transmission Line, Segments 1 through 6; (4) the Byron South Transmission Line, Segments 1 and 2, and (5) the Byron to Wempleton Transmission Line, Segments 1 through 8. These attached database results for Byron and the associated ROWs show that several protected resources may be in the vicinity of the project location.

Activities During the License Renewal Terms

Renewal of Byron Units 1 and 2 operating licenses will involve neither new construction, nor any land disturbing activities, changes to plant operations, or modifications of the transmission system that connects the plant to the regional electric grid. Operation and maintenance activities during the terms of the renewed licenses are only expected to occur in previously disturbed areas or existing ROWs. Also, Exelon and ComEd adhere to regulatory requirements regarding sensitive areas that could contain threatened or endangered species and work closely with USFWS and the Illinois DNR to protect these resources. Therefore, Exelon expects that continued operation and maintenance of Units 1 and 2 over the license renewal period (i.e., an additional 20 years for each unit), including maintenance of the ROWs for the transmission line and cooling tower makeup water intake and blowdown discharge pipelines, would not adversely affect any species (or ecologically significant habitats) that is federally listed or proposed for federal listing as threatened or endangered.

Nevertheless, Exelon is requesting your help to identify potential impacts or other issues we may have overlooked that need to be addressed in the Byron license renewal environmental report. We are also interested in learning of any information your staff believes could help expedite the NRC's review of the Byron license renewal application. Hence, in closing, we would appreciate receiving a response from you detailing such issues and information for the Byron site and the ROWs for the transmission line and cooling tower makeup water intake and blowdown discharge pipelines. We would also welcome your confirmation of our conclusion that Byron license renewal activities would not adversely affect any species that is federally listed or proposed for listing as threatened and endangered.

Because Exelon will incorporate a copy of your response, as well as this letter, into the Byron license renewal environmental report that will be submitted to the NRC as part of the Byron license renewal application, your response will be most helpful if it is received by December 14, 2012.

Please refer any questions regarding this submittal to Nancy Ranek, our License Renewal Environmental Lead, at (610) 765-5369.

Sincerely,

Michael P. Gallagher

Michael P. Gallagher

Enclosures:
- Figure 1: Project Location Map
- Figure 2: Byron to Wempleton and Cherry Valley Transmission Line ROWs
- Figure 3: Byron South Transmission Line ROW
- EcoCAT Reports:
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  - (2) Byron Station Blowdown Area on Rock River
  - (3) Byron Station to Cherry Valley Transmission Line, Segments 1 through 6
  - (4) Byron Station South Transmission Line, Segments 1 and 2
  - (5) Byron Station to Wempleton Transmission Line, Segments 1 through 8

Exelon Generation

Michael P. Gallagher

November 09, 2012

Mr. Richard Nelson
U. S. Fish & Wildlife Service
Rock Island Field Office
1511 47th Avenue
Moline, IL 61265

SUBJECT: Exelon Generation, LLC – Byron Station Units 1 and 2 License Renewal Project. Request for Information on Listed Species and Sensitive Habitats – Ogle County

Dear Mr. Nelson:

Exelon Generation, LLC (Exelon) plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for Byron Station (Byron) Units 1 and 2, in June 2013. The existing operating license for Unit 1 will expire on October 31, 2024, and the existing operating license for Unit 2 will expire on November 6, 2026. Renewed licenses would allow Byron Units 1 and 2 to operate until 2044 and 2046, respectively.

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Project Features

Byron is in northern Illinois near the center of Ogle County, approximately 90 miles west-northwest of Chicago, 17 miles southwest of Rockford, and 3.7 miles south-southwest of the City of Byron, as shown in Figure 1.

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  - (5) Byron Station to Wempleton Transmission Line, Segments 1 through 8

Figure 1 Project Location Map

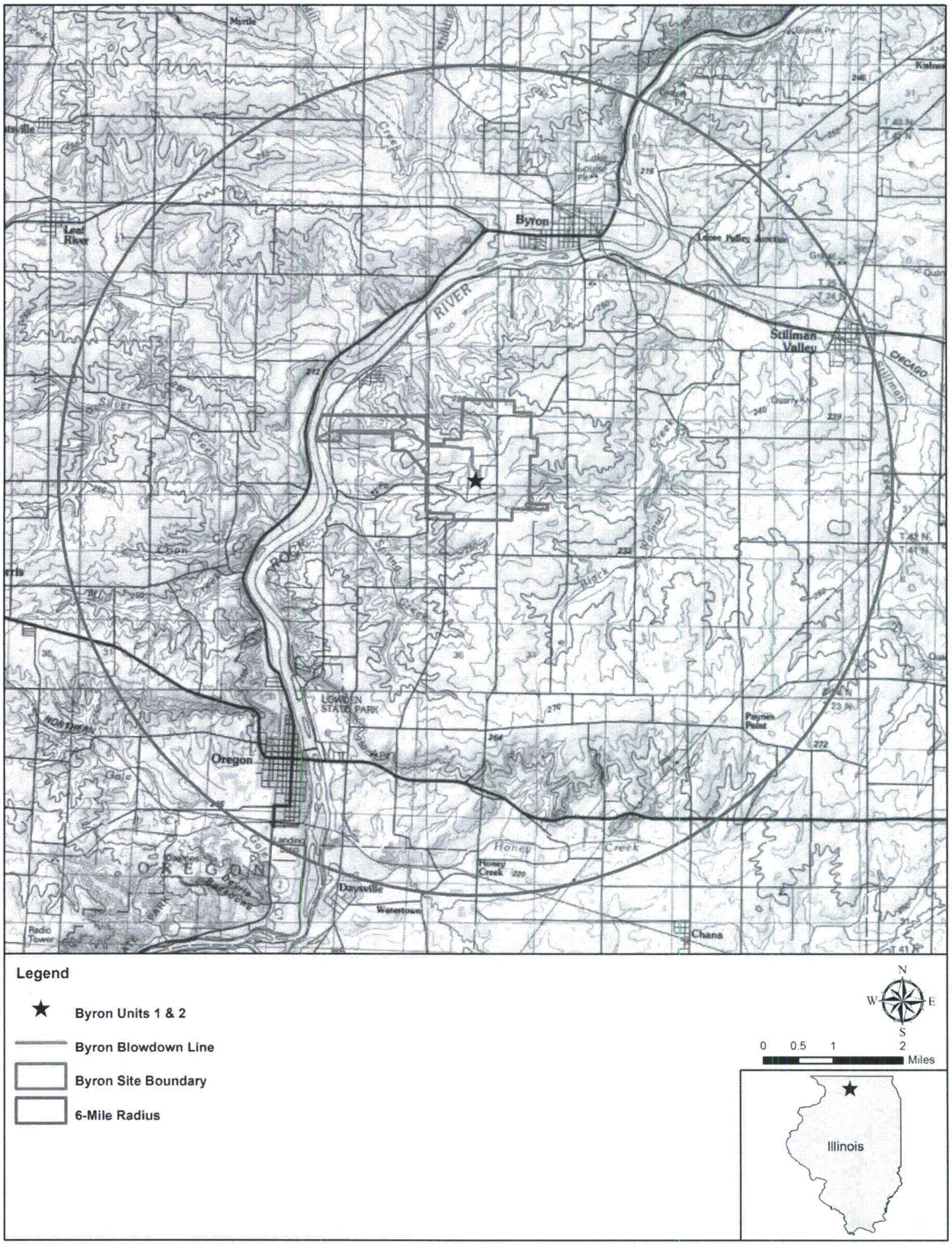


Figure 2 Byron to Wempleton and Cherry Valley Transmission Line Right-of-Ways

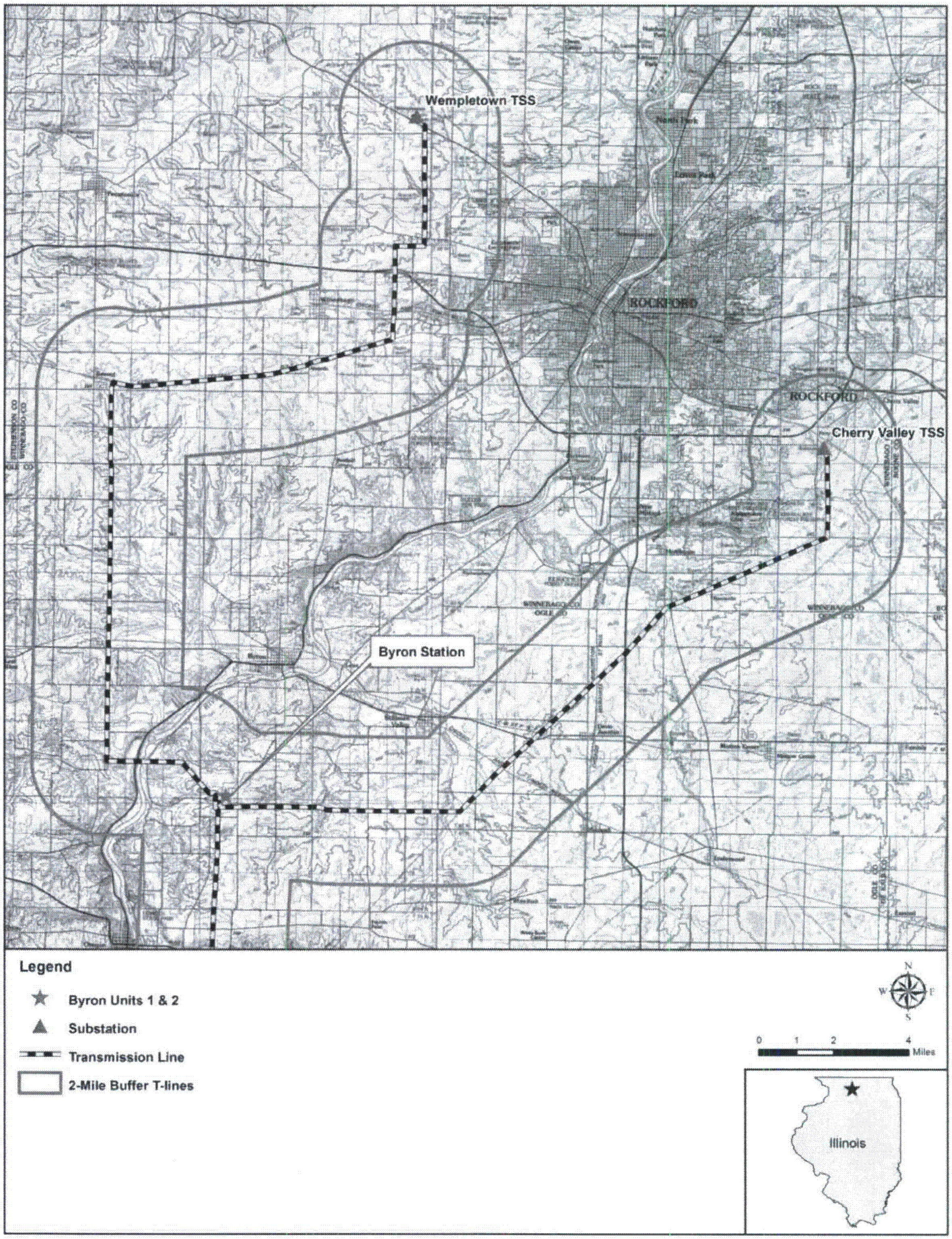
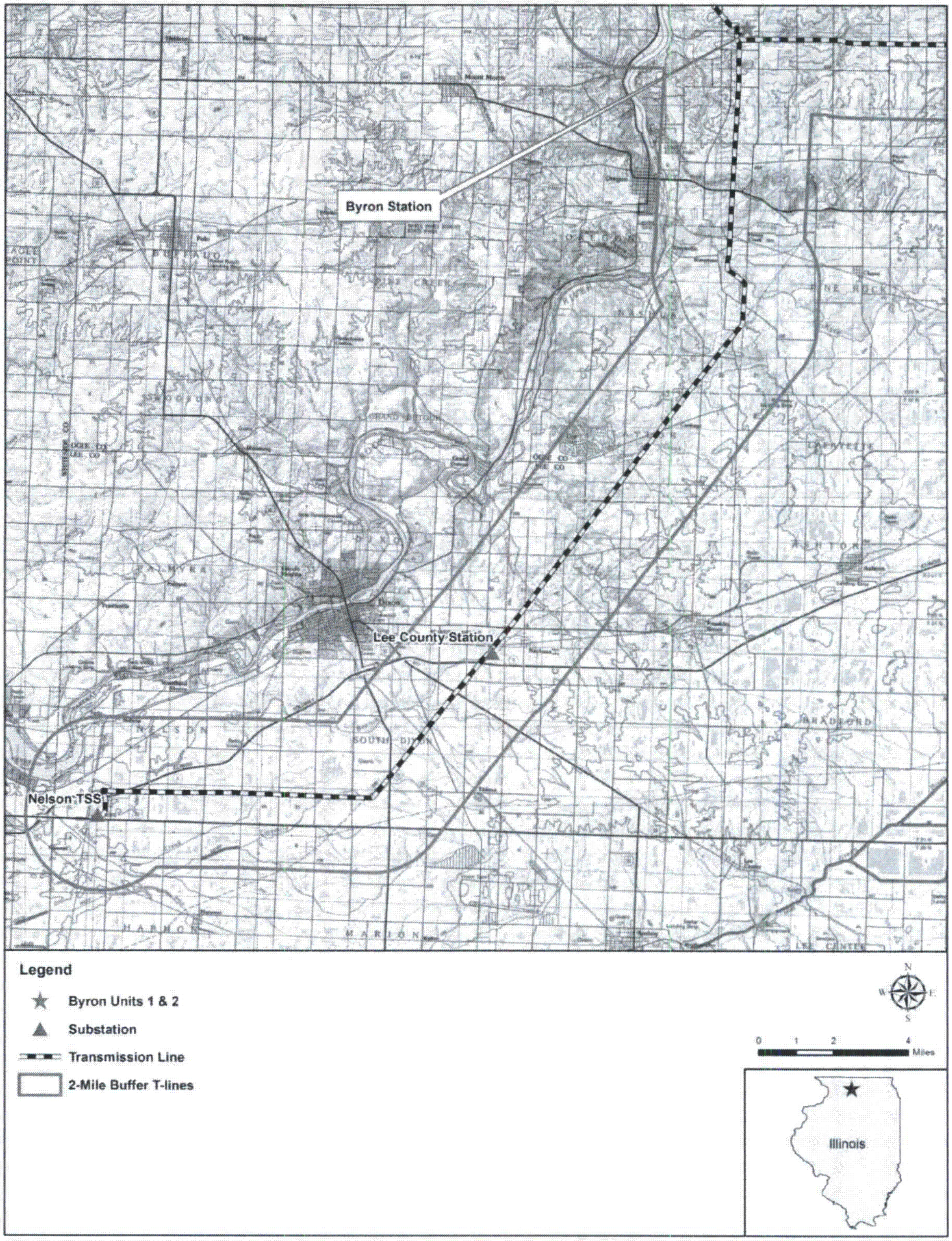


Figure 3 Byron South Transmission Line Right-of-Way



EcoCAT
Ecological Compliance Assessment Tool

Applicant: Exelon Generation Company LLC
Contact: Robert J Tarr
Address: 200 Exelon Way
Kennett Square, PA 19348

IDNR Project #: 1210838
Date: 03/16/2012

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Station property
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

Byron Dragway Prairie INAI Site
Commonwealth Edison Prairie INAI Site
Jarrett Prairie INAI Site
Byron Dragway Prairie Natural Heritage Landmark
Jarrett Prairie Nature Preserve
Black Sandshell *(Ligumia recta)*
Redroot *(Ceanothus herbaceus)*

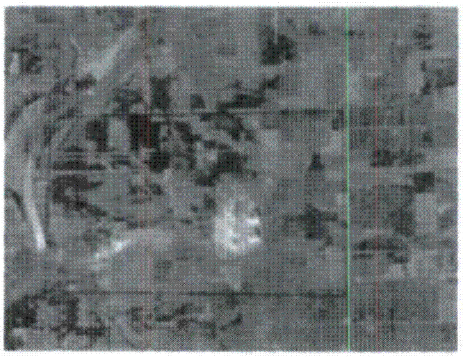
Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle

Township, Range, Section:

24N, 10E, 10	24N, 10E, 11
24N, 10E, 12	24N, 10E, 13
24N, 10E, 14	24N, 10E, 15
24N, 10E, 22	24N, 10E, 23
24N, 10E, 24	24N, 11E, 7
24N, 11E, 18	24N, 11E, 19



Page 1 of 2

IDNR Project Number: 1210838

IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

Disclaimer

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1305771
Contact:	Robert J Tarr	Date:	10/30/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Blowdown Area on River
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

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Byron Dragway Prairie INAI Site
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Jarrett Prairie INAI Site
Byron Dragway Prairie Natural Heritage Landmark
Jarrett Prairie Nature Preserve
Black Sandshell *(Ligumia recta)*
Downy Yellow Painted Cup *(Castilleja sessiliflora)*
Prairie Bush Clover *(Lespedeza leptostachya)*
Wooly Milkweed *(Asclepias lanuginosa)*

Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle

Township, Range, Section:

24N, 10E, 1	24N, 10E, 2
24N, 10E, 3	24N, 10E, 9
24N, 10E, 10	24N, 10E, 11
24N, 10E, 12	24N, 10E, 14
24N, 10E, 15	24N, 10E, 16
24N, 11E, 6	25N, 10E, 35

IDNR Project Number 1305771

25N, 10E, 36 25N, 11E, 31
25N, 11E, 32

IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210840
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Cherry Valley Transmission Segment 1
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

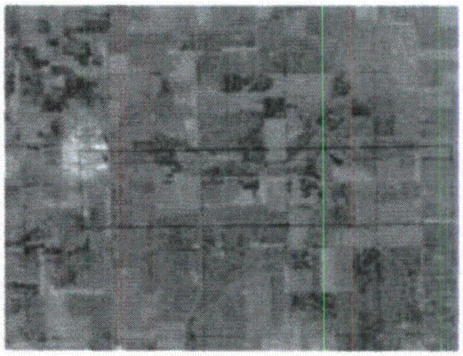
This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

Commonwealth Edison Prairie INAI Site

Location

The applicant is responsible for the accuracy of the location submitted for the project.



County: Ogle

Township, Range, Section:

24N, 10E, 13	24N, 10E, 24
24N, 11E, 15	24N, 11E, 16
24N, 11E, 17	24N, 11E, 18
24N, 11E, 19	24N, 11E, 20
24N, 11E, 21	24N, 11E, 22

IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

IDNR Project Number: 1210840

Disclaimer

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210841
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Cherry Valley Transmission Segment 2
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

Beach Cemetery Prairie INAI Site
Beach Cemetery Prairie Nature Preserve

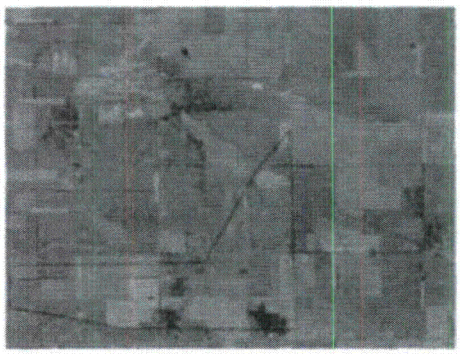
Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle

Township, Range, Section:

24N, 11E, 13	24N, 11E, 14
24N, 11E, 15	24N, 11E, 22
24N, 11E, 23	24N, 11E, 24
42N, 1E, 20	42N, 1E, 29
42N, 1E, 30	42N, 1E, 31
42N, 1E, 32	



IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

IDNR Project Number: 1210841

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210842
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Cherry Valley Transmission Segment 3
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

Beach Cemetery Prairie INAI Site
Beach Cemetery Prairie Nature Preserve

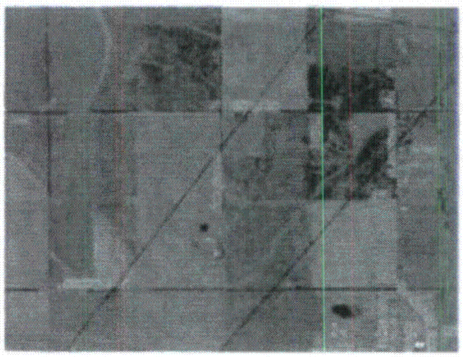
Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle

Township, Range, Section:

42N, 1E, 10	42N, 1E, 11
42N, 1E, 14	42N, 1E, 15
42N, 1E, 16	42N, 1E, 20
42N, 1E, 21	42N, 1E, 22
42N, 1E, 28	42N, 1E, 29
42N, 1E, 32	



IL Department of Natural Resources Contact

Impact Assessment Section
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Division of Ecosystems & Environment

IDNR Project Number: 1210842

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210843
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Cherry Valley Transmission Segment 4
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

Winquist Prairie INAI Site
Winquist Prairie Natural Heritage Landmark
Prairie Bush Clover *(Lespedeza leptostachya)*

Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle

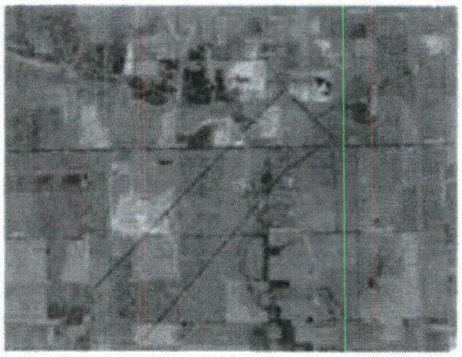
Township, Range, Section:

42N, 1E, 1	42N, 1E, 2
42N, 1E, 11	42N, 1E, 12
42N, 1E, 14	42N, 2E, 6

County: Winnebago

Township, Range, Section:

43N, 1E, 36	43N, 2E, 31



Page 1 of 2

IDNR Project Number: 1210843

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Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210845
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Cherry Valley Transmission Segment 5
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

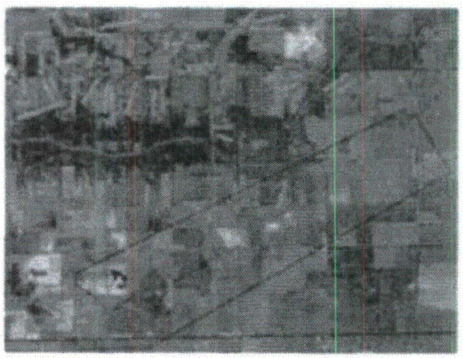
The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

Kishwaukee River INAI Site
Kishwaukee River South Branch INAI Site
Winquist Prairie INAI Site
Winquist Prairie Natural Heritage Landmark
Black Sandshell *(Ligumia recta)*
Black Sandshell *(Ligumia recta)*
Gravel Chub *(Erimystax x-punctatus)*
Prairie Bush Clover *(Lespedeza leptostachya)*

Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle
Township, Range, Section:
42N, 2E, 5 42N, 2E, 6
County: Winnebago
Township, Range, Section:
43N, 2E, 21 43N, 2E, 22
43N, 2E, 23 43N, 2E, 26
43N, 2E, 27 43N, 2E, 28



IDNR Project Number: 1210845

43N, 2E, 29	43N, 2E, 30
43N, 2E, 31	43N, 2E, 32
43N, 2E, 33	

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210846
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Cherry Valley Transmission Segment 6
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

Kishwaukee River INAI Site
Kishwaukee River South Branch INAI Site
Black Sandshell *(Ligumia recta)*
Black Sandshell *(Ligumia recta)*
Gravel Chub *(Erimystax x-punctatus)*
Ground Juniper *(Juniperus communis)*

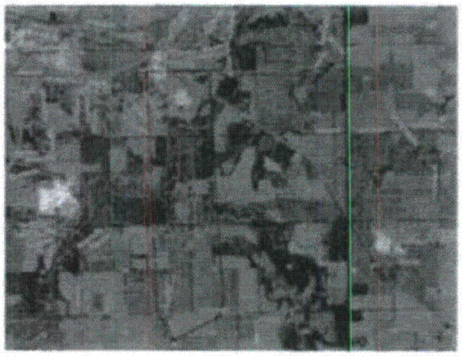
Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Winnebago

Township, Range, Section:

43N, 2E, 10	43N, 2E, 11
43N, 2E, 14	43N, 2E, 15
43N, 2E, 22	43N, 2E, 23
43N, 2E, 26	43N, 2E, 27



Page 1 of 2

IDNR Project Number: 1210846

IL Department of Natural Resources Contact
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EcoCAT
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Applicant: Exelon Generation Company LLC
Contact: Robert J Tarr
Address: 200 Exelon Way
Kennett Square, PA 19348

IDNR Project #: 1210870
Date: 03/16/2012

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, South Transmission Segment 1
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

Commonwealth Edison Prairie INAI Site

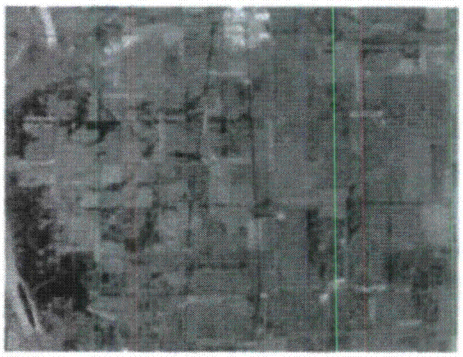
Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle

Township, Range, Section:

23N, 10E, 1	24N, 10E, 13
24N, 10E, 24	24N, 10E, 25
24N, 10E, 35	24N, 10E, 36



IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

IDNR Project Number: 1210870

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EcoCAT
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Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210872
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, South Transmission Segment 2
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

Kyte River INAI Site
Kyte River Bottoms INAI Site
Pine Rock INAI Site
Kyte River Bottoms Land And Water Reserve
Pine Rock Nature Preserve
Black Sandshell *(Ligumia recta)*
Gravel Chub *(Erimystax x-punctatus)*

Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle

Township, Range, Section:

23N, 10E, 1	23N, 10E, 12
23N, 10E, 13	23N, 10E, 24
23N, 10E, 25	23N, 10E, 36
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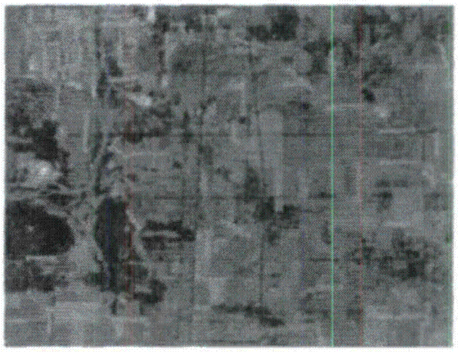
23N, 11E, 30	23N, 11E, 31



IDNR Project Number: 1210872

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210847
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Wempleton Transmission Segment 1
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database shows the following protected resources may be in the vicinity of the project location:

Commonwealth Edison Prairie INAI Site
Black Sandshell *(Ligumia recta)*
Redroot *(Ceanothus herbaceus)*

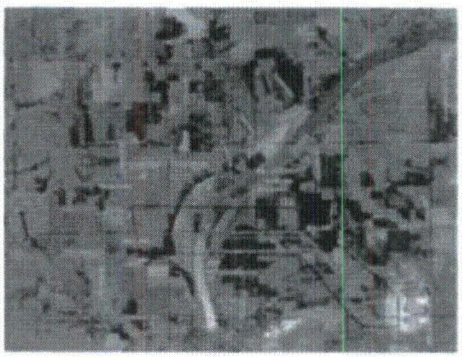
Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle

Township, Range, Section:

24N, 10E, 9	24N, 10E, 10
24N, 10E, 11	24N, 10E, 13
24N, 10E, 14	24N, 10E, 15
24N, 10E, 16	24N, 10E, 24



IL Department of Natural Resources Contact
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217-785-5500
Division of Ecosystems & Environment

IDNR Project Number: 1210847

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Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210849
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Wempleton Transmission Segment 2
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database contains no record of State-listed threatened or endangered species, Illinois Natural Area Inventory sites, dedicated Illinois Nature Preserves, or registered Land and Water Reserves in the vicinity of the project location.

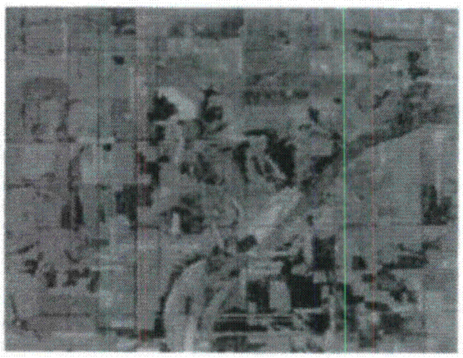
Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle

Township, Range, Section:

24N, 10E, 4
24N, 10E, 9
24N, 10E, 16
25N, 10E, 28
25N, 10E, 33



IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

IDNR Project Number: 1210849

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210852
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission (NRC) for Byron Generating Station, Units 1 and 2, Wempleton Transmission Segment 3
Address: 4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database contains no record of State-listed threatened or endangered species, Illinois Natural Area Inventory sites, dedicated Illinois Nature Preserves, or registered Land and Water Reserves in the vicinity of the project location.

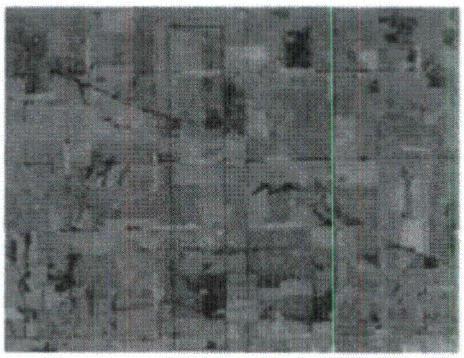
Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle

Township, Range, Section:

25N, 10E, 9
25N, 10E, 16
25N, 10E, 21
25N, 10E, 28
25N, 10E, 33



IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

IDNR Project Number: 1210852

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210854
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Wempleton Transmission Segment 4
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

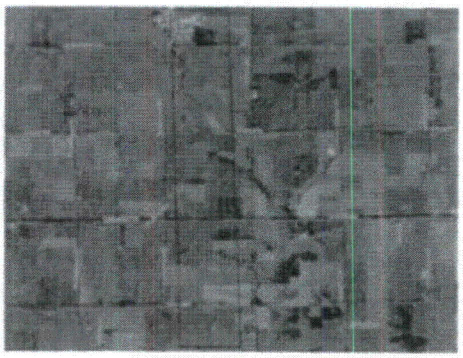
This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database contains no record of State-listed threatened or endangered species, Illinois Natural Area Inventory sites, dedicated Illinois Nature Preserves, or registered Land and Water Reserves in the vicinity of the project location.

Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Ogle
Township, Range, Section:
25N, 10E, 4 25N, 10E, 9
County: Winnebago
Township, Range, Section:
26N, 10E, 21 26N, 10E, 28
26N, 10E, 33



IL Department of Natural Resources Contact
Impact Assessment Section
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Division of Ecosystems & Environment

IDNR Project Number: 1210854

Disclaimer

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210856
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Wempleton Transmission Segment 5
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database contains no record of State-listed threatened or endangered species, Illinois Natural Area Inventory sites, dedicated Illinois Nature Preserves, or registered Land and Water Reserves in the vicinity of the project location.

Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Winnebago

Township, Range, Section:

26N, 10E, 21	26N, 10E, 22
26N, 10E, 23	26N, 10E, 24
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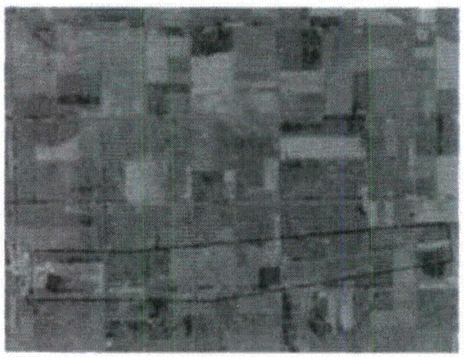

IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

IDNR Project Number: 1210856

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210860
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission (NRC) for Byron Generating Station, Units 1 and 2, Wempleton Transmission Segment 6
Address: 4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

This project was submitted for information only. It is not a consultation under Part 1075.

The Illinois Natural Heritage Database contains no record of State-listed threatened or endangered species, Illinois Natural Area Inventory sites, dedicated Illinois Nature Preserves, or registered Land and Water Reserves in the vicinity of the project location.

Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Winnebago

Township, Range, Section:

26N, 11E, 2	26N, 11E, 3
26N, 11E, 10	26N, 11E, 11
26N, 11E, 14	26N, 11E, 15
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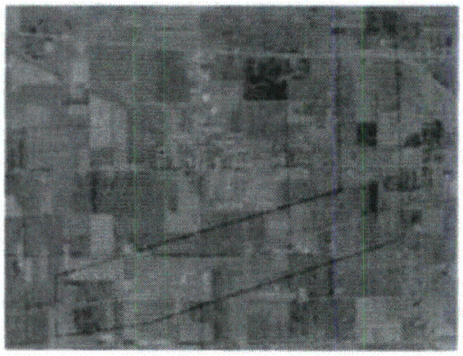

IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

IDNR Project Number: 1210860

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EcoCAT
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Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210864
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Wempleton Transmission Segment 7
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

Natural Resource Review Results

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Location

The applicant is responsible for the accuracy of the location submitted for the project.

County: Winnebago

Township, Range, Section:

26N, 11E, 1	26N, 11E, 2
26N, 11E, 3	27N, 11E, 22
27N, 11E, 23	27N, 11E, 24
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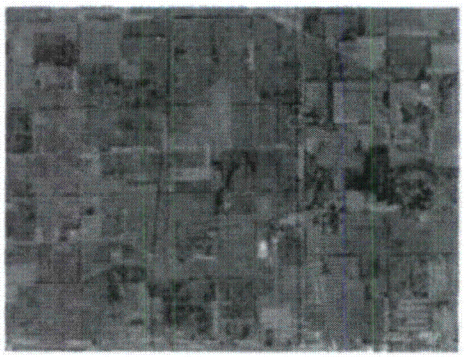

IL Department of Natural Resources Contact
Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

IDNR Project Number: 1210864

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EcoCAT
Ecological Compliance Assessment Tool

Applicant:	Exelon Generation Company LLC	*IDNR Project #:*	1210866
Contact:	Robert J Tarr	Date:	03/16/2012
Address:	200 Exelon Way Kennett Square, PA 19348		

Project: Renewal of Facility Operating Licenses by the U.S. Nuclear Regulatory Commission
Address: (NRC) for Byron Generating Station, Units 1 and 2, Wempleton Transmission Segment 8
4450 N German Church Road, Byron

Description: Exelon Generation Company LLC seeks renewal of the NRC operating licenses for Byron Generating Station, Units 1 and 2, in order to provide an option for power generation capability beyond the term of the current operating licenses, as such needs may be determined by State, utility, and where authorized, Federal (other than the NRC) decision makers. License renewal will authorize no new construction or operational changes either at the Station or along the associated electricity transmission line rights-of-way.

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Location

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County: Winnebago

Township, Range, Section:

27N, 11E, 11	27N, 11E, 12
27N, 11E, 13	27N, 11E, 14
27N, 11E, 23	27N, 11E, 24

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Impact Assessment Section
217-785-5500
Division of Ecosystems & Environment

IDNR Project Number: 1210866

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Ranek, Nancy L.:(GenCo-Nuc)

From:	Duyvejonck, Jon [jon_duyvejonck@fws.gov]
Sent:	Thursday, December 06, 2012 9:17 AM
To:	Ranek, Nancy L.:(GenCo-Nuc)
Subject:	Byron Station License Renewal

Nancy, The Service has reviewed the in formation provided in your letter of November 9, 2012 regarding the license renewal for the Byron, IL nuclear generating station. Based on this information and the fact that no changes in the operation are proposed, we have no comments to offer at this time.

--
Jon Duyvejonck
US Fish and Wildlife Service
Rock Island Field Office
tel. 309/757-5800, ex 207

Biological Evaluation – Byron Station

Executive Summary

Exelon Generation, LLC (Exelon Generation) plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for Byron Station (Byron) Units 1 and 2 in June 2013. The existing operating license for Unit 1 will expire on October 31, 2024, and the existing operating license for Unit 2 will expire on November 6, 2026. Renewed licenses would allow Byron Units 1 and 2 to operate until 2044 and 2046, respectively. The proposed action is the extensions by the NRC of the licenses for the two units at Byron.

The application for license renewal includes an environmental report (ER) that describes the site as well as the Byron facilities and operations. The ER also describes the potentially affected environment including aquatic resources and riparian communities, critical and important habitats, and endangered and threatened species. Extensive descriptions of the site, the facilities and operations, and the affected environment can be found in the Applicant's Environmental Report – Operating License Renewal Stage, Byron Station, which will be submitted to the NRC in June 2013. The contents of the Byron License Renewal ER were available to the analyst who prepared this biological evaluation.

Based on information regarding plant operations and the affected environment, analysts with expertise in specific subject matter areas and the National Environmental Policy Act have made conclusions regarding the potential effects of the continued operation of Byron on the affected environment. For protected species, biologists reviewed the state and federal protected species lists and compiled a list of state or federally endangered, threatened, or proposed species that have been reported in Ogle County (see ER Table 2.5-1). Biologists reviewed published habitat descriptions of all federally-listed species, and interviewed Exelon Generation biologists regarding occurrences of these species at Byron.

The Summary Table of Federally- Endangered or Threatened Species at the Byron Station, below, provides Exelon Generation's determination regarding the effect of continued operations on each species. The bases for these conclusions are provided in the accompanying text. Based on this review, and the fact that Byron operations do not now affect any protected species, that Byron is not proposing different operating parameters for the license renewal term, and that issuing a renewed license does not authorize construction, Exelon Generation believes that operation of the Byron Station during the terms of the renewed licenses is not likely to adversely affect any federally-listed species.

Exelon Generation provided a project description in its letter to the U. S. Fish and Wildlife Service, dated November 9, 2012. Additional information is available in the ER. As indicated in the Summary Table below, Federally- Endangered or Threatened Species reported in Ogle County are limited to the Indiana bat (*Myotis sodalis*), prairie bush clover (*Lespedeza leptostachya*), and Eastern prairie fringed orchid (*Platanthera leucophaea*). Federally designated critical habitat for the Indiana bat does not exist in Ogle County. Critical habitat has not been federally designated for the prairie bush clover nor the Eastern prairie fringed orchid.

Summary Table of Federally- Endangered or Threatened Species at the Byron Station		
SPECIES	**FEDERAL STATUS**	**DETERMINATION**
Indiana bat *Myotis sodalis*	Endangered	No effect
Prairie bush clover *Lespedeza leptostachya*	Threatened	No effect
Eastern prairie fringed orchid *Platanthera leucophaea*	Threatened	No effect

Introduction

Most of the 1,782-acre Byron site is occupied by power generating facilities, support/admin facilities, transmission facilities (switchyard, towers), utility and pipeline rights-of-way, roads, and parking lots. Approximately 750 acres of the site are leased to local farmers for agriculture. Wildlife habitat at the Byron site is limited to scattered wooded areas, meadows, and grassland parcels. The existing meadows and grassland areas have been impacted by various historical activities and are not remnants of undisturbed prairie habitat. In addition, the wooded areas, meadows, and grassland parcels are near active, brightly-lit industrial facilities and are criss-crossed by roads, transmission corridors, and the intake/discharge pipeline corridor. There is no high-quality wildlife habitat on the Byron site, and animal species seen there are those typical of northwestern Illinois, such as the raccoon, Virginia opossum, common crow, American robin, and white-throated sparrow. Byron withdraws makeup water for the circulating water system from, and discharges permitted effluents to, the Rock River. No federally listed fish or mussel species is believed to occur in the Rock River in the vicinity of the Byron site.

Species-specific Assessments

Indiana bat

Federally-endangered Indiana bats (*Myotis sodalis)* winter (hibernate) in caves and use a variety of habitats in summer, from pasturelands to forests. Summer roosts are typically in mature forests where dead trees, hollow trees, snags and live, older trees with peeling bark may be found. There is no undisturbed natural habitat on the Byron property. There are no large blocks of mature forest on the property. The fact that there is no high-quality roost habitat coupled with the fact that Byron is a noisy (PA system, pumps, diesels, heavy equipment), lighted, industrial facility means that Indiana bats are not likely to be found in the vicinity, except as transients moving between wintering and summering areas. Renewal of Byron's operating licenses will involve no new construction or land-disturbing activities. License renewal will not entail any change in plant operations or plant maintenance routines. There will be no change in the way wooded portions of the site are managed. Exelon Generation therefore concludes that renewal of the Byron operating license would have no effect on the Indiana bat.

Prairie bush clover

Prairie bush clover (*Lespedeza leptostachya)*, federally listed as threatened, is typically found only in open, prairie-like areas with moderately damp to dry soils. The open areas on the Byron site are not optimal habitat for the prairie bush clover. Exelon Generation environmental personnel and contractors

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have never observed this species on plant property. Renewal of Byron's operating licenses will involve no new construction or land-disturbing activities. License renewal will not entail any change in plant operations or plant maintenance routines. Exelon Generation therefore concludes that renewal of the Byron operating license would have no effect on the prairie bush clover.

Eastern prairie fringed orchid

The Eastern prairie fringed orchid (*Platanthera leucophaea)*, federally listed as threatened, occurs in a wide variety of habitats, including mesic prairie, wetlands such as sedge meadows, marsh edges, and bogs. It requires full sun for optimum growth and flowering and a grassy habitat with little or no woody encroachment. Optimal habitat for the Eastern prairie fringed orchids does not exist on the Byron site, and Exelon Generation environmental personnel and contractors have never observed Eastern prairie fringed orchids on plant property. Renewal of Byron's operating licenses will involve no new construction or land-disturbing activities. License renewal will not entail any change in plant operations or plant maintenance routines. Exelon Generation therefore concludes that renewal of the Byron operating license would have no effect on the Eastern prairie fringed orchid.

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Appendix D

Cultural Resources Correspondence

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Exelon Generation.

Michael P. Gallagher
Vice President, License Renewal
Exelon Nuclear

200 Exelon Way
Kennett Square, PA 19348

[illegible] Office
[illegible] Fax
www.exeloncorp.com

michaelp.gallagher@exeloncorp.com

November 09, 2012

Ms. Anne E. Haaker
Deputy State Historic Preservation Officer
Preservation Services Division
Illinois Historic Preservation Agency
1 Old State Capitol Plaza
Springfield, Illinois 62701-1507

SUBJECT: Exelon Generation, LLC - Byron Station Units 1 and 2 License Renewal Application. Request for Information on Historic and Archaeological Resources

Dear Ms. Haaker:

Exelon Generation, LLC (Exelon) plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for Byron Station (Byron) Units 1 and 2, in June 2013. The existing operating license for Unit 1 will expire on October 31, 2024, and the existing operating license for Unit 2 will expire on November 6, 2026. Renewed licenses would allow Byron Units 1 and 2 to operate until 2044 and 2046, respectively.

As part of the license renewal process, the NRC requires license renewal applications to include environmental reports assessing the impacts from license renewal activities on historic and archeological resources on the Byron site and within the transmission line rights-of-way (ROW) that connect the plant to the transmission system. Pursuant to the National Environmental Policy Act (NEPA), this letter seeks input from the Illinois SHPO regarding such effects in the vicinity of Byron. Later, NRC may also request an informal consultation with your office in accordance with Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470), and the federal Advisory Council on Historic Preservation regulations (36 CFR 800).

Project Features

Byron is in northern Illinois near the center of Ogle County, approximately 90 miles west-northwest of Chicago, 17 miles southwest of Rockford, and 3.7 miles south-southwest of the City of Byron, as shown in Figure 1.

The Byron site property includes approximately 1,782 acres, which consists of the main site area and a right-of-way (ROW) to the Rock River for the cooling tower makeup water intake and blowdown discharge pipelines. The main site area consists of approximately 1,398 acres while the water pipelines ROW consists of the remaining 384 acres. The site is situated on a topographic high in the Rock River Hill Country physiographic province, in an agricultural area.

The nuclear generating facilities at Byron are sited in the approximate center of the main site area and include the two reactor containment buildings and related structures, two natural draft cooling towers, a switchyard, administration buildings, warehouses, and other features. The cooling tower makeup water intake and blowdown discharge pipelines ROW runs from the northwest site boundary approximately 2 miles west to the Rock River.

Three 345-kilovolt (345-kV) electrical transmission line ROWs totaling an additional approximately 1,210 acres, shown on Figures 2 and 3, were constructed with the station to connect it to the electric grid and are considered to be within the scope of the license renewal project. One ROW runs north and then east from Byron approximately 30 miles to the Wempleton Transmission Substation, located approximately 7 miles northwest of Rockford, IL. A second ROW runs northeast from Byron for approximately 21 miles, to the Cherry Valley Transmission Substation. The third ROW goes directly south for a total length of 8.5 miles to its intersection with the Nelson to Cherry Valley transmission line, which existed before Byron was constructed. All three ROWs pass through primarily agricultural land with some areas of forest or lesser value land use categories. These ROWs are owned and maintained Commonwealth Edison Company (ComEd). In locations where a ROW passes through farmland, the land generally continues to be used as farmland.

Identification of Historic and Archeological Resources

Using the National Register Information System (NRIS) on-line database, a search was conducted to identify any historic properties listed on the National Register of Historic Places (NRHP) within a six- mile radius of the Byron property, which encompasses the ROW for the cooling tower makeup water intake and blowdown discharge pipelines, and within two miles of the transmission line ROWs of interest. Eight sites listed on the NHRP are within six miles of Byron, and no sites are within two miles of any of the ROWs. Table 1 lists the identified historic properties within six miles of Byron.

A search of the Illinois State Archaeological Site Files identified 204 previously recorded archaeological sites within six miles of the Byron facility, or within two miles of the transmission line ROWs of interest. Eight of the previously recorded archeological sites are on the Byron property, and another seven are wholly or partially within one of the transmission line ROWs. None of the archaeological resources located on Byron and in the three transmission line ROWs was added after the original surveys were completed prior to construction. Table 2 lists the archaeological resources on Byron and within the ROWs.

Activities During the License Renewal Term

Renewal of Byron Units 1 and 2 operating licenses will involve neither new construction, nor any land disturbing activities, changes to plant operations, or modifications of the transmission system that connects the plant to the regional electric grid. Operation and maintenance activities during the terms of the renewed licenses are only expected to occur in previously disturbed areas or existing ROWs. Hence, Exelon believes that continued operation and maintenance of Units 1 and 2 over the license renewal terms (i.e., an additional 20 years for each unit), including maintenance of the ROWs for the transmission line and cooling tower makeup water intake and blowdown discharge pipelines, would not adversely affect any archeological or historically significant resources. Even so, Exelon Generation is implementing specific procedures, including a Cultural Resources Management Plan (CRMP), for protecting cultural resources in undisturbed areas from activities related to operation and maintenance on the Byron plant site, including the ROW for the cooling tower makeup water intake and blowdown discharge pipelines. Therefore, effects on cultural resources from future activities would be identified in advance and avoided or appropriately mitigated.

In the case of the three project-related transmission line ROWs, ComEd has established maintenance procedures for transmission line ROWs that involve minimal land disturbance and are unlikely to result in inadvertent adverse impacts to potential historic or archaeological resources.

As stated earlier, this letter seeks input from the Illinois SHPO regarding the effects that license renewal activities may have on historic and archeologically significant resources in the vicinity of Byron. After your review of the information provided in this letter, Exelon would appreciate your sending a letter detailing any concerns you may have about historic and archaeological resources in the area of Byron, or within two miles of the ROWs of interest, or alternatively, confirming that operation of Byron over the license renewal terms would have no effect on known historic or archaeological resources.

Because Exelon will incorporate a copy of your response, as well as this letter, into the Byron license renewal environmental report that will be submitted to the NRC as part of the Byron license renewal application, your response will be most helpful if it is received by December 14, 2012.

Please refer any questions regarding this submittal to Nancy Ranek, our License Renewal Environmental Lead, at (610) 765-5369. Thank you in advance for your assistance.

Sincerely,

Michael P Gallagher

Michael P Gallagher

Enclosures:
- Figure 1: Project Location Map
- Figure 2: Byron to Wempleton and Cherry Valley Transmission Line ROWs
- Figure 3: Byron to Nelson-Cherry Valley Transmission Line ROW
- Table 1: Sites Listed on the National Register of Historic Places within 6 Miles of Byron
- Table 2: Archeological Sites on Byron Station Property or Wholly or Partially Within Byron ROWs

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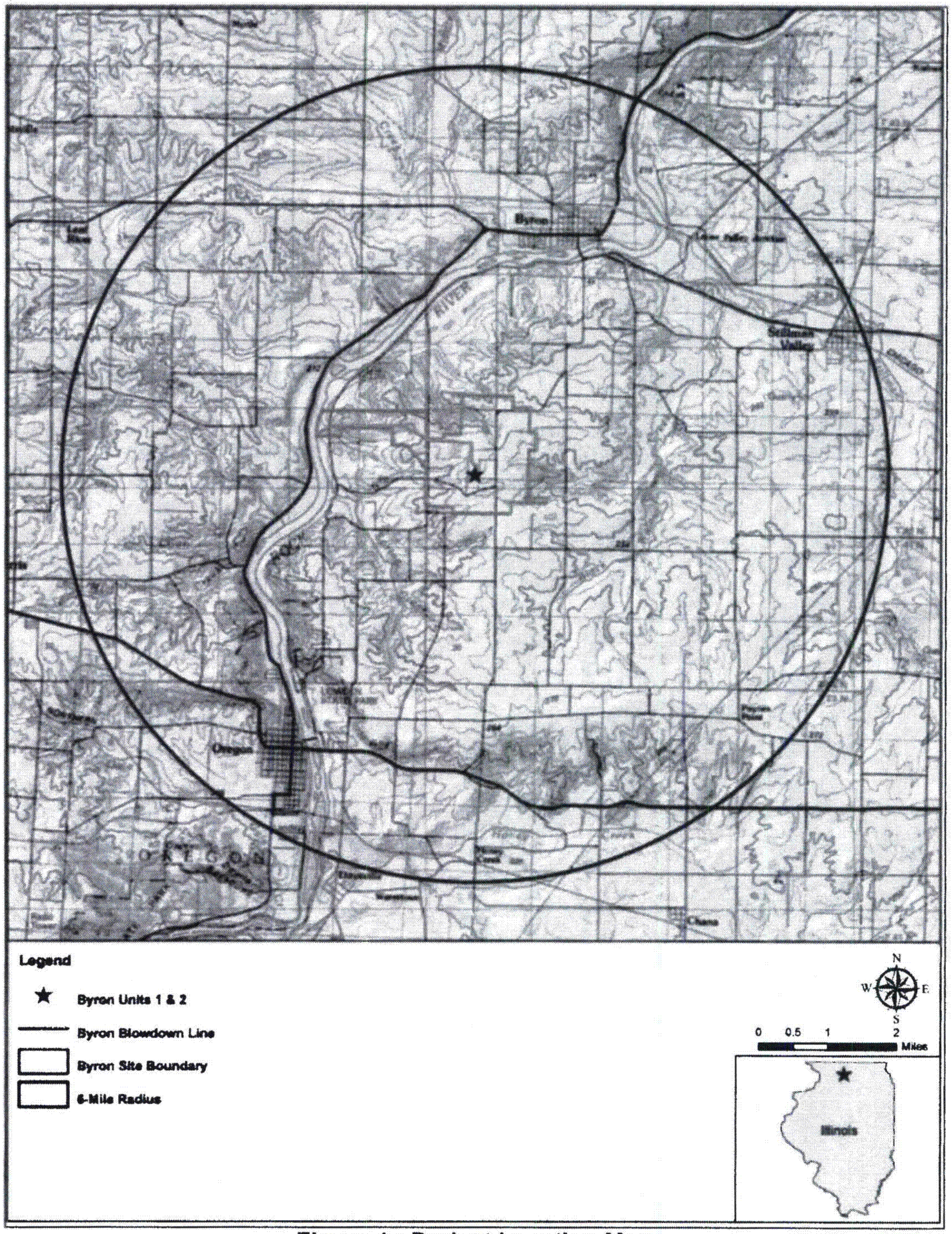

Figure 1: Project Location Map

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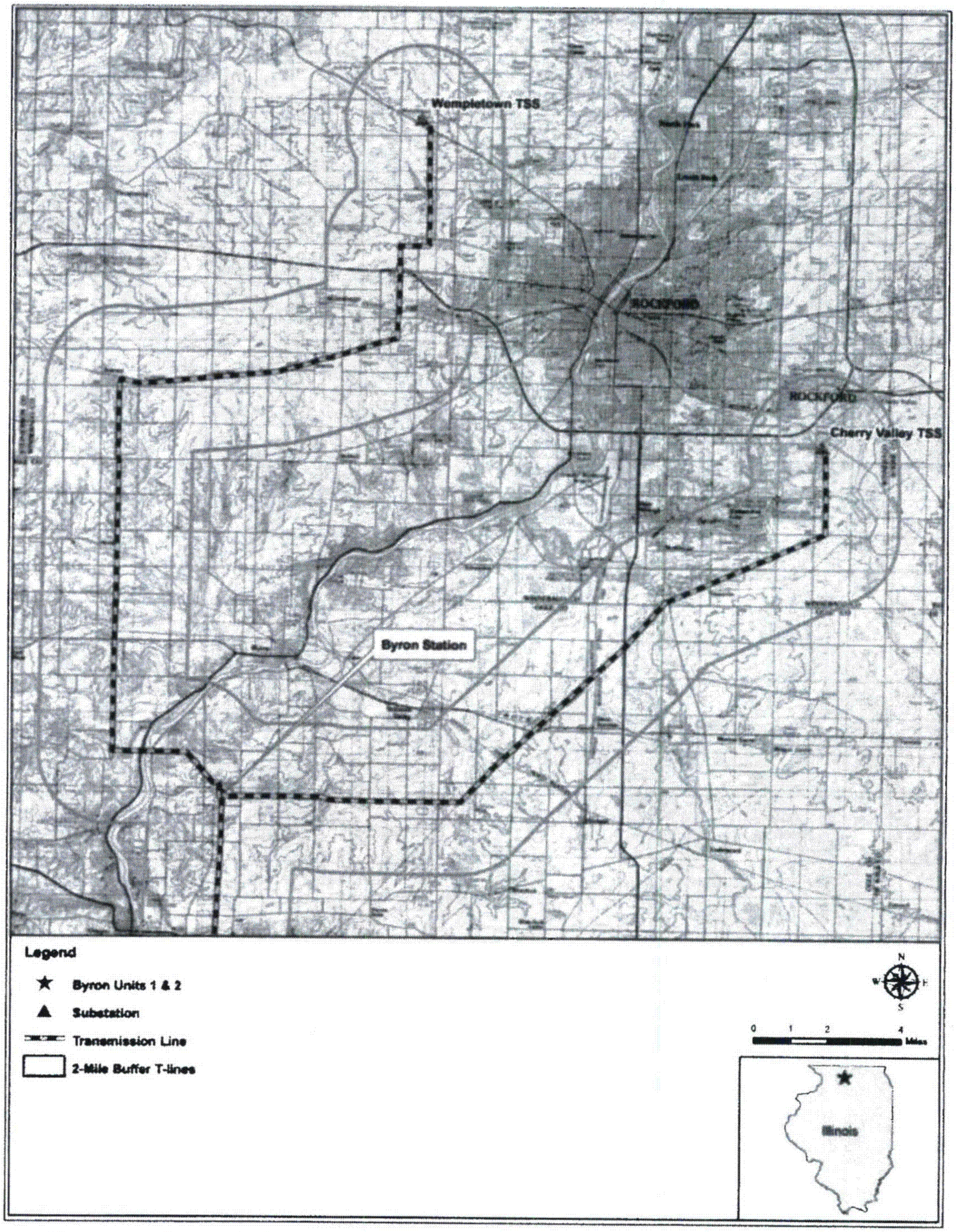

Figure 2: Byron to Wempleton and Cherry Valley Transmission Line ROWs

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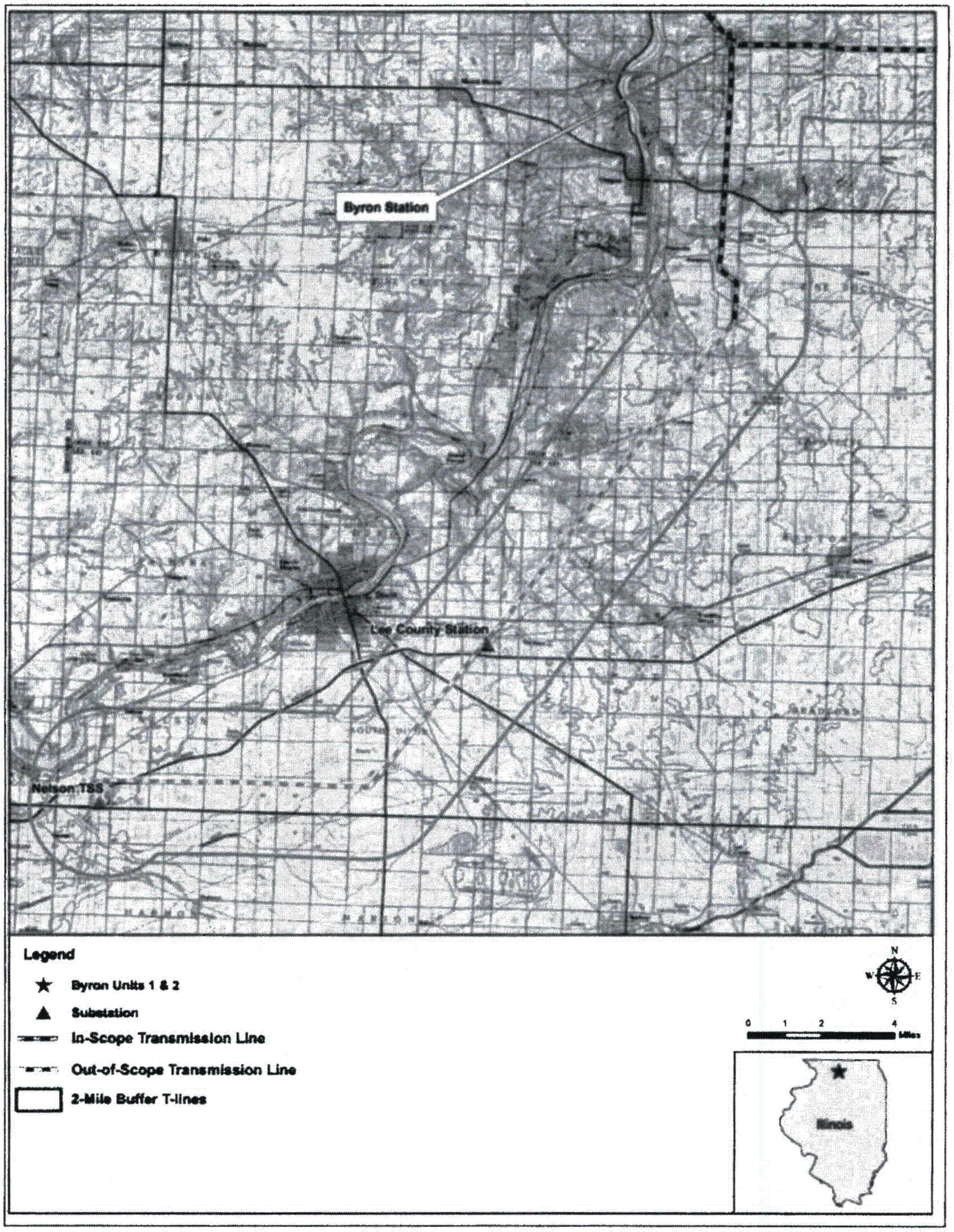

Figure 3: Byron to Nelson-Cherry Valley Transmission Line ROWs

Table 1. Sites listed on the National Register of Historic Places within 6 miles of Byron

Site Name	Address	City, County	Distance from Station or Line (miles)
Soldier's Monument	Chestnut and 2nd Streets	Byron, Ogle	3.7
Stillman's Run Battle Site	Roosevelt and Spruce Streets.	Stillman Valley, Ogle	5.6
Chana School	201 N. River Road.	Oregon, Ogle	4
Ogle County Courthouse	Courthouse Square	Oregon, Ogle	4.2
Pinehill	400 Mix Street	Oregon, Ogle	4.6
Oregon Commercial Historic District	Roughly Bounded by Jefferson, Franklin, 5th and 3rd Streets	Oregon, Ogle	4.3
Oregon Public Library	300 Jefferson Street	Oregon Ogle	4.5
Chicago, Burlington, and Quincy Railroad Depot	400 Collins Street	Oregon Ogle	5.3

Table 2. Archaeological Sites on Byron Station Property or Wholly or Partially Within Byron ROWs

Site Number	Site Type	Location
11OG153	Archaic	Byron Station Property
11OG154	Archaic	Byron Station Property
11OG155	Unknown Prehistoric	Byron Station Property
11OG156	Unknown Prehistoric	Byron Station Property
11OG157	Unknown Prehistoric	Byron Station Property
11OG158	Unknown Prehistoric	Byron Station Property
11OG175	Unknown Prehistoric	Byron Station Property
11OG176	Unknown Prehistoric	Byron Station Property
11OG223	Archaic	Transmission Line ROW
11OG224	Prehistoric Isolated Find	Transmission Line ROW
11OG225	Middle to Late Woodland	Transmission Line ROW
11OG227	Prehistoric Unknown	Transmission Line ROW
11OG228	Prehistoric Unknown	Transmission Line ROW
11OG232	Archaic to Woodland	Transmission Line ROW
11OG234	Archaic	Transmission Line ROW

Illinois Historic
Preservation Agency

1 Old State Capitol Plaza • Springfield, Illinois 62701-1512 • www.illinois-history.gov

Ogle County PLEASE REFER TO: IHPA LOG #006111312
Byron
West of the Rock River
NRC
Operating license renewal, Exelon Generation, LLC

November 15, 2012

Michael P. Gallagher
Exelon Generation, LLC
200 Exelon Way
Kennett Square, PA 19348

Dear Mr. Gallagher:

We have reviewed the documentation submitted for the referenced project(s) in accordance with 36 CFR Part 800.4. Based upon the information provided, no historic properties are affected. We, therefore, have no objection to the undertaking proceeding as planned.

Please retain this letter in your files as evidence of compliance with section 106 of the National Historic Preservation Act of 1966, as amended. This clearance remains in effect for two (2) years from date of issuance. It does not pertain to any discovery during construction, nor is it a clearance for purposes of the Illinois Human Skeletal Remains Protection Act (20 ILCS 3440).

If you are an applicant, please submit a copy of this letter to the state or federal agency from which you obtain any permit, license, grant, or other assistance.

Sincerely,

Anne E. Haaker

Anne E. Haaker
Deputy State Historic
Preservation Officer

A teletypewriter for the speech/hearing impaired is available at 217-524-7128. It is not a voice or fax line.

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Appendix E

Microbiological Correspondence

Byron Station Environmental Report

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Exelon Generation.

Michael P. Gallagher
Vice President, License Renewal
Exelon Nuclear

200 Exelon Way
Kennett Square, PA 19348

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www.exeloncorp.com

michaelp.gallagher@exeloncorp.com

January 23, 2013

David W. Culp, Ph.D., Deputy Director
Illinois Department of Public Health
Office of Health Protection
525 W. Jefferson St., 2nd Floor
Springfield, Illinois 62761-0001

SUBJECT: Exelon Generation, LLC – Byron Station Units 1 and 2 License Renewal Project. Request for information on Thermophilic Pathogens – Ogle County

Dear Dr. Culp:

In May 2013, Exelon Generation Company, LLC (Exelon Generation; a subsidiary of Exelon Corporation) plans to apply to the Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for Byron Station (Byron), Units 1 and 2. The Byron Units began commercial operation in 1985 and 1987, respectively. The existing operating license for Byron Unit 1 expires October 31, 2024, and the existing operating license for Byron Unit 2 expires November 6, 2026. License renewal will extend the license terms to October 31, 2044 and November 6, 2046, respectively.

The NRC requires that the license renewal application include an environmental report assessing potential impacts from license renewal activities, including continued operations. One such impact is the "impact of the proposed action [license renewal] on public health from thermophilic organisms in the affected water" (10 CFR 51.53(c)(3)(ii)(G)). Accordingly, we are contacting you to obtain input regarding potential public health concerns associated with the enteric pathogens *Salmonella* spp and *Shigella* spp as well as *Pseudomonas aeruginosa* bacterium, thermophilic fungi, *Legionella* spp in unusually high concentrations, and the free-living amoeba of the genera *Naegleria* and *Acanthomoeba*. Of greatest concern is the genus *Naegleria*, comprising four species. To date only one species, *N. fowleri*, has been determined to be pathogenic in humans.

Project Features

Byron is located in northern Illinois near the center of Ogle County, approximately 90 miles (mi) west-northwest of Chicago, 17 mi southwest of Rockford, and 3.7 mi south-southwest of the City of Byron. The Rock River is approximately 2 mi west of the western site boundary.

The following paragraphs provide background information on the Byron cooling system, and Exelon Generation's assessment of potential effects on the public. We are requesting your help to identify issues regarding thermophilic organisms that we may have overlooked, but that should be addressed in the Byron license renewal environmental report. We are particularly interested in learning of any information your staff believes could expedite the NRC's review of the Byron license renewal application.

Cooling System

Each of Byron's two units has a closed-cycle recirculating cooling water system with a natural draft cooling tower. An open cooling water basin and intake flume is located between the two natural draft cooling towers. Makeup water for the cooling towers to replace water lost to evaporation, drift, and blowdown comes from the Rock River. Blowdown water is returned to the Rock River through an NPDES-permitted (IL0048313) outfall (Outfall 001) for the purpose of reducing dissolved solids that build up in the circulating water system as the condenser cooling water recycles through the natural draft cooling towers. Byron operates an onsite package sewage treatment plant. The effluent from the sewage treatment plant mixes with the blowdown water discharge before both are released through Outfall 001. The outfall structure discharges through a 275-ft-long rip-rapped channel into the east side of the river approximately 200 feet downstream of the intake structure.

The flow rate of blowdown discharged to Rock River ranges between 29 and 38 cubic feet per second (cfs), depending on water chemistry (concentrations of mineral solids) in the cooling tower basins Results of thermal modeling prior to construction of the station predicted that the blowdown would create a thermal plume with a surface area ranging from 0.45 to 2.8 acres between May and August and that discharge temperatures would meet water quality standards.

Under Illinois Administrative Code (IAC) Title 35, Section 302.102(b)(8), "a [temperature] mixing zone must not contain more than 25 percent of the cross-sectional area or volume of flow of a stream." In Special Condition 3 of NPDES permit IL0048313, the Illinois EPA has determined that Byron's blowdown discharge meets this criterion as well as the thermal water quality standard in Title 35, Section 302.211. In addition, as specified in Special Condition 12 of NPDES permit IL0048313, Byron must explicitly demonstrate compliance with the thermal water quality standard on a daily basis during times when the Rock River flow is less than 2,400 cfs, or the temperature difference between the main river temperature and the water quality standard is less than 3°F.

Byron also has an agreement with the Illinois Department of Natural Resources (DNR) to limit consumption of water from the Rock River for makeup to the Byron cooling systems to no more than 9 percent of total river flow during times when the river flow rate drops below 679 cfs. To maintain compliance, Byron adjusts the circulating water system makeup and blowdown flows, and if necessary, would reduce the power output from the units.

Byron water systems that recirculate and blow down to the Rock River are treated with biocides, including sodium hypochlorite and sodium bromide, for biofouling control. Additionally, sulfuric acid, polyphosphate, potassium phosphonate, acrylic polymer, and triazole are used for scaling control; zinc for corrosion control; and polyacrylate for silt dispersal. Makeup from the river is treated with a low concentration of copper ions to prevent zebra mussel infestation.

An Environmental Protection Plan is incorporated in the NRC operating licenses for Byron. The Environmental Protection Plan incorporates the NPDES permit by reference. Blowdown flow and temperature are monitored and reported to the Illinois EPA in monthly NPDES Discharge Monitoring Reports.

The stream segment (IL_P-20) of the Rock River receiving the discharge from Byron Outfall 001 is identified in the December 2012 *Illinois Integrated Water Quality Report and Section 303(d) List* as fully supporting primary (and secondary) contact. These designations are based on fecal coliform measurements only. Primary contact is "any recreational or other water use in which there is prolonged and intimate contact with the water involving considerable risk of ingesting water in quantities sufficient to pose a significant health hazard such as swimming and water skiing" (IAC Title 35, Section 301.355).

Conclusions

The temperature of the blowdown water discharged from Byron's circulating water system to the Rock River is monitored and reported to the Illinois EPA to verify compliance with the Station's NPDES permit. The size of the discharge thermal plume (mixing zone) is consistent with Illinois EPA regulatory requirements. The circulating water system is treated with biocides, and the sewage treatment plant effluent mixes with the circulating water system blowdown prior to discharge. For these reasons, Exelon Generation concludes that blowdown water discharges from Byron are having little effect on the small risk to public health posed by exposure to thermophilic pathogens possibly present in stream segment IL_P-20 of the Rock River.

Furthermore, because renewal of the Byron Units 1 and 2 operating licenses by NRC will authorize no new construction, refurbishment or operational changes to the circulating water system that would affect thermal characteristics of the discharge, Exelon Generation concludes that the proposed license renewals would not contribute to any increase in adverse effects on public health from exposure to *N. fowleri* or any other thermophilic pathogen in the Rock River.

In closing, we would appreciate receiving a response from you detailing issues or information that we may have overlooked and that your staff believes could expedite NRC's review of the Byron License Renewal Application. We would also welcome your confirmation of our conclusions that renewing the Byron operating licenses would not increase adverse effects on public health from exposure to thermophilic pathogens in the Rock River.

Because Exelon Generation will incorporate a copy of your response, as well as this letter, into the environmental report that will be submitted to the NRC as part of the Byron License Renewal Application, your response will be most helpful if we receive it by February 13, 2013.

Please call Nancy Ranek (610) 765-5369, Exelon Generation's License Renewal Environmental Lead, if you have questions or require additional information. Thank you in advance for your assistance.

Respectfully,

Michael P. Gallagher
Vice President – License Renewal
Exelon Generation, LLC

Illinois Department of
PUBLIC HEALTH

MP8 3.13.13

Applies to Both
Byron & Braidwood

Pat Quinn, Governor
LaMar Hasbrouck, MD, MPH, Director

525-535 West Jefferson Street · Springfield, Illinois 62761-0001 · www.idph.state.il.us

March 3, 2013

Mr. Michael P Gallagher
Vice President, License Renewal Exelon Nuclear
200 Exelon Way
Kennett Square, PA 19348

Dear Mr. Gallagher:

The Illinois Department of Public Health (IDPH) has received your letter requesting that the Office of Health Protection review part of your application for license renewal for Byron Station Units 1 and 2. The Division of Environmental Health has determined that evaluating and commenting on this license renewal application is outside the scope of our mission and that staff do not have the expertise necessary to adequately evaluate the application.

If you have additional health-related questions, please contact Tiffanie Denny, Environmental Toxicologist, at 217-782-5830 or TTY (for hearing impaired use only) 800-547-0466.

Sincerely,

Ken McCann, MA, LEHP
Chief, Division of Environmental Health

JLP

Improving public health, one community at a time

printed on recycled paper

Appendix F

Severe Accident Mitigation Alternatives Analysis Rev. 2

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LIST OF TABLES

LIST OF FIGURES

Acronyms Used in Attachment F

AF	auxiliary feedwater
AFW	auxiliary feedwater
AOT	allowable outage time
AMSAC	anticipated transient without scram mitigating system actuation circuitry
AP	auxiliary power
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
CC	component cooling water
CCF	common cause failure
CCP	centrifugal charging pump
CCW	component cooling water
CDF	core damage frequency
CET	containment event tree
CF	containment failure
CHR	containment heat removal
CIS	containment isolation system
COP	containment overpressurization
CPI	consumer price index
CS	containment spray
CST	condensate storage tank
CV	chemical and volume control system
CVCS	chemical and volume control system
DCH	direct containment heating
DG	diesel generator
DMS	diverse mitigation system
DOE	Department of Energy
ECCS	emergency core cooling system
EDG	emergency diesel generator
EE	external events
EFPD	effective full power days
EPRI	Electric Power Research Institute
EPZ	emergency planning zone
ESF	engineered safety features
ESFAS	engineered safety features actuation system

Acronyms Used in Attachment F	
ETE	evacuation time estimate
F&O	fact and observation
FP	fire protection
FPIE	full power internal events
F-V	Fussell-Vesely
FW	feedwater
GE	general emergency
HCLPF	high confidence of low probability of failure
HEP	human error probability
HPI	high pressure injection
HRA	human reliability analysis
HVAC	heating ventilation and air-conditioning
HX	heat exchanger
IA	instrument air
IE	initiating event
IPE	individual plant examination
IPEEE	individual plant examination – external events
ISGTR	induced steam generator tube rupture
ISLOCA	interfacing system LOCA
JHEP	joint human error probability
LCO	limiting conditions of operation
LERF	large early release frequency
LMFW	loss of main feedwater
LOCA	loss of coolant accident
LOOP	loss of off-site power
MAAP	modular accident analysis program
MACCS2	MELCOR accident consequences code system, version 2
MACR	maximum averted cost-risk
MCC	motor control center
MCR	main control room
MDAFW	motor-driven auxiliary feedwater
MFW	main feedwater
MOV	motor operated valve
MSPI	mitigating systems performance index

Acronyms Used in Attachment F	
MUR	measurement uncertainty recapture
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OECR	off-site economic cost risk
PDP	positive displacement pump
PDS	plant damage state
PGA	peak ground acceleration
PI-SGTR	pressure induced steam generator tube rupture
PMF	probable maximum flooding
PMP	probable maximum precipitation
PORV	power operated relief valve
PRA	probabilistic risk analysis
PSA	probabilistic safety assessment
PWR	pressurized water reactor
RAI	request for additional information
RCFC	reactor containment fan coolers
RCP	reactor coolant pump
RCS	reactor coolant system
RDR	real discount rate
RHR	residual heat removal
RLE	review level earthquake
RPS	reactor protection system
RPV	reactor pressure vessel
RRW	risk reduction worth
RWST	refueling water storage tank
SAMA	severe accident mitigation alternative
SAT	system auxiliary transformer
SBO	station blackout
SG	steam generator
SGTR	steam generator tube rupture
SI	safety injection
SLB	steam line break
SLOCA	small loss of coolant accident
SOARCA	state of the art consequences analysis

Acronyms Used in Attachment F	
SR	supporting requirement
SRP	standard review plan
SSPS	solid state protection system
SX	essential service water
TI-SGTR	thermally induced steam generator tube rupture
TS	technical specification
URE	updating requirement evaluation
VA	auxiliary building HVAC
VB	vessel breach
VCT	volume control tank
WS	normal service water

SEVERE ACCIDENT MITIGATION ALTERNATIVES

The severe accident mitigation alternatives (SAMA) analysis discussed in Section 4.20 of the Environmental Report is presented below.

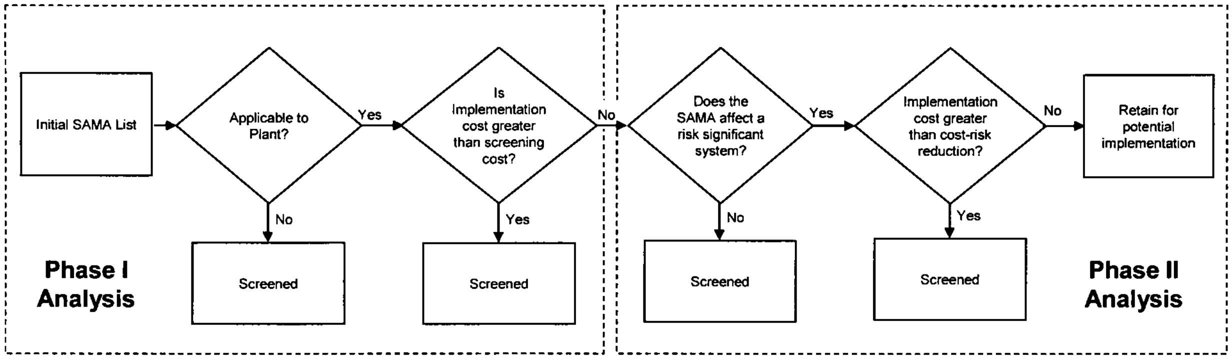
F.1 METHODOLOGY

The methodology selected for this analysis is contained in NEI 05-01, Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document (NEI 2005), which has been reviewed and endorsed by the U.S. Nuclear Regulator Commission (NRC). It involves identifying SAMA candidates that have potential for reducing plant risk and determining whether or not the implementation of those candidates is beneficial on a cost-risk reduction basis. The metrics chosen to represent plant risk include the core damage frequency (CDF), the dose-risk, and the offsite economic cost-risk. These values provide a measure of both the likelihood and consequences of a core damage event.

The SAMA process consists of the following steps:

- Byron Station (Byron) Probabilistic Risk Assessment (PRA) Model – Use the Byron Internal Events PRA model as the basis for the analysis (Section F.2). Incorporate External Events contributions as described in Section F.4.6.2.
- Level 3 PRA Analysis – Use the Byron Level 1 and 2 Internal Events PRA output and site-specific meteorology, demographic, land use, and emergency response data as input in performing a Level 3 PRA using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section F.3). Incorporate External Events contributions as described in Section F.4.6.2.
- Baseline Risk Monetization – Use U.S. Nuclear Regulatory Commission (NRC) regulatory analysis techniques to calculate the monetary value of the unmitigated Byron severe accident risk. This becomes the maximum averted cost-risk that is possible (Section F.4).
- Phase 1 SAMA Analysis – Identify potential SAMA candidates based on the Byron Probabilistic Risk Assessment (PRA) (including the current fire model), Individual Plant Examination – External Events (IPEEE), and documentation from the industry and the NRC. Screen out SAMA candidates that are not applicable to the Byron design or are of low benefit in pressurized (PWRs) such as Byron, candidates that have already been implemented at Byron or whose benefits have been achieved at Byron using other means, and candidates whose estimated cost exceeds the maximum possible averted cost-risk (Section F.5).
- Phase 2 SAMA Analysis – Calculate the risk reduction attributable to each of the remaining SAMA candidates and compare to the estimated cost of implementation to identify the net cost-benefit. PRA insights are also used to screen SAMA candidates in this phase (Section F.6).
- Sensitivity Analysis – Evaluate how changes in the SAMA analysis assumptions might affect the cost-benefit evaluation (Section F.7).
- Conclusions – Summarize results and identify conclusions (Section F.8).

The steps outlined above are described in more detail in the subsections of this appendix. The graphic below summarizes the high level steps of the SAMA process.



SAMA SCREENING PROCESS

F.2 BYRON PRA MODEL

The SAMA analysis is based upon Byron PRA model BB011b1, which includes an integrated internal flooding analysis, but not internal fires, seismic events, or other external events. The original Byron PRA was submitted to the NRC to satisfy the requirements of NRC Generic Letter 88-20 (NRC 1989). Since the original Individual Plant Examination (IPE) submittal to the NRC in April 1994 (ComEd 1994), a Modified IPE was submitted in March 1997 (ComEd 1997). The Modified IPE answered requests for additional information (RAI) from the NRC relative to the original IPE and incorporated plant procedure changes and modifications. The PRA was developed from the Modified IPE and since that time, it has been updated on numerous occasions to maintain consistency with the operating plant and to reflect the latest PRA technology.

The following subsections provide more detailed information related to the evolution of the Byron Internal Events PRA model and the current results. These topics include:

- PRA changes since the IPE / IPEEE
- Level 1 model overview
- Level 2 model overview
- PRA model review summary

Sections F.4.6.2 and F.5.1.6 provide a description of the process used to integrate external events contributions into the Byron SAMA process.

F.2.1 PRA MODEL CHANGES SINCE THE IPE/IPEEE

Compared with the IPE, the current PRA includes more current equipment availability and reliability data as well as any subsequent plant configuration changes that have had an impact on the risk profile. In addition to updating the data and plant and procedure changes, the model was converted from a support state model to a single top fault tree model. Over the course of multiple updates, there were many changes to PRA models and databases in each element of the PRA. These changes included:

- Revision of the definition of core damage and the success criteria
- Changes in the selection of initiating events and revision of initiating event frequencies
- Complete revisions to event tree analysis
- Enhancements and additions of system fault trees
- Enhanced treatment of offsite power recovery
- Upgraded PRA reliability database with plant-specific information
- Revision to common cause failures (CCFs) and the CCF data

- Revision to treatment of human actions
- Revised internal flooding analyses

Table F.2-1 provides a summary of the model revision history, including a description of the major update issues for each revision.

F.2.2 LEVEL 1 MODEL OVERVIEW

The Byron Level 1 PRA model includes a comprehensive treatment of accident sequences producing core damage from internal events at full power, including internal flooding. The frequency of all sequences for which reactor core cooling performance degrades beyond this point is defined as the Core Damage Frequency (CDF). The annual average CDF for each of the Byron units from the current analysis is shown in the following table.

CDF RESULTS FOR BYRON UNITS 1 AND 2 (BB011b1)

Unit	CDF	Truncation Limit
Byron Unit 1	3.97E-5	1.0E-10
Byron Unit 2	3.82E-5	1.0E-10

The BB011b1 model, which was used to support the SAMA evaluation, was released to document the replacement of the "LERF only" model in the BB011b PRA with the WCAP-16341-P Level 2 model. The Level 1 portions of the BB011b and BB011b1 models are the same. The discussion in F.2.2 describes the Level 1 model that is common to both the BB011b and BB011b1 models.

The leading causes of core damage are described in the following sections.

The freeze date for the inclusion of plant specific date for the model was December 2010. A specific freeze date for physical changes is more difficult to establish given that issues are tracked in a database and addressed based on the priority of the change and the resources available. It is possible that recent risk significant changes have been incorporated in the BB011b/BB011b1 model while the incorporation of older, non-risk significant changes has been deferred until a later model update.

For internal events contributors, the differences between the units are minor and are documented in the PRA system notebook. For the purposes of the SAMA analysis, the Unit 1 model is used as the quantification basis and considered to be representative of both units. For the fire contributors, there are differences in the units which translate to measurable differences in plant risk. For the SAMA analysis, the SAMA identification process was performed separately for each unit (refer to section F.5.1.6.1) to account for the differences. For SAMA quantification, the external events multiplier was based on the larger of the two units' CDF values (section F.4.6.2) and for quantification of fire specific SAMAs, the contributions from the unit specific fire zones were used (section F.6).

F.2.2.1 CONTRIBUTION TO CDF BY INITIATING EVENT

Initiating event contributions to the CDF profile are shown in figures F.2-1 and F.2-2. Details of the highest ranking initiating event contributions are briefly described below. The equipment failures or failures of operator actions which would produce core damage are highlighted.

Loss of Essential Service Water: Loss of Essential Service Water (SX) contributes between 45% and 46% to the CDF.

One set of important cutsets includes a loss of SX (e.g., due to common cause failure of all SX pumps) with failure of the operators to execute main feedwater restoration. Previously, such events were addressed by use of the diesel-driven auxiliary feedwater (AFW) pump, but new restrictions that require a running SX pump to prevent unintended recirculation and overheating of the diesel AFW pump now fail the diesel AFW pump on loss of all SX pumps.

Another important set of cutsets also applies to loss of SX scenarios, but includes operator action dependencies. Loss of SX initiated by loss of a running pump requires operator actions to restore SX by starting the opposite SX pump, cross-tying to the opposite unit, or providing an alternate cooling and suction source to the chemical and volume control (CV) pumps in order to maintain reactor coolant pump (RCP) seal cooling. If the RCP seal loss of coolant accident (LOCA) occurs, the loss of SX also inhibits the ability to remove decay heat during eventual recirculation operations, leading to core damage. Modeling of these sequences includes dependencies among these operator actions and credit for delayed recovery of SX and/or seal cooling.

The contribution of Loss of SX events remains high due to the high probability of an RCP Seal LOCA following a loss of SX. Loss of SX remains a challenging event even if there is not an RCP Seal LOCA as it is vital support to numerous systems (e.g., AF and room cooling for CV, residual heat removal (RH), and the EDGs).

Loss of SX leads to a loss of both sources of RCP seal cooling. The RCP thermal barriers are cooled by the Component Cooling Water (CC) System, and RCP seal injection is provided by the CV pumps. SX serves as the ultimate heat sink for CC as well as providing oil and room cooling for the CV pumps. Without cooling, temperature-induced degradation of the RCP seals may lead to a Seal LOCA event (1 in 5 probability), which is then modeled as a Small LOCA. Loss of SX also fails or degrades much of the key safety equipment needed to maintain primary inventory control. With CV and safety injection (SI) pumps failed due to cooling dependencies on SX, high-pressure primary makeup is unavailable. Continuing primary leakage leads to eventual core damage. The alternate means of cooling the CV pump lube oil coolers from the fire protection (FP) system and the switching of the CV pump intake to the cooler refueling water storage tank (RWST) are important actions in reducing the importance of loss of SX events.

Loss of Component Cooling Water: Loss of Component Cooling Water (CCW) contributes about 21% of CDF with this revision. Several of the minor model changes reduced the contribution of Loss of CCW events, including the modeling of recovery action to align and start the 0CC pump, removal of extraneous common cause failure terms, addition of Loss of CCW initiating events as exclusions to split CC train operation, and correction of some dependent human failure probabilities.

Internal Flooding: Internal Flooding sequences contribute 14-15% to CDF. Overall, the dominant internal flood scenario for CDF involves a rupture of the Fire Protection system within the common areas of the radiological controlled area of the Auxiliary Building. These particular flood scenarios account for about two-thirds of the total internal flood contribution to CDF.

Small LOCA: Small LOCA contributes about 4% to the CDF. Small LOCAs are leaks in the reactor coolant system pressure boundary into the containment with nominal leak rates that are equivalent to those which would be produced by ideal break sizes from about ½ inch to 2 inches in diameter. These include small pipe failures, failures in other pressure boundary components such as RCP seals, and leaks from the pressurizer relief, head vent, and pressurizer safety valves. These leak sources are generally separated into isolable and non-isolable sources. Note that this section discusses the importance of LOCAs from an initiating event perspective. Consequential RCP Seal LOCAs (i.e., failures due to a result of loss of seal injection and cooling) are not discussed in this category, since they are not Small LOCA initiating events, but are modeled as consequential Small LOCAs.

Small LOCAs, which are typically major contributors to PWR PRA results, have a high contribution to CDF due to the multiple mitigation systems required to function to prevent core damage. Since the leak size is not large enough to remove decay heat from the core, decay heat must be removed through the Steam Generators using the Auxiliary Feedwater Pumps, the

Startup Feedwater Pump, or Motor Driven Feedwater Pump. Reactor coolant system (RCS) inventory must also be maintained using emergency core cooling system (ECCS) Injection. Use of the Motor Driven and Startup Feedwater Pumps as a backup to the AF Pumps is hindered since the Safety Injection Signal isolates the Main Feedwater System. Small LOCAs are significantly more likely to occur than larger LOCAs.

The majority of the risk due to accident sequences initiated by small LOCAs is failure of the operator to secure the RH pumps in the mini-flow mode (to prevent their failure).

In Revision 6F, new cutsets included a LOCA with failure of the RH pumps and/or heat exchangers due to their dependence on CC. Small LOCAs are the most likely, so appear with the greatest frequency, but other LOCAs (including consequential LOCAs) also appear in the results.

Loss of Auxiliary Electric Power (AP): This initiating event category contributes approximately 5-6% of the total CDF. These initiating events represent failures of an AP power source to a running component, which then leads to a plant transient. The most important AP failures as initiating events lead to a Loss of SX or Loss of CCW, which are discussed above.

Steam Generator Tube Rupture: This initiating event category represents 3-4% of CDF. As with Small LOCAs, Steam Generator Tube Ruptures (SGTRs) require both Auxiliary Feedwater for Decay Heat Removal and ECCS Injection for RCS Inventory Control. Mitigation of this event is further complicated by the need to identify and isolate the ruptured Steam Generator. In the highest-ranking SGTR sequences, the operators fail to identify and isolate the ruptured steam generator and/or fail to depressurize and cooldown the RCS. If both actions fail, then core damage occurs due to the loss of RCS inventory from the affected steam generator (SG). If the ruptured SG is not isolated or the RCS depressurization / cooldown occurs late in the scenario, the steam generator is overfilled, the power operated relief valves (PORVs) are challenged, and pass liquid. The PORVs are then assumed to fail to fully close. In these scenarios, residual heat removal (RHR) is required for long term cooling, and its failure leads to core damage.

General Transients & LMFW: This initiating event category, which includes general reactor trips and losses of main feedwater (LMFW), accounts for approximately 2% of the total CDF. The General Transient scenarios involve a failure of steam generator heat removal via auxiliary feedwater (AF system failures), followed by the operator failing to re-establish main feedwater using the startup or motor-driven feedwater pumps, followed by failure of bleed and feed cooling. The relatively high frequency of general transient initiating events (as compared to other initiating events) is the primary cause for the importance of this initiator.

Other Transients: This group of events contributes less than 5% of the CDF. The most significant events are Loss of Offsite Power, Loss of a 125V DC Bus, and interfacing system loss of coolant accident (ISLOCA). Each of the contributing events in this group comprises less than 2% of CDF.

RCP Seal LOCA: Also shown in Figure F.2-1 is the contribution of RCP Seal LOCA to the CDF results for Byron; RCP Seal LOCAs account for approximately two-thirds of the total CDF. A majority of the RCP Seal LOCA CDF originates from Loss of SX or Internal Flood initiating events. These initiators are described previously. Loss of Offsite Power and Loss of Component Cooling Water initiators also contribute to the importance of the RCP seals.

F.2.2.2 TOP RANKING ACCIDENT SEQUENCES

The top ranked accident sequences are discussed in Table F.2-2. Examining the top accident sequences provides another perspective on the contributors to CDF. The Byron PRA consists of ten (10) event trees, which contain more than 100 accident sequences. About 10 sequences contribute to 99% of the total CDF. Table F.2-2 presents the significant accident sequences according the definition used in the American Society of Mechanical Engineers (ASME) PRA Standard, which includes all sequences in the top 95% of CDF and any individual sequences contributing more than 1%. The top 8 accident sequences comprise about 95% of the total CDF.

F.2.2.3 RISK IMPORTANCE OF BYRON SYSTEMS

The Fussell-Vesely (F-V) importance measures evaluated from the Byron Unit 1 CDF model are used to evaluate one aspect of risk importance. F-V has been chosen to represent risk importance because it includes consideration of the impact of both initiating events and mitigation capability. Since failure or unavailability of a system may play a role in causing an initiating event or mitigating its consequences, the evaluation of system importance using F-V importance measures includes both aspects contributing to the risk of an accident. Figure F.2-3 shows the relative risk importance of systems at Byron Unit 1 from both initiating event causes and mitigation aspects, based on CDF. The Unit 2 results are very similar; the differences between the units have minor impacts on CDF. Note that basic events representing initiating event pipe rupture (LOCAs and internal floods) and operator actions are not included on the system importance figure since they do not directly relate to system component performance.

As seen in Figure F.2-3, the Essential Service Water (SX) system is the most important system with about 50% contribution. Much of the SX system importance is due to its role as an initiator. Very few options are available to prevent core damage after a total loss of SX.

The Component Cooling Water (CC) system is next most important at 21%. It also gets much of its importance due to its role as an initiating event.

The Auxiliary Electric Power (AP) system shows 16% contribution, a slight increase from the previous model. This contribution reflects both initiating events that can lead to Loss of SX or Loss of CC as well as AP component failures.

The Auxiliary Building Ventilation (VA) system, at 14%, reflects the need for room cooling for several key pumps, most notably the RH pumps. This shows more importance at Byron due to high VA plenum unavailability factors.

The Auxiliary Feedwater (AF) system is the next most important system at Byron from a CDF perspective (~3%). The contribution from AF reflects loss of the manual crosstie capability that was installed to allow the motor driven AF pumps to be used for either unit. This effectively decreased the available AF pumps per unit from 3 pumps to 2 pumps.

A similar effect results in normal Feedwater (FW) showing as next most important at 3%. This contribution includes both loss of feedwater as the initiating transient and loss of the pumps as a potential source of feedwater to the steam generators.

F.2.2.4 IMPORTANT OPERATOR ACTIONS

During the course of an accident, significant benefit is gained from the correct performance of the operator crew in implementing the appropriate Emergency Operator Procedures as well as performing other actions to place the plant in a safe stable condition. Table F.2-3 lists actions that are significant contributors to CDF.

F.2.3 LEVEL 2 MODEL OVERVIEW

The Byron Level 2 model is a state-of-the-art Level 2 analysis structure designed to address the Category II requirements of Regulatory Guide 1.200 and the ASME PRA Standard. The Level 2 analysis uses available technical work from the Byron Level 1 PRA and the Modular Accident Analysis Program (MAAP) results where appropriate, but applies the most recent accident progression research, current industry practices, and realistic plant-specific analyses. The Level 2 model is implemented in the CAFTA software package, which is consistent with the Level 1 PRA.

The Level 2 model is generally consistent with the "Simplified Level 2 Modeling Guidelines," WCAP-16341-P (WEST 2005), which many plants are currently using as a basis for updated Level 2 analyses. This WCAP provides a common, standardized method for PWRs with large dry containments to produce an analysis that generally meets capability category II of the ASME PRA standard. The guidance particularly addresses the latest understanding for induced steam generator tube ruptures, direct containment heating, and other important Level 2 phenomena. While the WCAP is focused on modeling the large early release frequency (LERF) for the ASME standard, it includes guidance for including intact, small, and late releases to provide a more complete, though still standardized, Level 2 analysis. In addition to providing results at this level of detail, the Byron Level 2 model is structured to quantify contributions on a "detailed release category" level, which allows the assignment of source terms that are more representative of the sequences to which they are applied.

F.2.3.1 LEVEL 1 TO LEVEL 2 MAPPING

Plant damage states (PDS) and their representative Level 1 accident scenarios provide an interface between the Level 1 and Level 2 analyses. Each Level 1 accident sequence that leads to core damage consists of a unique combination of an initiating event followed by the success or failure of various plant systems (including operator actions). Due to the large number of accident sequences created by the Level 1 PRA, the Level 1 sequences that result in core damage can be grouped into plant damage state bins. Each bin collects all of those sequences for which the progression of core damage, the release of fission products from the fuel, the status of the containment and its safeguards systems, and the potential for mitigating the potential radiological source terms are similar. The detailed containment event tree (CET) then analyzes each plant damage state bin as a group.

Plant damage state bins can be used as the entry states to the containment event tree quantification (similar to initiating events for the Level 1 PRA), or can be used to direct sequences onto specific containment event tree branches. The PDS bins for Byron are characterized by the status of containment bypass due to SGTR or ISLOCA, reactor coolant system pressure, and the availability of FW/AFW. A sequence by sequence classification was performed and documented as part of the Level 2 analysis.

F.2.3.1.1 Selection of Plant Damage State Parameters

The definition of plant damage states incorporates information from the outcome of the Level 1 analysis that is important to the determination of containment response and the release of radioactive materials into the environment.

The modeling approach for the current revision of the Level 2 PRA uses the CAFTA software package, which analyzes the Level 1 and Level 2 logic together in a single large fault tree. Active systems such as containment coolers and containment spray are modeled in the Level 2 analysis alongside the Level 2 phenomenological events in order to accurately account for system dependencies with Level 1 systems, such as actuation signals, electrical power, and cooling water.

Along with containment systems performance, the CETs consider the influence that physical and chemical processes have on the integrity of the containment and on the release of fission products once core damage has occurred. The important physical conditions in the RCS and the containment include the pressure inside the reactor vessel at the onset of core damage, whether the reactor cavity is flooded, and the availability of cooling on the secondary side of the steam generators.

In the Level 2 analysis, the RCS pressure identified in the definition of PDSs is that which occurs at the onset of core damage. Events that could influence the change in pressure after the onset of core damage but prior to vessel breach are addressed in the CET. The two most important effects of high pressure for a Level 2 PRA are challenges to the steam generator tubes and direct containment heating. Because of this, two RCS pressure level categories are considered in the PRA: high and low. Pressure level assignment was based on the accident initiators (e.g., medium and large LOCAs result in low pressure) and the availability of feedwater (which results in pressure low enough to alleviate steam generator tube challenges). In general, either a medium/large LOCA, depressurization through the PORVs, or makeup to the steam generators is required to reach low pressure. Without secondary side cooling, smaller LOCAs (including seal LOCAs) and transients are modeled as high pressure scenarios.

AFW/FW availability is tracked separately from RCS pressure in the plant damage states because it is used in the scrubbing assessment for SGTR scenarios and because it impacts the timing of low pressure core damage scenarios.

Initiating events that bypass containment are treated separately in the Level 2 CET. As mentioned in the discussion of top events, containment bypass is identified by ISLOCA and SGTR events.

F.2.3.1.2 Plant Damage State Classifications

The plant damage state, therefore, is a three character code that defines the important sequence characteristics for the Level 2 analysis (containment status, RCS pressure, AFW

Availability). The assignment of each individual Level 1 sequence is based on the following scheme:

- Containment Bypassed (by initiator, not containment isolation failure)
  - B: Bypass (ISLOCA or SGTR)
  - N: Not bypassed (all other events)
- RCS Pressure
  - H: High Pressure (sequences without significant RCS leakage, anticipated transient without scram (ATWS) sequences)
  - L: Low Pressure (sequences that depressurize due to significant RCS leakage, such as large LOCA or medium LOCA).
  - -: Not Used (e.g., for containment bypass scenarios, RCS pressure is not asked)
- AFW/FW Available
  - A: AFW or FW is available to provide makeup to the SGs (AFW is assumed to be available for pass through nodes. The exception is for secondary line break cases where AFW operability may be compromised).
  - N: AFW/FW is not available to provide makeup to the SGs.
  - -: Not Used (e.g., for containment isolation failure scenarios, AFW/FW availability is not asked)

Table F.2-4 provides the mapping of the Level 1 sequences to the Byron plant damage states. Table F.2-5 documents the correlation between the Plant Damage States and the Level 2 sequences (i.e., defines which PDSs are used as "initiators" for the Level 2 sequence).

F.2.3.2 CONTAINMENT EVENT TREE DESCRIPTION

To assess the accident progression following a core damage event, this Level 2 analysis uses the containment event tree shown in Figure F.2-4 based on the containment event trees (CETs) provided in WCAP-16341-P. While the function of the CET is essentially the same as the WCAP CETs, some changes were made to accommodate the capabilities and features of Byron PRA model. The event tree begins with one or more core damage sequences, and then asks a number of questions to determine the type of release, if any, that occurs. Each question is modeled as a top event in the event tree and the outcome is based on previous work for Byron (including logic taken from the existing model), recent accident progression research, and the guidance provided in the WCAP. Each top event in the event tree is discussed below.

Plant Damage States

This first node of the containment event tree represents the collection of all core damage sequences from the Level 1 PRA into plant damage states. The assignment of core damage sequences to plant damage states provided in Table F.2-4.

Containment Bypass

Level 1 PRA sequences with an initiating steam generator tube rupture or an un-isolated interfacing systems LOCA (ISLOCA) will bypass containment and are addressed by this node. In the CET, the "down" branch on this node represents the bypassed condition while the "up" branch is used for non-bypassed scenarios.

The Byron-specific ISLOCA analysis does not explicitly show that the likely release paths from ISLOCAs would be submerged and no credit is taken for scrubbing by any potentially overlying pool of water. In addition, no credit is assumed to be available for scrubbing by the auxiliary building.

For SGTR core damage scenarios, the analysis assumes that the steam generator PORV will stick open once it passes water, providing a direct path to the atmosphere. While slightly conservative, this assumption is made because the SG PORVs are not designed to pass high pressure water and assuming the PORV sticks open simplifies the analysis. For steam generator tube rupture cases with AFW available, the "Scrub" node accounts for the potential of the operators to maintain water over the tubes to provide release scrubbing.

Containment Isolation

For non-bypass scenarios, the possibility of containment isolation failure exists to provide a fission product release path through containment. The existing Byron PRA provides the associated containment isolation system (CIS) fault trees. The Level 2 model directly incorporates the CIS fault tree model into this top event. The containment isolation system includes all potential penetration locations with pipe sizes greater than 2 inches. Further details of the containment isolation system analysis are located in the Containment Isolation System Notebook.

Reactor Coolant System Pressure

The next two top events are both used to characterize whether RCS pressure has been reduced enough to preclude induced SGTR events, but this node also considers if the degree of depressurization is large enough to preclude high pressure melt ejection events related to early containment failure (below about 200 psig based on WCAP 16341-P). A success (up path) on the RCS Pressure node represents core damage scenarios where the reactor coolant system is at low pressure due to a medium or large loss of coolant accident (identified by the plant damage state). Low pressure means that pressure is insufficient to challenge the steam generator tubes or result in direct containment heating later in the accident progression. The branch is determined by the initiating event from the Level 1 PRA.

AFW or FW Available

Another method for reducing reactor pressure is through use of the steam generators. If steam generator makeup is available to the SGs as dictated by the Level 1 model logic, a decay heat removal path is available and the reactor can be reduced in pressure (to around 1000 psi). This pressure reduction will eliminate the challenge to the steam generator tubes, but it is not assumed to preclude the potential for direct containment heating (which is negligible for Byron). In general, AFW/FW is considered available for heat removal if flow is available to 3 of 4 SGs or to 2 of 4 SGs in conjunction with operator action to manage the cooldown process. The Level 1 PRA is used to identify the availability of Feedwater and AFW, which is traced in the Level 2 PRA through the assignment of plant damage states.

Water Over SG Tubes

For SGTR events, the magnitude of the release would be reduced if the radionuclides have to travel through a pool of water. This node is used for SGTR scenarios with AFW available and represents the probability that the operators will maintain about 10 feet (or more) of water over the top of the SG tubes (release scrubbing). Based on the guidance in WCAP-16341-P, the magnitude of the release can be reduced from Large to Small if the SG water level is maintained at least 10 feet above the top of the SG tubes. For Byron, a plant specific human reliability analysis (HRA) was performed to develop a probability of failing to perform this control task. The plant procedures instruct the operators to control level between 40% and 50% narrow range, which corresponds to between 7 and 8.8 feet above the top of the SG tubes. The procedure bases indicate this action is directed for the purpose of providing a scrubbing mechanism for any releases through the tubes and while the depth of water is less than the 10 feet described in the WCAP, it is considered to be adequate. The plant specific MAAP results demonstrate the large reduction in the source term resulting from a water depth of about 7 feet. The "up" path in the CET represents the condition in which water level is successfully maintained above the SG tubes.

No Pressure-Induced Steam Generator Tube Rupture

Core damage sequences that continue on the high pressure branch are assumed to be at or near the primary PORV/safety relief valve setpoint. Without water in the steam generators, there is a possibility of pressure-induced steam generator tube rupture early in the scenario.

Because the pressure is high from the beginning of the scenario, this question is asked prior to any operator actions or other reactor coolant system failures that could depressurize the RCS. Details of this evaluation are based on WCAP-16341-P and are documented in the Byron Level 2 document. This event is modeled via basic event 1L2-SGT-VF-PISGR. The "up" path in the CET represents the condition in which no pressure induced steam generator tube rupture (PI-SGTR) occurs.

RCS Depressurization

If the steam generator tubes survive the initial pressure differential, the operators could take action to depressurize the reactor coolant system in order to reduce the likelihood of tube rupture or direct containment heating. To do so, the operators would open a primary system PORV. If successful, the scenario transfers to a low-pressure accident progression. If the RCS is not depressurized, either due to human inaction or equipment failure, additional high-pressure failures are considered. This action appears in the plant Severe Accident Control Room Guideline Initial Response (SACRG-1) as well as in the emergency operating procedures (1BWFR-C.1, "response to inadequate core cooling"). This top event is modeled by gate 1HIGH-P and the HRA for the action is documented in the Byron Level 2 document, which includes consideration of human dependence factors. The gate couples the existing system fault tree with an operator action 1RY-DEPL2--HPVOA, "OPS FAIL TO DEP RCS AFTER CD TO PREVENT INDUCED TUBE RUPTURE". The human error probability for this operator action is set to 2.5E-02 based on the HRA performed to support the Byron Level 2 analysis. The "up" path in the CET represents the condition in which depressurization is successful.

No Thermally-Induced Steam Generator Tube Rupture

With the reactor coolant system remaining at high pressure and without feedwater to enough steam generators to depressurize the reactor, the likelihood of thermally-induced creep rupture of steam generator tubes is addressed. As with pressure-induced tube rupture, the age and condition of the steam generator tubes must be considered. Failure probabilities for moderately-damaged tubes are used to account for plant aging during the license renewal term. Details of this evaluation are in the Byron Level 2 document. Basic event 1L2-SGT-VF-TISGR represents the probability in the model. The "up" path in the CET represents the condition in which no thermally induced steam generator tube rupture (TI-SGTR) occurs.

Hot Leg Rupture

During high-pressure core damage scenarios, a "race" occurs to determine where the RCS will first fail. While the reactor vessel will eventually fail as the molten core degrades the lower vessel head, failures may also occur in the steam generator tubes (discussed above) or in the hot leg or surge line of the reactor coolant system. For high-pressure, station-blackout-like scenarios which tend to occur on this branch, the likelihood of hot leg failure is very high. Based on the WCAP, this analysis uses a likelihood of 98% for hot leg failure (basic event 1L2-RCS-VF-DEP2 is used to represent the probability of vessel failure (0.02)). When hot leg failure occurs prior to vessel breach, the reactor coolant system depressurizes prior to failing the lower vessel head, thus eliminating the possibility of high-pressure core melt events leading to direct containment heating. This is generally a beneficial failure since it prevents direct containment heating. The "up" path in the CET represents the condition in which hot leg failure occurs before vessel breach.

For scenarios in which Hot Leg Rupture is asked after a thermally induced tube rupture, recent State of the Art Consequence Analysis (SOARCA) insights indicate that it is likely that the hot leg will fail at about the same time as the TI-SGTR event. If the hot leg fails shortly after the TI-SGTR, then the release pathway is essentially terminated. The radionuclides from the core are transferred into containment rather than to the secondary side through the broken SG tubes. Event 1L2-NO-HLF-TISGTR (0.1) represents the probability that a hot leg failure does not occur at or shortly after the TI-SGTR such that the release continues through the broken SG tubes. The event probability is based on NUREG/CR-7110 (NRC 2012) in which multiple sensitivity analyses indicate that the hot leg would fail within 10 minutes after TI-SGTR and that only 0.6% of the iodine inventory would be released by the time of the hot leg failure. Based on the rapid increase in the creep rupture damage index at the time of TI-SGTR, it would be unlikely that the hot leg would remain intact for a period long enough for the release to transition to a point where it may be considered "large" (potentially 10% of the Iodine/Cesium based on WCAP-16341-P). In this case, the 0.1 probability of the hot leg remaining intact was assigned based on judgment to enumerate an "unlikely" event ("down" branch in the CET). The "up" path in the CET represents the condition in which hot leg failure occurs at about the time of TI-SGTR to terminate the release through the tubes.

Containment Failure at Vessel Breach

Three primary causes for containment failure at the time of reactor vessel breach apply to Byron – steam explosion, hydrogen burn, and direct containment heating. The analysis of these containment challenges follows the guidance in WCAP-16341-P. Low pressure sequences (such as due to a LOCA) reduce reactor coolant system pressure to the point where containment is only subject to steam explosion and hydrogen burn challenges. Low pressure sequences due to steam generator cooling do not depressurize as far, and therefore consider steam explosion, hydrogen burn, and direct containment heating. High pressure sequences with depressurization after core damage due to operator action or hotleg failure are primarily subject to hydrogen burn challenges. High pressure scenarios at the time of vessel breach are primarily subject to direct containment heating challenges. Therefore, different branches through the event tree require different early containment failure probabilities. This model assigns probability CFE1 to the combination of steam explosion and hydrogen burn, CFE2 to hydrogen burn by itself, CFE3 to direct containment heating, CFE4 to the combination of all three effects. Recent research has provided an improved understanding of these phenomena and each is discussed below.

Ex-vessel steam explosions due to the pouring of the molten core into a pool of water can challenge the integrity of the containment via damage to the reactor cavity. Based on WCAP-16341-P, this is a greater issue for free-standing reactor cavities (as opposed to excavated cavities). Because Byron is an excavated cavity, steam explosions do not pose a failure mechanism for early containment failure.

Hydrogen burns can challenge the integrity of the containment by creating high pressure excursions. The amount of hydrogen released into containment depends upon the amount of core damage at the time of vessel failure. Scenarios that lead to hydrogen burns at plants like Byron are limited to about 50% zirconium oxidation (excluding in-vessel recovery cases). Based on WCAP-16341-P, the plant-specific probability of early containment failure at Byron due to hydrogen burn is less than 0.001 at 40% oxidation and at 50% oxidation. To capture the possibility of containment failure due to hydrogen burn and/or steam explosion and maintain flexibility in the model, a probability of 0.001 will be used for both CFE1 and CFE2 in the model.

Direct containment heating (DCH) is also addressed by WCAP-16341-P. The WCAP reports plant-specific conditional containment failure probabilities due to direct containment heating for several plants, including Byron. The suggested probability is reported as 0.000 to cover all scenarios, and includes the effects of blowdown of the RCS, debris-to-gas heat transfer, exothermic metal/steam & metal/oxygen reactions, and hydrogen combustion that occur during a high-pressure melt ejection. To capture the possibility of DCH and maintain flexibility in the model, a CFE3 probability of 0.001 will be used in the model.

Note that previous Byron containment analyses have identified that the Unit 2 containment failure probabilities are slightly higher than the Unit 1 containment failure probabilities due to the existence of Bunker Ramo electrical penetrations in each Unit 2 containment. The containment failure probabilities due to DCH reported in the WCAP are copied from NUREG/CR-6338 (NRC 1996), which recognizes this difference between the Byron units (See Table 6.1 and Appendix D of NUREG/CR-6338). However, the strength of the unit 2 containments is sufficient to produce the same 0.000 failure probability for DCH, thereby removing the Unit 1/Unit 2 difference from the new Byron Level 2 model.

Based on the above assessments, the probability of early containment failure at Byron is negligible for any sequence. However, in order to maintain flexibility in the model for sensitivity analyses, all four early containment failure probabilities (CFE1, CFE2, CFE3, & CFE4) are maintained in the model and assigned a probability of 0.001.

Reactor Containment Fan Coolers

Containment Heat Removal in the Byron Level 2 model can be accomplished only through the Reactor Containment Fan Coolers. The Containment Spray System, which is described separately, has no heat removal capability and RHR is not included given that core damage would generally have been avoided if it had been available. The Level 2 PRA models the containment heat removal function via gate 1CHR in the general event tree based on the WCAP, which is linked to the reactor containment fan cooler (RCFC) logic previously developed for the Byron model. One of the four RCFCs is required for success.

Note that for some Level 2 scenarios, this function may not be available due to power or cooling water failures; however, the fault tree models these support systems accordingly. Failure of containment heat removal will allow the containment to slowly pressurize until failure. The plant-specific MAAP calculations use a median failure pressure of 125 psig to define containment overpressure failure for Unit 1 (containment shell failure) and 98 psig for Unit 2 (Bunker Ramo Electrical Penetrations).

Containment Spray

The Containment Spray (CS) system at Byron is not connected to a heat sink, cannot provide containment heat removal alone, and is considered separately in the CET for its ability to transfer water to the reactor cavity. The Byron Level 1 PRA does not include the containment spray system and the system model was developed to support the Level 2 analysis.

When containment heat removal is available to prevent long term containment overpressurization failures, consideration is given to the potential for basemat meltthrough. The basemat meltthrough probability in WCAP-16341-P is dependent on multiple variables, including whether or not there is water on the containment floor (i.e., in the reactor cavity). The simplifying assumption made in the WCAP Level 2 model related to the presence of water in the reactor cavity is that, if containment spray functions, the volume of the RWST is transferred to the cavity; otherwise, the cavity is assumed to be "dry".

For cases in which containment heat removal fails, success of containment spray could reduce the magnitude of the release by providing a scrubbing mechanism within containment. For the Level 2 analysis, no credit is taken for the impact of scrubbing to reduce the magnitude of the late release. This is primarily because for the dominant scenarios, the containment spray pumps would be unavailable (loss of Service Water Events fail the Containment Spray pumps).

Basemat Meltthrough

If no other containment failures occur during an accident scenario and containment heat removal exists, the last containment failure mode to examine is basemat meltthrough. If not cooled by an overlying water pool, the molten corium will begin to attack and erode the concrete basemat. Several beneficial factors at Byron make basemat meltthrough less severe than other plants. First, Byron has a "wet" containment design. If the RWST is injected into the primary system or containment via ECCS or containment spray, the water will drain to the reactor cavity and provide cooling of the molten corium, thus reducing the chance of basemat meltthrough. Second, the Byron basemat is 9 feet thick under the reactor. Even without cooling of the molten corium, basemat meltthrough will require many hours to erode through this thickness of concrete. Third, Byron has a relatively large cavity floor area, meaning the molten corium will have more space to spread. This results in a shallow layer (about 8 inches thick) of corium which can be more easily cooled by overlying water (over 30 feet). For the containment event trees, sequences including injection of the RWST can avoid basemat meltthrough with a high probability of success, while sequences without injection are subject to eventual basemat meltthrough. Basemat meltthrough is only questioned if containment heat removal is successful and the status of the cavity (wet vs. dry) is determined based on the operation of the CS system. The probability of having basemat meltthrough with a shallow layer of corium and a deep water pool in the cavity is assigned a value of 0.05 (basic event 1L2-CNT-VF-BMMTW), based on guidance in the WCAP. For scenarios where the cavity is dry, basic event 1L2-CNT-VF-BMMTD models eventual basemat meltthrough with a probability of 1.0.

F.2.3.3 LEVEL 2 RELEASE CATEGORY DEFINITIONS

The Level 2 PRA containment event tree sequences are categorized into four general release categories, which are described below.

INTACT

Containment structure and function succeed and prevent a substantial release of fission products. Source term calculations assume normal plant leakage to determine offsite consequences.

LATE

Containment failure occurs, but is considered late because of a significant time delay between core damage and containment failure. Releases may be large or small, but offsite consequences are limited to latent health effects and contamination.

SERF

Containment function is bypassed, but the radioactive release is scrubbed by an overlying water pool or limited by the size of the containment failure, reducing the offsite health effects.

LERF

WCAP-16341-P identifies the types of sequences that should be defined as Large-Early evolutions based on a review of documented industry definitions for "Large" and "Early". Byron uses the same classification scheme to identify the Large-Early sequences in the CET. In general, containment failure occurs early in the scenario. Early releases are defined as those releases that occur within a short time following core damage based on plant-specific source term calculations, such that adequate evacuation time is not available to protect the public from prompt health effects. "Large" releases are determined by plant-specific source term calculations for the sequences defined to be "Large-Early" (i.e., "Large" is not tied to a specific fraction of inventory for a given radionuclide), but it is generally greater than 4 percent of the CsI inventory for Byron.

F.2.3.3.1 Detailed Level 2 Release Category Definitions

A number of different Level 2 sequences contribute to each of the four general release categories above. Because the actual release characteristics will vary depending on how the containment event tree progresses, detailed release categories further define the Level 2 sequences. These detailed release categories consider the scenario characteristics and the ultimate containment failure mode. Each Level 2 sequence is mapped into one of these detailed release categories.

INTACT

This release category captures all of the INTACT sequences. Because the containment is essentially intact, sequence variations have a negligible impact on the release characteristics. INTACT-01, INTACT-02, INTACT-03, INTACT-04, and INTACT-05 contribute to this category. Releases to the environment are via normal containment leakage.

LATE-BMT-AFW

This release category captures sequences that result in basemat meltthrough with feedwater available to the steam generators. Because basemat meltthrough takes a significant amount of time to erode the thick basemat at Byron, the release is small and significantly delayed. LATE-01, LATE-02, LATE-04, and LATE-05.

LATE-BMT-NOAFW

This release category captures sequences that result in basemat meltthrough without feedwater available to the steam generators. Because basemat meltthrough takes a significant amount of time to erode the thick basemat at Byron, the release is small and significantly delayed. LATE-07, LATE-08, LATE-10, and LATE-11 contribute to this category.

LATE-CHR-AFW

This release category captures sequences that result in containment failure due to late overpressure with feedwater available to the steam generators. LATE-03 and LATE-06 contribute to this category.

LATE-CHR-NOAFW

This release category captures sequences that result in containment failure due to late overpressure without feedwater available to the steam generators. LATE-09, LATE-12, LATE-13, and LATE-14 contribute to this category.

LERF-ISLOCA

This release category captures sequences caused by an un-isolated ISLOCA. Those sequences from LERF-11 with ISLOCA initiating events contribute to this category.

LERF-CI

This release category captures sequences that result in containment isolation failure. LERF-09 contributes to this release category.

LERF-CFE

This release category captures sequences that result in early containment failure due to steam explosion, hydrogen burn, and/or direct containment heating at the time of vessel breach. LERF-01, LERF-02, LERF-03, LERF-04, LERF-05, AND LERF-06 contribute to this category.

LERF-SGTR-AFW

This release category captures sequences caused by a steam generator tube rupture that have successful operation of auxiliary feedwater, but the operators fail to control SG level above 40% narrow range level and the water inventory in the steam generators does not provide significant fission product scrubbing. With or without isolation of the ruptured steam generator, SGTR sequences with core damage provide a direct release path to the environment through the steam generator relief valves. Those sequences from LERF-10 with SGTR initiating events and successful AFW contribute to this category.

LERF-SGTR-NOAFW

This release category captures sequences caused by a steam generator tube rupture that also have failed AFW. With or without isolation of the ruptured steam generator, SGTR sequences with core damage provide a direct release path to the environment through the steam generator relief valves. Those sequences from LERF-11 with SGTR initiating events and AFW failure contribute to this category.

LERF-ISGTR

This release category captures sequences that result in either a pressure-induced or thermally-induced steam generator tube rupture that bypasses containment. LERF-07 and LERF-08 contribute to this category.

SERF -TISGTR-HLF

The sequences within this path are those that evolve into thermally induced steam generator tube ruptures, but are shortly followed by a hot leg failure, which effectively terminates the release from the ruptured steam generator. Basemat failure may or may not occur; however, the leakage from the ruptured SG tubes before hot leg failure results in a small/early release and this release is the dominant concern for this sequence. SERF-01 contributes to this category.

SERF-SGTR-AFW-SC

Sequences within this path are bypass scenarios due to a steam generator tube rupture. The operators successfully maintain feedwater in the ruptured steam generator to scrub the radioactive release, resulting in a small, early release through the steam generator tube rupture. SERF-02 contributes to this category.

F.2.3.4 REPRESENTATIVE SEQUENCES

For each detailed release category defined above, accident progression calculations predict the timing and amount of release. Table F.2-6 describes the representative sequences for each detailed release category. The first column includes the dominant Level 2 sequence to each release category, with the percentage of that category that the sequence contributes. The representative sequences are selected considering both the likelihood of the scenario and its potential consequences. The potential consequences of the scenarios are based on judgment given that source terms are generally not available for a sequence unless it is identified as a representative sequence.

Because source terms are applied at the detailed release category level, however, the sequences within any given release category typically have very similar release characteristics. The differences are often limited to whether feed and bleed or recirculation fails and in many cases, such a difference would have a minimal impact on the source term. The sequence that is judged to be associated with a higher potential source term is used as the representative sequence unless there is another sequence that accounts for a majority of the release category frequency and the sequence with the "higher" source term accounts for less than about 10 percent of the release category frequency. In those cases, the "majority" sequence would be chosen as representative.

F.2.3.5 SOURCE TERM RESULTS

The Byron MAAP (version 4.06) model was used to calculate source terms for each of the detailed release categories above. The timing of important events and the timing and magnitude of fission product releases for each representative sequence is documented in Table F.2-7.

F.2.3.6 LEVEL 2 RELEASE CATEGORY FREQUENCIES

Table F.2-8 shows the calculated results for the detailed release categories.

F.2.4 PRA MODEL TECHNICAL ADEQUACY FOR SAMA

As part of the PRA maintenance program, the Byron PRA model has been subjected to both internal and peer reviews since the submittal of the IPE, including the following:

- 1999 Westinghouse Owner's Group Peer Review (performed on Revision 0 of the PRA)
- Standard Self Assessments – Several self-assessments have been performed on the PRA, the most recent of which was completed in June, 2012.
  - Performed on model of record BB011a,
  - Evaluated against ASME/ANS RA-Sa-2009 (ASME 2009)

The 1999 Westinghouse Owners' Group peer review resulted in a total of 27 Level "A" and "B" Findings and Observations, all of which have been closed out.

The 2012 self-assessment identified two (2) supporting requirements (SRs) that were classified as not being met and about twenty (20) that were considered to only meet the Capability Category I requirements.

The following table summarizes the issues related to the SRs that were "not met" and how this assessment could potentially impact the SAMA analysis. Note that the review was performed on the BB011a "LERF only" model that was replaced by the Byron 2012 Level 2 model (BB011b1) used to support the SAMA analysis.

Review of ASME Supporting Requirements Classified as Not Met in the BB011a Self-Assessment

SR	Assessment Comments	Potential Impact on SAMA
LE-G5	Since the NUREG/CR-6595 approach has been used, the LERF analysis is inherently structured to support applications that do not require significant capability for distinction among application-related changes to LERF contributors. LE-G5-01 and URE BB-0966	This SR is related to identifying and documenting potential limitations in the LERF analysis that would impact applications. This is a documentation issue and would not directly impact the SAMA analysis. In addition, the 2012 Level 2 model used to support the SAMA analysis includes an assessment of model limitations and this SR is met.
LE-G6	BB-PRA-015 does not include a definition of significant accident progression sequence. Since the LERF methodology follows the conservative NUREG/CR-6595 process, not meeting this requirement has no significant impact on risk-informed applications for which Capability Category I LERF is appropriate. LE-G6-01 and URE BB-0967	The Byron Level 2 model used to support the SAMA analysis includes a definition of a significant accident sequence and it is consistent with the definition provided in the ASME/ANS RA-Sa-2009. This issue has been resolved.

The table below includes the original assessment comments associated with the SRs that only met Capability Category I in conjunction with an assessment of how the failure to meet Capability Category II could impact the SAMA analysis. Most of the SRs that were classified as only meeting the Capability Category I requirements were related to the BB011a “LERF only” model that was replaced by the Byron 2012 Level 2 model (BB011b1) used to support the SAMA analysis.

Review of ASME Supporting Requirements Classified as CC I in the BB011a Self-Assessment

SR	Assessment Comments	Potential Impact on SAMA
IE-A8	B/B PRA-001, Rev. 5, Initiating Event Analysis, does not include a plant personnel interview section or discussion. This gap is captured in fact and observation (F&O) IE-A8-001 and URE BB-0958.	Capability Category II requires plant personnel interviews as part of the initiating event identification process. The existing list of initiating events is believed to be complete and while it is possible other events could exist, they would be small contributors and would not impact the SAMA analysis. No meaningful impact on SAMA.
SC-A5	The mission time as used in the PRA analysis is 24 hours. Refer to section 2.1.2 and Table 2-1 of BB PRA-003, revision 2, Success Criteria Notebook. SC-A5-01 and URE BB-0961	For SR SC-A5, the Byron / Byron PRA model uses a 24-hour mission time for most events. Core damage is assumed for scenarios that do not reach core damage in 24 hours, but are not in safe/stable state. Additional work could be performed to support redefining some sequences as non-core damage events. For SAMA, the current modeling approach is conservative in that it increases the maximum averted cost risk (MACR) and adds potential sequences that could be recovered by a SAMA (increasing the averted cost benefit of a SAMA). Due to human dependence issues and limits on the ways recovery actions are credited in the PRA, the potential changes to mission time assessments to support alternate endstate classifications are likely limited. No meaningful impact on SAMA.
HR-E3	While the HRA-related procedures were discussed with Operations and Operations training personnel, only a subset of the entirety of procedure usage within the modeled sequences were covered in operator interviews and simulator observations as documented in Appendices D, E, and F of the HRA Notebook (BB-PRA-004, VOLUME 1). Insights from the interviews and observations are factored into the associated HFE evaluations as documented in Appendices A and F of the HRA Notebook (BB-PRA-004, VOLUME 1). Refer to Section 3 and Appendices A, D, E, and F of the HRA Notebook (BB-PRA-004, VOLUME 1).	The incorporation of operator interview results into HRA can impact the analyst's understanding of the modeled actions. For Byron, not all actions in the model or all sequences in which the actions are used in the model were discussed in the interviews. The most important actions are well defined and are supported by interviews. No significant changes to the PRA results would be expected as a result of performing interviews for the remaining actions. No meaningful impact on SAMA

Review of ASME Supporting Requirements Classified as CC I in the BB011a Self-Assessment

SR	Assessment Comments	Potential Impact on SAMA
HR-E4	Only a subset of the entirety of plant response in the modeled scenarios were covered in operator interviews and simulator observations as documented in Appendices D, E, and F of the HRA Notebook (BB-PRA-004, VOLUME 1). Insights from the interviews and observations are factored into the associated HFE evaluations as documented in Appendices A and F of the HRA Notebook (BB-PRA-004, VOLUME 1). Refer to Section 3 and Appendices A, D, E, and F of the HRA Notebook (BB-PRA-004, VOLUME 1).	The incorporation of simulator observation data into HRA can potentially provide more accurate timing information and an enhanced understanding of the modeled actions beyond what interviews alone can provide. For Byron, not all actions in the model were observed in the simulator. There is no way to predict what changes, if any, to timing or modeling assumptions would result from additional operator interviews. The availability of interview information for the most important actions at Byron limits the potential knowledge gaps that may otherwise be filled by simulator observations. No meaningful impact on SAMA
LE-B1	The NUREG/CR-6595 methodology is used to identify LERF contributors. The set defined is consistent with the contributors in Table 4.5.9-3 for large dry containments. A search for unique plant issues, required for Capability Category II, was not performed. Level 1 scenarios are grouped for analysis in the Level 2 event trees based on the methodology presented in NUREG/CR-6595. Plant damage states are used to maintain the link to the appropriate supporting MAAP runs.	The WCAP methodology was used to identify LERF contributors and this issue is considered to be addressed by the Level 2 model used to support the SAMA analysis. No impact.
LE-C1	The NUREG/CR-6595 methodology is used to assess containment challenges resulting from the various LERF contributors. The LERF fault tree logic models the NUREG/CR-6595 CET logic, and contributions are grouped by LERF event tree designator.	WCAP methodology developed accident sequences consistent with the failure modes identified and the plant specific failure rates provided in that guidance were used in the Byron Level 2 model. No impact.
LE-C2	The NUREG/CR-6595 methodology is used to assess containment challenges resulting from the various LERF contributors. Treatment of operator actions is therefore conservative.	The Byron severe accident control room guidance was reviewed to identify and incorporate actions that were judged to have the potential to mitigate severe accidents. No impact.

Review of ASME Supporting Requirements Classified as CC I in the BB011a Self-Assessment

SR	Assessment Comments	Potential Impact on SAMA
LE-C3	Repair of equipment is not addressed in the LERF model.	No credit was taken for any actions to repair equipment to mitigate the Level 2 accident sequences. AC power recovery is treated in the Level 1 model and no additional credit was applied for the Level 2 model. This is consistent with the general PRA practice of not modeling actions to repair failed equipment due to the uncertainties related to the causes of equipment failure and the availability of timely repair strategies. This is considered to meet the intent of LE-C3. No impact.
LE-C4	The NUREG/CR-6595 methodology is used to assess containment challenges resulting from the various LERF contributors. The LERF fault tree logic models the NUREG/CR-6595 CET logic, and contributions are grouped by LERF event tree designator.	This issue is addressed by the Level 2 model used to support the SAMA analysis. SG flooding and post core damage RCS depressurization was incorporated into the Level 2 model based on a review of the severe accident control room guidance. In addition, State of the Art Consequence Analyses (SOARCA) insights were used to enhance the SGTR analysis. No impact.
LE-C9	The NUREG/CR-6595 approach has been implemented, and credit for equipment operation or operator actions in adverse environments is not credited.	No operator actions that would be taken in adverse environments or opportunities for continued equipment operation in a harsh environment were identified that would realistically mitigate LERF scenarios. Human actions potentially taken after core damage are credited, but they are not in hazardous environments. SOARCA insights were used to enhance the SGTR analysis, however. The Level 2 model used for the SAMA analysis is considered to meet capability category II for LE-C9. No impact.
LE-C10	LE-C9 is Cat I so this SR is Cat I.	The Byron severe accident control room guidance and sequences were reviewed to identify potential mitigating factors as part of the Level 2 model used to support the SAMA analysis. This issue is considered to be resolved. No impact.

Review of ASME Supporting Requirements Classified as CC I in the BB011a Self-Assessment

SR	Assessment Comments	Potential Impact on SAMA
LE-C11	The NUREG/CR-6595 approach is modeled; continued operation of equipment or operator actions affected by containment failure is not credited.	No operator actions that would be taken after containment failure or opportunities for continued equipment operation after containment failure were identified that would realistically mitigate LERF scenarios. Human actions potentially taken after core damage are credited, but they are not in hazardous environments. SOARCA insights were used to enhance the SGTR analysis, however. The Level 2 model used for the SAMA analysis is considered to meet capability category II for LE-C11. No impact.
LE-C12	Cat I since LE-C11 is Cat I.	SOARCA results for induced SGTR are supported by plant specific MAAP runs. The Level 2 model used for the SAMA analysis is considered to meet capability category II for LE-C12. No impact.
LE-C13	The NUREG/CR-6595 approach has been implemented, and no credit is taken for scrubbing of containment bypasses.	SG flooding is credited in the Level 2 model and the impact is modeled by plant specific HRA and MAAP runs. This issue is addressed by the Level 2 model used to support the SAMA analysis. No impact.
LE-D2	The NUREG/CR-6595 approach has been used.	A plant specific analysis was used to identify the weakest point in containment and used to define the failure pressure for the plant specific MAAP analysis, but no location specific impact is modeled. Low potential impact.
LE-D3	The NUREG/CR-6595 approach has been used.	A plant specific analysis was used to identify the weakest point in containment and used to define the failure pressure for the plant specific MAAP analysis, but no location specific impact is modeled. Low potential impact.
LE-D5	Steam generator isolation is modeled in the SGTR fault tree logic. The modeling is generally conservative in that any failure of any line to isolate, regardless of size, is treated as failure of SG isolation.	Plant specific, detailed HRA supports the operator action to isolate the SG and the model includes the hardware required to perform the isolation. Additional enhancements to model temperature/pressure effects on hardware operation are expected to have a small impact on SAMA.
LE-D6	The NUREG/CR-6596 approach is used. An induced steam generator tube rupture (ISGTR) probability is assigned for the possibility of induced SGTR for sequences per the NUREG methodology.	The WCAP methodology, in conjunction with plant specific analysis of SG PORV response, is considered to meet capability category II requirements. No impact.

Review of ASME Supporting Requirements Classified as CC I in the BB011a Self-Assessment

SR	Assessment Comments	Potential Impact on SAMA
LE-E2	Parameter estimates for accident progression phenomena are selected in accordance with NUREG/CR-6595, and are generally conservative.	Phenomena values are based on plant-specific values and industry calculations that match plant specific features based on guidance in the WCAP. This issue is addressed by the Level 2 model used to support the SAMA analysis. No impact.
LE-E3	The LERF model is based on NUREG/CR-6595. Early containment failures (e.g., failure prior to recirc), bypass sequences (e.g., SGTR, ISLOCA), and isolation failures following core damage are modeled as LERF.	This issue is addressed by the WCAP Level 2 model used to support the SAMA analysis. No impact.
LE-F1	The spreadsheet for BB-PRA-015 includes an assessment of LERF contribution by accident class, which is equivalent to identification of the contributors to LERF. Although an assessment by PDS is not currently provided, the information is available to do so. Since the SR wording for Cat I indicates "e.g., PDS" but the wording for Cat II/III does not include the "e.g.", the Category assignment for this SR is Cat I, even though more than an identification of significant contributors has been performed.	Documentation issue, which is considered to be resolved by the Level 2 document. No impact.
LE-G3	The spreadsheet for BB-PRA-015 includes an assessment of LERF contribution by accident class, which is equivalent to identification of the contributors to LERF. Although an assessment by PDS is not currently provided, the information is available to do so. Since the SR wording for Cat I indicates "e.g., PDS" but the wording for Cat II/III does not include the "e.g.", the Category assignment for this SR is Cat I, even though more than an identification of significant contributors has been performed. LE-G3-01 and URE BB-0964	Documentation issue, which is considered to be resolved by the Level 2 document. No impact.

The Byron PRA model BB011b1 results are suitable for use as a resource in the SAMA identification process. This conclusion is based on:

- The PRA technical capability evaluations that have been performed to demonstrate technical adequacy of the PRA,
- The PRA maintenance and update processes that are in place to ensure that the model reflects the as-built, as operated plant.

Although there are some open items from the self assessment that will not be resolved until future model updates are performed, they have insignificant impact on the conclusions of the SAMA analysis.

F.3 LEVEL 3 RISK ANALYSIS

This section addresses the key input parameters and analysis of the Level 3 portion of the risk assessment. In addition, Section F.7.3 summarizes a series of sensitivity evaluations to potentially critical parameters.

F.3.1 ANALYSIS

The MACCS2 code (NRC 1998), version 1.13.1, was used to perform the Level 3 probabilistic risk assessment (PRA) for Byron. The MACCS2 code was developed to support probabilistic risk assessments (NRC 1998) and is the code typically used to calculate off-site population dose and costs in support of a SAMA analysis, as recognized in NEI 05-01 (NEI 2005). The atmospheric transport and dispersion straight-line Gaussian modeling incorporated in MACCS2 has been compared against more complex modeling approaches, such as the three-dimensional ADAPT/LODI code, and shown to be acceptable for the purposes of the MACCS2 code (NRC 2004b).

For the Byron MACCS2 analysis, the input parameter values used in NUREG-1150 (NRC 1990a), as detailed in NUREG/CR-4551 (NRC 1990b) and reflected in the MACCS2 "Sample Problem A," (NRC 1998) formed the initial bases. NUREG-1150 is a seminal work in PRA performed by the NRC and the national laboratories that includes a Level 3 PRA for five different reactor sites. It was subjected to extensive peer review and has been accepted by the NRC as a standard reference for MACCS2 inputs for SAMA analyses. Where applicable, these initial values were replaced with site specific values applicable to Byron and the surrounding region. Site-specific data included population distribution, regional economic parameters such as property value of farm and non-farm land, and meteorological data. Generic economic parameters from the NUREG-1150 study for the costs of evacuation, relocation and decontamination were escalated from the time of their formulation (1986) to more recent (July 2012) costs. Plant-specific release data included release frequencies and the time-dependent distribution of nuclide releases from 13 accident sequences at Byron. The behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points (i.e., declaration of a General Emergency) and evacuation time estimates (ET 2003). These data were used in combination with site specific meteorology to calculate risk impacts (exposure and economic) to the surrounding population within 50 miles.

F.3.2 POPULATION

The population surrounding the Byron site is estimated for the year 2046, the last year of projected operation for Unit 2 given a 20 year license extension.

The population distribution projection was based on year 2000 census data available via SECPOP2000 (NRC 2003). (Year 2010 census data has not yet been incorporated into the SECPOP code or incorporated into the state projection data used to estimate county growth rates at the time of the Level 3 analysis.) The baseline resident year 2000 population from SECPOP was determined for each of 160 grid elements of a polar coordinate grid consisting of sixteen directions (i.e., N, NNE, NE,...NNW) for each of ten concentric distance rings with outer radii at 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles surrounding the site. Transient population data from the Byron Evacuation Time Estimate (ETE) study (ET 2003) for the approximate 10 mile radial area around the site was added to the SECPOP permanent population, consistent with the guidance of NEI 05-01 (NEI 2005), on a grid element basis. In addition to the ETE category of transient population, the ETE category special facilities population was also included in the initial year 2000 population estimate. To estimate growth rates, Illinois (IDOC 2012), Wisconsin (WDOA 2012), and Iowa (SDCI 2012) county population projection data from applicable state data sources for the year 2030 were used. Table F.3-1 presents the county growth rates for the years 2000 to 2030. Individual growth rates were calculated for each grid element based on the county growth rates and the proportion of land in each grid element associated with the applicable counties. The combined resident and transient data (including special facilities) were projected from year 2000 to 2030, and then from 2030 to 2046 (using the year 2000 to 2030 growth rate times a 0.53 factor, i.e., 16/30) to calculate the 2046 population distribution. If county growth rate data projected a declining population for 2000 to 2030 for a particular county, zero population growth was assumed for that county. This condition only existed for the two Iowa counties of Clinton and Jackson.

The total year 2046 population for the 160 grid elements in the 50-mile region is estimated at 1,734,765. The distribution of the population is given for the 10-mile radius and the 50-mile radius from Byron in Tables F.3-2 and F.3-3, respectively.

F.3.3 ECONOMY

MACCS2 requires certain regional agricultural and land based economic data (e.g., fraction of land devoted to farming, annual farm sales, fraction of farm sales resulting from dairy production, and property value of farm and non-farm land) for each of the 160 grid elements. This data can be generated by SECPOP2000 (NRC 2003), but due to known errors associated with the economic parameter processing portion of the SECPOP2000 code, SECPOP2000 was not utilized to develop the county specific economic values for the Byron analysis. Instead, the economic values were developed manually following the SECPOP calculation approach documented in NUREG/CR-6525 (NRC 2003) using data from the 2007 National Census of Agriculture (USDA 2009) and 2007 data (for consistency with the census of agricultural data) from the Bureau of Economic Analysis (BEA 2012) for each of the 21 counties surrounding the plant, to a distance of 50 miles. Economic values were updated to July 2012 using the consumer price index (CPI) from the Bureau of Labor Statistics (BLS 2012). The values used for each of the 160 grid elements were based on the data for each of the applicable counties multiplied by the fraction of that element composed of the applicable county. Region-wide wealth data (i.e., farm wealth and non-farm wealth) were based on county-weighted averages for the region within 50-miles of the site using the same economic data sources. The portion of each county within 50-miles of the site was accounted for in the calculation. County specific land use and related economic parameter values are summarized in Table F.3-4.

In addition, generic economic data that is applied to the region as a whole were revised from the NUREG-1150 based data in order to account for cost escalation since 1986, the year that input was first specified. A factor of 2.09, representing cost escalation from 1986 (CPI index of 109.6) to July 2012 (CPI index of 229.1) was applied to parameter values describing cost of evacuating and relocating people and decontamination activities.

MACCS2 generic economic parameter values utilized in the Byron analysis are summarized in Table F.3-5.

F.3.4 FOOD AND AGRICULTURE

Food ingestion is modeled using the new MACCS2 ingestion pathway model COMIDA2, consistent with MACCS2 User's Guide (NRC 1998). The COMIDA2 model utilizes national based food production parameters derived from the annual food consumption of an average individual such that site specific food production values are not utilized. The fraction of population dose due to food ingestion is typically small compared to other population dose sources. For Byron, approximately 5.6% of the total population dose is due to food ingestion.

F.3.5 NUCLIDE RELEASE

The core inventory at the time of the accident is based on a plant specific calculation (Exelon 2008b). The core inventory represents bounding isotopic values (i.e., largest) for 100 effective full power days (EFPD) or 542.9 EFPD (end of cycle) for the core operating at 3586.6 MWt, the current licensed power level. This calculation reflects the current fuel management / burnup approach. Table F.3-6 summarizes the estimated Byron core inventory used in the MACCS2 analysis. Exelon has submitted a license amendment request (Exelon 2011) for a Measurement Uncertainty Recapture (MUR) power uprate for Byron, of approximately 1.63% (i.e., from 3586.6 MWt to 3645 MWt). This proposed power uprate is included in the MACCS2 basecase analysis by including a core inventory scaling factor of 1.0163. The assumption of no MUR power uprate (i.e., scaling factor of 1.0) is evaluated in the sensitivity analysis.

Byron nuclide release groups, as represented using the MAAP computer code, are related to the MACCS2 release groups as shown in Table F.3-7. Thirteen radiological release categories were modeled, each segmented into three plumes. Consistent with the guidance of NEI 05-01 (NEI 2005), a plume release height of 30.3 m (99.4 ft) above grade is used representing a release from the mid-height of the containment. Buoyant plume rise is modeled assuming a thermal plume heat content of 10 MW for all releases except intact containment (where zero heat content is assumed). A value of 10 MW bounds typical values in NUREG/CR-4551 (NRC 1990b). Assumptions associated with release height and plume heat content are considered in the sensitivity analyses, presented in Section F.7.3.

For each of the thirteen release categories, a representative MAAP case was chosen based on a review of the Level 2 model cutsets and the dominant types of scenarios that contribute to the release category. Brief descriptions of each release category, dominant Level 2 sequences, and the representative MAAP case are provided in Table F.3-8. Representative MAAP cases were run until a plateau of the CsI and CsOH release fractions were achieved. Experience has shown that CsI is a primary contributor to early dose, and CsOH is a primary contributor to late dose and cleanup costs. In some cases, the MAAP cases were run to times that exceeded the plume release times allowed by MACCS2. In such cases, plumes were moved forward in time in the modeling to meet MACCS2 limitations. These time adjustments are noted in Table F.2-7.

Multiple release duration periods (i.e., plume segments) were defined which represent the time distribution of each category's releases. A summary of the release magnitude and timing for those cases is provided in Table F.2-7.

A dry deposition velocity of 0.01 m/sec is used for the MACCS2 analysis, consistent with NRC recommendation as documented in the MACCS2 Sample Problem A (NRC 1998). The dry deposition velocity is considered in the sensitivity analysis, presented in Section F.7.3.

F.3.6 EVACUATION

Reactor trip for each sequence was taken as time zero relative to the core containment response times. A General Emergency (GE) is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. For the Byron analysis the time of the GE declaration was estimated based on the Byron emergency action levels (Exelon 2012). The declaration times are presented in Table F.2-7. For most release categories the GE time is established as the time of core damage. However, a minimum GE time of 30 minutes is used for release categories with core damage projected to occur in less than 30 minutes. For the LERF-SGTR-NOAFW, the GE is declared earlier than the time of core damage based on the known loss of AFW. For two release categories (i.e., LERF-SGTR-AFW and SERF-SGTR-AFW-SC), the GE times were moved forward in time (i.e., earlier) in association with moving the plume segments release time earlier to meet MACCS2 release delay limitations of a maximum of 96 hours following accident initiation. Because the GE time modeled was moved earlier the same amount as the plume segment release times, this earlier modeling of GE time does not impact evacuation related timing issues. The only impact is that there is less time incorporated in the MACCS2 calculation for natural decay thereby adding a slight conservatism to the modeling.

Ninety five percent of the population within 10 miles of the plant (Emergency Planning Zone, EPZ) is assumed to evacuate and 5 percent is assumed not to evacuate, consistent with the MACCS2 User's Guide (NRC 1998). These values are conservative relative to the NUREG-1150 study (NRC 1990a), which assumed evacuation of 99.5 percent of the population within the EPZ.

The evacuees are assumed to begin evacuation 115 minutes after a general emergency has been declared at a base evacuation radial speed of 4.4 m/sec. The time to begin evacuation and the base speed are derived from the site specific evacuation study (ET 2003). The evacuation speed is a time-weighted average value accounting for season, time of day, and weather conditions. It is noted that the longest evacuation time presented in the study (i.e., full 10 mile EPZ, winter daytime adverse weather conditions) is 3 hours 50 minutes (from the issuance of the advisory to evacuate). The evacuation parameters were considered further in the sensitivity analyses presented in Section F.7.3.

F.3.7 METEOROLOGY

Annual hourly meteorology Byron data sets from 2008 through 2010 were processed for use in the MACCS2 analysis. Of the hourly data of interest (10-meter wind speed, 10-meter wind direction, multi-level temperatures used to calculate stability class, and precipitation), less than 4% of the data were missing for each of the three years of data. Traditionally, up to 10% of missing data is considered acceptable. MACCS2 requires complete sequential hourly data for the full year, and therefore missing data must be estimated. The percentages of data hours that included estimated data for missing data for years 2008, 2009, and 2010 were 3.2%, 1.5%, and 1.6%, respectively. Data gaps were filled in the following manner (order of priority):

- Wind direction data gaps for the 30-foot (10-meter) sensor were filled by using wind direction data from the 250-foot sensor, if available. Wind speed data gaps resulting from calm winds were assigned a 0.5 mph wind speed.
- Data gaps of less than six consecutive hours were filled by interpolation.
- Wind speed data gaps of greater than six consecutive hours were filled using the power law and wind speed data from the 250-foot sensor, if available. This was only required for the 2008 dataset.
- Data gaps of six or more consecutive hours were filled by substitution from the same hour of a nearby day.

The 10-meter wind speed and direction were combined with precipitation and atmospheric stability (derived from the vertical temperature gradient) to create the hourly data file for each year for use by MACCS2.

The 2008 data set was found to result (see Section F.7.3 for discussion of sensitivity analysis) in the largest economic cost risk and dose risk compared to the 2009 and 2010 data sets. Therefore, the 2008 hourly meteorology was selected as the base case.

Atmospheric mixing heights were specified for AM and PM hours for each season of the year. These values ranged from 300 meters to 1600 meters, as documented in the Byron UFSAR (Exelon 2010), based on Holzworth data (EPA 1972).

F.3.8 MACCS2 RESULTS

Table F.3-9 shows the mean off-site doses and economic impacts to the region within 50 miles of Byron for each of 13 release categories calculated using MACCS2. The mean off-site dose impacts are multiplied by the annual frequency for each release category and then summed to obtain the dose-risk and offsite economic cost-risk (OECR) for each unit.

F.4 BASELINE RISK MONETIZATION

This section explains how Byron calculated the monetary value of the status quo (i.e., accident consequences without SAMA implementation). Byron also used this analysis to establish the maximum benefit that could be achieved if all on-line Byron risk were eliminated, which is referred to as the Maximum Averted Cost-Risk (MACR). Per the site PRA model (designated BB011b1), the Unit 1 internal events CDF of 3.97E-05 (at a truncation of 1E-10/yr) was used for the calculations in the following sections. External risk is addressed in Section F.4.6.2.

F.4.1 OFF-SITE EXPOSURE COST

The baseline annual off-site exposure risk was converted to dollars using the NRC's conversion factor of $2,000 per person-rem, and discounted to present value using NRC standard formula (NRC 1997):

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

Where:

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

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

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

r = real discount rate (as fraction) = 0.03 per year

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

The Level 3 analysis showed an annual off-site population dose risk of 34.45 person-rem. The calculated value for C using 20 years and a 3 percent discount rate is approximately 15.04. Therefore, calculating the discounted monetary equivalent of accident dose-risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (15.04). The calculated off-site exposure cost is $1,066,436.

F.4.2 OFF-SITE ECONOMIC COST RISK

The Level 3 analysis showed an annual off-site economic risk of $254,593. Calculated values for off-site economic costs caused by severe accidents must be discounted to present value as well. This is performed in the same manner as for public health risks and uses the same C value. The resulting value is $3,828,979.

F.4.3 ON-SITE EXPOSURE COST RISK

Occupational health was evaluated using the NRC recommended methodology that involves separately evaluating immediate and long-term doses (NRC 1997).

For immediate dose, the NRC recommends using the following equation:

Equation 1:

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

Where:

W_{IO}	=	monetary value of accident risk avoided due to immediate doses, after discounting
R	=	monetary equivalent of unit dose ($2,000 per person-rem)
F	=	accident frequency (events per year) (3.97E-05 (internal events CDF)) at an average 1E-10/yr truncation
D_{IO}	=	immediate occupational dose [3,300 person-rem per accident (NRC estimate)]
$_S$	=	subscript denoting status quo (current conditions)
$_A$	=	subscript denoting after implementation of proposed action
r	=	real discount rate (0.03 per year)
t_f	=	years remaining until end of facility life (20 years).

Assuming F_A is zero, the best estimate of the immediate dose cost is:

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

$$= 2{,}000*3.97E\text{-}05*3{,}300*\{[1 - \exp(-0.03*20)]/0.03\}$$

$$= \$3{,}941$$

For long-term dose, the NRC recommends using the following equation:

Equation 2:

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

Where:

W_{LTO}	=	monetary value of accident risk avoided long-term doses, after discounting, $
D_{LTO}	=	long-term dose [20,000 person-rem per accident (NRC estimate)]
m	=	years over which long-term doses accrue (as long as 10 years)

Using values defined for immediate dose and assuming F_A is zero, the best estimate of the long-term dose is:

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

= 2,000*3.97E-05 *20,000*{[1 – exp(-0.03*20)]/0.03} {[1 –exp(-0.03*10)]/0.03*10}

= $20,633

The total occupational exposure is then calculated by combining Equations 1 and 2 above. The total accident related on-site (occupational) exposure risk (W_O) is:

W_O = $W_{IO} + W_{LTO}$ = ($3,941+$20,633) = $24,574

F.4.4 ON-SITE CLEANUP AND DECONTAMINATION COST

The total undiscounted cost of a single event in constant year dollars (C_{CD}) that NRC provides for cleanup and decontamination is $1.5 billion (NRC 1997). The net present value of a single event is calculated as follows. NRC uses the following equation to integrate the net present value over the average number of remaining service years:

$$PV_{CD} = [C_{CD}/mr][1-\exp(-rm)]$$

Where:

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

C_{CD} = total undiscounted cost for a single accident in constant dollar years

r = real discount rate (0.03)

m = years required to return site to a pre-accident state

The resulting net present value of a single event is $1.3E+09. The NRC uses the following equation to integrate the net present value over the average number of remaining service years:

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

Where:

PV_{CD} = net present value of a single event ($1.3E+09)

r = real discount rate (0.03)

t_f = 20 years (license renewal period)

The resulting net present value of cleanup integrated over the license renewal term, $1.95E+10, must be multiplied by the internal events CDF (3.97E-05) to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is $773,752.

F.4.5 REPLACEMENT POWER COST

Long-term replacement power costs were determined following the NRC methodology in NRC 1997. The net present value of replacement power for a single event, PV_{RP}, was determined using the following equation:

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

Where:

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

r = 0.03

t_f = 20 years (license renewal period)

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

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

Where:

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

After applying a correction factor to account for Byron's size relative to the "generic" reactor described in NUREG/BR-0184 (NRC 1997) (i.e., 1185 megawatt electric / 910 megawatt electric), the replacement power costs are determined to be 7.20E+09 ($-year). Multiplying 7.20E+09 ($-year) by the CDF (3.97E-05) results in a replacement power cost of $285,652.

F.4.6 MAXIMUM AVERTED COST-RISK

The Byron MACR is the total averted cost-risk if all internal and external events risk associated with on-line operation were eliminated. This is calculated by summing the following components:

- Maximum Internal Events Averted Cost-Risk
- Maximum External Events Averted Cost-Risk

As described in Section F.5.1, the MACR is used in the SAMA identification process to determine the depth of the importance list review. In addition, the MACR is used in the Phase I analysis as a means of screening SAMAs. The following subsections provide a description of how each of these components is calculated and used together to obtain the Byron MACR.

F.4.6.1 INTERNAL EVENTS MAXIMUM AVERTED COST-RISK

The maximum internal events averted cost-risk is the sum of the contributors calculated in Sections F.4.1 through F.4.5:

Maximum Averted Internal Events Cost-Risk

Off-site exposure cost	$1,066,436
Off-site economic cost	$3,828,979
On-site exposure cost	$24,574
On-site cleanup cost	$773,752
Replacement power cost	$285,652
Total cost (per unit)	$5,979,393

This total represents the per unit monetary equivalent of the risk that could be eliminated if all risk associated with on-line internal event hazards (including internal floods) could be eliminated for Byron. The internal events MACR is rounded to next highest thousand ($5,980,000) for SAMA calculations. It should be noted that the Phase II cost benefit calculations account for the difference between the rounded MACR and the actual MACR by adding the difference to the averted cost-risk calculated for each SAMA.

F.4.6.2 EXTERNAL EVENTS MAXIMUM AVERTED COST-RISK

The maximum averted cost-risk for external events must be quantified for the cost benefit calculations; however, this cost-risk must be estimated based on information in the IPEEE (ComEd 1996) given that complete, current, quantifiable external events models are not available for Byron (other than for fire, which is discussed further in section F.5.1.6). Resources have been committed to update the seismic model for the site and a fire model update is in progress, but those models are not developed to the point where they can be used for quantitative or qualitative input to the SAMA analysis. As a result, an alternate method of accounting for the external events contributions must be established.

The method chosen to account for external events contributions in the SAMA analysis is to use a multiplier on the internal events results. In previous SAMA analyses, it has been assumed that the risk posed by external events and internal events is approximately equal. This assumption is not unreasonable unless available analyses indicate that there are external events contributors that present a disproportionate risk to the site. Based on the magnitude of the Byron fire CDF relative to the internal events CDF, it was concluded that the development of an external events multiplier was warranted.

The external events multiplier is the ratio of the total CDF (including internal and external) to only the internal events CDF. The lack of detailed analyses makes it difficult to establish a meaningful CDF for the non-fire initiator groups; however, some assumptions can be made about the non-quantified initiator groups that could be used to further develop a total external events CDF.

The Byron IPEEE methodology implies that if the plant licensing bases are met, the plant and facilities design meets the 1981 Standard Review Plan (SRP) criteria, and the site walkdown does not reveal any potential vulnerability not already considered in the design basis analysis, then the CDF posed by an initiator is less than the 1.0E-06 per year screening criterion. As described in Section F.5.1.6, these conditions are met for Byron and no contributors greater than 1.0E-06 were expected for any of the external events excluding internal fires. Based on this condition, a CDF of 1.0E-06 per year could be assumed for each of the contributors for which no complete quantitative basis exists to obtain a more detailed estimate of the external events CDF.

The latest available fire results are from the 2009 revision of the Byron fire model (Exelon 2009). While an update of that model was in progress at the time the SAMA analysis was performed, the process was in its infancy and no information was available that could have been used to provide qualitative or quantitative input to the SAMA analysis. However, the 2009 Byron fire model does use the latest fire ignition frequencies from EPRI 1016735 (EPRI 2008).

In the 2009 fire model, the Unit 2 model is not refined to the same degree as the Unit 1 model, so the Unit 1 model is used as the basis for fire quantification. For the purposes of establishing the Byron SAMA External Events multiplier, the larger of the two quantified configurations (Unit 0 component cooling HX aligned to Unit 1) is used as the CDF (5.39E-05/yr).

Assuming a CDF of 1.00E-06/yr for the non-fire external events contributors and using the Unit 1 Fire CDF of 5.39E-05/yr, the external events contributions could be summarized as follows:

Modified IPEEE Contributor Summary

Fire	5.39E-05
Seismic	1.00E-06
High Winds	1.00E-06
Transportation & Nearby Facility Accidents	1.00E-06
External Flooding	1.00E-06
Total EE CDF	**5.79E-05**

The External Events multiplier is the ratio of the total CDF (including internal and external events) to the internal events CDF. Using the total external events of 5.79E-05 from above and the Unit 1 internal events CDF of 3.97E-05, the External Events multiplier is:

EE Multiplier = (3.97E-05 + 5.79E-05) / 3.97E-05 = 2.5

F.4.6.3 BYRON MAXIMUM AVERTED COST-RISK

The total MACR can be obtained by multiplying the internal events cost-risk by the EE multiplier of 2.5:

Single Unit MACR = $5,980,000 * 2.5 = $14,950,000

Alternatively, as stated in Section F.4.6, the MACR can be represented by the internal and external events contributions (based on the relative contribution of the CDF values to the total CDF):

Internal Events	=	$5,980,000
External Events	=	$8,970,000
Single Unit Maximum Averted Cost-Risk	=	$14,950,000

The MACR and implementation costs are considered on a per-unit scale for consistency (unless otherwise noted).

F.5 PHASE 1 SAMA ANALYSIS

The Phase 1 SAMA analysis, as discussed in Section F.1, includes the development of the initial SAMA list and a coarse screening process. This screening process eliminated those candidates that are not applicable to the plant's design or are too expensive to be cost beneficial even if the risk of on-line operations were completely eliminated. The following subsections provide additional details of the Phase 1 process.

F.5.1 SAMA IDENTIFICATION

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

- Byron PRA results and PRA Group Insights
- Industry Phase 2 SAMAs (review of potentially cost effective Phase 2 SAMAs from selected plants, as documented in section F.5.1.3)
- Byron Individual Plant Examination IPE (ComEd 1994)
- Byron IPEEE (ComEd 1996)

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

In addition to the "Industry Phase 2 SAMA" review identified above, an industry based SAMA list was used in a different way to aid in the development of the Byron plant specific SAMA list. While the industry Phase 2 SAMA review cited above was used to identify potential SAMAs from specific sites that might have been overlooked in the development of the Byron SAMA list due to PRA modeling issues, a generic SAMA list was used to help identify the types of changes that could be used to address the areas of concern identified through the Byron importance list review. For example, if Instrument Air availability was determined to be an important issue for Byron, the industry list would be reviewed to determine if a plant enhancement had already been conceived that would address Byron's needs. If an appropriate SAMA was found to exist, it would be used in the Byron list to address the Instrument Air issue; otherwise, a new SAMA would be developed that would meet the site's needs. This generic list was compiled as part of the development of multiple industry SAMA analyses and is available in NEI 05-01 (NEI 2005).

It should be noted that the process used to identify Byron SAMA candidates focuses on plant specific characteristics and is intended to address only those issues important to the site. An evaluation of the generic SAMAs in NEI 05-01, as they are written, provides little benefit because in most cases the systems are not exactly the same as those at Byron. Without modifying the NEI 05-01 SAMAs to match the systems at Byron, many would be screened as "not applicable". Further, the scopes of the generic SAMAs are not tailored to match the needs of a specific plant such that the generic SAMAs may only address a fraction of the required functions. As a result, evaluation of the entire generic SAMA list would only be useful after each SAMA has been modified to address the plant specific risk profile. The processes used for Byron were more efficient than evaluating the entire generic SAMA list, as written.

F.5.1.1 LEVEL 1 BYRON IMPORTANCE LIST REVIEW

The importance list review was performed to identify the failure scenarios most important to Byron risk and to develop methods to mitigate those scenarios. For each event on the importance list, the reasons for the event's importance are determined through sequence and systems analysis. Strategies to mitigate the relevant failures are developed based on accident sequence review, plant knowledge, and industry insights. For Byron, importance lists were developed and reviewed for the internal events model while for the fire model, the top contributing fire zone results were reviewed to identify SAMAs.

The importance list itself was developed from the Byron PRA cutsets and is comprised of the model's basic events sorted according to their risk reduction worth (RRW) values. The events with the largest RRW values in this list are those events that would provide the greatest reduction in the CDF if the failure probability were set to zero. Because a PRA's importance list can be extensive, it is desirable to limit the review to only those contributors that could yield potentially cost beneficial results. One method that can be used to limit the scope of the importance list review is to correlate the RRW value threshold to the lowest expected cost of implementation for a SAMA. Usually, operator action modifications in the form of procedure changes are among the least expensive enhancements that can be made at a site, so they are often used as the representative "lowest cost SAMA". For Byron, operator actions were considered as potential SAMA candidates and documented in Tables F.5-1, F.5-2a, and F.5-2b. The cost of a procedure change varies depending on the type of procedure that is being changed, the scope of the changes that are proposed, and the training program changes, but the lower end of the cost estimates range from $50,000 to $100,000 (CPL 2006). For Byron, the upper end of this range ($100,000) is used as the lowest cost SAMA to account for engineering analysis, the update of procedure text and supporting documentation, and training. The cost is considered to be a per unit cost.

The RRW value corresponding to $100,000 was determined to be about 1.017 for the internal events model. In some SAMAs, the RRW correlation is based on the total MACR that accounts for all external events contributions. For Byron, this was not done because 1) the fire results were reviewed separately for the purposes of SAMA identification, 2) the fire model is in an interim state. If the surrogate CDF values identified in Section F.4.6.2 for the non-fire external events are considered, the review threshold would be lowered slightly, but the impending implementation of the AFW Cross-tie would conversely increase the threshold slightly. Based on these factors, the use of the current internal events CDF to establish the review threshold is considered to result in an adequate review of the risk contributors for Byron. However, because the importance review to an RRW value of 1.005 was performed for the Braidwood SAMA analysis, applicable review results were generally available for Byron to the 1.005 level and the Byron SAMA analysis extended the importance review to an RRW value of 1.005.

Table F.5-1 documents the disposition of each basic event in the Level 1 internal events model with an RRW value of 1.005 or greater. The depth of the RRW review is consistent with NEI 05-01 guidance as well as other SAMA analyses.

For the fire analysis, the review threshold was correlated to the IPEEE screening threshold of a 1.0E-06 CDF. A direct correlation of fire CDF to potential averted cost-risk could be performed, but given the interim state of the model, this was not considered to be the best approach. The fire results are likely overly conservative and are also likely to change as the model is refined, but a review of all contributors with CDFs above 1.0E-06 is considered to provide some assurance the important issues have been identified for the site. Because the units are different with regard to fire events, the review was performed separately for Units 1 and 2. Section F.5.1.6.1 includes the detailed results of the fire zone review.

F.5.1.2 LEVEL 2 BYRON IMPORTANCE LIST REVIEW

A similar review was performed on the importance listings from the Level 2 results. In this case, two separate Level 2 importance lists were developed. The reviews were performed on composite importance files for the following release categories:

- Large Early (LERF-ISLOCA, LERF-CI, LERF-CFE, LERF-SGTR-AFW, LERF-SGTR-NOAFW, LERF-ISGTR)
- Late (LATE-CHR-AFW, LATE-CHR-NOAFW, LATE-BMMT-AFW, LATE-BMMT-NOAFW)

These groupings were developed to prevent high frequency-low consequence events (i.e., the "Intact" release category) from biasing the importance lists. The release categories included in the review account for over 91 percent of the dose-risk while accounting for only about 70 percent of the Level 2 frequency. Exclusion of the other results from the Level 2 review allows the contributors that are most important to dose-risk and cost-risk to rise to the top of the importance lists.

The Level 2 basic events were also reviewed down to the 1.005 level. As described for the Level 1 RRW list, the review threshold was based only on the internal events results given that a separate, explicit review of the fire results was performed for SAMA identification.

Tables F.5-2a and F.5-2b document the disposition of each basic event in the Level 2 RRW lists with RRW values greater than 1.005.

F.5.1.3 INDUSTRY SAMA REVIEW

The SAMA identification process for Byron is primarily based on the PRA importance listings, the IPE, and the IPEEE. In addition to these plant-specific sources, selected industry SAMA submittals and the associated Generic Environmental Impact Statement documents were reviewed to identify any Phase II SAMAs that were determined to be potentially cost beneficial at other plants. These SAMAs were further analyzed and included in the Byron SAMA list if they were considered to address potential risks not identified by the Byron importance list review.

While many of the industry SAMAs reviewed are ultimately shown not to be cost beneficial, some are close contenders and a small number have been estimated to be potentially cost beneficial at other plants. Use of the Byron importance ranking should identify the types of changes that would most likely be potentially cost beneficial for Byron, but review of selected industry Phase II SAMAs may capture potentially important changes not identified for Byron due to PRA modeling differences or SAMAs that represent alternate methods of addressing risk. Given this potential, it was considered prudent to include a review of selected industry Phase II SAMAs in the Byron SAMA identification process. In order to improve the likelihood generic Westinghouse issues would be captured and that the SAMAs reviewed would be relevant to the Braidwood design, six Westinghouse PWRs were used as the sources for the SAMAs:

- Vogtle (SNC 2007, NRC 2008a)
- Shearon Harris (CPL 2006, NRC 2008b)
- H.B. Robinson (NRC 2003a)
- Prairie Island (NMC 2008, NRC 2011)
- Wolf Creek (WCNOC 2006, NRC 2008c)
- Indian Point Unit 2 (Entergy 2007, NRC 2010)

Six Westinghouse PWR sites were chosen from available documentation to serve as the potential Phase 2 SAMA sources. Many of the industry Phase 2 SAMAs were already represented by other SAMAs in the Byron list, were known not to impact important plant systems or be relevant to the Byron design, or were judged not to have the potential to be close contenders for Byron. As a result, they were not added to the Byron SAMA list. If there were any unique SAMAs that were considered to have the potential to be cost effective for Byron, they were added to the list. The cost effective SAMAs for each of the sites identified above are reviewed in the following subsections.

F.5.1.3.1 Vogtle

Vogtle identified two SAMAs in the baseline analysis that were determined to be potentially cost beneficial. Two additional SAMAs were identified as potentially cost beneficial in the 95th percentile PRA results sensitivity analysis (SAMAs 6 and 16), but after more detailed assessments of the associated implementation costs, it was concluded that SAMAs 6 and 16 were not cost beneficial.

Review of Vogtle Potentially Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for Byron	Disposition for Byron SAMA List
2	Maintain Full Time Black Start Capability of the Plant Wilson Combustion Turbines	There is no local power station with the capability of providing power to the Byron switchyard for which operational procedures could be modified to maintain full time black start capability for station blackout (SBO) support. Not applicable.	Not required for the SAMA list
4	Prepare Procedures and Operator Training for Cross-Tying an Opposite Unit DG	Byron already has procedures for inter-unit cross-tie of the emergency buses.	Not required for the SAMA list

F.5.1.3.2 Shearon Harris

Review of Shearon Harris Potentially Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for Byron	Disposition for Byron SAMA List
9	Proceduralize Actions to Open emergency diesel generator (EDG) Room Doors on Loss of heating ventilation and air-conditioning (HVAC) and Implement Portable Fans	The EDG room cooling system, which is modeled in the PRA, is not an important contributor to plant risk for Byron. No SAMA required.	Not required for the SAMA list
6	Flood Mitigation for Scenarios 6 and 7	This is a plant specific internal flooding issue related to valve qualification in flooding conditions; however, similar issues have not been identified in the review of the Byron flooding contributors.	Not required for the SAMA list
8	Alternate Seal Cooling and Direct Feed to Transformer 1B3-SB	This SAMA was developed to address loss of 4kV bus events where power is available to the opposite 4kV bus, but vital equipment has failed on the powered bus. Specifically, it provides an alternate power feed to the bus supporting an available AFW pump and procedure changes to increase the CCW heatup time so that the swing charging pump can be aligned to the opposite power division for seal injection. This SAMA is specific to the Harris configuration where simple procedure changes could be made that would provide adequate time to allow operators to align the swing charging pump to the opposite division of power. There is no equivalent condition for Byron and this SAMA is not applicable.	Not required for the SAMA list

F.5.1.3.3 H.B. Robinson

The H.B. Robinson SAMA analysis used a generic SAMA list as its starting point and few plant specific insights were available that might pertain specifically to Westinghouse PWRs. While CP&L did not identify any potentially cost beneficial SAMAs, the NRC identified two potentially cost beneficial SAMAs as part of the external events risk review, which are discussed below.

Review of H.B. Robinson Potentially Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for Byron	Disposition for Byron SAMA List
1437-13-1	Replace cast-iron yokes on RHR valves	This is a seismic vulnerability specific to the Robinson configuration. There are no Byron RHR components with high confidence of low probability of failure (HCLPF) values below the 0.3g review threshold and the RHR valve yokes were not identified as a potential weakness at Byron.	Not required for the SAMA list
1437-13-2	Install a radiant heat shield on the electrical conduit to the shutdown DG	This is a fire vulnerability specific to the Robinson configuration. Byron does not have a shutdown DG and this enhancement is not applicable to the site.	Not required for the SAMA list

F.5.1.3.4 Prairie Island Nuclear Generating Plant

Review of Prairie Island Potentially Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for Byron	Disposition for Byron SAMA List
3	Provide Alternate Flowpath from RWST to Charging Pump Suction	Failure of the RWST flowpath to the charging pumps is not a significant contributor for Byron. SAMA not required.	Not required for the SAMA list
9	Analyze Room Heat-up for Natural/Forced Circulation (Screenhouse Ventilation)	This SAMA was developed to support the use of alternate room cooling (via a heatup analysis) in the plant's screenhouse when normal cooling fails. For Byron, the loss of screenhouse cooling is not required for any PRA systems. SAMA not required.	Not required for the SAMA list
19a	Provide a Reliable Backup Water Source for Replenishing the RWST	A SAMA for automated RWST refill was developed for Byron based on the PRA importance list review (SAMA 14).	Already included
N/A	Provide a Gagging Device for Closing a stuck-open SG Safety Valve in SGTR Events	Based on information in the DCPP RAI responses (PG&E 2010), gagging devices are installed for maintenance tasks and are useful for preventing PORVs from opening, but are not designed to reclose a stuck open PORV. This SAMA is not considered to be viable and is not included in the Byron SAMA list.	Not required for the SAMA list

Review of Prairie Island Potentially Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for Byron	Disposition for Byron SAMA List
22	Provide Compressed Air Backup for Instrument Air to Containment	Air systems are modeled for Byron, but system failures are not significant contributors to risk. SAMA not required.	Not required for the SAMA list

F.5.1.3.5 Wolf Creek Generating Station

Review of Wolf Creek Generating Station Potentially Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for Byron	Disposition for Byron SAMA List
2	Modify the Controls and Operating Procedures for Sharpe Station to Allow for Rapid Response	There is no local power station with the capability of providing power to the Byron switchyard for which operational procedures could be modified to provide rapid start capability for SBO support. Not applicable.	Not required for the SAMA list
4 (case 2)	Update emergency procedures to direct local, manual closure of the RHR EJHV8809A and EJHV8809B valves if they fail to close remotely	This SAMA was developed to address questions about the ability of motor operated valves (MOVs) to close against the differential pressure in a specific ISLOCA sequence for Wolf Creek. Discussions with an Exelon MOV Program engineer indicate that local operation of the valve may be successful depending on several factors. For example, if the motor gearing is the limit, the handwheel may function if enough force could be applied to the handwheel. If other portions of the valve are not capable of withstanding the force required to close, then the isolation will fail. For Byron, general training would direct operators to attempt a local valve closure given remote operation failure, so the Wolf Creek SAMA would provide no tangible benefit. A different SAMA (SAMA 19) was developed for Byron to replace the 8809 valves (and others) with valves of a different design to ensure a success path is available in ISLOCA scenarios.	Not required for the SAMA list
5	Enhance procedures to direct operators to open EDG Room doors for alternate room cooling	The EDG room cooling system, which is modeled in the PRA, is not an important contributor to plant risk for Byron. No SAMA required.	Not required for the SAMA list
1	Permanent, Dedicated Generator for the NCP with Local Operation of Turbine Driven AFW After 125V Battery Depletion	This was designed to assist in an SBO that included a seal LOCA. The design includes a 4kV, 500kW EDG to power a charging pump and transformer to support the 125V battery chargers. Byron does not have a turbine driven AFW pump and the diesel pump requires SX for lube oil cooling, so the SAMA is not applicable to the plant configuration.	Not required for the SAMA list

Review of Wolf Creek Generating Station Potentially Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for Byron	Disposition for Byron SAMA List
3	AC Cross-tie Capability	Byron already has 4KV AC cross-tie capability.	Already Implemented
13	Alternate Fuel Oil Tank with Gravity Feed Capability	For Wolf Creek, fuel oil failures contributed significantly to the CDF and an alternate method to transfer fuel to the EDG day tank was determined to be cost effective. The Byron fuel oil transfer configuration includes redundant pump trains for each diesel and fuel oil transfer failures are not significant contributors to plant risk. SAMA not required.	Not required for the SAMA list
14	Permanent, Dedicated Generator for the NCP, one Motor Driven AFW Pump, and a Battery Charger	This was designed to assist in an SBO that included a seal LOCA. The design includes a 4kV, 500kW EDG to power a charging pump, an AFW pump, and a transformer to support the 125V battery chargers. For Byron, both the charging pumps and the AFW pumps ultimately require SX for cooling and this SAMA would require additional changes to make it applicable to the site. The Diverse Mitigation System (DMS) is proposed as the full scope SBO mitigation enhancement (SAMA 11); however, an alternate design could be investigated that uses a dedicated generator/ seal injection system to prevent seal LOCAs in conjunction with a portable SG makeup pump.	Included as SAMA 26.

F.5.1.3.6 Indian Point Energy Center Unit 2

Review of Indian Point U2 Potentially Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for Byron	Disposition for Byron SAMA List
028	Provide a Portable Diesel Driven Battery Charger	This SAMA was designed to prolong AFW availability in an SBO by using a portable generator to provide alternate battery charging capability. No discussion is provided in the Indian Point U2 SAMA analysis about primary side makeup requirements. The industry initiatives for SBO mitigation, which are commitments, are more comprehensive than this SAMA and are addressed by the "DMS" SAMAs for Byron. No additional SAMAs required.	Not required for the SAMA list
044	Use Fire Water System as Backup for Steam Generator Inventory	This enhancement was intended to provide alternate steam generator (SG) makeup capability and relies on Fire Water as a suction source, but includes a new, electric, 800 gpm pump to provide flow. The Fire Water system is a low pressure system that does not address early losses of SG makeup. Byron includes a SAMA to complete the AFW X-tie, which addresses the loss of AFW scenarios in a more cost effective manner. No additional SAMAs required.	Not required for the SAMA list
054	Install Flood Alarm in the 480V AC Switchgear Room	Providing a water sensor in the 480V AC Switchgear room would provide early warning of flood conditions and improve the probability isolation could occur before equipment damage. Internal flooding events for the Switchgear Rooms are not significant contributors for Byron and are below the review threshold for SAMA identification.	Not required for the SAMA list
056	Keep RHR Heat Exchanger Discharge MOVs Normally Open	The intent of this SAMA is to reduce the contribution of failures of the RHR heat exchanger (HX) valves to open on demand. The Byron RHR HX outlet valves are normally open/fail open valves.	Not required for the SAMA list

Review of Indian Point U2 Potentially Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for Byron	Disposition for Byron SAMA List
060	Provide Added Protection Against Flood Propagation from Stairwell 4 into the 480V AC Switchgear Room	This change addresses a plant specific internal flooding issue and includes changes to the swing direction of a door, addition of ductwork, and a check valve. Internal flooding events for the Switchgear Rooms are not significant contributors for Byron and are below the review threshold for SAMA identification.	Not required for the SAMA list
061	Provide Added Protection Against Flood Propagation from the Deluge Room into the 480V AC Switchgear Room	This change addresses a plant specific internal flooding issue and includes upgrading the deluge room to close off flood paths. Internal flooding events for the Switchgear Rooms are not significant contributors for Byron and are below the review threshold for SAMA identification.	Not required for the SAMA list
065	Upgrade the Alternate Safe Shutdown System to Allow Timely Restoration of Seal Injection and Cooling	This SAMA involves providing a hardwired connection from the Alternate Safe Shutdown System power supply to a safety injection (SI) pump to improve the probability that the operators can restore RCP seal cooling in a timely manner. Byron does not have a similar system that could be enhanced for this function and the SAMA is not applicable to the site as written. However, SAMA 2, which was identified based on the PRA results, involves replacing existing equipment to provide an alternate means of seal cooling on failure of the running systems.	Already included

F.5.1.3.7 Industry SAMA Identification Summary

The important issues for Byron are generally considered to be addressed by the SAMAs developed through the PRA importance list review. The plant changes suggested as part of that review were developed to meet the specific needs of the plant such that those SAMAs are more likely to provide effective means of risk reduction than SAMAs taken from other sites. However, effort was made to review other industry SAMA analyses to determine if other sites identified plant changes that could be cost beneficial for Byron based on modeling differences or other factors. For Byron, the industry review identified a potential alternate design for the implementation of the DMS that has been included in the Phase 1 SAMA list for consideration:

- DMS Using a Dedicated Generator, Self-Cooled Charging Pump, and a Portable AFW Pump (SAMA 26)

F.5.1.4 BYRON IPE PLANT IMPROVEMENT REVIEW

The Byron IPE, unlike many industry IPEs, did not document a definitive list of proposed plant enhancements. Instead, the IPE describes the Commonwealth Edison (ComEd) accident management program and how it was used to assess the IPE and Accident Management insights from the Byron, Braidwood and other ComEd plant IPEs, which were assessed together given that the insights were generally considered to be applicable to both the Byron and Braidwood sites. The discussion indicates that over 220 IPE and Accident Management insights were developed that were potentially applicable to PWRs and that they were evaluated by the review team; however, these insights are not specifically provided. A plant enhancement that is described in the IPE, a procedure modification to direct inter-unit 4 kV AC emergency bus cross-tie in non-SBO scenarios, was evaluated as part of the IPE process. The IPE includes a section documenting the impact of implementing the procedure, which was subsequently implemented at the site. One additional procedure enhancement, which was grouped in the Accident Management Guidance category, is described in the IPE. The insight was to update the plant procedures to direct reactor cavity flooding in core damage scenarios to provide a means of exterior vessel cooling. The IPE states that this potential procedure change was to be evaluated as part of the implementation of the Westinghouse Owner's Group Severe Accident Management Guidance. No other specific proposed plant changes were identified in the IPE. The table below summarizes the status of these changes for Byron:

Status of IPE Plant Enhancements

Description of Potential Enhancement	Status of Implementation	Disposition
Modify plant procedures to allow inter-unit cross-tie for non-SBO conditions	Implemented	No further evaluation required.
Update severe accident guidelines to direct reactor cavity flooding to prevent reactor vessel failure	Implemented	No further evaluation required.

The limited number of plant changes explicitly suggested in the IPE has been implemented at Byron and therefore no further review of these items is required.

F.5.1.5 BYRON IPEEE PLANT IMPROVEMENT REVIEW

Similar to the IPE, any proposed plant changes that were previously rejected based on non-SAMA criteria should be re-examined as part of this SAMA analysis. In addition, any issues that are in the process of being resolved should be examined because their resolutions could be important to the disposition of some SAMAs. The IPEEE was used to identify these items.

The only potential plant improvements identified in the Byron IPEEE were related to seismic initiators. The following table summarizes the status of the potential plant enhancements resulting from the IPEEE processes and the treatment of each in the SAMA analysis.

Status of IPEEE Plant Enhancements

Description of Potential Enhancement	Status of Implementation	Disposition
Control room ceiling diffusers are made of aluminum and, if dislodged by a seismic event, may pose a personnel hazard (seismic)	Resolved.	No SAMAs Required
Valve operator on 1(2)CV112E in contact with adjacent plat form/steel grating.	Resolved.	No SAMAs Required
Unanchored heat trace cabinet located in vicinity of MCC 1AP32E	Resolved	No SAMAs Required
Multiple MCCs, battery chargers, and breakers were found not to be tied together posing an impact issue (seismic).	Resolved.	No SAMAs Required.

The above plant changes suggested in the IPEEE have been resolved by the site and no further review is required.

F.5.1.6 EXTERNAL EVENTS IN THE BYRON SAMA ANALYSIS

The IPEEE was used in the Byron SAMA analysis primarily to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences. The types of events considered in the Byron external events analysis were identified by NUREG-1470 (NRC 1991) and included:

- Internal Fires
- Seismic Events
- High Winds and Tornadoes
- External Flooding
- Transportation and Nearby Facility Accidents
- Rail Transportation Accidents (treated as part of transportation and nearby facility accidents)

- Barge Transportation Accidents
- Pipeline Transportation Accidents
- Military Facilities
- On-site Hazardous Material Accidents
- Severe Temperature Transients
- Severe Weather Storms
- Lightning Strikes
- External Fires
- Extraterrestrial Activity
- Volcanic Activity
- Abrasive Windstorms

These potential contributors were evaluated using a progressive screening approach, per NUREG-1407, which resulted in the screening of most initiator types, but designated five initiators for further analysis:

- Internal Fires (Section F.5.1.6.1)
- Seismic Events (Section F.5.1.6.2)
- High Wind Events (Section F.5.1.6.3)
- External Floods (Section F.5.1.6.4)
- Transportation and Nearby Facility Accidents (Section F.5.1.6.5)

The external event types that were not explicitly evaluated in the IPEEE for Byron are considered to be negligible contributors to risk and they are excluded from further consideration in the SAMA identification process.

The types of information available for the initiators that were evaluated by Byron varies based on the manner in which they were addressed in the IPEEE and the Fire model. For instance, core damage frequency information was developed as part of the fire risk analysis while the seismic margins analysis does not directly provide any core damage frequency estimates. Finally, a progressive screening approach was employed to address the other external events contributors that were considered to be applicable to the site and no quantitative information is available for those events.

While CDF results are available for fire events, the results are not necessarily compatible with those of the internal events analysis. For example, the Fire model is based on the NUREG/CR-6850 (EPRI 2005) methodology, which includes conservative approaches to address areas of uncertainty. This model is also in the development stage and it is not considered to be mature enough to use as a quantitative basis for detailed risk assessments. Finally, the fire model is not linked to the Level 2 PRA model and the consequences of the corresponding core damage scenarios are not available.

Because of the differences in the methods used to evaluate the external events risks, each of the external event contributors must be considered in a manner suiting the type of analysis performed. A summary of the review process used to identify SAMAs is provided for each of the external event types listed above followed by a description of the method used to quantitatively incorporate external events contributions into the SAMA analysis.

F.5.1.6.1 Internal Fires

As discussed above, the techniques used to model external events vary according to the type of initiator being analyzed. For Byron, the 2009 Byron Fire PRA (Exelon 2009) is available for use in the SAMA analysis, but the model is considered to be an interim implementation of NUREG/CR-6850 given that not all tasks identified in that document are completely addressed or implemented in model. This was due to the graded approached used to develop the analysis and to the changing state-of-the-art methodologies at the time the analysis was developed.

The approach taken for the SAMA analysis is to use the fire model results to develop potential SAMAs and to use risk insights from both the fire and internal events PRA models to approximate potential averted cost-risk for the SAMAs. Even if it was considered appropriate to use the fire results directly for SAMA quantification, the fire model is not integrated with the most recent Level 2 and 3 analyses that are available to support the SAMA analysis, which prevents the evaluation of accident consequences in a manner consistent with the process used for the internal events models. Finally, the fire model is based on a previous revision of the PRA (Revision 6C) rather than the current revision (BB011b1), which introduces additional area of inconsistency.

While the fire model results are not necessarily comparable to the current PRA results, the SAMA analysis directly uses the fire CDF to develop the external events multiplier, as described in Section F.4.6.2.

The SAMA identification process for the fire model uses an IPEEE screening criterion to identify those fire contributors that are potentially significant to risk. Specifically, any fire zone with a CDF greater than the IPEEE screening threshold of 1.0E-06/yr was reviewed to identify potential SAMAs. Review of additional fire scenarios is possible, but this approach was chosen to limit the review of the interim model results to the largest contributors (the top 12 fire zones for Unit 1 and the top 14 fire zones for Unit 2 (26 fire zones in all)).

The fire CDFs used to identify the fire zones for review are based on the Byron fire PRA scenario results, which include the fire ignition frequencies from EPRI 1016735 (EPRI 2008). The fire scenario results for each zone were reviewed and grouped together to help identify target equipment that is common to multiple scenarios in a given fire zone. The reviews were performed and documented separately for the two units given that there are differences between them. The following tables provide a list of the fire zones with CDFs greater than 1.0E-06/yr.

Major Byron Unit 1 Fire Contributors

Fire Zone	Major Scenarios	Zone Description	CDF
11.3-0	D	AUXILIARY BUILDING GENERAL AREA, ELV. 364	1.38E-05
11.6-0	F	AUXILIARY BUILDING GENERAL AREA, ELV. 426	6.00E-06
5.2-1	B, D	DIVISION 11 engineered safety feature (ESF) SWITCHGEAR ROOM	4.19E-06
11.3-1	B	UNIT 1 CONTAINMENT PIPE PENETRATION AREA	3.98E-06
11.4-0	F	AUXILIARY BUILDING GENERAL AREA, ELV. 383	3.79E-06
11.4C-0	V	RADWASTE AND REMOTE SHUTDOWN PANEL CONTROL ROOM	3.58E-06
11.6C-0	A	AUXILIARY BUILDING LAUNDRY ROOM	1.81E-06
17.2-2	A	SX COOLING TOWER-DIV. 11/21 (BYR)	1.57E-06
18.14A-1	C	SX TOWER ELECTRICAL EQUIPMENT ROOM, DIV. 12 (BYR)	1.49E-06
5.1-1	B,D	DIVISION 12 ESF SWITCHGEAR ROOM	1.27E-06
3.4A-1	A	UNIT 1 CABLE RISER AREA ELV. 451	1.18E-06
18.3-1	A	UNIT 1 MAIN STEAM AND AUXILIARY FEEDWATER PIPE TUNNEL	1.13E-06

Major Byron Unit 2 Fire Contributors

Fire Zone	Major Scenarios	Zone Description	CDF
11.6-2	A	Division 22 containment electrical penetrations area	2.05E-05
11.4-0	E	Auxiliary building general area, elv. 383	1.40E-05
11.6-0	L	Auxiliary building general area, elv. 426	1.06E-05
5.2-2	B, D	Division 21 ESF switchgear room	6.51E-06
11.4c-0	Z	Radwaste and remote shutdown panel control room	3.62E-06
1-2	A	Unit 2 Containment	2.01E-06
11.3f-2	A	Safety injection pump 2b room	1.84E-06
11.3g-2	A	Centrifugal charging pump 2b room	1.84E-06
17.2-2	A	SX Cooling Tower-Div. 11/21 (Byr)	1.69E-06
11.3a-2	A	Safety injection pump 2a room	1.69E-06
18.14A-1	C	Fuel handling building	1.75E-06
5.1-2	B, D	Division 22 ESF switchgear room	1.56E-06
3.2-0	T4	Auxiliary building elv. 439	1.17E-06
5.5-2	Z, P, Q	Unit 2 auxiliary electric equipment room	1.49E-06

For each fire zone with a CDF greater than 1.0E-06/yr, the contributing risk factors were reviewed to determine what measures could be taken to mitigate the fire event and the corresponding core damage sequences. Further discussion is provided for each of these fire compartments below.

U1: 11.3-0 (Scenario D), Auxiliary building general area, elv. 364

This fire scenario fails the heat removal medium for recirculation mode and fails the alternate room cooling for the division 2 injection pumps. Enhancements that would reduce the risk of these scenarios include SAMAs that improve secondary side heat removal capability and those that prevent seal LOCAs. Potential SAMAs include replacing the positive displacement pump (PDP) with a self-cooled, auto start pump for alternate RCP seal cooling (SAMA 2), installation of no-leak RCP seals (SAMA 4), installing alternate AFW pump cooling in conjunction with alternate RCP seal cooling (SAMA 13), completing the AFW crosstie (SAMA 15), and automating refill of the diesel driven AFW fuel oil tank (SAMA 18).

Fire scenario D is caused by a fire in MCC 132X1, which does propagate to other equipment. The cables for the RH, SI, and CVCS pump cubicle cooler fans could potentially be protected to improve the likelihood that they will be available for injection and seal cooling (SAMA 27).

U1: 11.6-0 (Scenario F), Aux Building General Area, Elevation 426'

This scenario is initiated in 480V MCC 134X, which leads to failure of a wide range of division 1 equipment, including: AFW, head vent valves (small LOCA), CCW, CVCS, and seal LOCAs are top contributors.

For the cases in which AFW is successful, recirculation mode is ultimately required for success due to the fire induced small LOCA condition, but having the ability to perform cooldown using secondary side heat removal provides an additional path to success that does not require the pressurizer PORVs. As a result, improving AFW reliability, which could be accomplished by implementing the AFW cross-tie (SAMA 15), would significantly reduce the risk of these scenarios. Another potential means of reducing the risk of these scenarios would be to provide automated makeup capability to the RWST to increase the time available for system cooldown to be performed (SAMA 14).

In addition, a notable contributor for this scenario is the operator failure to stop the RH pump when it is running without CC flow to the heat exchanger. A potential means of reducing the risk of this scenario is to change the procedures to direct initiation of CC flow to the RH heat exchangers when the pumps start (SAMA 7).

There are targets both above and around the ignition source and the installation of fire barriers around MCC 134X could potentially reduce the risk of these scenarios (SAMA 28).

U1: 5.2-1 (Scenarios B, D), Division 11 ESF Switchgear Room

The larger contributor, fire scenario "B", is initiated in 4KV bus 141, which results in failure of bus 141 and essentially all division 1 equipment.

Scenario "D" is initiated in bus 131X and results in failure of division 1 safety related 480V AC power, which has a similar impact to scenario "B".

In these cases, the SG makeup function is important and the AFW cross-tie (SAMA 15) is a means of improving the availability of this function. The DMS could provide SG makeup capability (SAMA 11).

In these scenarios, loss of the equipment occurs due to failure of the ignition source and the means of preventing loss of the equipment is limited to enhancements that prevent the fire from developing. Incipient fire detectors are a potential means of accomplishing this goal; however, the reliability of incipient detectors to prevent fires has neither been established nor accepted in the industry, and this enhancement is not suggested as a SAMA.

U1: 11.3-1 (Scenario B), Unit 1 Containment Pipe Penetration Area

Fires in this scenario essentially fail all high pressure injection (HPI), division 1 recirculation, division 1 secondary side heat removal, RCP seal cooling to 2 of 4 pumps directly and the remaining 2 by loss of RWST inventory to the sump (with failure of the volume control tank (VCT) path).

The fire ignition source for this scenario is MCC 131X1, the failure of which results in the loss of the equipment identified above. Because the fire induced failures identified above are the result of damage to the ignition source for the fire scenario, the means of preventing loss of the equipment is limited to enhancements that prevent the fire from developing. Incipient fire detectors are a potential means of accomplishing this goal; however, the reliability of incipient detectors to prevent fires has neither been established nor accepted in the industry, and this enhancement is not suggested as a SAMA.

Installation of no leak RCP seals (SAMA 4) would prevent primary side inventory loss and reduce the risk from these fire scenarios. Completing the implementation of the AFW cross-tie enhancement would provide an alternate means of secondary side heat removal (SAMA 15). Implementation of the DMS may also provide a means of mitigating the scenarios (SAMA 11).

U1: 11.4-0 (Scenario F), Auxiliary Building General Area, Elevation 383'

Fire scenario "F" is initiated in AFW pump 1A or 2A, which results in failure of the division 1 AFW pumps for both units and the Unit 1 division 2 AFW pump.

For cases with only one AFW pump in the opposite unit, the AFW cross-tie is assumed to be unavailable.

Primary system cooling is available for these fire scenarios, but the operator failures lead to core damage. The DMS could potentially provide alternate secondary side heat removal capability, but operator action dependence issues would limit its benefit for the largest contributors (e.g., with recirculation start or RH pump trip for pump operation without CC flow to the RH HX). SAMAs that could reduce the risk of these scenarios include a procedure change to align CCW flow to the RH Heat Exchanges on RH pump start (SAMA 7) and automating the swap to recirculation mode (SAMA 29).

Protecting the AFW 1B and 2A pumps and cables in the Aux Building General Area, Elevation 383', is a potential means of improving the probability that these pumps will remain available for SG makeup after these fires (SAMA 30).

U1: 11.4c-0 (Scenario V), Radwaste and Remote Shutdown Panel Control Room

This fire scenario includes seal cooling failure (CCW and CVCS), AFW failure, high pressure injection failure (CVCS), and failure of the Unit 1 SX system (no containment heat removal).

These failures can potentially be mitigated by the DMS capabilities; the portable SG injection pump can be used to provide SG makeup (through the FW connection point to bypass the AFW valve failures, in this case) and the "no leak" seals would maintain primary side inventory with makeup from an alternate 480V pump (SAMA 11). Installation of a diesel driven SX pump could also provide a potential success path (SAMA 1).

For this scenario, the ignition sources are the Unit 1 remote shutdown control panels (1PL04J, 1PL05J and 1PL06J). Because the fire induced failures identified above are the result of damage to the ignition source for the fire scenario, the means of preventing loss of the equipment is limited to enhancements that prevent the fire from developing. Incipient fire detectors are a potential means of accomplishing this goal; however, the reliability of incipient detectors to prevent fires has neither been established nor accepted in the industry, and this enhancement is not suggested as a SAMA.

U1: 11.6c-0 (Scenario A), Auxiliary building laundry room

This scenario is a bounding fire that is based on the total initiating event frequency for the zone, which in this zone consists of all transient initiators.

The consequences of the fire are fairly broad and include division 1 power (including the 141-241 4 kV X-tie) and multiple failures of division 1 equipment (which are already unavailable due to the power failure).

The largest contributors to the consequential CDF for this scenario are failures of the division 2 AFW pump, division 2 SX equipment failures, and division 2 RHR system failures.

These failures can potentially be mitigated by the DMS capabilities; the portable SG injection pump can be used to provide SG makeup and the "no leak" seals would maintain primary side inventory (SAMA 11).

No practical SAMAs have been identified to prevent the transient fires in this fire zone and because the fire is a bounding fire, no specific information is available regarding fire propagation or ignition sources that would help identify effective equipment protection methods.

U1: 17.2-2 (Scenario A), SX Cooling Tower-Div. 11/21

In this "bounding" fire scenario, the fire induced failures include SX cooling tower cells "A" through "D" (for those that are in standby). Other random failures contribute to the loss of SX.

Loss of SX leads to RCP seal LOCAs in cases where alternate cooling to the charging pumps fails. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Instead of replacing the PDP to protect the RCP seals, a passive means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4). The DMS expands on the inclusion of the "no-leak" seals to include a portable, long term SG makeup capability and primary side makeup pump (SAMA 11).

Because the fire is a "bounding" scenario, fire scenarios are not developed for all of the specific ignition sources in the fire zone, which limits the potential for fire specific SAMA identification.

U1: 18.14A-1 (Scenario C), SX Tower Electrical Equipment Room

In this scenario, the fire induced failures include SX cooling tower cells "E" and "F" as well as multiple SX basin makeup sources.

Loss of SX leads to RCP seal LOCAs in cases where alternate cooling to the charging pumps fails. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Instead of replacing the PDP to protect the RCP seals, a passive means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4). The DMS expands on the inclusion of the "no-leak" seals to include a portable, long term SG makeup capability and primary side makeup pump (SAMA 11).

In this scenario, loss of the equipment occurs due to failure of the ignition source and the means of preventing loss of the equipment is limited to enhancements that prevent the fire from developing. Incipient fire detectors are a potential means of accomplishing this goal; however, the reliability of incipient detectors to prevent fires has neither been established nor accepted in the industry, and this enhancement is not suggested as a SAMA.

U1: 5.1-1 (Scenarios B, D), Division 12 ESF Switchgear Room

These scenarios are the result of a fire initiating in the "B" 4KV ESF bus or the "B" 480V ESF bus. These fires essentially eliminate an entire division of equipment. The largest contributors to these fire scenarios are failures of the SX system, including operator failure to start the standby SX pump on loss of the running pump, "A" SX pump maintenance, and failure of the "A" SX pump min flow path. These failures could be mitigated by installing a diesel driven SX pump train (SAMA 1) or automating start of the standby SX pump on low pressure (SAMA 3). Implementation of the DMS would also provide an alternate means of providing heat removal without SX (SAMA 11).

U1: 3.4A-1 (Scenario A), Unit 1 Cable Riser Area Elevation 451'

In this "bounding" fire scenario, the fire induced failures include an extensive amount of equipment including thermal barrier cooling, both divisions of HPI, and division 1 of AFW, EDG, SX, CCW, SI, and division 1 emergency 480V AC power.

These scenarios lead to loss of RCP seal cooling and seal LOCAs are a considerable risk. Installation of no leak RCP seals (SAMA 4) would prevent primary side inventory loss and reduce the risk from these fire scenarios. The PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Completing the implementation of the AFW cross-tie enhancement would provide an alternate means of secondary side heat removal (SAMA 15). The DMS expands on the inclusion of the "no-leak" seals to include a portable, long term SG makeup capability and primary side makeup pump (SAMA 11).

Because the fire is a "bounding" scenario, fire scenarios are not developed for all of the specific ignition sources in the fire zone, which limits the potential for fire specific SAMA identification.

U1: 18.3-1 (Scenario A), Unit 1 Main Steam and Auxiliary Feedwater Pipe Tunnel

In this "bounding" fire scenario, the fire induced failures include failure of the low steam line pressure signal, failure of the main steam isolation valve isolation capability, and failure of both divisions of AFW (due to closure of all AFW isolation valves, which precludes use of the AFW X-tie).

The existing procedures include guidance to locally open the AF013A-H valves when verifying AFW flow after a system start, but this action is not credited in the model. If this action were included and credited, the frequency of these scenarios would be reduced and SAMAs would not be required.

Enhancements could be performed that would further reduce risk, however. Given that Feedwater/Condensate system is not credited, heat removal must be performed through initiation of feed and bleed and recirculation cooling for heat removal. Improving the reliability of these functions would reduce the risk of these fire scenarios. SAMAs that could accomplish this include a procedure change to align CCW flow to the RH Heat Exchanges on RH pump start (SAMA 7) and automating the swap to recirculation mode (SAMA 29).

Because the fire is a "bounding" scenario, fire scenarios are not developed for all of the specific ignition sources in the fire zone, which limits the potential for fire specific SAMA identification.

UNIT 2

U2: 11.6-2 (Scenario A), Division 22 Containment Electrical Penetrations Area

In this "bounding" fire scenario, the fire induced failures result in a loss of a wide range of division 2 equipment, including AFW, SI, RHR, the 2B EDG, and SX. Also, thermal barrier cooling and both charging pumps are failed in addition to MCC 231X4. These failures result in a loss of RCP seal cooling, which results in an RCP seal LOCA in most of the contributors.

Installing the "no-leak" seals is a potential means of addressing this fire scenario (SAMA 4). The PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Implementation of the DMS would also address the cases in which the seals do not fail through the SG makeup capability, but the cost of the additional scope of the DMS for only 10% of this fire scenario would not be cost beneficial. A smaller portion of the contribution is associated with the failure to stop the RH pumps when CC is not flowing to the RH heat exchangers. A potential means of reducing the risk of this scenario is to change the procedures to direct initiation of CC flow to the RH heat exchangers when the pumps start (SAMA 7).

Because the fire is a "bounding" scenario, fire scenarios are not developed for all of the specific ignition sources in the fire zone, which limits the potential for fire specific SAMA identification.

U2: 11.4-0 (Scenario E), Auxiliary Building General Area, Elevation 383

Fire scenario "E" is initiated in 480V MCC 232X1, which results in failure of SX pump 2B, SX unit 2 CC HX outlet, AFW pump 2B, charging pump 2B, RH pump 2B, SI pump 2B, EDG 2B, and others. Most of the failures are related to loss of the ignition source.

In most scenario "E" cases, an additional SX hardware failure eliminates the last remaining heat sink, and core damage occurs. The AFW cross-tie would help mitigate these failures by providing a heat sink that is not dependent on the unit's SX system (SAMA 15). Seal LOCAs are also a contributor, which could be addressed by "no-leak" seals (SAMA 4). For scenario "B", the largest contributors to the conditional core damage probability are failures of the "B" AFW pump, including the failure to refill the diesel fuel oil tank and multiple pump hardware failures. Automating the refill function would reduce the contribution of these scenarios (SAMA 18). AFW "B" hardware failures could be mitigated with the AFW cross-tie (SAMA 15).

In this scenario, the fire induced damage is primarily the result of the loss of the ignition source, so fire barriers would provide little benefit for this scenario. Because many of the fire induced failures identified above are the result of damage to the ignition source for the fire scenario, the means of preventing loss of the equipment is limited to enhancements that prevent the fire from developing. Incipient fire detectors are a potential means of accomplishing this goal; however, the reliability of incipient detectors to prevent fires has neither been established nor accepted in the industry, and this enhancement is not suggested as a SAMA.

U2: 11.6-0 (Scenario L), Aux Building General Area, Elevation 426'

Scenario "L" is initiated in 480V MCC 234X, which results in the failure of essentially an entire division of safety equipment (division 1). Thermal barrier cooling is also failed and AFW B is failed due to loss of flow to 3 of 4 SGs due to AFW isolation valve closure (prevents all SG makeup through the AFW system).

Seal LOCAs are could be addressed by "no-leak" seals (SAMA 4). Alternatively, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2).

For cases such as these where AFW is not available, improving the reliability of recirculation mode and RH availability would reduce risk. SAMAs that could accomplish this include a procedure change to align CCW flow to the RH Heat Exchanges on RH pump start (SAMA 7) and automating the swap to recirculation mode (SAMA 29).

For scenario "L", installing cable wrap to protect the 2AF013A, B, and D cables would help preserve the AFW function and reduce the risk of this scenario (SAMA 31).

U2: 5.2-2 (Scenarios B, D), Division 21 ESF Switchgear Room

These fire scenarios result in wide range of failures that essentially eliminate an entire division (division 1) of equipment and the division 1 inter-unit 4kV cross-tie.

One of the larger contributors to the conditional core damage probability for the scenario is the operator failure to refill the DG B fuel oil tank. Automating the refill capability would help reduce the risk from these fires (SAMA 18). An additional contributor is failure to start the standby SX pump on loss of the initially running pump; this could be addressed by automating start of the standby pump (SAMA 3). Another contributor is the failure of the operators to establish a cool suction source for the charging pumps on loss of SX. Replacing the existing PDP with a self-cooled charging pump with auto start capability would mitigate these scenarios (SAMA 2). Installation of "no-leak" RCP seals is another means of addressing the failure of seal cooling (SAMA 4).

Fire scenario B is caused by a fire in 4160V switchgear 241, which results in the loss of most of the critical loads for this scenario. Because the fire induced failures identified above are the result of damage to the ignition source for the fire scenario, the means of preventing loss of the equipment is limited to enhancements that prevent the fire from developing. Incipient fire detectors are a potential means of accomplishing this goal; however, the reliability of incipient detectors to prevent fires has neither been established nor accepted in the industry, and this enhancement is not suggested as a SAMA. Fire scenario D occurs in the 231X switchgear and similarly, the impact from this fire is mostly caused by loss of the ignition source.

U2: 11.4C-0 (Scenario Z), Radwaste and Remote Shutdown Panel Control Room

This fire scenario includes CCW failure, AFW failure, high pressure injection failure (CVCS pumps), and failure of the Unit 2 SX system (no containment heat removal).

These failures can potentially be mitigated by the DMS capabilities; the portable SG injection pump can be used to provide SG makeup (through the FW connection point to bypass the AFW valve failures, in this case) and the "no leak" seals would maintain primary side inventory with makeup from an alternate 480V pump (SAMA 11). Installation of a diesel driven SX pump could also provide a potential success path (SAMA 1).

For this scenario, the ignition sources are the Unit 2 remote shutdown control panels (2PL04J, 2PL05J and 2PL06J). Because the fire induced failures identified above are the result of damage to the ignition source for the fire scenario, the means of preventing loss of the equipment is limited to enhancements that prevent the fire from developing. Incipient fire detectors are a potential means of accomplishing this goal; however, the reliability of incipient detectors to prevent fires has neither been established nor accepted in the industry, and this enhancement is not suggested as a SAMA.

U2: 1-2 (Scenario A), Unit 2 Containment

In this "bounding" fire scenario, the fire induced failures include a LOCA through the reactor head vent, failure to re-seat of the PORVs, failure of the block valves to open (if they are initially closed), failure of the low pressurizer pressure signal for SI, and failure of the high pressure recirculation suction path for both divisions of the CV/SI pumps (through CV8804A and SI8804B), and loss of the RCFC low speed mode on all fans.

For the cases in which AFW is successful, recirculation mode is ultimately required for success due to the fire induced small LOCA condition, but having the ability to perform cooldown using secondary side heat removal provides an additional path to success that does not require the pressurizer PORVs. As a result, improving AFW reliability, which could be accomplished by implementing the AFW cross-tie (SAMA 15), would significantly reduce the risk of these scenarios. Another potential means of reducing the risk of these scenarios would be to provide makeup capability to the RWST to increase the time available for system cooldown to be performed (SAMA 14).

Because the fire is a "bounding" scenario, fire scenarios are not developed for all of the specific ignition sources in the fire zone, which limits the potential for fire specific SAMA identification. Given that the RCPs are the largest contributors to the ignition frequency, a potential means of reducing the fire frequency would be through a mechanism to prevent the fire. Incipient fire detectors are a potential means of accomplishing this goal; however, the reliability of incipient detectors to prevent fires has neither been established nor accepted in the industry, and this enhancement is not suggested as a SAMA.

U2: 11.3F-2 (Scenario A), Safety Injection Pump 2B Room

In this "bounding" fire scenario, the fire induced failures include failure of the division 1 RWST low-low level signal for auto opening of 2SI8811A, failure of the high pressure recirculation suction path for both divisions of the CV/SI pumps (through CV8804A and SI8804B), and loss of SI pump 2B.

Without high pressure recirculation capability, the importance of AFW for heat removal is high. As a result, improving AFW reliability, which could be accomplished by implementing the AFW cross-tie (SAMA 15), would significantly reduce the risk of these scenarios. The impact of this fire is likely overstated given that the model does not credit existing procedures that direct the operators to locally open the valves if they do not open remotely (and at least the CV8804A valve would be accessible).

Because the fire is a "bounding" scenario, fire scenarios are not developed for all of the specific ignition sources in the fire zone, which limits the potential for fire specific SAMA identification.

U2: 11.3G-2 (Scenario A), Centrifugal Charging Pump 2B Room

In this “bounding” fire scenario, the fire induced failures include failure of charging pump 2B and the high pressure recirculation suction path for both divisions of the CV/SI pumps (through CV8804A and SI8804B).

Without high pressure recirculation, the importance of AFW for heat removal is increased. As a result, improving AFW reliability, which could be accomplished by implementing the AFW cross-tie (SAMA 15), would significantly reduce the risk of these scenarios. Automating the refill function for the diesel driven AFW fuel oil tank would also reduce the contribution of these scenarios (SAMA 18). The impact of this fire is likely overstated given that the model does not credit existing procedures that direct the operators to locally open the valves if they do not open remotely (and at least the CV8804A valve would be accessible).

Because the fire is a “bounding” scenario, fire scenarios are not developed for all of the specific ignition sources in the fire zone, which limits the potential for fire specific SAMA identification.

U2: 17.2-2 (Scenario A), SX Cooling Tower-Div. 11/21

In this “bounding” fire scenario, the fire induced failures include SX cooling tower cells “A” through “D” (for those that are in standby). Other random failures contribute to the loss of SX.

Loss of SX leads to RCP seal LOCAs in cases where alternate cooling to the charging pumps fails. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Instead of replacing the PDP to protect the RCP seals, a passive means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4). The DMS expands on the inclusion of the “no-leak” seals to include a portable, long term SG makeup capability and primary side makeup pump (SAMA 11).

Because the fire is a “bounding” scenario, fire scenarios are not developed for all of the specific ignition sources in the fire zone, which limits the potential for fire specific SAMA identification.

U2: 11.3A-2 (Scenario A), Safety Injection Pump 2A Room

In this “bounding” fire scenario, the fire induced failures include failure of failure of SI pump 2A, the high pressure recirculation suction path for both divisions of the CV/SI pumps (through CV8804A and SI8804B), and the CV/SI suction cross-tie valves.

Without high pressure recirculation capability, the importance of AFW for heat removal is high. As a result, improving AFW reliability, which could be accomplished by implementing the AFW cross-tie (SAMA 15), would significantly reduce the risk of these scenarios. Automating the refill function for the diesel driven AFW fuel oil tank would also reduce the contribution of these scenarios (SAMA 18). The impact of this fire is likely overstated given that the model does not credit existing procedures that direct the operators to locally open the valves if they do not open remotely (and at least the CV8804A valve would be accessible).

Because the fire is a "bounding" scenario, fire scenarios are not developed for all of the specific ignition sources in the fire zone, which limits the potential for fire specific SAMA identification.

U2: 5.1-2 (Scenarios B, D), Division 22 ESF Switchgear Room

These fire scenarios result in wide range of failures that essentially eliminate an entire division (division 2) of equipment and the division 2 inter-unit 4kV cross-tie.

One of the larger contributors to the conditional core damage probability for the scenario is the operator failure to refill the DG B fuel oil. Automating the refill capability would help reduce the risk from these fires (SAMA 18). A smaller contributor is failure to start the standby SX pump on loss of the initially running pump; this could be addressed by automating start of the standby pump (SAMA 3). Another contributor is the failure of the operators to establish a cool suction source for the charging pumps on loss of SX. Replacing the existing PDP with a self-cooled charging pump with auto start capability would mitigate these scenarios (SAMA 2). Installation of "no-leak" RCP seals is another means of addressing the failure of seal cooling (SAMA 4).

Fire scenario B is caused by a fire in 4160V switchgear 242, which results in the loss of most of the critical loads for this scenario. Because the fire induced failures identified above are the result of damage to the ignition source for the fire scenario, the means of preventing loss of the equipment is limited to enhancements that prevent the fire from developing. Incipient fire detectors are a potential means of accomplishing this goal; however, the reliability of incipient detectors to prevent fires has neither been established nor accepted in the industry, and this enhancement is not suggested as a SAMA. Fire scenario D occurs in the 232X switchgear and similarly, the impact from this fire is mostly caused by loss of the ignition source.

U2: 3.2-0 (Scenario T4), Auxiliary Building Elevation 439'

In this transient fire scenario, the fire induced failures are widespread and include failure of AFW 2B, thermal barrier cooling, RCP seal injection path for pumps B and C, CCW 2B, the B CC to RH Heat exchanger path, charging pump 2B, DG 2B, SX pump 2B, Unit 2 SX heat exchanger outlet path (no flow), SX cross-tie line failure, and 2SX034 fails closed (fails all SX with other failures).

For these cases, there is a complete loss of RCP seal cooling for half of the pumps and seal LOCAs are a driving concern. Installation of "no-leak" RCP seals is the most means of addressing the failure of seal cooling, but because all SX is lost, an alternate SG makeup source is required. The DMS provides these capabilities (SAMA 11).

This areas is a frequently travelled area of the plant and completely eliminating work or transportation of potential ignition sources through the area is not likely feasible, but in without other alternatives, such measures could be considered. In this case, however, there are existing plant procedures to operate valves that are assumed to fail closed that are not credited in the PRA (for example, opening the SX cross-tie valve could be performed locally to restore SX). If these procedures were credited, the risk of this scenario would be reduced below the review threshold and no additional SAMAs are suggested.

U2: 5.5-2 (Scenarios Z, P, Q), Unit 2 Auxiliary Electric Equipment Room

The "Z" scenario includes failure of both AFW pumps and a majority of the conditional core damage probability is associated with two operator actions: failure to align recirculation mode, and failure to stop the RHR pumps when they are running without CC cooling to the heat exchangers. SAMAs that could reduce the risk of these scenarios include a procedure change to align CCW flow to the RH Heat Exchanges on RH pump start (SAMA 7), and automating the swap to recirculation mode (SAMA 29).

The "P" scenario includes fire induced failures of AFW A, thermal barrier cooling, "A" division of CVCS RWST suction, sump suction valve 2SI8811A, and DG 2A. Larger contributors to the conditional core damage probability include operator failures to refill the "B" AFW fuel oil tank, align recirculation mode, and to stop the RHR pumps when they are running without CC cooling to the heat exchangers. SAMAs that could reduce the risk of these scenarios include automating the AFW diesel fuel oil refill function (SAMA 18), a procedure change to align CCW flow to the RH Heat Exchanges on RH pump start (SAMA 7), and automating the swap to recirculation mode (SAMA 29). Completing the AFW cross-tie would also impact some of the risk (SAMA 15). RCP seal LOCAs are additional contributors that could be addressed with "no-leak" RCP seals (SAMA 4) or DMS (SAMA 11).

Fire scenario "Q" is essentially the division 2 version of scenario "P" and the same SAMAs are applicable.

E.5.1.6.1.1 Fire SAMA Identification Summary

Based on a review of the Byron fire area results, four (4) additional SAMAs have been identified for inclusion in the Phase 1 SAMA list:

- Protect RH, SI, and CVCS Cubicle Cooling Fan Cables in Fire Zone 11.3-0 (SAMA 27)

- Install Fire Barriers around MCC 134X (SAMA 28)
- Protect AFW Cables in the Aux Building General Area, Elevation 383' (SAMA 30)
- Protect Cables for 2AF013A, B, and D in the Aux Building General Area, Elevation 426' (SAMA 31)

F.5.1.6.2 Seismic Events

The IPEEE (ComEd 1996) indicates that the EPRI seismic margins methodology was used to identify the minimal set of equipment required to safely shut the reactor down and to determine if that equipment is capable of surviving the Review Level Earthquake (RLE). The RLE, which is generally larger than the design basis earthquake, is a seismic event determined by a combination of the site's seismic hazard and seismic design basis that is intended to challenge the plant and identify the weak links for seismic events that are larger than the RLE. Equipment that is not capable of withstanding the RLE, which at Byron is a 0.3g event that results in a peak acceleration value of 0.636g at 8 Hz, is identified and required to be addressed. While methods exist for using this information to develop a figure of merit, it is not technically equivalent to a core damage frequency and was not performed as part of the Byron IPEEE.

It should also be noted that even in a seismic probabilistic risk assessment, the pedigree of information is not equivalent to what is used in the internal events models. Given that there is a limited amount of seismic response information available for nuclear power plants, analysis techniques developed to model the plant response often compensate by ingraining a conservative bias in their methodologies to prevent overestimating the capabilities of the plants. While seismic risk evaluations are helpful in the identification of potential plant weaknesses, the degree of uncertainty in the CDF and other results is likely significantly larger than for internal events. With these limitations in mind, the Byron IPEEE seismic results and history were reviewed in order to determine if there were any unresolved issues that could impact Byron risk. The issues of potential interest included:

- Unfinished plant enhancements that were determined to be required to ensure the equipment on the Safe Shutdown List would be capable of withstanding the RLE.
- Additional plant enhancements that were identified as a means of reducing plant risk, but were not implemented at the plant.

An effort was also made to use the results of the equipment and structural screening documentation to determine if any outlier issues there were screened in the IPEEE could impact seismic risk at Byron.

The conclusion of the seismic analysis for Byron was that the plant HCLPF is greater than 0.30g peak ground acceleration (PGA) and no programmatic issues were identified. However, Table

3.3 of the IPEEE documents the "outliers" that were identified as part of the seismic capacity assessments. These are generally items with potential seismically induced interaction issues for which it was difficult to calculate a High Confidence of Low Probability of Failure value. Those that were not clearly identified as resolved in the IPEEE are identified below in conjunction with their dispositions for the SAMA analysis.

Summary of Seismic Outlier Resolutions

Equipment ID #	Outlier Finding	SAMA Disposition[1]
1(2)CV112E	Valve operator is in contact with adjacent platform steel/grating, which poses an impact hazard.	Evaluations have determined that the affected piping systems and valve are adequate with the reduced clearance. Also, for 2CV112E, the grating has been modified. No SAMAs are considered to be required.
1(2)AP25E	Seismic interaction concern. Not bolted to adjacent MCC 1(2)AP44E and may impact MCC during seismic event.	Bolted adjacent MCCs together as required. No SAMAs are considered to be required.
1(2)AP27E	Seismic interaction concern. Not bolted to adjacent MCC 1(2)AP47E and may impact MCC during seismic event.	Bolted adjacent MCCs together as required. No SAMAs are considered to be required.
1AP11E, 1AP13E Transformers	"Shipping" bolts securing internal coils to frame are not tight (approximate ¼-1/2" gap as nut is backed off).	Bolts tightened during B1R08. No SAMAs are considered to be required.
1AP10E 2AP06E 2AP10E 2AP12E Switchgear	Seismic interaction concern. Adjacent, unanchored spare breakers(s) poses an interaction hazard.	Seismic interaction issues were addressed. No SAMAs are considered to be required.
1(2)DC03E 1(2)DC05E	Adjacent cabinets not bolted together.	Evaluation has determined that consequences of relay chatter can be resolved by a proceduralized operator action. No SAMAs are considered to be required.

[1] Plant resolutions are based on the information provided in the plant seismic walkdown reports (Exelon 2012a, Exelon 2012b) unless otherwise noted.

Summary of Seismic Outlier Resolutions

Equipment ID #	Outlier Finding	SAMA Disposition[1]
1IP05E 1IP07E 1IP06E 1IP08E	Interaction (impact) concern with adjacent filter duct box which is unsecured.	Duct box was secured to fan cabinet during B1R08. No SAMAs are considered to be required.
2DC04E 2DC06E	Adjacent cabinets not bolted together.	Evaluation has determined that consequences of relay chatter can be resolved by a proceduralized operator action. No SAMAs are considered to be required.
1RD05E 2RD05E	Seismic interaction concern. Not bolted to adjacent 1(2)RD03E. May impact during seismic event.	A plant evaluation (NTS #454-240-96-146-11A) has determined that consequences of relay chatter are either an annunciator in the MCR or a reactor trip signal, which are acceptable and desirable conditions for the plant after a seismic event.. No SAMAs are considered to be required.
1(2)AP92E 1(2)AP93E	Not tied to adjacent MCC.	As indicated in plant drawings (6E-0-3502 (Note 10), 6E-0-3507 (Note 9), and 6E-0-3391BE), the cabinets have been tied together, which was confirmed by a plant walkdown. Breakers were relocated in designated areas where no interaction hazard exists. No SAMAs are considered to be required.
2IP06E 2IP08E	Interaction (impact) concern with adjacent fire extinguisher (A-8-27) which has an open (unsecured) retaining bracket.	Fire extinguisher brackets secured. No SAMAs are considered to be required.
2AP98E	One "shipping" bolt securing internal coils to frame is not tight (approximate ¼" gap as nut is backed off).	Bolts were tightened during B2R07. No SAMAs are considered to be required.

Summary of Seismic Outlier Resolutions

Equipment ID #	Outlier Finding	SAMA Disposition[1]
0PM01J 0PM02J 1PM01J 1PM04J 1PM05J 1PM06J 1PM07J 1PM11J 1PM12J 2PM01J 2PM04J 2PM05J 2PM06J 2PM07J 2PM11J 2PM12J	Unsecured aluminum diffusers in suspended ceiling pose a personnel hazard to operators if they are dislodged due to seismic motion.	Analysis was performed which evaluated the diffusers' capacity for withstanding a seismic event of a magnitude required by the IPEEE without an adverse effect. Conclusively, the ceiling diffusers are capable of withstanding a seismic event of a magnitude required by the IPEEE without adverse effect.
1(2)PA01J 1(2)PA02J 1(2)PA03J 1(2)PA04J 1(2)PA06J 1(2)PA07J 1(2)PA08J 1(2)PA09J 1(2)PA10J 1(2)PA11J 1(2)PA12J 1(2)PA13J 1(2)PA14J 1(2)PA27J 1(2)PA28J 1(2)PA33J 1(2)PA34J 1(2)PA51J 1PA52J	Adjacent cabinets not bolted together.	Interactions were evaluated that addressed the loads for panels and concluded that they were acceptable when linked together. Vendor walkdown confirmed these cabinets to be linked together. No SAMAs are considered to be required.

F.5.1.6.3 High Winds and Tornadoes

The approach taken to analyze the high wind, flood, transportation and nearby facility, and "other" external event risk in the Byron IPEEE was to implement a progressive screening approach. The first three steps included 1) a review of Byron specific hazard data and licensing basis, 2) identification of significant changes since Operating License issuance, and 3) verification that the Byron design met the 1981 Standard Review Plan (SRP) criteria (in NUREG-1407, the 1975 SRP criteria are specified, but the 1981 SRP was determined to be equivalent for use as an IPEEE screening tool). An affirmative determination that the 1981 SRP screening criteria were met resulted in the screening of the hazard on the basis that conformance to the SRP met the IPEEE screening criterion.

For the SAMA analysis, this process is considered adequate for screening events that do not pose a credible threat to plant operations. However, any issues that could impact plant safety are reconsidered to determine if the development of a SAMA is appropriate to address the risk. For Byron, no high wind or tornado vulnerabilities were identified in the IPEEE and there are no relevant potential plant enhancements.

In conclusion, no high wind or tornado related SAMAs are required for Byron.

F.5.1.6.4 External Floods

For external flooding events, Byron Station was determined to meet the NRC's SRP for external flooding and these types of events were screened from further review. The IPEEE indicates that roof loading and grade level effects were considered related to Probable Maximum Precipitation (PMP) or Probable Maximum Flooding (PMF) events.

For PMP events, the IPEEE indicated that even under the worst postulated conditions, the roof design loads were not exceeded.

Flooding as a result of PMP or PMF effects was determined to not challenge the plant. Maximum Flood levels from the Rock River were determined to peak at 708.3 feet mean sea level while plant grade is 870 feet mean sea level. The river screen house would be flooded by the PMF and the essential service water makeup pumps would fail, but the deep well makeup pumps have been qualified to survive the design basis seismic event and would be available as a backup source.

For PMP events with short term pooling of water at plant grade, plant structures were found to be protected by curbed entries that would prevent water incursion.

For Byron, no external flooding vulnerabilities were identified in the IPEEE and there are no relevant potential plant enhancements.

F.5.1.6.5 Transportation and Nearby Facility Accidents

Transportation and nearby facility accidents were included in the Byron IPEEE to account for human errors or equipment failures that may occur in events not directly related to the power generation process at the plant. The types of hazards considered for analysis included:

- Ground Transportation Accidents
- Accidents at Nearby Facilities
- Aircraft Accidents

Both road and rail shipments in the area of the plant were evaluated by the NRC using the criteria in the SRP. No conditions were identified that posed a significant risk to the site and these types of events were screened from further consideration in the IPEEE. No SAMAs, therefore, are required to address these types of events.

The potential for nearby facility accidents was reviewed in the IPEEE and it was determined that of the facilities located near the plant, none posed a significant risk to the plant. A number of nearby industries and facilities ranging from manufacturing facilities for building materials and parts for quarries were identified, no conditions were identified that posed a significant risk to the site and events at nearby facilities were screened from further consideration in the IPEEE. No SAMAs, therefore, are required to address these types of events.

It is recognized that the types of credible threats to nuclear facilities by aircraft have changed since the time the IPEEE was published. While this is true, efforts are underway within the industry to address this issue in conjunction with other forms of sabotage. Based on the fact that this topic is currently being analyzed in another forum and due to the complexity of the issue, intentional aircraft impact events are considered to be out of the scope of the SAMA analysis. Accidental aircraft impact was reviewed in the IPEEE and while it was determined that 4 airports are located within 10 miles of the site, the centerline for the closest low altitude airway was 5 miles from the plant. The conclusion in the IPEEE was that the SRP acceptance criteria were met and accidental aircraft impact posed no significant threat to plant operations. No SAMAs, therefore, are required to address these types of events.

F.5.2 PHASE 1 SCREENING PROCESS

The initial list of SAMA candidates is presented in Table F.5-3. The process used to develop the initial list is described in Section F.5.1.

The purpose of the Phase 1 analysis is to use high-level knowledge of the plant and SAMAs to preclude the need to perform detailed cost-benefit analyses on them. The following screening criteria were used:

- Applicability to the Plant: If a proposed SAMA does not apply to the Byron design, it is not retained. Similarly, any SAMAs that have already been implemented by Exelon or achieve results that Exelon has achieved by other means can be screened as they are not applicable to the current plant design. These criteria are not often explicitly used in the Phase I analysis because the SAMA identification methodology generally excludes such SAMAs; however, they are listed as a possible screening method given that there may be circumstances in which a SAMA would be included in the list even if it is not relevant to the site. An example may be the inclusion of a high profile SAMA that is well known in the industry, but not applicable to the specific site design. Such a SAMA may be included for documentation purposes. Another example may be an unimplemented SAMA from the IPE that has been superseded by another plant enhancement.
- Implementation Cost Greater than Screening Cost: If the estimated cost of implementation is greater than the modified MACR (refer to Section F.4.6), the SAMA cannot be cost beneficial and is screened from further analysis.

Table F.5-3 provides a description of how each SAMA was dispositioned in Phase 1. Those SAMAs that required a more detailed cost-benefit analysis are passed to the Phase 2 analysis and evaluated in Section F.6. Table F.6-1 contains the Phase 2 SAMAs.

F.6 PHASE 2 SAMA ANALYSIS

The SAMA candidates identified as part of the Phase 2 analysis are listed in Table F.6-1. The base PRA model was manipulated to simulate implementation of each of the proposed SAMAs and then quantified to determine the risk benefit. Truncation values and binning cutoffs are the same as used in the base PRA model (CDF, LERF, Seismic and Fire), including Level 2 endstates.

In general, in order to maximize the potential risk benefit due to implementation of each of the SAMAs, the failure probabilities assigned to new basic events, such as human error probabilities (HEPs), were optimistically chosen so as not to inadvertently screen out any potential cost-beneficial SAMAs. Also, any new model logic that was added to the PRA model in order to simulate SAMA implementation was also simplified and optimistically configured to achieve the same effect.

Determining whether or not any given Phase 2 SAMA is potentially cost beneficial involved calculating what is known as the averted cost-risk, which was obtained by a multi-step process that includes the use of the baseline MACR as well as the internal events PRA results and a multiplier to account for external events contributions.

- The averted cost-risk is the difference between the baseline MACR and the MACR for the configuration in which the SAMA has been implemented ($MACR_{SAMA}$). The $MACR_{SAMA}$ is comprised of the internal events contribution and the external events contribution.
  - The internal events portion of the $MACR_{SAMA}$ is calculated in the same manner as for the baseline MACR using the CDF, Level 2 PRA results, etc., as shown in Sections F.4.1 through F.4.6.1.
  - The contribution from the external events to the $MACR_{SAMA}$ is accounted for by multiplying the internal events $MACR_{SAMA}$ by the External Events Multiplier (refer to section F.4.6.2).

For some SAMAs identified by the Fire results review, the internal events PRA does not provide a means of modeling the impact of the SAMA. In these cases, the averted cost-risk is estimated using fire model insights and information from the internal events MACR calculation. The averted cost-risk is obtained by multiplying the internal events contribution to the MACR by the ratio of the CDF eliminated by the SAMA to the base internal events CDF.

  - The assumption is that the fire CDF is proportional to the internal events MACR. For example, if the SAMA is assumed to eliminate the entire CDF associated with Unit 1 fire zone 5.1-1, the averted cost risk would be (1.27E-06 / 3.97E-05 * $5,979,393 = $191,280)

Finally, a SAMA is determined to be potentially cost beneficial if its net value is positive. The net value is determined by the following equation:

Net Value = averted cost-risk – cost of implementation

The implementation costs used in the Phase 1 and 2 analyses consist of industry estimates, Byron specific estimates, or in some cases, combinations of these two sources. It should be noted that Byron specific implementation costs do include contingency costs for unforeseen difficulties, but do not account for any replacement power costs that may be incurred due to consequential shutdown time unless specifically noted. Table F.5-3 provides implementation costs for each Phase 1 and Phase 2 SAMA.

The following sections describe the cost-benefit analysis that was used for each of the Phase 2 SAMA candidates.

It should be noted that apart from fire considerations, Byron units 1 and 2 are essentially identical in design and operation. The differences associated with fire related issues have been addressed by performing unit specific fire SAMA identification tasks and by using unit specific risk insights for quantification, when relevant. SAMAs developed to prevent or mitigate fire damage or propagation in a specific fire scenario required a unit specific quantification using the method described above. Unit specific fire SAMAs are applicable only to the unit for which they were derived. SAMAs identified to mitigate the impact of fire damage (e.g., SAMA 11 – Implement DMS) were all also applicable to the internal events model and the External Events Multiplier was used to account for any fire related benefits for those types of SAMAs.

For all non-fire based SAMAs, the unit 1 PRA model was employed to evaluate the risk benefits and averted costs for each of the SAMAs, and was viewed as also being applicable to Unit 2. That is, if a particular SAMA proves potentially cost beneficial for Unit 1, it will likewise be potentially cost beneficial for Unit 2.

F.6.1 SAMA 2: REPLACE THE POSITIVE DISPLACEMENT PUMP WITH A SELF COOLED, AUTO START PUMP

Loss of SX requires swap of the charging pump suction source to the RWST as well as alignment of an alternate lube oil cooling source to maintain RCP seal injection. Replacing the positive displacement pump with a self-cooled pump with the capability to auto start on loss of charging and SX flow would provide a means of seal cooling on loss of the normal pumps. Providing an automatic transfer switch to allow power from either division would enhance the SAMA's capability.

Assumptions:

The seal injection pump is assumed to have a failure probability of 1E-3. Division 1 and division 2 emergency 480V AC power are assumed to be available to the new seal injection pump with an automatic transfer switch that is 100% reliable.

PRA Model Changes to Model SAMA:

The fault tree was updated to incorporate the self-cooled pump and power supplies under the existing seal injection logic.

Model Change(s):

The following modeling changes were made:

- New OR gate 1SAMA2-SEAL-INJ: Include new event 1SAMA2 and new gate 1SAMA2-POWER.
- New AND gate 1SAMA2-POWER: Include existing gates 1AP-BUS131X4 and 1AP-BUS132X4.
- New event 1SAMA2: SAMA 2 SEAL INJECTION PUMP FAILS; 1.00E-03.
- Under existing gate 1CSLOCA: Added NEW gate 1SAMA2-SEAL-INJ.
- Under existing gate 1CSLOCA-IE: Added NEW gate 1SAMA2-SEAL-INJ.
- Under existing gate 1LOSC-141: Added NEW gate 1SAMA2-SEAL-INJ.
- Under existing gate 1LOSC-142: Added NEW gate 1SAMA2-SEAL-INJ.
- Under existing gate 1LOSC-LOOP: Added NEW gate 1SAMA2-SEAL-INJ.
- Under existing gate 1RCP-SEALLOCA-SLB: Added NEW gate 1SAMA2-SEAL-INJ.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	1.36E-05	24.90	$218,298
Percent Change	65.7%	29.8%	14.3%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	3.35E-06	1.25E-01	3.62E-02	$118	$34
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	8.79E-08	1.63E-02	2.71E-03	$22	$4
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	6.13E-07	1.05E+01	3.41E-01	$35,721	$1,159
LATE-CHR-NOAFW	8.35E-06	8.34E-06	1.78E+01	1.78E+01	$187,040	$186,816
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	1.47E-07	3.41E-01	1.37E-01	$1,655	$663
LERF-CFE	3.55E-08	1.03E-08	8.88E-02	2.58E-02	$582	$169
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.69E-07	6.97E-01	6.97E-01	$8,205	$8,205
Total	4.19E-05	1.47E-05	3.55E+01	2.49E+01	$254,593	$218,298

Applying the process described in Section F.4 yields an internal events cost-risk of $4,403,284. After accounting for "round up" of the base internal events cost-risk, this value is $4,403,891. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$4,403,891 * 2.5 = \$11,009,728$$

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

SAMA 2 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$11,009,728	$3,940,272

Based on a $5,751,110 cost of implementation for Byron, the net value for this SAMA is -$1,810,838 ($3,940,272 - $5,751,110), which indicates this SAMA is not cost beneficial.

F.6.2 SAMA 3: AUTO START OF STANDBY SX PUMP

The SX system includes logic that starts the standby SX pump for initiating events that generate SI or bus under-voltage signals, but for events without these signals, manual start of the standby SX pump is required when the running pump fails.

Automating the start of the standby SX pump would help reduce the reliance of operators to maintain cooling to critical loads. Use of flooding interlocks could be used to prevent auto actuation in flooding scenarios.

Assumptions:

It is assumed that the auto start logic of the standby SX pump can represented by a lumped event accounting for hardware and support system dependencies. The failure probability of the event (1SX-AUTOSTART) is assumed to be 1E-04.

The new autostart function also serves as a backup to the SI and undervoltage start signals.

PRA Model Changes to Model SAMA:

The standby SX pump start logic has been modified to include the auto start event (1SX-AUTOSTART) such that a failure of the SX pump to start requires failure of both the automated start function and the manual operator action.

Model Change(s):

Event 1SX-AUTOSTART has been included under the following gates:

- 1SX-PUMP-1A-SIG1: SX PUMP IS NOT STARTED MANUALLY FOR OTHER INITIATORS
- 1SX-PM1A-DG-ACT: SX PUMP 1A FTS VIA SIGNAL FAULT (DG SUPPORT- IELOP CAN BE PRESUMD; DC
- 1SX-PM1A-LOOP: SX PUMP 1A IS NOT ACTIUATED FOR LOOP IE
- 1SX-PM1B-DG-ACTSX PUMP 1B FTS VIA SIGNAL FAULT (DG SUPPORT- IELOP CAN BE PRESUMD; DC
- 1SX-PM1B-LOOP: SX PUMP 1A IS NOT ACTIUATED FOR LOOP IE
- 1SX-PUMP-1B-SIG1: SX PUMP IS NOT STARTED MANUALLY FOR OTHER INITIATORS

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.22E-05	30.57	$231,705
Percent Change	18.9%	13.8%	9.0%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq.S_{AMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.16E-05	1.25E-01	1.25E-01	$118	$118
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	1.18E-05	1.05E+01	6.56E+00	$35,721	$22,302
LATE-CHR-NOAFW	8.35E-06	7.96E-06	1.78E+01	1.70E+01	$187,040	$178,304
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	2.98E-07	3.41E-01	2.77E-01	$1,655	$1,344
LERF-CFE	3.55E-08	2.84E-08	8.88E-02	7.10E-02	$582	$466
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.59E-07	6.97E-01	6.71E-01	$8,205	$7,900
Total	4.19E-05	3.43E-05	3.55E+01	3.06E+01	$254,593	$231,705

Applying the process described in Section F.4 yields an internal events cost-risk of $5,283,419. After accounting for "round up" of the base internal events cost-risk, this value is $5,284,026. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5{,}284{,}026 * 2.5 = \$13{,}210{,}065$$

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

SAMA 3 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$13,210,065	$1,739,935

Based on a $1,130,300 cost of implementation for Byron, the net value for this SAMA is $609,635 ($1,739,935 - $1,130,300), which indicates this SAMA is potentially cost beneficial.

F.6.3 SAMA 4: INSTALL "NO LEAK" RCP SEALS

For loss of RCP seal cooling scenarios, a passive means of reducing the probability of an RCP seal LOCA is to replace the existing pump seals with "no leak" seals (e.g., Westinghouse "shield" seals) that are less likely to fail on loss of cooling.

Assumptions:

The “no-leak” seal capabilities are assumed to be represented by a lower RCP seal LOCA probability. The “no leak” seals are assumed to reduce the seal LOCA probability by a factor of 1000.

PRA Model Changes to Model SAMA:

The impact of implementing this SAMA has been estimated by modifying the base model cutset file. Using the cutset editor, the deleted flag “FLAG-SEAL-LOCA” is restored to the cutsets and assigned a value of 1E-3. Because the cutsets already include events that represent seal LOCA probabilities that are less than 1.0, this process ultimately reduces the probability that a seal LOCA occurs to less than the assumed value of 1E-3, but it conservatively shows an increased averted cost-risk for the SAMA.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	1.33E-05	24.54	$215,658
Percent Change	66.5%	30.8%	15.3%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	3.21E-06	1.25E-01	3.47E-02	$118	$33
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	8.42E-08	1.63E-02	2.59E-03	$22	$4
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	3.35E-07	1.05E+01	1.86E-01	$35,721	$633
LATE-CHR-NOAFW	8.35E-06	8.25E-06	1.78E+01	1.76E+01	$187,040	$184,800
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	1.46E-07	3.41E-01	1.36E-01	$1,655	$658
LERF-CFE	3.55E-08	1.02E-08	8.88E-02	2.55E-02	$582	$167
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.66E-07	6.97E-01	6.89E-01	$8,205	$8,113
Total	4.19E-05	1.42E-05	3.55E+01	2.45E+01	$254,593	$215,658

Applying the process described in Section F.4 yields an internal events cost-risk of $4,344,644. After accounting for "round up" of the base internal events cost-risk, this value is $4,345,251. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$4,345,251 * 2.5 = \$10,863,128$$

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

SAMA 4 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$10,863,128	$4,086,872

Based on a $12,230,000 cost of implementation for Byron, the net value for this SAMA is -$8,143,128 ($4,086,872 - $12,230,000), which indicates this SAMA is not cost beneficial.

F.6.4 SAMA 5: MODIFY THE STARTUP FEEDWATER PUMP TO START USING THE AMSAC SG LOW-LOW-LOW LEVEL SIGNAL TO MITIGATE AFW FAILURE

For accident sequences in which main feedwater has tripped and AFW has failed to start, it is necessary to manually restart the FW system for continued SG makeup. By modifying the startup feedwater pump to auto start and align on low steam generator level, the need for operator intervention after AFW failure is essentially eliminated. Use of the anticipated transient without scram mitigating system actuation circuitry (AMSAC) low-low-low SG level signal is an additional benefit that mitigates start signal failures.

Assumptions:

The auto start logic is only applicable to the startup FW pump, but to simplify the modeling, the auto start logic is also assumed to be capable of starting the main FW pump. This conservatively increases the averted cost-risk for this SAMA.

PRA Model Changes to Model SAMA:

The startup FW pump start logic has been modified to include the auto start event (1SUFW-AUTOSTART) such that a failure of the FW pumps to start requires failure of both the automated start function and the manual operator action.

Model Change(s):

The following modeling changes were made:

- Under gates 1FWR-TRANS and 1ALTFW-SLOCA: Added new AND gate 1FW-FWR-START. Deleted 1FW-FWR-OA
- New AND gate 1FW-FWR-START: Included existing gate 1FW-FWR-OA and new event 1SUFW-AUTOSTART.
- New event 1SUFW-AUTOSTART: AUTO START LOGIC FOR ALT FW FUNCTION. Failure prob. = 1.00E-04
- Under gate 1ALTFW-SGTR: Added new AND gate 1FW-FWR-START-SGTR. Deleted 1FW-FWR-OA-SGTR.
- New AND gate 1FW-FWR-START-SGTR: Included existing gate 1FW-FWR-OA-SGTR and new event 1SUFW-AUTOSTART.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.60E-05	28.00	$176,115
Percent Change	9.3%	21.0%	30.8%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	Freq.$_{BASE}$	Freq.$_{SAMA}$	Dose-Risk$_{BASE}$	Dose-Risk$_{SAMA}$	OECR$_{BASE}$	OECR$_{SAMA}$
INTACT	1.16E-05	1.12E-05	1.25E-01	1.21E-01	$118	$114
SERF-TISGTR-HLF	6.49E-09	5.49E-09	6.17E-03	5.22E-03	$44	$37
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	6.04E-08	6.36E-03	4.83E-03	$14	$11
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	5.00E-06	1.78E+01	1.07E+01	$187,040	$112,000
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.34E-07	3.41E-01	3.11E-01	$1,655	$1,506
LERF-CFE	3.55E-08	3.14E-08	8.88E-02	7.85E-02	$582	$515
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	4.17E-11	6.68E-04	3.25E-05	$6	$0
LERF-ISGTR	2.69E-07	1.64E-07	6.97E-01	4.25E-01	$8,205	$5,002
Total	4.19E-05	3.80E-05	3.55E+01	2.80E+01	$254,593	$176,115

Applying the process described in Section F.4 yields an internal events cost-risk of $4,473,821. After accounting for "round up" of the base internal events cost-risk, this value is $4,474,428. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$4,474,428 * 2.5 = \$11,186,070$$

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

SAMA 5 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$11,186,070	$3,763,930

Based on a $657,200 cost of implementation for Byron, the net value for this SAMA is $3,106,730 ($3,763,930 - $657,200), which indicates this SAMA is potentially cost beneficial.

F.6.5 SAMA 7: ESTABLISH FLOW TO THE RH HX ON RH PUMP START

To prevent overheating the RH pumps when they are operating on min-flow without CC cooling to the heat exchangers, procedure EP-0 (and potentially others) could be changed to direct the operators to align CC to the RH HX when the RH pumps start. This precludes the need for the operators to rely on a continuous action statement to protect the RH pumps if secondary side cooling is not established.

Assumptions:

It is assumed that the procedures can be modified in a way such that the flow to the HX is started when the corresponding RHR pump is confirmed to be running and that the step is written distinct manner (potentially with the caution that exists in the current FR-H.1 procedure related to the limitations on the RH pump run time without flow to the HX). It is assumed the impact of these changes can be approximated by crediting graphically distinct procedures and a "check" cue in the HRA methodology for the HFE 1RH-SP-X---HPMOA. The result is a reduction in the HEP from 7.3E-04 to 1.4E-04.

Unless the HEP is the lead action in a joint human error probability (JHEP), the value of the independent HEP has a small impact on the JHEP value. No changes are made to the JHEPs unless the chronologically first action is 1RH-SP-X---HPMOA.

PRA Model Changes to Model SAMA:

The database and recovery files were changed to use the updated HEPs reflecting the procedure modification.

Model Change(s):

The following modeling changes were made:

- 1RH-SP-X---HPMOA: HEP changed from 7.3E-04 to 1.4E-04.
- 1RX-JHEP33-HOADA: Updated JHEP calc from 3.9E-05 to reflect modified independent HEP value: 1.4E-4 * ((1 + 19*2.7E-03) / 20) = 7.4E-06.

- 1RX-JHEP42-HOADA: Updated JHEP calc from 3.7E-05 to reflect modified independent HEP value: 1.4E-4 * ((1 + 19*9.6E-04) / 20) = 7.1E-06

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.88E-05	35.41	$254,363
Percent Change	2.3%	0.1%	0.1%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.07E-05	1.25E-01	1.16E-01	$118	$109
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.36E-06	1.33E+00	1.31E+00	$8,349	$8,228
LATE-BMMT-AFW	5.30E-07	4.87E-07	1.63E-02	1.50E-02	$22	$20
LATE-BMMT-NOAFW	7.95E-08	7.81E-08	6.36E-03	6.25E-03	$14	$14
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.35E-06	1.78E+01	1.78E+01	$187,040	$187,040
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.59E-07	3.41E-01	3.34E-01	$1,655	$1,619
LERF-CFE	3.55E-08	3.46E-08	8.88E-02	8.65E-02	$582	$567
LERF-SGTR-AFW	5.49E-08	5.40E-08	1.31E-01	1.29E-01	$1,005	$988
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.68E-07	6.97E-01	6.94E-01	$8,205	$8,174
Total	4.19E-05	4.09E-05	3.55E+01	3.54E+01	$254,593	$254,363

Applying the process described in Section F.4 yields an internal events cost-risk of $5,950,012. After accounting for "round up" of the base internal events cost-risk, this value is $5,950,619. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,950,619 * 2.5 = \$14,876,548$$

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

SAMA 7 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,876,548	$73,452

Based on a $100,000 cost of implementation for Byron, the net value for this SAMA is -$26,548 ($73,452 - $100,000), which indicates this SAMA is not cost beneficial.

F.6.6 SAMA 8: INSTALL KILL SWITCHES FOR THE FIRE PROTECTION PUMPS IN THE MCR

Currently, it is not possible to terminate all flow from the fire protection system in the main control room (MCR). In the event of a flood caused by a fire protection system break, the availability of controls in the MCR that would allow the operators to shut down the fire protection pumps would increase the likelihood that the flood could be terminated before critical equipment is damaged.

<u>Assumptions:</u>

Installation of kill switches in the MCR will reduce the time required to perform the action to terminate the flood and potentially in a simplification of the control scheme. Each pump is assumed to have a dedicated, two position control switch that is distinct from the other controls on the main control room fire protection control panel.

With the revised controls proposed for this SAMA, the manipulation time for this action is assumed to be 3 minutes (1 minute for each pump).

The flood mitigation factors include multiple actions, including the initial flood termination action, but are not wholly determined by the flood termination action HEP. The flood mitigation factors were recalculated using the above assumptions.

<u>PRA Model Changes to Model SAMA:</u>

A recovery file was developed to modify the cutsets to use the updated Fire Protection flood mitigation factors the Auxiliary Building Fire Protection floods.

Model Change(s):

The following changes were made to the cutsets:

- FLMITIG--G-T1-FP: Probability changed from 2.23E-04 to 1.10E-04.
- FLMITIG-M1-T1-FP: Probability changed from 3.33E-04 to 1.66E-04.
- FLMITIG-M2-T1-FP: Probability changed from 2.19E-03 to 1.89E-03.
- FLMITIG-M3-T1-FP: Probability changed from 6.94E-03 to 3.88E-03

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.83E-05	34.53	$250,489
Percent Change	3.5%	2.6%	1.6%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.16E-05	1.25E-01	1.25E-01	$118	$118
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	1.75E-05	1.05E+01	9.73E+00	$35,721	$33,075
LATE-CHR-NOAFW	8.35E-06	8.29E-06	1.78E+01	1.77E+01	$187,040	$185,696
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.54E-07	3.41E-01	3.29E-01	$1,655	$1,597
LERF-CFE	3.55E-08	3.40E-08	8.88E-02	8.50E-02	$582	$558
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.68E-07	6.97E-01	6.94E-01	$8,205	$8,174
Total	4.19E-05	4.04E-05	3.55E+01	3.45E+01	$254,593	$250,489

Applying the process described in Section F.4 yields an internal events cost-risk of $5,851,638. After accounting for "round up" of the base internal events cost-risk, this value is $5,852,245. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,852,245 * 2.5 = \$14,630,613$$

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

SAMA 8 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,630,613	$319,387

Based on a $338,830 cost of implementation for Byron, the net value for this SAMA is -$19,443 ($319,387 - $338,830), which indicates this SAMA is not cost beneficial.

F.6.7 SAMA 9: INSTALL FLOW RESTRICTORS IN FIRE PROTECTION PIPES

Large breaks in the fire protection systems are significant contributors to plant risk. Installing flow restrictors in the auxiliary building piping would increase the time available to respond to these flooding events. Locating flow restrictors outside the auxiliary building upstream of valves 0FP209A, 0FP209B, and FP033 would provide adequate protection for auxiliary building floods.

<u>Assumptions:</u>

It is assumed that fire protection code will allow the installation of flow restrictors in the fire protection system lines. If this is not possible, it is assumed that a flow analysis can be performed that will allow the throttling of the 0FP209A, 0FP209B, and 0FP033 valves (which may need to be replaced by valves of a different type) to achieve similar results.

It is assumed that the flow restrictions will limit flow of Fire Protection breaks in the Auxiliary building to 1000 gpm and that 1000 gpm is adequate to meet fire suppression requirements.

The increase in the time available to terminate the fire protection flood reduces the flood mitigation factor to 1.2E-4. Because the flow restrictors would limit flow to 1000 gpm for all Auxiliary Building Fire Protection breaks, this flood mitigation factor is assumed to be applicable to all Auxiliary Building Fire Protection flooding scenarios.

PRA Model Changes to Model SAMA:

A recovery file was developed to modify the cutsets to use the updated Fire Protection flood mitigation factor for all Auxiliary Building Fire Protection floods.

Model Change(s):

The following changes were made to the cutsets:

- FLMITIG--G-T1-FP: Probability changed from 2.23E-04 to 1.2E-04.
- FLMITIG-M1-T1-FP: Probability changed from 3.33E-04 to 1.2E-04.
- FLMITIG-M2-T1-FP: Probability changed from 2.19E-03 to 1.2E-04.
- FLMITIG-M3-T1-FP: Probability changed from 6.94E-03 to 1.2E-04

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.66E-05	33.49	$245,971
Percent Change	7.8%	5.5%	3.4%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	Dose-$Risk_{BASE}$	Dose-$Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.16E-05	1.25E-01	1.25E-01	$118	$118
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	1.59E-05	1.05E+01	8.84E+00	$35,721	$30,051
LATE-CHR-NOAFW	8.35E-06	8.23E-06	1.78E+01	1.75E+01	$187,040	$184,352
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.40E-07	3.41E-01	3.16E-01	$1,655	$1,533
LERF-CFE	3.55E-08	3.24E-08	8.88E-02	8.10E-02	$582	$531

Release Category	Freq.$_{BASE}$	Freq.$_{SAMA}$	Dose-Risk$_{BASE}$	Dose-Risk$_{SAMA}$	OECR$_{BASE}$	OECR$_{SAMA}$
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.66E-07	6.97E-01	6.89E-01	$8,205	$8,113
Total	4.19E-05	3.88E-05	3.55E+01	3.35E+01	$254,593	$245,971

Applying the process described in Section F.4 yields an internal events cost-risk of $5,705,994. After accounting for "round up" of the base internal events cost-risk, this value is $5,706,601. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,706,601 * 2.5 = \$14,266,503$$

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

SAMA 9 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,266,503	$683,497

Based on a $349,300 cost of implementation for Byron, the net value for this SAMA is $334,197 ($683,497 - $349,300), which indicates this SAMA is potentially cost beneficial.

F.6.8 SAMA 10: ALTER DUCTWORK BETWEEN THE AUX BLDG SUMP DRAIN ROOM AND THE SX PUMP ROOM

Currently, the ductwork between the Auxiliary Building Sump Drain Room and the SX Pump Rooms provides a flowpath for flood water when the Auxiliary Building Sump Drain Room fills with water (at a depth of about 12 feet). Water then flows through the ductwork to the SX pump room and damages the SX pumps. Eliminating this pathway will increase the time available to mitigate the flooding event by precluding SX pump damage from the flooding event.

<u>Assumptions:</u>

The ductwork modification prevents water intrusion into the SX pump room duct until water level reaches the 364' elevation. It is assumed that the actual failure level is the same as that for the other critical equipment located on that level such that the time available for flood termination is the same as what is currently used for the internal flooding assessment.

This SAMA eliminates the "T1" flooding scenarios that are related to failing SX due to the existing duct connections between the SX pumps rooms and the Auxiliary Building Sump Drain Room.

The flood mitigation factors for the normal service water (WS) and SX floods are simplified to the HEPs for termination of the flood before the level reaches elevation 364'.

PRA Model Changes to Model SAMA:

A recovery file was developed to modify the cutsets to use the updated Fire Protection flood mitigation factor for all Auxiliary Building floods.

Model Change(s):

The following changes were made to the cutsets:

- Set probability of the following "T1" flood events to 0.0: FLMITIG-FPCVCOOL, FLMITIG--G-T1-FP, FLMITIG--G-T1-SX, FLMITIG--G-T1-WS, FLMITIG-M1-T1-FP, FLMITIG-M1-T1-WS, FLMITIG-M2-T1-FP, FLMITIG-M3-T1-FP, FLMITIG-M3-T1-WS, FLMITIG--M-T1-SX.
- FLMITIG-M3-T2-WS: Probability changed from 2.14E-04 to 1.8E-04.
- FLMITIG--M-T2-SX: Probability changed from 2.09E-03 to 1.4E-04

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.50E-05	31.32	$227,001
Percent Change	11.8%	11.7%	10.8%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.16E-05	1.25E-01	1.25E-01	$118	$118
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	1.50E-05	1.05E+01	8.34E+00	$35,721	$28,350
LATE-CHR-NOAFW	8.35E-06	7.50E-06	1.78E+01	1.60E+01	$187,040	$168,000
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	2.77E-07	3.41E-01	2.58E-01	$1,655	$1,249
LERF-CFE	3.55E-08	3.10E-08	8.88E-02	7.75E-02	$582	$508
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.46E-07	6.97E-01	6.37E-01	$8,205	$7,503
Total	4.19E-05	3.70E-05	3.55E+01	3.13E+01	$254,593	$227,001

Applying the process described in Section F.4 yields an internal events cost-risk of $5,311,758. After accounting for "round up" of the base internal events cost-risk, this value is $5,312,365. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,312,365 * 2.5 = \$13,280,913$$

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

SAMA 10 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$13,280,913	$1,669,087

Based on a $1,320,300 cost of implementation for Byron, the net value for this SAMA is $348,787 ($1,669,087 - $1,320,300), which indicates this SAMA is potentially cost beneficial.

F.6.9 SAMA 11: IMPLEMENT DMS

The diverse and flexible coping strategies (FLEX) guide identifies different means of addressing required plant functions, but for this SAMA a specific approach is proposed. A portable 480V AC generator is proposed as a means of supporting long term diesel driven AFW operation by means of maintaining instrumentation and control power for the system by energizing the buses used for the battery chargers. A portable, engine driven SG makeup pump would provide an alternate means of SG makeup, with injection connections available on different divisions. Fire protection should provide both condensate storage tank (CST) makeup and a suction source connection for the portable SG makeup pump. Use of high temperature RCP seals would limit primary system leakage and the positive displacement pump could be replaced by one that could be powered by the portable generator for long term RCS makeup. A means of providing borated makeup to the RWST is also required, which could potentially be performed using the fire protection system and an eductor. Finally, a connection point to an outside source would have to be provided for the containment spray system for long term spray capability in an SBO.

Assumptions:

SAMA 11 was generally identified as a means of mitigating scenarios in which loss of SG makeup is a slowly developing evolution, such as in SBO events where battery depletion eventually fails diesel driven AFW or in loss of SX cases in which the AFW pumps (motor or diesel driven) may be able to run for some time before failure. No credit is taken for the DMS in LOCA or ATWS scenarios. The DMS is credited in SGTR cases as most cases include success of injection where time would be available to recover steam generator makeup. Prior to core damage, activity levels are expected to be low enough to perform any alignment required.

The DMS capabilities are assumed to be represented by a lower RCP seal LOCA probability and indefinite steam generator makeup capability. The "no leak" seals are assumed to reduce the seal LOCA probability by a factor of 1000. The steam generator makeup capability includes alignment and control of a portable 480V generator to support diesel driven AFW makeup or alignment and control of a portable SG makeup pump. A new event with a failure probability of 1E-2 is used for this function.

It is assumed that the cognitive failure to diagnose the need for secondary cooling (1FW-FRH1--HSGOA), which is related to the AFW X-tie, FW restoration, and bleed and feed, will also fail the DMS. In addition, any dependent combinations are also assumed to fail the DMS.

PRA Model Changes to Model SAMA:

The fault tree was updated to incorporate the DMS event and cognitive failure logic. After quantification, the deleted flag "FLAG-SEAL-LOCA" is restored to the cutsets in the cutset editor and assigned a value of 1E-3. Because the cutsets already include events that represent seal LOCA probabilities that are less than 1.0, this process ultimately reduces the probability that a seal LOCA occurs to less than the assumed value of 1E-3, but it conservatively shows an increased averted cost-risk for the SAMA.

Model Change(s):

The following modeling changes were made:

- New event 1DMS: DMS - OPS FAIL TO ALIGN/USE 480V CHARGER OR PORTABLE SG MAKEUP PUMP, 1.0E-02
- New OR gate 1DMS-FAILS: Include new event 1DMS, 1FW-FRH1---HSGOA, 1RX-JHEP03-HOADA and similar events for the following JHEP combinations: 07, 09, 11, 12, 14, 17, 21, 24, 25, 27, 39, 49, 50, 54, 58, 64, 74, and 80.
- Under gate 1AFW: Added NEW gate 1DMS-FAILS.
- Under gate 1AFW-LOOP-3SG: Added NEW gate 1DMS-FAILS.
- Under gate 1AFW-LOOP-2SG: Added NEW gate 1DMS-FAILS.
- Under gate 1AFW-SBO-3SG: Added NEW gate 1DMS-FAILS.
- Under gate 1AFW-SBO-2SG: Added NEW gate 1DMS-FAILS.
- Under gate 1AFW-LOB-MDP-3SG: Added NEW gate 1DMS-FAILS.
- Under gate 1AFW-LOB-MDP-2SG: Added NEW gate 1DMS-FAILS.
- Under gate 1AFW-LOB-DDP-3SG: Added NEW gate 1DMS-FAILS.
- Under gate 1AFW-LOB-DDP-2SG: Added NEW gate 1DMS-FAILS.
- Under gate 1AF-UBR-LATE: Added NEW gate 1DMS-FAILS.
- Under gate 1AF-UBR-LATE: Added NEW gate 1DMS-FAILS.
- Under gate 1AF-DP-LATE: Added NEW gate 1DMS-FAILS.

Post quantification, set flag FLAG-SEAL-LOCA to a probability of 1E-3.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	**Dose-Risk**	**OECR**
Base Value	3.97E-05	35.45	$254,593
SAMA Value	4.66E-06	7.11	$32,430
Percent Change	88.3%	80.0%	87.3%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	Freq.$_{BASE}$	Freq.$_{SAMA}$	Dose-Risk$_{BASE}$	Dose-Risk$_{SAMA}$	OECR$_{BASE}$	OECR$_{SAMA}$
INTACT	1.16E-05	2.25E-06	1.25E-01	2.43E-02	$118	$23
SERF-TISGTR-HLF	6.49E-09	1.52E-09	6.17E-03	1.44E-03	$44	$10
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	8.41E-08	1.63E-02	2.59E-03	$22	$4
LATE-BMMT-NOAFW	7.95E-08	3.12E-08	6.36E-03	2.50E-03	$14	$6
LATE-CHR-AFW	1.89E-05	3.36E-07	1.05E+01	1.87E-01	$35,721	$635
LATE-CHR-NOAFW	8.35E-06	4.26E-07	1.78E+01	9.07E-01	$187,040	$9,542
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	2.49E-08	3.41E-01	2.32E-02	$1,655	$112
LERF-CFE	3.55E-08	2.81E-09	8.88E-02	7.03E-03	$582	$46
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.82E-08	6.97E-01	7.30E-02	$8,205	$860
Total	4.19E-05	4.96E-06	3.55E+01	7.11E+00	$254,593	$32,430

Applying the process described in Section F.4 yields an internal events cost-risk of $828,760. After accounting for "round up" of the base internal events cost-risk, this value is $829,367. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$829,367 * 2.5 = \$2,073,418$$

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

SAMA 11 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$2,073,418	$12,876,582

Based on a $13,030,000 cost of implementation for Byron, the net value for this SAMA is -$153,418 ($12,876,582 - $13,030,000), which indicates this SAMA is not cost beneficial.

F.6.10 SAMA 13: ALTERNATE AFW COOLING WITH SEAL PROTECTION

For loss of SX events with consequential loss of offsite power (LOOP), the AFW lube oil coolers are unavailable and the AFW pumps are assumed to fail. The motor driven AFW pump discharge flow could be routed back to the lube oil coolers to provide a self-cooling mechanism that would eliminate the SX dependence. The cooling water return flow could potentially be returned to the AFW pump discharge path. For RCP seal protection, replacing the positive displacement pump (PDP) with a self-cooled pump with the capability to auto start on loss of charging flow/and or high seal injection water temp would provide a success path.

Assumptions:

This SAMA is assumed to eliminate the SX dependence for motor driven AFW pump operation. The diesel driven AFW pumps is not modified for this SAMA given that an additional change would be required to provide flow to the cubicle coolers and because power is available to the motor driven AFW pump for most of the scenarios this SAMA is intended to address.

The seal injection pump is assumed to have a failure probability of 1E-3. Division 1 and division 2 emergency 480V AC power are assumed to be available to the new seal injection pump with an automatic transfer switch that is 100% reliable.

The AFW cross-tie is assumed to be unavailable for dual unit LOSX events (even after implementation) because the "A" pump would be needed on the opposite unit.

PRA Model Changes to Model SAMA:

The fault tree was updated to incorporate the self-cooled pump and power supplies under the existing seal injection logic. In addition, the SX dependencies were removed for the motor driven AFW pump.

Model Change(s):

The following modeling changes were made:

- New OR gate 1SAMA13-SEAL-INJ: Include new event 1SAMA13 and new gate 1SAMA13-POWER.
- New AND gate 1SAMA13-POWER: Include existing gates 1AP-BUS131X4 and 1AP-BUS132X4.
- New event 1SAMA13: SAMA 13 SEAL INJECTION PUMP FAILS; 1.00E-03.
- Under existing gate 1CSLOCA: Added NEW gate 1SAMA13-SEAL-INJ.
- Under existing gate 1CSLOCA-IE: Added NEW gate 1SAMA13-SEAL-INJ.
- Under existing gate 1LOSC-141: Added NEW gate 1SAMA13-SEAL-INJ.
- Under existing gate 1LOSC-142: Added NEW gate 1SAMA13-SEAL-INJ.

- Under existing gate 1LOSC-LOOP: Added NEW gate 1SAMA13-SEAL-INJ.
- Under existing gate 1RCP-SEALLOCA-SLB: Added NEW gate 1SAMA13-SEAL-INJ.
- Under existing gates 1AF-PUMP1A-FR-HW-X, 1AF-PUMP1A-FR-HW, and Removed gate 0SX-ALL----CSRPG-FT.
- Under existing gates 1AF-PUMP-1A-FTR-SUPPORT and 1AF-TRAIN-1A-X-ND: Removed gate 1AF-PUMP1A-OIL.
- Under existing gate 2AF-XTIE-AF1A-FTR: Removed gate 1AF-PUMP1A-OIL-XTIE.
- Under existing gate 1AFW-SBO-MDP: Removed gate 1AFW-MDP-ND-SX.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	5.66E-06	7.13	$31,120
Percent Change	85.7%	79.9%	87.8%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	3.35E-06	1.25E-01	3.62E-02	$118	$34
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	8.79E-08	1.63E-02	2.71E-03	$22	$4
LATE-BMMT-NOAFW	7.95E-08	7.93E-08	6.36E-03	6.34E-03	$14	$14
LATE-CHR-AFW	1.89E-05	6.16E-07	1.05E+01	3.42E-01	$35,721	$1,164
LATE-CHR-NOAFW	8.35E-06	3.06E-07	1.78E+01	6.52E-01	$187,040	$6,854
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	8.28E-08	3.41E-01	7.70E-02	$1,655	$373
LERF-CFE	3.55E-08	3.06E-09	8.88E-02	7.65E-03	$582	$50
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.15E-10	6.68E-04	6.35E-04	$6	$5

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
LERF-ISGTR	2.69E-07	4.56E-08	6.97E-01	1.18E-01	$8,205	$1,391
Total	4.19E-05	6.35E-06	3.55E+01	7.13E+00	$254,593	$31,120

Applying the process described in Section F.4 yields an internal events cost-risk of $836,976. After accounting for "round up" of the base internal events cost-risk, this value is $837,583. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$837,583 * 2.5 = \$2,093,958$$

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

SAMA 13 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$2,093,958	$12,856,042

Based on a $5,951,110 cost of implementation for Byron, the net value for this SAMA is $6,904,932 ($12,856,042 - $5,951,110), which indicates this SAMA is potentially cost beneficial.

F.6.11 SAMA 14 AUTOMATED RWST MAKEUP

For SGTR scenarios, in which cooldown has failed, installing an automated RWST makeup system could provide a means of maintaining injection indefinitely. The makeup pump should be powered from a diesel backed bus. A boron source is required to ensure criticality does not occur. Including an alarm that identifies system actuation would provide an additional cue to address plant issues that have led to RWST depletion.

For non-SGTR scenarios, the availability of automated RWST makeup would extend the time available to transition to recirculation mode.

Assumptions:

The RWST makeup capability will extend the time available to perform required actions in SGTR scenarios and scenarios requiring transition to recirculation mode, but it is assumed that the actions to control injection and perform a cooldown will eventually have to be taken to reach a successful endstate (i.e., injection with RWST makeup alone is not a success state). For this evaluation, it is assumed that the HEPs for the following operator actions are reduced by a factor of 10:

- 1SI-HPR----HSYOA: OPERATORS FAIL TO ESTABLISH HIGH PRESSURE RECIRC (SLOW EVENT)
- 1RC-LCD----HSYOA: OPERATORS FAIL TO TERMINATE BREAK FLOW ON SGTR

In addition, the JHEPs including those actions were reviewed to determine which of the dependent actions would be impacted by this SAMA. Most of the JHEPs were already set to the floor value of 1.0E-06, but 1RX-JHEP28-HOADA, 1RX-JHEP51-HOADA and 1RX-JHEP71-HOADA would be impacted. 1RX-JHEP51-HOADA and 1RX-JHEP71-HOADA, which are related to establishing recirculation, were set to 0.0 for simplicity. 1RX-JHEP28-HOADA, which is the dependent combination of 1RC-DS-SGTRHDVOA and 1RC-LCD----HSYOA, is impacted, but the impact is on the chronologically second, or dependent, action of the pair. The impact is limited in these cases, but the JHEP was revised to reflect a factor of 10 reduction in 1RC-LCD----HSYOA and a change in the assessed dependence level from MODERATE to LOW.

PRA Model Changes to Model SAMA:

The cutsets were updated to account for the changes to the HEPs and JHEPs due to the increased time available for action.

Model Change(s):

The following modeling changes were made to the results cutsets:

- Event 1SI-HPR----HSYOA: HEP changed from 6.8E-03 to 6.8E-04.
- Event 1RC-LCD----HSYOA: HEP changed from 3.2E-03 to 3.2E-04.
- Event 1RX-JHEP51-HOADA: Set to 0.0.
- Event 1RX-JHEP71-HOADA: Set to 0.0.
- 1RX-JHEP28-HOADA: Updated JHEP calc from 3.3E-04 to reflect modified independent HEP value: 6.3E-3 * ((1 + 19*3.2E-04) / 20) = 3.2E-04

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.93E-05	35.34	$253,720
Percent Change	1.0%	0.3%	0.3%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.12E-05	1.25E-01	1.21E-01	$118	$114
SERF-TISGTR-HLF	6.49E-09	6.12E-09	6.17E-03	5.81E-03	$44	$41
SERF-SGTR-AFW-SC	1.38E-06	1.32E-06	1.33E+00	1.27E+00	$8,349	$7,986
LATE-BMMT-AFW	5.30E-07	5.28E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	6.50E-08	6.36E-03	5.20E-03	$14	$12
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.34E-06	1.78E+01	1.78E+01	$187,040	$186,816
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.65E-07	3.41E-01	3.39E-01	$1,655	$1,646
LERF-CFE	3.55E-08	3.53E-08	8.88E-02	8.83E-02	$582	$579
LERF-SGTR-AFW	5.49E-08	5.21E-08	1.31E-01	1.25E-01	$1,005	$953
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.62E-07	6.97E-01	6.79E-01	$8,205	$7,991
Total	4.19E-05	4.14E-05	3.55E+01	3.53E+01	$254,593	$253,720

Applying the process described in Section F.4 yields an internal events cost-risk of $5,951,964. After accounting for "round up" of the base internal events cost-risk, this value is $5,952,571. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,952,571 * 2.5 = \$14,881,428$$

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

SAMA 14 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,881,428	$68,572

Based on a $3,800,000 cost of implementation for Byron, the net value for this SAMA is -$3,731,428 ($68,572 - $3,800,000), which indicates this SAMA is not cost beneficial.

F.6.12 SAMA 15 RESOLVE REGULATORY ISSUES AND COMPLETE IMPLEMENTATION OF THE INTER UNIT AFW CROSS-TIE

The inter unit AFW cross-tie is in place at the site, but regulatory issues must be resolved before it can be considered "implemented". Once the process is complete, it will allow one unit to use the other unit's AFW system to provide SG makeup. The cross-tie valve requires local, manual action for operation.

Due to the timing of the submittal of the license renewal application, the official PRA model does not credit the AFW cross-tie action, but this SAMA documents the estimated impact of implementing the cross-tie in the existing model.

Section F.7.4 includes a sensitivity analysis that assesses the impact of implementing the AFW cross-tie on the cost benefit results of the remaining SAMAs.

<u>Assumptions:</u>

The AFW cross-tie action is currently included in the PRA model (1AF-XTIE—EHXVOA) with the action's execution failure probability set to 1.0. The failure to diagnose the need to initiate the AFW cross-tie alignment is already included in the model with a non 1.0 probability. The diagnosis component of the action is represented by a common cognitive term that addresses the set of potential actions that are performed in response to loss of secondary side heat removal (for example, alignment of the startup FW pump for SG makeup). Because this event is already incorporated into the analysis in a way that includes use of the cross-tie, no changes are required to the cognitive term or the associated joint HEPs.

The execution failure probability was previously estimated to be 2.4E-2 and that estimate is used to represent the cross-tie alignment failure probability in this analysis.

PRA Model Changes to Model SAMA:

The cutsets were updated to account for the completion of the AFW cross-tie modification.

Model Change(s):

The following modeling changes were made to the results cutsets:

- Event 1AF-XTIE--EHXVOA: HEP changed from 1.0 to 2.4E-02.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.89E-05	34.71	$246,863
Percent Change	2.0%	2.1%	3.0%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.09E-05	1.25E-01	1.18E-01	$118	$111
SERF-TISGTR-HLF	6.49E-09	2.11E-09	6.17E-03	2.00E-03	$44	$14
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	4.44E-08	6.36E-03	3.55E-03	$14	$8
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.04E-06	1.78E+01	1.71E+01	$187,040	$180,096
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.60E-07	3.41E-01	3.35E-01	$1,655	$1,624
LERF-CFE	3.55E-08	3.49E-08	8.88E-02	8.73E-02	$582	$572
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.46E-07	6.97E-01	6.37E-01	$8,205	$7,503
Total	4.19E-05	4.08E-05	3.55E+01	3.47E+01	$254,593	$246,863

Applying the process described in Section F.4 yields an internal events cost-risk of $5,818,963. After accounting for "round up" of the base internal events cost-risk, this value is $5,819,570. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5{,}819{,}570 * 2.5 = \$14{,}548{,}925$$

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

SAMA 15 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,548,925	$401,075

There are no significant costs associated with completing the implementation of this modification and because the decision has already been made implement this change, it is not considered to be a traditional SAMA. The results are provided to document and demonstrate the estimated impact of the AFW cross-tie. However, the averted cost-risk of $401,075 is treated as the net value of this SAMA for this portion of the analysis.

F.6.13 SAMA 16 INSTALL HIGH FLOW SENSORS ON THE NON-ESSENTIAL SERVICE WATER SYSTEM

Installing flow sensors in the WS lines with logic to trip the pumps on high flow conditions is a potential means of terminating WS flood events before critical systems are damaged.

Assumptions:

It is assumed that this SAMA eliminates all risk associated with WS flooding scenarios.

PRA Model Changes to Model SAMA:

The cutsets were updated to delete the contributions from WS flood initiators.

Model Change(s):

The following modeling changes were made to the results cutsets:

- Event %FL1WS-GA0----T1: Event set to 0.0.
- Event %FL1WS-GT0----NA: Event set to 0.0.
- Event %FL1WSM1A0----T1: Event set to 0.0.
- Event %FL1WSM2A0----T1: Event set to 0.0.
- Event %FL1WSM3A0HVACT1: Event set to 0.0.

- Event %FL1WSM3A0----T1: Event set to 0.0.
- Event %FL1WSM3A0----T2: Event set to 0.0.
- Event %FL1WSM3A1DAFPT1: Event set to 0.0.
- Event %FL1WSM3A2DAFPT1: Event set to 0.0.
- Event %FL1WSM3A2DAFPT2: Event set to 0.0.
- Event %FL1WS-MT0----NA: Event set to 0.0.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.90E-05	33.82	$238,089
Percent Change	1.8%	4.6%	6.5%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.16E-05	1.25E-01	1.25E-01	$118	$118
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	1.88E-05	1.05E+01	1.05E+01	$35,721	$35,532
LATE-CHR-NOAFW	8.35E-06	7.66E-06	1.78E+01	1.63E+01	$187,040	$171,584
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.08E-07	3.41E-01	2.86E-01	$1,655	$1,389
LERF-CFE	3.55E-08	3.47E-08	8.88E-02	8.68E-02	$582	$569
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.50E-07	6.97E-01	6.48E-01	$8,205	$7,625
Total	4.19E-05	4.10E-05	3.55E+01	3.38E+01	$254,593	$238,089

Applying the process described in Section F.4 yields an internal events cost-risk of $5,663,001. After accounting for "round up" of the base internal events cost-risk, this value is $5,663,608. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{\text{SAMA}} = \$5,663,608 * 2.5 = \$14,159,020$$

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

SAMA 16 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,159,020	$790,980

Based on a $993,800 cost of implementation for Byron, the net value for this SAMA is -$202,820 ($790,980 - $993,800), which indicates this SAMA is not cost beneficial.

F.6.14 SAMA 17 USE AMASC FOR ALTERNATE LOW SG LEVEL AFW INITIATION

For non-ATWS, the AMSAC logic could be used to provide a backup initiation signal for AFW. This would mitigate failures of the normal solid state protection system (SSPS) initiation system.

Assumptions:

For this analysis, it is assumed that the AMSAC logic is 100 percent reliable and that the implementation of the SAMA can be modeled by eliminating the independent manual AFW initiation HFE in conjunction with all associated JHEPs.

PRA Model Changes to Model SAMA:

The fault tree was updated to use the existing AMSAC logic as a backup initiation signal to the AFW initiation logic.

Model Change(s):

The following HFEs were set to 0.0:

- 1AF-STARTFWHPMOA: OPERATORS FAIL TO MANUALLY START AF PUMPS FROM CR (LOFW)
- 1AF-START-BHPMOA: OPERATORS FAIL TO LOCALLY START B AUXILIARY FEEDWATER PUMP
- 1AF-START--HPMOA: OPERATORS FAIL TO MANUALLY START AF PUMPS FROM CR (NON-LOFW EVENT)

- Joint HEPs: 1RX-JHEP19-HOADA, 1RX-JHEP20-HOADA, 1RX-JHEP21-HOADA, 1RX-JHEP29-HOADA, 1RX-JHEP35-HOADA, 1RX-JHEP36-HOADA, 1RX-JHEP38-HOADA, 1RX-JHEP39-HOADA, 1RX-JHEP40-HOADA, 1RX-JHEP41-HOADA, 1RX-JHEP64-HOADA, 1RX-JHEP70-HOADA, 1RX-JHEP71-HOADA, 1RX-JHEP73-HOADA, 1RX-JHEP74-HOADA

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.96E-05	35.41	$254,210
Percent Change	0.3%	0.1%	0.2%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.15E-05	1.25E-01	1.24E-01	$118	$117
SERF-TISGTR-HLF	6.49E-09	5.77E-09	6.17E-03	5.48E-03	$44	$39
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.25E-08	6.36E-03	5.80E-03	$14	$13
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.34E-06	1.78E+01	1.78E+01	$187,040	$186,816
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.63E-07	3.41E-01	3.38E-01	$1,655	$1,637
LERF-CFE	3.55E-08	3.48E-08	8.88E-02	8.70E-02	$582	$571
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.65E-07	6.97E-01	6.86E-01	$8,205	$8,083
Total	4.19E-05	4.18E-05	3.55E+01	3.54E+01	$254,593	$254,210

Applying the process described in Section F.4 yields an internal events cost-risk of $5,969,721. After accounting for "round up" of the base internal events cost-risk, this value is $5,970,328. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,970,328 * 2.5 = \$14,925,820$$

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

SAMA 17 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,925,820	$24,180

Based on a $981,730 cost of implementation for Byron, the net value for this SAMA is -$957,550 ($24,180 - $981,730), which indicates this SAMA is not cost beneficial.

F.6.15 SAMA 18 AUTOMATE REFILL OF THE DIESEL DRIVEN AFW PUMP FUEL OIL DAY TANK

The action to refill the diesel driven AFW pump fuel oil day tank is currently a manual action. Level sensors in the tank could be used to control a fill valve on the gravity feed line to automate the function, which would potentially improve system reliability.

Assumptions:

For this analysis, it is assumed that the action is 100 percent reliable. Implementation of this SAMA is assumed to eliminate the independent HFE and all dependent combinations that include the action.

PRA Model Changes to Model SAMA:

The cutsets were modified by setting the action representing the failure to refill the AFW diesel fuel oil, and all JHEPs including that event, to 0.0.

Model Change(s):

The following HFEs were set to 0.0:

- 1AF01PB-FO-HXVOA: OPERATORS FAIL TO REFILL DDAFP FUEL OIL DAY TANK FROM STORAGE TANK
- Joint HEPs: 1AF01PB-FO-HXVOA, 1RX-JHEP03-HOADA, 1RX-JHEP04-HOADA, 1RX-JHEP07-HOADA, 1RX-JHEP16-HOADA, 1RX-JHEP17-HOADA, 1RX-JHEP19-HOADA, 1RX-JHEP21-HOADA, 1RX-JHEP24-HOADA, 1RX-JHEP29-HOADA, 1RX-JHEP31-

HOADA , 1RX-JHEP35-HOADA, 1RX-JHEP36-HOADA, 1RX-JHEP38-HOADA, 1RX-JHEP39-HOADA, 1RX-JHEP40-HOADA, 1RX-JHEP41-HOADA, 1RX-JHEP43-HOADA, 1RX-JHEP46-HOADA, 1RX-JHEP50-HOADA, 1RX-JHEP51-HOADA, 1RX-JHEP53-HOADA, 1RX-JHEP54-HOADA, 1RX-JHEP55-HOADA, 1RX-JHEP57-HOADA, 1RX-JHEP58-HOADA, 1RX-JHEP60-HOADA, 1RX-JHEP65-HOADA, 1RX-JHEP68-HOADA, 1RX-JHEP77-HOADA, 1RX-JHEP79-HOADA , 1RX-JHEP83-HOADA

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.95E-05	35.32	$253,239
Percent Change	0.5%	0.4%	0.5%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.13E-05	1.25E-01	1.22E-01	$118	$115
SERF-TISGTR-HLF	6.49E-09	6.07E-09	6.17E-03	5.77E-03	$44	$41
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	6.88E-08	6.36E-03	5.50E-03	$14	$13
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.30E-06	1.78E+01	1.77E+01	$187,040	$185,920
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.65E-07	3.41E-01	3.39E-01	$1,655	$1,646
LERF-CFE	3.55E-08	3.53E-08	8.88E-02	8.83E-02	$582	$579
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.62E-07	6.97E-01	6.79E-01	$8,205	$7,991
Total	4.19E-05	4.15E-05	3.55E+01	3.53E+01	$254,593	$253,239

Applying the process described in Section F.4 yields an internal events cost-risk of $5,949,619. After accounting for "round up" of the base internal events cost-risk, this value is $5,950,226. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{\text{SAMA}} = \$5{,}950{,}226 * 2.5 = \$14{,}875{,}565$$

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

SAMA 18 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,875,565	$74,435

Based on a $1,608,680 cost of implementation for Byron, the net value for this SAMA is -$1,534,245 ($74,435 - $1,608,680), which indicates this SAMA is not cost beneficial.

F.6.16 SAMA 19 REPLACE MOVS IN THE RHR DISCHARGE LINE WITH VALVES THAT CAN ISOLATE AN ISLOCA EVENT

For cases in which the check valves fail in the RHR discharge line and an ISLOCA occurs, the event could be terminated if the containment isolation valves were capable of closing after the ISLOCA has occurred. Replacing the existing valves (MOVs _SI8809A, _SI8809B, and _SI8840) with an alternate design could provide this capability.

Assumptions:

It is assumed that implementation of this SAMA will eliminate all risk from the ISLOCA events occurring in the RHR discharge lines

PRA Model Changes to Model SAMA:

The cutsets were modified by setting the events representing ISLOCAs in the RHR discharge line to 0.0.

Model Change(s):

The following event was set to 0.0:

- %RCS-RHR-DISCHIE: FREQ OF EXPOSING RHR PUMP DISCHARGE HEADERS TO RCS PRESSURE

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.95E-05	32.08	$245,394
Percent Change	0.5%	9.5%	3.6%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.16E-05	1.25E-01	1.25E-01	$118	$118
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.34E-06	1.78E+01	1.78E+01	$187,040	$186,816
LERF-ISLOCA	3.40E-07	8.21E-08	4.42E+00	1.07E+00	$11,832	$2,857
LERF-CI	3.67E-07	3.67E-07	3.41E-01	3.41E-01	$1,655	$1,655
LERF-CFE	3.55E-08	3.55E-08	8.88E-02	8.88E-02	$582	$582
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.69E-07	6.97E-01	6.97E-01	$8,205	$8,205
Total	4.19E-05	4.16E-05	3.55E+01	3.21E+01	$254,593	$245,394

Applying the process described in Section F.4 yields an internal events cost-risk of $5,734,097. After accounting for "round up" of the base internal events cost-risk, this value is $5,734,704. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,734,704 * 2.5 = \$14,336,760$$

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

SAMA 19 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,336,760	$613,240

Based on a $900,000 cost of implementation for Byron, the net value for this SAMA is -$286,760 ($613,240 - $900,000), which indicates this SAMA is not cost beneficial

F.6.17 SAMA 21 INSTALL AN EMERGENCY ISOLATION VALVE IN EACH OF THE RHR SUCTION LINES

For cases in which the two motor operated isolation valves in the RHR suction line fail and result in the overpressurization of the low pressure RHR piping, a LOCA outside containment can occur if the RHR piping breaks. In the event of a piping break, having an additional, normally open MOV located on the high pressure piping capable of closing against RCS pressure would provide a means of terminating the ISLOCA event.

Assumptions:

It is assumed that implementation of this SAMA will eliminate all risk from the ISLOCA events occurring in the RHR suction lines

PRA Model Changes to Model SAMA:

The cutsets were modified by setting the events representing ISLOCAs in the RHR suction lines to 0.0.

Model Change(s):

The following event was set to 0.0:

- %RCS-RHR-SUCT-IE: FREQUENCY OF HAVING RCS PRESSURE IN THE RHR SUCTION LINE

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.97E-05	34.59	$252,107
Percent Change	0.0%	2.4%	1.0%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.16E-05	1.25E-01	1.25E-01	$118	$118
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.34E-06	1.78E+01	1.78E+01	$187,040	$186,816
LERF-ISLOCA	3.40E-07	2.75E-07	4.42E+00	3.58E+00	$11,832	$9,570
LERF-CI	3.67E-07	3.67E-07	3.41E-01	3.41E-01	$1,655	$1,655
LERF-CFE	3.55E-08	3.55E-08	8.88E-02	8.88E-02	$582	$582
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.69E-07	6.97E-01	6.97E-01	$8,205	$8,205
Total	4.19E-05	4.18E-05	3.55E+01	3.46E+01	$254,593	$252,107

Applying the process described in Section F.4 yields an internal events cost-risk of $5,915,947. After accounting for "round up" of the base internal events cost-risk, this value is $5,916,554. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,916,554 * 2.5 = \$14,791,385$$

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

SAMA 21 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,791,385	$158,615

Based on an $1,600,000 cost of implementation for Byron, the net value for this SAMA is -$1,441,385 ($158,615 - $1,600,000), which indicates this SAMA is not cost beneficial.

F.6.18 SAMA 22 INSTALL THE SAME HIGH FLOW ISOLATION LOGIC USED ON VALVE _CC685 ON VALVE _CC9438

In the event that an RCP Thermal Barrier Cooling heat exchangers breaks, the current in-containment relief valves are designed to relieve pressure at 2485 psig, which would be within the capacity of the piping up to the isolation boundary. However, if the Thermal Barrier Cooling Hx were to break and the isolation valve failed to close, the CC system could be over pressurized and inventory could be transferred outside containment through the 150 psid relief valves. A potential means of mitigating this event would be to install the same isolation logic used on valve _CC685 on valve_CC9438.

<u>Assumptions:</u>

It is assumed that implementation of this SAMA will eliminate all risk from the ISLOCA events occurring in the RCP thermal barrier cooling heat exchangers.

<u>PRA Model Changes to Model SAMA:</u>

The cutsets were modified by setting the events representing ISLOCAs in the RCP thermal barrier cooling heat exchangers to 0.0.

<u>Model Change(s):</u>

The following event was set to 0.0:

%RCP-HX-RUPT--IE: FREQUENCY OF RCP HEAT EXCHANGER RUPTURE

<u>Results of SAMA Quantification:</u>

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.97E-05	35.24	$253,847
Percent Change	0.0%	0.6%	0.3%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.16E-05	1.25E-01	1.25E-01	$118	$118
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.34E-06	1.78E+01	1.78E+01	$187,040	$186,816
LERF-ISLOCA	3.40E-07	3.25E-07	4.42E+00	4.23E+00	$11,832	$11,310
LERF-CI	3.67E-07	3.67E-07	3.41E-01	3.41E-01	$1,655	$1,655
LERF-CFE	3.55E-08	3.55E-08	8.88E-02	8.88E-02	$582	$582
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.69E-07	6.97E-01	6.97E-01	$8,205	$8,205
Total	4.19E-05	4.19E-05	3.55E+01	3.52E+01	$254,593	$253,847

Applying the process described in Section F.4 yields an internal events cost-risk of $5,961,668. After accounting for "round up" of the base internal events cost-risk, this value is $5,962,275. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,962,275 * 2.5 = \$14,905,688$$

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

SAMA 22 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,905,688	$44,312

Based on a $250,000 cost of implementation for Byron, the net value for this SAMA is -$205,688 ($44,312 - $250,000), which indicates this SAMA is not cost beneficial.

F.6.19 SAMA 23 INSTALL A PASSIVE HYDROGEN IGNITION SYSTEM

For accident scenarios resulting in the generation of hydrogen in quantities sufficient to cause significant hydrogen detonations, containment failure is possible. A potential means of preventing these containment failure scenarios would be to install a passive hydrogen ignition system.

Assumptions:

It is assumed that implementation of this SAMA will eliminate all containment failures due to hydrogen detonation. Some of the Level 2 events that represent containment failure due to hydrogen detonations also include containment failure due to other phenomena, but no attempt is made to separate them from the hydrogen failures. This results in an increased averted cost-risk, which makes it more likely that the SAMA will be cost effective.

PRA Model Changes to Model SAMA:

The cutsets were modified by setting the events representing containment failure due to hydrogen detonation to 0.0.

Model Change(s):

The following events were set to 0.0:

- 1L2-CNT-VF-CFE1: Early Cont Failure due to Hydrogen Burn or Stm Expl
- 1L2-CNT-VF-CFE2: Early Cont Failure due to Hydrogen Burn
- 1L2-CNT-VF-CFE4: Early Cont Failure due to Direct Containment Heating, Hydrogen Burn, or Stm Expl

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.97E-05	35.34	$253,787
Percent Change	0.0%	0.3%	0.3%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.16E-05	1.25E-01	1.25E-01	$118	$118
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.34E-06	1.78E+01	1.78E+01	$187,040	$186,816
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.67E-07	3.41E-01	3.41E-01	$1,655	$1,655
LERF-CFE	3.55E-08	0.00E+00	8.88E-02	0.00E+00	$582	$0
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.69E-07	6.97E-01	6.97E-01	$8,205	$8,205
Total	4.19E-05	4.19E-05	3.55E+01	3.53E+01	$254,593	$253,787

Applying the process described in Section F.4 yields an internal events cost-risk of $5,963,958. After accounting for "round up" of the base internal events cost-risk, this value is $5,964,565. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,964,565 * 2.5 = \$14,911,413$$

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

SAMA 23 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,911,413	$38,587

Based on a $760,000 cost of implementation for Byron, the net value for this SAMA is -$721,413 ($38,587 - $760,000), which indicates this SAMA is not cost beneficial.

F.6.20 SAMA 24 PROVIDE A REACTOR VESSEL EXTERIOR COOLING SYSTEM

This SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head can be submerged in water. For Byron, use of existing emergency power is adequate to address the highest contributors.

Assumptions:

It is assumed that the implementation of this SAMA is 100 percent effective at preventing relocation of the core to the containment floor. For cases in which containment heat removal is successful, this would result in the reclassification of the basemat melt through scenarios as "intact" cases.

For containment overpressure failure cases, this SAMA would result in the retention of the core in the vessel without an overlying pool of water. The dominant scenarios for the existing containment overpressure failure cases are those in which containment spray is available and water is transferred to the containment floor. In these scenarios, use of the exterior vessel cooling system could actually prevent scrubbing of the release; however, for simplicity, the benefit of this SAMA is not reduced to address the fact that this SAMA would eliminate the scrubbing mechanism for these scenarios. This assumption increases this SAMA's averted cost-risk.

With the exception of hydrogen detonation, the early containment failure modes are linked to reactor vessel failure such that early containment failure would likely be avoided if reactor vessel failure is prevented. For simplicity, it is assumed that this SAMA eliminates all early containment failures.

PRA Model Changes to Model SAMA:

The events in the PRA model associated with early containment failure and basemat failure have been set to 0.0.

Model Change(s):

The following event probability changes were made to the PRA model:

- 1L2-CNT-VF-CFE1: Early Cont Failure due to Hydrogen Burn or Stm Expl, set to 0.0.
- 1L2-CNT-VF-CFE2: Early Cont Failure due to Hydrogen Burn, set to 0.0.
- 1L2-CNT-VF-CFE3: Early Cont Failure due to Direct Containment Heating, set to 0.0
- 1L2-CNT-VF-CFE4: Early Cont Failure due to Direct Containment Heating, Hydrogen Burn, or Stm Expl, set to 0.0.
- 1L2-CNT-VF-BMMTD: Probability of BMMT with a dry cavity, set to 0.0.
- 1L2-CNT-VF-BMMTW: Probability of BMMT with water in the cavity, set to 0.0.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.97E-05	35.34	$253,974
Percent Change	0.0%	0.3%	0.2%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.16E-05	1.25E-01	1.25E-01	$118	$118
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	0.00E+00	1.63E-02	0.00E+00	$22	$0
LATE-BMMT-NOAFW	7.95E-08	0.00E+00	6.36E-03	0.00E+00	$14	$0
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.35E-06	1.78E+01	1.78E+01	$187,040	$187,040
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.67E-07	3.41E-01	3.41E-01	$1,655	$1,655
LERF-CFE	3.55E-08	0.00E+00	8.88E-02	0.00E+00	$582	$0
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005

Release Category	Freq.$_{BASE}$	Freq.$_{SAMA}$	Dose-Risk$_{BASE}$	Dose-Risk$_{SAMA}$	OECR$_{BASE}$	OECR$_{SAMA}$
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.69E-07	6.97E-01	6.97E-01	$8,205	$8,205
Total	4.19E-05	4.13E-05	3.55E+01	3.53E+01	$254,593	$253,974

Applying the process described in Section F.4 yields an internal events cost-risk of $5,966,733. After accounting for "round up" of the base internal events cost-risk, this value is $5,967,340. The external events contributions are accounted for by multiplying this value by 2.5:

Total Cost-Risk$_{SAMA}$ = $5,967,340 * 2.5 = $14,918,350

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

SAMA 24 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,918,350	$31,650

Based on a $1,250,000 cost of implementation for Byron, the net value for this SAMA is -$1,218,350 ($31,650 - $1,250,000), which indicates this SAMA is not cost beneficial.

F.6.21 SAMA 25 INSTALL A FILTERED CONTAINMENT VENT

This SAMA would provide a means of preventing long term containment overpressure failures by relieving pressure through a scrubbed release path. While post core damage venting is undesirable, a controlled scrubbed release is preferable to an unscrubbed release through a containment break.

Assumptions:

It is assumed that this SAMA is 100 percent reliable in operation, but the effectiveness of the radionuclide scrubbing mechanism is not complete. For this analysis, it is assumed that the filtered vent reduces the consequential dose and offsite economic cost associated with containment overpressure failures by a factor of 10.

PRA Model Changes to Model SAMA:

The results of the Level 3 model (dose, offsite economic cost) for the LATE-CHR-AFW and LATE-CHR-NOAFW endstates are reduced by a factor of 10.

Model Change(s):

The following changes were made to the L3 results:

- LATE-CHR-AFW: Dose-risk and OECR multiplied by 0.1.
- LATE-CHR-NOAFW: Dose-risk and OECR multiplied by 0.1.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.97E-05	9.99	$54,108
Percent Change	0.0%	71.8%	78.7%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.16E-05	1.25E-01	1.25E-01	$118	$118
SERF-TISGTR-HLF	6.49E-09	6.49E-09	6.17E-03	6.17E-03	$44	$44
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.30E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.95E-08	6.36E-03	6.36E-03	$14	$14
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+00	$35,721	$3,572
LATE-CHR-NOAFW	8.35E-06	8.35E-06	1.78E+01	1.78E+00	$187,040	$18,704
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.67E-07	3.41E-01	3.41E-01	$1,655	$1,655
LERF-CFE	3.55E-08	3.55E-08	8.88E-02	8.88E-02	$582	$582
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6

Release Category	Freq.$_{BASE}$	Freq.$_{SAMA}$	Dose-Risk$_{BASE}$	Dose-Risk$_{SAMA}$	OECR$_{BASE}$	OECR$_{SAMA}$
LERF-ISGTR	2.69E-07	2.69E-07	6.97E-01	6.97E-01	$8,205	$8,205
Total	4.19E-05	4.19E-05	3.55E+01	9.99E+00	$254,593	$54,108

Applying the process described in Section F.4 yields an internal events cost-risk of $2,198,225. After accounting for "round up" of the base internal events cost-risk, this value is $2,198,832. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$2,198,832 * 2.5 = \$5,497,080$$

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

SAMA 25 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$5,497,080	$9,452,920

Based on a $5,700,000 cost of implementation for Byron, the net value for this SAMA is $3,752,920 ($9,452,920 - $5,700,000), which indicates this SAMA is potentially cost beneficial.

F.6.22 SAMA 26 DMS USING A DEDICATED GENERATOR, SELF COOLED CHARGING PUMP, AND A PORTABLE AFW PUMP

This SAMA represents an alternate configuration of the DMS in which seal LOCAs are prevented using a seal injection system rather than by “no leak” seals. A dedicated 480V AC generator is proposed as a means of supporting long term SG makeup by maintaining the buses used for the battery chargers for SG level instrumentation and for powering a self-cooled primary side seal injection pump. A portable, engine driven SG makeup pump would provide an alternate means of SG makeup, with injection connections available on different divisions. Fire protection should provide both CST makeup and a suction source connection for the portable SG makeup pump A means of providing borated makeup to the RWST is also required, which could potentially be performed using the fire protection system and an eductor. Finally, a connection point to an outside source would have to be provided for the containment spray system for long term spray capability in an SBO.

Assumptions:

SAMA 26 was generally identified as a means of mitigating scenarios in which loss of SG makeup is a slowly developing evolution, such as in SBO events where battery depletion eventually fails AFW or in loss of SX cases in which the AFW pumps may be able to run for some time before failure. No credit is taken for the DMS in LOCA (other than seal LOCA) or ATWS scenarios. The DMS is credited in SGTR initiators as most cases include success of injection where time would be available to recover secondary side heat removal in the event of an initial AFW failure. Prior to core damage, activity levels are expected to be low enough to perform any alignment required.

The DMS capabilities are assumed to be represented by indefinite AFW makeup capability and by an alternate high pressure injection function capable of providing alternate seal injection to prevent RCP seal LOCAs. The current PRA does not include credit for RWST refill, so the PRA is structured to require recirculation mode in seal LOCA evolutions even with AFW success. This SAMA, however, includes an RWST makeup capability that is assumed to preclude the need for recirculation mode. Long term containment overfill is potentially an issue that could ultimately prevent success in these cases, but it is assumed that a success of DMS high pressure injection and SG makeup results in a successful endstate. In order to simplify the modeling process, the seal LOCA flag is used to model the impact of the DMS high pressure seal injection system. The self-cooled charging pump is assumed to reduce the frequency of seal LOCA sequences by a factor of 100.

The AFW makeup capability includes alignment and control of a dedicated (permanently installed) 480V generator and alignment and control of a portable SG makeup pump. A new event with a failure probability of 1E-2 is used for this function.

It is assumed that the cognitive failure to diagnose the need for secondary cooling (1FW-FRH1---HSGOA), which is related to the AFW X-tie, FW restoration, and bleed and feed, will also fail the DMS. In addition, any dependent combinations are also assumed to fail the DMS.

PRA Model Changes to Model SAMA:

The capabilities of SAMA 26 are essentially the same as those for SAMA 11 with the exception that the seal LOCAs are mitigated by an injection capability rather than prevented by an alternate seal design. The impact of the seal injection system is modeled by manipulating the cutsets from SAMA 11.

Model Change(s):

The cutsets from SAMA 11 were modified to reflect the use of the DMS primary injection capability for Seal LOCA mitigation.

The following modeling changes were made to the SAMA 11 cutsets:

- The FLAG-SEAL-LOCA flag was replaced by event 1DMS (as defined in SAMA 11) to represent the use of the DMS to mitigate Seal LOCAs.
- To address potential dependency issues, the 1DMS event was replaced by event 1DMS-DEPENDENT (set to 1.0) for any cutsets including failure to diagnose the need for feed and bleed (represents complete cognitive dependence between feed and bleed and primary side injection with the DMS). The HFEs addressed included 1FW-FRH1---HSGOA, 1RX-JHEP03-HOADA and similar events for the following JHEP combinations: 07, 09, 11,12, 14, 17, 21, 24, 25, 27, 39, 49, 50, 54, 58, 64, 74, and 80.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	4.90E-06	7.21	$32,778
Percent Change	87.7%	79.7%	87.1%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	Freq.$_{BASE}$	Freq.$_{SAMA}$	Dose-Risk$_{BASE}$	Dose-Risk$_{SAMA}$	OECR$_{BASE}$	OECR$_{SAMA}$
INTACT	1.16E-05	2.33E-06	1.25E-01	2.52E-02	$118	$24
SERF-TISGTR-HLF	6.49E-09	1.52E-09	6.17E-03	1.44E-03	$44	$10
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	8.80E-08	1.63E-02	2.71E-03	$22	$4
LATE-BMMT-NOAFW	7.95E-08	3.12E-08	6.36E-03	2.50E-03	$14	$6
LATE-CHR-AFW	1.89E-05	5.04E-07	1.05E+01	2.80E-01	$35,721	$953
LATE-CHR-NOAFW	8.35E-06	4.27E-07	1.78E+01	9.10E-01	$187,040	$9,565
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	2.63E-08	3.41E-01	2.45E-02	$1,655	$119
LERF-CFE	3.55E-08	2.97E-09	8.88E-02	7.43E-03	$582	$49
LERF-SGTR-AFW	5.49E-08	5.48E-08	1.31E-01	1.31E-01	$1,005	$1,003
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.82E-08	6.97E-01	7.30E-02	$8,205	$860
Total	4.19E-05	5.21E-06	3.55E+01	7.21E+00	$254,593	$32,778

Applying the process described in Section F.4 yields an internal events cost-risk of $843,494. After accounting for "round up" of the base internal events cost-risk, this value is $844,494. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$844,494 * 2.5 = \$2,110,253$$

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

SAMA 26 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$2,110,253	$12,839,747

Based on a $2,400,000 cost of implementation for Byron, the net value for this SAMA is $10,439,747 ($12,839,747 - $2,400,000), which indicates this SAMA is potentially cost beneficial.

F.6.23 SAMA 27 PROTECT RH, SI, AND CVCS CUBICLE COOLING FAN CABLES IN FIRE ZONE 11.3-0

While most of the equipment damage in the dominant fire scenario in zone 11.3-0 is related to the loss of MCC 132X1 (the ignition source), protecting the cables related to the RH, SI, and CVCS pump cubicle cooling fans may reduce the likelihood that room cooling will be failed for those pumps.

Assumptions:

This SAMA will eliminate all of the risk associated with fire zone 11.3-0.

The ratio of internal events cost-risk to internal events CDF is equal to the ratio of fire cost-risk to fire CDF.

PRA Model Changes to Model SAMA:

The CDF associated with fire zone 11.3-0 was changed from 1.38E-05 to 0.0 to model the installation of the cable protection.

Results of SAMA Quantification:

The averted cost-risk for this SAMA is the cost-risk associated with fire zone 11.3-0 because this SAMA is assumed to entirely eliminate it. Using the assumptions identified above, the result is as follows:

$5,979,393 / 3.97E-05 * 1.38E-05 = $2,078,479

Based on a $975,000 cost of implementation for Byron, the net value for this SAMA is $1,103,479 ($2,078,479 - $975,000), which indicates this SAMA is potentially cost beneficial.

F.6.24 SAMA 28 INSTALL FIRE BARRIERS AROUND MCC 134X

Fires that start in this MCC are exacerbated by the propagation of the fire to nearby equipment. Installation of fire barriers to protect the equipment could mitigate the consequences of the fires.

Assumptions:

This SAMA will eliminate all of the risk associated with fire zone 11.6-0.

The ratio of internal events cost-risk to internal events CDF is equal to the ratio of fire cost-risk to fire CDF.

PRA Model Changes to Model SAMA:

The CDF associated with fire zone 11.6-0 was changed from 6.00E-06 to 0.0 to model the installation of the fire barriers.

Results of SAMA Quantification:

The averted cost-risk for this SAMA is the cost-risk associated with fire zone 11.6-0 because this SAMA is assumed to entirely eliminate it. Using the assumptions identified above, the result is as follows:

$5,979,393 / 3.97E-05 * 6.00E-06 = $903,687

Based on a $975,000 cost of implementation for Byron, the net value for this SAMA is -$71,313 ($903,687 - $975,000), which indicates this SAMA is not cost beneficial.

F.6.25 SAMA 29 AUTOMATE SWAP TO RECIRCULATION MODE

Fully automating the swap to recirculation mode and removing the operator from the process can improve the reliability of the action.

Assumptions:

It is assumed that this SAMA will eliminate the contributions from the failure to swap to recirculation mode.

PRA Model Changes to Model SAMA:

The independent and dependent operator action events associated with recirculation initiation are set to 0.0 to represent this SAMA.

Model Change(s):

The following events were set to 0.0:

- 1SI-HPR----HSYOA: OPERATORS FAIL TO ESTABLISH HIGH PRESSURE RECIRC (SLOW EVENT)
- 1RX-JHEP19-HOADA and similar events for the following JHEP combinations: 36, 51, 55, and 71.

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.94E-05	35.40	$254,103
Percent Change	0.8%	0.1%	0.2%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.12E-05	1.25E-01	1.21E-01	$118	$114
SERF-TISGTR-HLF	6.49E-09	6.12E-09	6.17E-03	5.81E-03	$44	$41
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.28E-07	1.63E-02	1.63E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	6.38E-08	6.36E-03	5.10E-03	$14	$12
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.34E-06	1.78E+01	1.78E+01	$187,040	$186,816
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.65E-07	3.41E-01	3.39E-01	$1,655	$1,646
LERF-CFE	3.55E-08	3.53E-08	8.88E-02	8.83E-02	$582	$579
LERF-SGTR-AFW	5.49E-08	5.49E-08	1.31E-01	1.31E-01	$1,005	$1,005
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.61E-07	6.97E-01	6.76E-01	$8,205	$7,961
Total	4.19E-05	4.15E-05	3.55E+01	3.54E+01	$254,593	$254,103

Applying the process described in Section F.4 yields an internal events cost-risk of $5,962,320. After accounting for "round up" of the base internal events cost-risk, this value is $5,962,927. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,962,927 * 2.5 = \$14,907,318$$

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

SAMA 29 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,907,318	$42,682

Based on a $1,225,000 cost of implementation for Byron, the net value for this SAMA is -$1,182,318 ($42,682 - $1,225,000), which indicates this SAMA is not cost beneficial.

F.6.26 SAMA 30 PROTECT AFW CABLES IN THE AUX BUILDING GENERAL AREA, ELEVATION 383'

Fires initiating in the AFW 1A pump result in damage to the AFW 1B and 2A pumps. Protecting the AFW cables in these areas will improve the potential for pumps 1B and 2A to remain available in these scenarios for SG makeup.

Assumptions:

This SAMA will eliminate all of the risk associated with fire zone 11.4-0.

The ratio of internal events cost-risk to internal events CDF is equal to the ratio of fire cost-risk to fire CDF.

PRA Model Changes to Model SAMA:

The CDF associated with fire zone 11.4-0 was changed from 3.79E-06 to 0.0 to model the installation of the fire barriers.

Results of SAMA Quantification:

The averted cost-risk for this SAMA is the cost-risk associated with fire zone 11.4-0 because this SAMA is assumed to entirely eliminate it. Using the assumptions identified above, the result is as follows:

$5,979,393 / 3.97E-05 * 3.79E-06 = $570,829

Based on a $975,000 cost of implementation for Byron, the net value for this SAMA is -$404,171 ($570,829 - $975,500), which indicates this SAMA is not cost beneficial.

F.6.27 SAMA 31 UNIT 2 SAMA - PROTECT CABLES FOR 2AF013A, B, AND D IN THE AUX BUILDING GENERAL AREA, ELEVATION 426'

Fires in this are (initiated in MCC 234X, for example) can fail both trains of AFW. Protecting the cables that are vulnerable (A, B, and D in the important scenario), would help preserve the AFW function.

Assumptions:

This SAMA will eliminate all of the risk associated with fire zone 11.6-0 (Unit 2).

The ratio of internal events cost-risk to internal events CDF is equal to the ratio of fire cost-risk to fire CDF.

PRA Model Changes to Model SAMA:

The CDF associated with fire zone 11.6-0 (Unit 2) was changed from 1.06E-05 to 0.0 to model the installation of the fire barriers.

Results of SAMA Quantification:

The averted cost-risk for this SAMA is the cost-risk associated with fire zone 11.6-0 (Unit 2) because this SAMA is assumed to entirely eliminate it. Using the assumptions identified above, the result is as follows:

$5,979,393 / 3.97E-05 * 1.06E-05 = $1,596,513

Based on a $975,000 cost of implementation for Byron, the net value for this SAMA is $621,513 ($1,596,513 - $975,000), which indicates this SAMA is potentially cost beneficial.

F.7 SENSITIVITY ANALYSIS

The following three uncertainties were further investigated as to their impact on the overall SAMA evaluation:

- Use a discount rate of 7 percent, instead of 3 percent used in the base case analysis.
- Use the 95th percentile PRA results in place of the point estimate PRA results.
- Selected MACCS2 input variables.
- Inclusion of the AFW Cross-tie modification as part of the base model

F.7.1 REAL DISCOUNT RATE

A sensitivity study has been performed in order to identify how the conclusions of the SAMA analysis might change based on the value assigned to the real discount rate (RDR). The original RDR of 3 percent, which could be viewed as conservative, has been changed to 7 percent and the maximum averted cost-risk was re-calculated using the methodology outlined in Section F.4.

Based on the reduction in the MACR to $10,970,000 (a 27 percent reduction of the baseline MACR), two additional SAMAs would be screened in Phase 1 that were not screened when the RDR of 3 percent was used (SAMAs 4 and 11).

The Phase 2 analysis was re-performed using the 7 percent RDR. As shown below, the determination of cost effectiveness changed for one of the Phase 2 SAMAs when the 7 percent RDR was used in lieu of 3 percent.

Summary of the Impact of the RDR Value on the Detailed SAMA Analyses

SAMA ID	Implementation Cost (per unit)	Averted Cost Risk (3 percent RDR)	Net Value (3 percent RDR)	Averted Cost Risk (7 percent RDR)	Net Value (7 percent RDR)	Change in Cost Effective - ness?
SAMA 2	$5,751,110	$3,940,272	-$1,810,838	$2,997,670	-$2,753,440	No
SAMA 3	$1,130,300	$1,739,935	$609,635	$1,296,275	$165,975	No
SAMA 5	$657,200	$3,763,930	$3,106,730	$2,718,822	$2,061,622	No
SAMA 7	$100,000	$73,452	-$26,548	$58,700	-$41,300	No
SAMA 8	$338,830	$319,387	-$19,443	$238,110	-$100,720	No
SAMA 9	$349,300	$683,497	$334,197	$510,260	$160,960	No
SAMA 10	$1,320,300	$1,669,087	$348,787	$1,226,492	-$93,808	Yes

Summary of the Impact of the RDR Value on the Detailed SAMA Analyses

SAMA ID	Implementation Cost (per unit)	Averted Cost Risk (3 percent RDR)	Net Value (3 percent RDR)	Averted Cost Risk (7 percent RDR)	Net Value (7 percent RDR)	Change in Cost Effective - ness?
SAMA 13	$5,951,110	$12,856,042	$6,904,932	$9,432,235	$3,481,125	No
SAMA 14	$3,800,000	$68,572	-$3,731,428	$51,795	-$3,748,205	No
SAMA 15	$0	$401,075	$401,075	$292,477	$292,477	No
SAMA 16	$993,800	$790,980	-$202,820	$570,825	-$422,975	No
SAMA 17	$981,730	$24,180	-$957,550	$17,985	-$963,745	No
SAMA 18	$1,608,680	$74,435	-$1,534,245	$54,630	-$1,554,050	No
SAMA 19	$900,000	$613,240	-$286,760	$440,220	-$459,780	No
SAMA 21	$1,600,000	$158,615	-$1,441,385	$113,510	-$1,486,490	No
SAMA 22	$250,000	$44,312	-$205,688	$31,712	-$218,288	No
SAMA 23	$760,000	$38,587	-$721,413	$27,615	-$732,385	No
SAMA 24	$1,250,000	$31,650	-$1,218,350	$22,650	-$1,227,350	No
SAMA 25	$5,700,000	$9,452,920	$3,752,920	$6,764,857	$1,064,857	No
SAMA 26	$2,400,000	$12,839,747	$10,439,747	$9,425,752	$7,025,752	No
SAMA 27	$975,000	$2,078,479	$1,103,479	$1,525,054	$550,054	No
SAMA 28	$975,000	$903,687	-$71,313	$663,067	-$311,933	No
SAMA 29	$1,225,000	$42,682	-$1,182,318	$32,587	-$1,192,413	No
SAMA 30	$975,000	$570,829	-$404,171	$418,837	-$556,163	No
SAMA 31	$975,000	$1,596,513	$621,513	$1,171,418	$196,418	No

F.7.2 95TH PERCENTILE PRA RESULTS

The results of the SAMA analysis can be impacted by implementing conservative values from the PRA's uncertainty distribution. If the best estimate failure probability values were consistently lower than the "actual" failure probabilities, the PRA model would underestimate plant risk and yield lower than "actual" averted cost-risk values for potential SAMAs. Re-assessing the cost-benefit calculations using the high end of the failure probability distributions is a means of identifying the impact of having consistently underestimated failure probabilities for plant equipment and operator actions included in the PRA model.

A Level 1 internal events model uncertainty analysis was not performed for Byron model BB011b1. However, an uncertainty analysis was performed on Byron model BB011a in 2012. Since the 95th percentile assessment employs a ratio rather than individual values, a determination was made to use the BB011a uncertainty results. The basis for this decision is that the 95th to CDF point estimate ratio is not expected to vary significantly between the two models, and hence, should provide a representative value. The availability and use of Level 2 uncertainties is unique since most plants incorporate only Level 1 analyses in their SAMA reports. The reason Level 2 analyses are not typically used is due to the differing degree of development and uncertainties between the two models. Specifically, the Level 1 model tends to represent the plant in a more thorough and comprehensive manner as opposed to the Level 2 model. Furthermore, there are more release contributors beyond those captured by LERF. As such, for the purposes of the 95th percentile analysis, only Level 1 results are used in the uncertainty process. The results of the Level 1 calculation are provided below.

In performing the sensitivity analysis, only the base case was used in determining the appropriate value for the 95th percentile. For those SAMAs that required the addition of new basic events, no new uncertainty distributions were assigned since the design and implementation of each SAMA was arbitrary and was defined by the analysis assumptions. The results of this uncertainty analysis, therefore, show the expected statistical uncertainty of the CDF risk metrics under the assumption that each SAMA was designed and implemented as it was specified in this analysis. All calculations were performed using version 3.0 of the EPRI Uncert software package for the Byron Unit 1 model.

The results of the uncertainty calculation are shown in the table below. The term CDF_{pe} refers to the nominal BB011a CDF point estimate of 4.26E-05.

Summary of Uncertainty Distribution (from BB011a)

Mean	5%	50%	95%	Factor > CDF_{pe}
3.95E-05	1.03E-05	2.78E-05	1.04E-04	2.49

The above table reveals a factor that is 2.49 greater than the respective point estimate CDF, which is in agreement with industry experience. Therefore, for this analysis, the 95th percentile multiplier derived from the base case is used to examine the change in the cost benefit for each SAMA.

F.7.2.1 PHASE 1 IMPACT

For Phase 1 screening, use of the 95th percentile PRA results will increase the MACR and may prevent the screening of some of the higher cost modifications. However, the impact on the overall SAMA results due to the retention of the higher cost SAMAs for Phase 2 analysis is typically small. This is due to the fact that the benefit obtained from the implementation of those SAMAs must be extremely large in order to be cost beneficial.

The impact of uncertainty in the PRA results on the Phase 1 SAMA analysis has been examined. The MACR is the primary Phase 1 criterion affected by PRA uncertainty. Thus, this portion of the sensitivity is focused on recalculating the MACR using the 95th percentile PRA results and re-performing the Phase 1 screening process. As discussed above, the 95th PRA results are a factor of 2.49 greater than the point estimate CDF.

In order to simulate the use of the 95th percentile PRA results on the cost benefit calculations, the same scaling factor calculated for the Level 1 results was assumed to apply to the Level 3 results. Because the MACR calculations scale linearly with the CDF, dose-risk, and off-site economic cost-risk, the 95th percentile MACR can be calculated by multiplying the base case MACR by 2.49. This results in a 95th percentile MACR of $37,225,500.

The initial SAMA list has been re-examined using the revised MACR to identify SAMAs that would have been retained for the Phase 2 analysis. Those SAMAs that were previously screened due to costs of implementation that exceeded $14.95 million are now retained if the costs of implementation are less than $37,225,500. For Byron, SAMAs 1, 12 and 20 were screened in the Phase 1 analysis based on excessive implementation cost. Because the implementation cost of SAMA 20 is less than the 95th percentile MACR, it has been retained for Phase 2 analysis.

Based on a detailed quantification of SAMA 20, new averted cost risk and net values at the 95th percentile were generated. As shown below, the net value for SAMA 20 is negative.

F.7.2.1.1 SAMA 20: Disallow On-Line RHR Maintenance

For cases in which one train of RHR is out of service for maintenance in such a way that it cannot respond in an accident scenario, the plant is vulnerable to single failure events for certain initiating events that require heat removal (for example LOCAs). Preventing on-line maintenance of RHR would significantly reduce the frequency of the associated core damage scenarios.

Assumptions:

It is assumed that implementation of this SAMA will eliminate all risk associated with RHR maintenance (no assessment is made to account for any increase in shutdown risk related to performing the maintenance during an outage).

PRA Model Changes to Model SAMA:

The cutsets were modified by setting the events representing RHR maintenance line to 0.0.

Model Change(s):

The following events were set to 0.0:

- 1RH01PA-----PMMM: RH PUMP 1RH01PA UNAVAILABLE DUE TO MAINTENANCE
- 1RH01PB-----PMMM: RH PUMP 1RH01PB UNAVAILABLE DUE TO MAINTENANCE

Results of SAMA Quantification:

Implementation of this SAMA yielded a moderate reduction in internal CDF and similar reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table:

	Internal CDF	Dose-Risk	OECR
Base Value	3.97E-05	35.45	$254,593
SAMA Value	3.95E-05	35.42	$254,257
Percent Change	0.5%	0.1%	0.1%

A further breakdown of the Dose-Risk and OECR information is provided in the table below according to release category:

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
INTACT	1.16E-05	1.13E-05	1.25E-01	1.22E-01	$118	$115
SERF-TISGTR-HLF	6.49E-09	6.31E-09	6.17E-03	5.99E-03	$44	$43

Release Category	$Freq._{BASE}$	$Freq._{SAMA}$	$Dose\text{-}Risk_{BASE}$	$Dose\text{-}Risk_{SAMA}$	$OECR_{BASE}$	$OECR_{SAMA}$
SERF-SGTR-AFW-SC	1.38E-06	1.38E-06	1.33E+00	1.33E+00	$8,349	$8,349
LATE-BMMT-AFW	5.30E-07	5.23E-07	1.63E-02	1.61E-02	$22	$22
LATE-BMMT-NOAFW	7.95E-08	7.22E-08	6.36E-03	5.78E-03	$14	$13
LATE-CHR-AFW	1.89E-05	1.89E-05	1.05E+01	1.05E+01	$35,721	$35,721
LATE-CHR-NOAFW	8.35E-06	8.34E-06	1.78E+01	1.78E+01	$187,040	$186,816
LERF-ISLOCA	3.40E-07	3.40E-07	4.42E+00	4.42E+00	$11,832	$11,832
LERF-CI	3.67E-07	3.65E-07	3.41E-01	3.39E-01	$1,655	$1,646
LERF-CFE	3.55E-08	3.53E-08	8.88E-02	8.83E-02	$582	$579
LERF-SGTR-AFW	5.49E-08	5.48E-08	1.31E-01	1.31E-01	$1,005	$1,003
LERF-SGTR-NOAFW	8.57E-10	8.57E-10	6.68E-04	6.68E-04	$6	$6
LERF-ISGTR	2.69E-07	2.66E-07	6.97E-01	6.89E-01	$8,205	$8,113
Total	4.19E-05	4.16E-05	3.55E+01	3.54E+01	$254,593	$254,257

Applying the process described in Section F.4 yields an internal events cost-risk of $5,967,807. After accounting for "round up" of the base internal events cost-risk, this value is $5,968,414. The external events contributions are accounted for by multiplying this value by 2.5:

$$\text{Total Cost-Risk}_{SAMA} = \$5,968,414 * 2.5 = \$14,921,035$$

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

SAMA 20 Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Byron Unit 1	$14,950,000	$14,921,035	$28,965

Based on a $20,000,000 cost of implementation for Byron, the net value for this SAMA is -$19,971,035 ($28,965 - $20,000,000), which indicates this SAMA is not cost beneficial. When the 95th percentile PRA results are used, the averted cost-risk is increased by a factor of 2.49 to $72,123, which still yields a negative net value ($72,123 - $20,000,000 = -$19,927,877). This SAMA is not cost beneficial.

F.7.2.2 PHASE 2 IMPACT

As discussed above, a single factor based on the 95th percentile for the base case is used to determine the impact of the cost-benefit analysis for the proposed SAMA candidates. The uncertainty analyses that are available for the Level 1 model are not available (or not used) for the Level 2 and 3 PRA models. In order to simulate the use of the 95th percentile results for the Level 2 and 3 models, the same scaling factor calculated for the Level 1 results was implicitly applied to the dose-risk and offsite economic cost-risk through the application of the multiplier to the base case averted cost-risk values.

The Phase 2 SAMA list was re-examined by multiplying the nominal averted cost risk by the ratio of the 95th percentile CDF to the point estimate CDF value (see Section F.7.2) to identify SAMAs that would be re-characterized as potentially cost beneficial, i.e., positive net value. Those SAMAs that were previously determined to be not cost beneficial due to implementation costs exceeding their associated nominal averted cost risk may be potentially cost beneficial at the revised 95th percentile averted cost risk. In this case, eight additional Phase 2 SAMAs become potentially cost beneficial (SAMAs 2, 7, 8, 11, 17, 19, 28 and 30).

F.7.2.3 95TH PERCENTILE SUMMARY

The following table provides a summary of the impact of using the 95th percentile PRA results on the detailed cost-benefit calculations that have been performed.

Summary of the Impact of Using the 95th Percentile PRA Results

SAMA ID	Implementation Cost (per unit)	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effectiveness?
SAMA 2	$5,751,110	$3,940,272	-$1,810,838	$9,811,277	$4,060,167	Yes
SAMA 3	$1,130,300	$1,739,935	$609,635	$4,332,438	$3,202,138	No
SAMA 4	$12,230,000	$4,086,872	-$8,143,128	$10,176,311	-$2,053,689	No
SAMA 5	$657,200	$3,763,930	$3,106,730	$9,372,186	$8,714,986	No
SAMA 7	$100,000	$73,452	-$26,548	$182,895	$82,895	Yes
SAMA 8	$338,830	$319,387	-$19,443	$795,274	$456,444	Yes
SAMA 9	$349,300	$683,497	$334,197	$1,701,908	$1,352,608	No
SAMA 10	$1,320,300	$1,669,087	$348,787	$4,156,027	$2,835,727	No
SAMA 11	$13,030,000	$12,876,582	-$153,418	$32,062,689	$19,032,689	Yes
SAMA 13	$5,951,110	$12,856,042	$6,904,932	$32,011,545	$26,060,435	No

Summary of the Impact of Using the 95th Percentile PRA Results

SAMA ID	Implementation Cost (per unit)	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effective-ness?
SAMA 14	$3,800,000	$68,572	-$3,731,428	$170,744	-$3,629,256	No
SAMA 15	$0	$401,075	$401,075	$998,677	$998,677	No
SAMA 16	$993,800	$790,980	-$202,820	$1,969,540	$975,740	Yes
SAMA 17	$981,730	$24,180	-$957,550	$60,208	-$921,522	No
SAMA 18	$1,608,680	$74,435	-$1,534,245	$185,343	-$1,423,337	No
SAMA 19	$900,000	$613,240	-$286,760	$1,526,968	$626,968	Yes
SAMA 20	$20,000,000	$28,965	-$19,971,035	$72,123	-$19,927,877	No
SAMA 21	$1,600,000	$158,615	-$1,441,385	$394,951	-$1,205,049	No
SAMA 22	$250,000	$44,312	-$205,688	$110,337	-$139,663	No
SAMA 23	$760,000	$38,587	-$721,413	$96,082	-$663,918	No
SAMA 24	$1,250,000	$31,650	-$1,218,350	$78,809	-$1,171,192	No
SAMA 25	$5,700,000	$9,452,920	$3,752,920	$23,537,771	$17,837,771	No
SAMA 26	$2,400,000	$12,839,747	$10,439,747	$31,970,970	$29,570,970	No
SAMA 27	$975,000	$2,078,479	$1,103,479	$5,175,413	$4,200,413	No
SAMA 28	$975,000	$903,687	-$71,313	$2,250,181	$1,275,181	Yes
SAMA 29	$1,225,000	$42,682	-$1,182,318	$106,278	-$1,118,722	No
SAMA 30	$975,000	$570,829	-$404,171	$1,421,364	$446,364	Yes
SAMA 31	$975,000	$1,596,513	$621,513	$3,975,317	$3,000,317	No

When the 95th percentile PRA results were applied to the Phase 1 analysis, the increase in the MACR resulted in the retention of one SAMA that was screened in the baseline Phase 1 analysis (SAMA 20). The Phase 2 calculations performed for this SAMA using the 95th percentile PRA results indicate that SAMA 20 is not cost beneficial.

When the 95th percentile PRA results were applied to the original Phase 2 calculations, eight SAMAs (2, 7, 8, 11, 17, 19, 28 and 30) that were previously classified as not cost effective were determined to be potentially cost effective. The use of the 95th percentile PRA results is not considered to provide the best assessment of the cost effectiveness of a SAMA; however, these additional SAMAs should be considered for implementation to address the uncertainties inherent in the SAMA analysis.

F.7.3 MACCS2 INPUT VARIATIONS

The MACCS2 model was developed using the best information available for the Byron site; however, reasonable changes to modeling assumptions can lead to variations in the Level 3 results. In order to determine how certain assumptions could impact the SAMA results, a sensitivity analysis was performed on parameters that have previously been shown to impact the Level 3 results. These parameters include:

- Meteorological data
- Evacuation timing and speed
- Release height and heat
- Deposition velocity
- Reactor power level
- Population estimates
- Population resettlement planning
- Generic economic inputs
- Economic rate of return

The risk metrics produced by MACCS2 that are evaluated in the sensitivity analyses are the 50 mile population dose risk and the 50 mile offsite economic cost risk. The subsections below discuss the changes in these results for each of the sensitivity parameters noted above. The final subsection, F.7.3.10, correlates the worst case changes identified in the sensitivity runs to a change in the site's averted cost-risk and discusses the implications of the sensitivity analysis on the SAMA analysis.

Sensitivity of Byron Baseline Risk to Parameter Changes

Parameter	Description	Pop. Dose Risk Δ Base (%)	Cost Risk Δ Base (%)
Meteorology	Year 2009 Meteorology	-4%	-2%
	Year 2010 Meteorology	-1%	-2%
Evacuation Time	Evacuation delay time increased from 115 minutes to 230 minutes (factor of 2)	-0.1%	0%
Evacuation Speed	Average evacuation speed decreased 50% from 4.4 m/sec to 2.2 m/sec.	+2%	0%
Release Height	Release height set to ground level (in lieu of mid-height of containment, 30.3 m).	-1%	-3%

Sensitivity of Byron Baseline Risk to Parameter Changes

Parameter	Description	Pop. Dose Risk Δ Base (%)	Cost Risk Δ Base (%)
	Release height set to top of containment , 60.7m (in lieu of mid-height of containment, 30.3 m).	+1%	+3%
Release Heat	No buoyant plume assumed (0 watts for each plume segment).	-0.2%	-3%
Deposition Velocity	Dry deposition velocity decreased from 0.01 m/sec to 0.005 m/sec (factor of 2)	-8%	-19%
Reactor Power	Reactor power decreased from 3645 MWt to 3586.6 MWt, reflective of no MUR uprate	-1%	-1%
Population	Year 2046 population uniformly increased 30%	+28%	+26%
Resettlement Planning	No "Intermediate Phase" resettlement planning (in lieu of 6 months)	+17%	-32%
	1 year "Intermediate Phase" resettlement planning (in lieu of 6 months)	-14%	+35%
Economic Inputs	Generic economic inputs increased (factor of 2)	-6%	+48%
Rate of Return	3% expected rate of return (in lieu of 7%)	+1%	-9%
	12% expected rate of return (in lieu of 7%)	-2%	+10%

F.7.3.1 METEOROLOGICAL SENSITIVITIES

In addition to the year 2008 base case meteorological data, years 2009 and 2010 were also analyzed. Analysis of year 2009 and 2010 data sets yielded population dose-risks and cost risks that were 1% to 4% less than 2008 results. As no particular criteria have been defined by the industry related to determining which meteorological data set should be used as a base case for a site, the year 2008 data is chosen for Byron given that it represents site meteorological conditions and results in the highest dose risk and cost risk of the three data sets.

F.7.3.2 EVACUATION SENSITIVITIES

The sensitivity of two evacuation parameters was assessed. The delay time to evacuation (increased from 115 minutes to 230 minutes) was found to have a negligible impact (approximately 0.1% decrease) on population dose risk. The dose impact of the increased delay time varied for the different release categories (i.e., some resulted in a dose increase, others in a dose decrease (notably LERF-ISLOCA), and some had no change). The differing impacts are attributed to the relationship between the start of evacuation movement and the time of the arrival of the risk significant plumes. The majority of the population dose risk is due to the long term dose associated with the late releases, notably the LATE-CHR-NOAFW and LATE-CHR-AFW release categories which contribute approximately 80% to the total population dose risk. The LERF-ISLOCA release category is the largest contributor (approximately 12%) to population dose risk that occurs in the early time frame. The majority of LERF-ISLOCA release occurs during the first hour in the first plume, shortly after the GE declaration. With a longer delay time individuals are modeled to be located at home (which provides some radiological shielding) longer before beginning travel in their vehicles (which provides less radiological shielding). For individuals closer to the plant site, the longer delay time results in the fast release passing over them at their residence prior to the start of evacuation movement. These individuals thus experience an early dose decrease (due to the shielding afforded by their residence as compared to their vehicles) for a longer delay time. This timing effect will vary across the analysis region based on the population distribution (e.g., distance from the site), meteorological conditions (e.g., wind speed), and evacuation speed. The sensitivity case demonstrates that the overall impact is negligible for the values used.

The evacuation speed sensitivity which decreased the average radial evacuation speed by a factor of two (from 4.4 m/sec to 2.2 m/sec), bounding the longest evacuation time in the ETE study, demonstrates a small impact on population dose. The population dose risk increased approximately 2% using the slower evacuation speed. An increase in population dose is the generally expected result for a slower evacuation speed since evacuees would be expected to be exposed to radiological releases for a longer period of time. It is noted that while evacuation assumptions do impact the population dose-risk estimates, they do not impact MACCS2 offsite economic cost-risk estimates because MACCS2 calculated cost-risks are based on land contamination levels which remain unaffected by evacuation assumptions and the number of people evacuating.

F.7.3.3 RELEASE HEIGHT & HEAT SENSITIVITIES

The release height sensitivity cases quantify the impact of the assumption related to the height of the release of the plumes. The baseline case assumes that the releases occur at approximately half the height of the containment building (30.3 m). Releases from higher heights tend to disperse material over a wider geographical region, generally impacting more people and creating larger long term dose and cleanup costs. A ground level release height (0 m) shows a decrease in dose risk and cost risk of 1% and 3%, respectively. A release from the top of containment (60.3 m) shows an increase in dose risk and cost risk of 1% and 3%, respectively. The impacts of release height assumptions are small.

The release heat sensitivity case evaluates the impact of assumptions of thermal plume effects. The base case assumed a heat content of 10 MW per plume segment, except for the intact containment release category where zero plume heat was assumed. The 10 MW per plume segment value is generally bounding for the values used in the NUREG-1150 (NRC 1990a) study as documented in NUREG/CR-4551 (NRC 1990b). Modeling plume heat increases the buoyancy effect of the released plumes and generally has similar impacts as modeling a higher release height. The sensitivity case assumed no thermal plume heat in the releases (i.e., no buoyant plumes). The impacts of assuming no plume heat are a dose risk and cost risk decrease of 0.2% and 3%, respectively.

F.7.3.4 DEPOSITION VELOCITY

The dry deposition velocity sensitivity case evaluates the impact of the fission product particle size as reflected in the deposition velocity parameter. The base case assumes a deposition velocity of 0.01 m/sec, consistent with the NRC recommendation documented in MACCS2 Sample Problem A (NRC 1998). The sensitivity case uses a deposition velocity of 0.005 m/sec, reflective of a smaller particle size. Assuming a lower deposition velocity results in a decrease in the dose risk and cost risk of 8% and 19%, respectively. This decrease is attributed to smaller particles traveling further and exiting the 50 mile analysis region.

F.7.3.5 REACTOR POWER

The reactor power sensitivity case evaluates the impact of not including the postulated measurement uncertainty recapture (MUR) power uprate. For this sensitivity case, the reactor power was decreased from 3645 MWt (assumes MUR implemented) to 3586.6 MWt (current licensed power level). Assuming the MUR power uprate is not implemented results in a very small decrease of dose risk and cost risk of 1%.

F.7.3.6 POPULATION SENSITIVITY

A population sensitivity case assesses the impact of population assumptions. The base case year 2046 population is uniformly increased by 30% in all grid elements of the 50-mile radius. This change has a significant impact on the dose risk and cost risk, increasing dose risk and cost risk by 28% and 26%, respectively. This sensitivity case demonstrates a significant dependence upon population estimates. This dependence is expected given that population dose and offsite economic costs are primarily driven by the regional population.

F.7.3.7 RESETTLEMENT PLANNING SENSITIVITIES

The MACCS2 consequence modeling incorporates an "intermediate phase" which depicts the time period following the release and immediate evacuation actions (termed the "early phase") and extends to the time when recovery efforts such as decontamination and resettlement of people are begun (termed the "long term phase"). The intermediate phase thus models the time period when decontamination and resettlement plans are being developed. MACCS2 allows the habitation of land during the intermediate phase unless projected dose criteria is exceeded, in which case individuals are relocated. MACCS2 allows an intermediate phase ranging from no intermediate phase to a maximum of one year. The intermediate phase sensitivities show significant impacts and are therefore discussed further:

- The no intermediate phase resettlement planning case is developed based on the NUREG-1150 (NRC 1990a) modeling approach. The 32% reduction in cost risk seen in the sensitivity results, however, is judged too optimistic in that the land decontamination efforts are modeled as starting one week after the accident (i.e., directly after the early phase ends) such that a significant portion of population relocation costs are omitted. For instance, the costs associated with temporary housing of interdicted individuals while decontamination strategies are developed and decontamination teams are contracted are not accounted for without an intermediate phase. It is believed that the NUREG-1150 studies omitted the intermediate phase because the intermediate phase coding was not validated at that time (NRC 1998). A competing factor is that the population dose increases (17% increase over the base case) because people are allowed to re-occupy the decontaminated land sooner.
- The 1 year intermediate phase resettlement planning case is developed based on the maximum length of time allowed by MACCS2 for the intermediate phase. A long intermediate phase can be unrealistic in that re-occupation of contaminated land is not performed during this phase even if contamination levels decrease (by natural radioactive decay and weathering) to levels which would allow it (i.e., resettlement is evaluated as part of the long term phase, not the intermediate phase). Therefore population relocation costs may be over estimated using a long (i.e., one year) intermediate phase. An intermediate phase of one year shows a 35% increase in cost risk estimates compared with the base case selection of 6 months. The population dose decreased by 14% with a longer intermediate phase due to later resettlement on decontaminated land.

The six month intermediate phase (base case) is judged to be a best estimate approach in that it provides reasonable time for both decontamination and resettlement planning to be performed. The sensitivity cases demonstrate that the six month value used in the base case provides mid-range results for the modeling choices available.

F.7.3.8 GENERIC ECONOMIC INPUTS SENSITIVITY

MACCS2 requires certain site specific economic data (e.g., fraction of land devoted to farming, annual farm sales, fraction of farm sales resulting from dairy production, and property value of farm and non-farm land) for each of the 160 spatial elements. The site specific base case values are calculated based on regional economic data.

In addition to these site specific values, generic economic data are utilized by MACCS2 to address costs associated with per diem living expenses (applied to owners of interdicted properties and relocated populations), relocation costs (for owners of interdicted properties), and decontamination costs. For the Byron base case, these generic costs are based on values used in the NUREG-1150 study (NRC 1990a) as documented in the NUREG/CR-4551 (NRC 1990b) updated to July 2012 using the consumer price index.

This sensitivity case is performed to determine the variability in population dose risk and cost risk based on changes to these generic based values. The sensitivity case increases key generic based economic parameters as identified in Table F.7-1. In general, the inputs were arbitrarily increased by factor of 2.0. The increase in these economic parameters resulted in an increase in cost risk of 48% and a decrease in dose risk of about 6%. A significant increase in cost risk is expected since population relocation and decontamination costs are major contributors to total cost as calculated by MACCS2.

F.7.3.9 RATE OF RETURN SENSITIVITIES

One of the economic cost components included in the MACCS2 calculated cost result is the financial loss associated with property and associated improvements (e.g., buildings) not achieving their expected annual rate of return during interdiction periods. A piece of land that is interdicted (i.e., not occupied) for a period of years will not achieve the historical rate of return or the rate of return achieved by other non-impacted properties during the interdiction period. This lack of expected return is an economic loss for the owner / society. The base case assumes a 7% expected rate of return, consistent with NRC guidance (NRC 2004a). A sensitivity case using a 3% expected rate of return shows a decrease in the expected cost risk of approximately 9%. This decrease in cost risk associated with the lower rate or return is expected since there is a lower expectation associated with the land's return on investment. A sensitivity case using a 12% expected rate of return, the value used in NUREG-1150 MACCS2 analyses (NRC 1990b), shows an increase cost risk of approximately 10%. For both sensitivity cases the dose risk changes are minor (1% to 2%).

F.7.3.10 IMPACT ON SAMA ANALYSIS

Several different Level 3 input parameters are examined as part of the Byron MACCS2 sensitivity analysis. The primary reason for performing these sensitivity runs is to identify any reasonable changes that could be made to the Level 3 input parameters that would impact the conclusions of the SAMA analysis. While the table in Section F.7.3 summarizes the changes to the dose-risk and OECR estimates for each sensitivity case, it is prudent to consider if any of these changes would result in the retention of the SAMAs that were screened using the baseline results.

Of all the MACCS2 sensitivity cases, the largest dose-risk increase, 28%, occurred in the Population (Year 2046 population uniformly increased 30%) case. The largest OECR increase, 48%, occurred in the Generic Economic Input sensitivity case. While these changes are not insignificant, they are relatively small compared to the 95th percentile PRA results sensitivity in Section F.7.2, which increases the averted cost-risk values for the SAMAs by almost 250 percent. Therefore, the 95th percentile PRA results sensitivity is considered to bound this case and no SAMAs would be retained based on this sensitivity that were not already identified in Section F.7.2.

F.7.4 INCLUSION OF THE AFW CROSS-TIE IN THE BASE MODEL

While the AFW Cross-tie modification is in the final stages of implementation for Byron, it was not officially implemented at the time the SAMA analysis was performed. Accordingly, the PRA model used for this analysis does not credit the AFW cross-tie. However, because the final implementation is imminent, a sensitivity analysis was performed to identify how the cross-tie capability would impact the SAMA analysis. In order to do this, the SAMA 15 (AFW Cross-tie) model was used as the new "base" model and the Phase 1 and 2 screening analyses were re-performed relative to that model.

Use of the SAMA 15 model as the base case resulted in a decrease in the MACR from $14,950,000 to $14,547,500, which is based on the PRA results documented in Section F.6.12 and the rounding up of the internal events cost-risk in the same manner as the base case. This slight reduction did not result in the screening of any additional SAMAs in the Phase 1 analysis.

The impact on the Phase 2 analysis was determined by performing the calculation/model changes identified for each SAMA in conjunction with the changes identified for SAMA 15. The following table provides a comparison of the Phase 2 results for the nominal plant configuration to the configuration in which the AFW Cross-tie has been implemented. As documented in the "Change in Cost Effectiveness?" column, implementation of the AFW cross-tie is would not alter the conclusions of the cost-benefit analysis.

Impact of Assuming Implementation of AFW Cross-tie for the SAMA Base Case

SAMA ID	Implementation Cost (per unit)	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (SAMA 15 Base Case)	Net Value (SAMA 15 Base Case)	Change in Cost Effective-ness?
SAMA 2	$5,751,110	$3,940,272	-$1,810,838	$3,930,097	-$1,821,013	No
SAMA 3	$1,130,300	$1,739,935	$609,635	$1,455,390	$325,090	No
SAMA 4	$12,230,000	$4,086,872	-$8,143,128	$4,093,340	-$8,136,660	No
SAMA 5	$657,200	$3,763,930	$3,106,730	$3,752,347	$3,095,147	No
SAMA 7	$100,000	$73,452	-$26,548	$73,255	-$26,745	No
SAMA 8	$338,830	$319,387	-$19,443	$327,560	-$11,270	No
SAMA 9	$349,300	$683,497	$334,197	$690,325	$341,025	No
SAMA 10	$1,320,300	$1,669,087	$348,787	$1,669,010	$348,710	No
SAMA 11	$13,030,000	$12,876,582	-$153,418	$12,479,355	-$550,645	No
SAMA 13	$5,951,110	$12,856,042	$6,904,932	$12,553,872	$6,602,762	No
SAMA 14	$3,800,000	$68,572	-$3,731,428	$47,235	-$3,752,765	No
SAMA 16	$993,800	$790,980	-$202,820	$799,070	-$194,730	No
SAMA 17	$981,730	$24,180	-$957,550	$13,957	-$967,773	No
SAMA 18	$1,608,680	$74,435	-$1,534,245	$79,665	-$1,529,015	No
SAMA 19	$900,000	$613,240	-$286,760	$610,042	-$289,958	No
SAMA 21	$1,600,000	$158,615	-$1,441,385	$155,417	-$1,444,583	No
SAMA 22	$250,000	$44,312	-$205,688	$41,117	-$208,883	No
SAMA 23	$760,000	$38,587	-$721,413	$28,082	-$731,918	No
SAMA 24	$1,250,000	$31,650	-$1,218,350	$30,717	-$1,219,283	No
SAMA 25	$5,700,000	$9,452,920	$3,752,920	$9,173,255	$3,473,255	No
SAMA 26	$2,400,000	$12,839,747	$10,439,747	$12,442,435	$10,042,435	No
SAMA27	$975,000	$2,078,479	$1,103,479	$2,064,311	$1,089,311	No
SAMA28	$975,000	$903,687	-$71,313	$897,526	-$77,474	No
SAMA29	$1,225,000	$42,682	-$1,182,318	$26,825	-$1,198,175	No
SAMA30	$975,000	$570,829	-$404,171	$566,938	-$408,062	No
SAMA31	$975,000	$1,596,513	$621,513	$1,585,630	$610,630	No

F.8 CONCLUSIONS

The benefits of revising the operational strategies in place at Byron and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. However, use of the PRA in conjunction with cost-benefit analysis methodologies provides an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on a larger future population. The results of this study indicate that many potential improvements were identified that warrant further review for potential implementation at Byron.

In summary, SAMAs 3, 5, 9, 10, 13, 15, 25, 26, 27, and 31 were found to be potentially cost beneficial in the baseline analysis.

When the 95th percentile PRA results are considered, SAMAs 2, 7, 8, 11, 16, 19, 28, and 30 are also potentially cost beneficial.

F.8.1 OPTIMAL SAMA SET

While many SAMAs are potentially cost beneficial for Byron when considered independently, it should be noted that many SAMAs address similar areas of risk. Implementation of one SAMA may result in a change in the potential benefits of the remaining SAMAs such that they are no longer cost beneficial. Review of the potentially cost beneficial SAMAs can help identify an "optimal" set of SAMAs for implementation, that is, a reduced set of SAMAs that will address the largest risk contributors for the site. For example, the industry initiative to address Fukushima insights led to the development of a mitigation strategy with capabilities similar to SAMA 11 (DMS), which may be fully implemented or implemented in part by Byron for reasons outside of the SAMA analysis, but would mitigate many of the largest contributors to site risk. In addition, the AFW Cross-tie is in the final stages of implementation and should be considered as complete for any future considerations. Beginning with these plant enhancements, the remaining set of SAMAs can be reviewed to identify those that would mitigate the contributors not addressed by SAMAs 11 and 15. It is recognized that there are different combinations of SAMAs that could achieve similar results, but this is a demonstration of a potential approach to interpreting the results of the cost benefit analysis.

Assuming that the AFW Cross-tie and the DMS have been implemented, the SAMAs that were identified as potentially cost beneficial in the 95th percentile sensitivity analysis were assessed to determine if they would remain potentially cost beneficial. The following table summarizes the results of this review.

Review of Impact of the DMS and AFW Cross-Tie on Cost Benefit Analysis

SAMA Number	SAMA Title	Discussion
2	Replace the Positive Displacement Pump with a Self-Cooled, Auto Start Pump	This SAMA is intended to prevent RCP seal LOCAs, but the DMS virtually eliminates the RCP seal LOCA contribution through the installation of "no-leak" seals. SAMA 2 would no longer be cost beneficial.
3	Auto Start of Standby SX Pump	Automating the start of the standby SX pump is primarily used to prevent RCP seal LOCAs. The DMS virtually eliminates the RCP seal LOCA contribution through the installation of "no-leak" seals. SAMA 3 would no longer be cost beneficial.
5	Modify the Startup Feedwater Pump to Start Using the AMSAC SG Low-Low-Low Level signal to Mitigate AFW Failure	This SAMA addresses human errors associated with initiation of secondary side heat removal, which would not be impacted by the DMS. SAMA 5 would remain a viable candidate for potential implementation.
7	Establish Flow to the RH HX on RH Pump Start	This SAMA helps reduce human errors after successful initiation of heat removal, which are dominated by small LOCA scenarios that the DMS would not mitigate. SAMA 7 would remain a viable candidate for potential implementation.
8	Install Kill Switches for the Fire Protection Pumps in the MCR	This SAMA primarily protects the SX pumps, which in turn helps prevent RCP seal LOCAs. The DMS virtually eliminates the RCP seal LOCA contribution through the installation of "no-leak" seals. SAMA 8 would no longer be cost beneficial.
9	Install Flow Restrictors in Fire Protection Pipes	This SAMA primarily protects the SX pumps, which in turn helps prevent RCP seal LOCAs. The DMS virtually eliminates the RCP seal LOCA contribution through the installation of "no-leak" seals. SAMA 9 would no longer be cost beneficial.
10	Alter Ductwork Between the Aux Bldg Sump Drain Room and the SX Pump Room	This SAMA primarily protects the SX pumps, which in turn helps prevent RCP seal LOCAs. The DMS virtually eliminates the RCP seal LOCA contribution through the installation of "no-leak" seals. SAMA 10 would no longer be cost beneficial.

Review of Impact of the DMS and AFW Cross-Tie on Cost Benefit Analysis

SAMA Number	SAMA Title	Discussion
13	Alternate AFW Cooling with Seal Protection	This SAMA provides a heat removal mechanism that is not dependent on SX. The DMS provides the same capability. SAMA 13 would no longer be cost beneficial.
16	Install High Flow Sensors On the Non-Essential Service Water System	This SAMA primarily protects the SX pumps, which in turn helps prevent RCP seal LOCAs. The DMS virtually eliminates the RCP seal LOCA contribution through the installation of "no-leak" seals. SAMA 16 would no longer be cost beneficial.
19	Replace MOVs in the RHR Discharge Line with Valves that Can Isolate an ISLOCA Event	The DMS would not impact ISLOCA risk. SAMA 19 would remain a viable candidate for potential implementation.
25	Install a Filtered Containment Vent	After implementation of the DMS and SAMA 15, the MACR would only be $2,068,145. Even using the 95th percentile multiplier of 2.49, the 95th percentile MACR of $5,149,681 is less than the estimated implementation cost of $5,700,000. This SAMA would no longer be cost beneficial.
26	DMS Using a Dedicated Generator, Self-Cooled Charging Pump, and a Portable AFW Pump	This is an alternate approach to the DMS and it is considered to be obviated by implementation of SAMA 11.
27	Protect RH, SI, and CVCS Cubicle Cooling Fan Cables in Fire Zone 11.3-0	This SAMA protects cables that are used to support RCP seal cooling and heat removal via RH. The DMS includes "no-leak" seals that would prevent most seal LOCAs and preclude the need for RH while providing an alternate secondary side heat removal source. SAMA 27 would no longer be cost beneficial.
28	Install Fire Barriers around MCC 134X	This SAMA addresses contributors related to RCP seal LOCAs, which are addressed by the DMS, but also scenarios that include failure to restore FW, which would not be impacted by the DMS due to human dependence issues. SAMA 28 is considered to remain a viable candidate for potential implementation.

Review of Impact of the DMS and AFW Cross-Tie on Cost Benefit Analysis

SAMA Number	SAMA Title	Discussion
30	Protect AFW Cables in the Aux Building General Area, Elevation 383'	This SAMA protects cables that are used to support AFW operation. While both the DMS and the AFW X-tie provide a means of SG makeup, an AFW pump is failed in both units by the fire, which renders the AFW x-tie unavailable. In addition, human dependence issues would limit the credit for the DMS in the largest contributing scenarios. Finally, FW/Condenser is assumed to be lost in fire events, it is not clear there would be enough time to implement the DMS before core damage. This SAMA would remain potentially cost beneficial.
31	Unit 2 SAMA - Protect Cables for 2AF013A, B, and D in the Aux Building General Area, Elevation 426'	This SAMA protects cables that are used to support AFW operation. While both the DMS and the AFW X-tie provide a means of SG makeup, the AFW system injection path is failed by the fire and because FW/Condenser is assumed to be lost in fire events, it is not clear there would be enough time to implement the DMS before core damage. This SAMA would remain potentially cost beneficial.

While a large number of SAMAs can be considered potentially cost beneficial for Byron when considered independently, there is a smaller subset of SAMAs that, if implemented, would render the remaining SAMAs "not cost beneficial". This subset is SAMAs 5, 7, 11, 15, 19, 28, 30, and 31[2].

[2] Given that the fire model is in an interim state, the cost benefit analysis for SAMAs 28, 30, and 31 should also be considered "interim" until the associated fire scenarios are further refined.

F.9 TABLES

Table F.2-1
Byron/Braidwood PRA Model Update History

Model change description	Rev.	Date	CDF	LERF	Comments
Original IPE	---	BY-04/1994 BW-06/1994	3.09E-05 2.74E-05	2.73E-06 2.62E-06	Initial IPE submittal, which was conducted to satisfy GL 88-20 requirements. This study was based on the support-state model methodology.
Modified IPE	---				IPE safety evaluation report was received on this study, which satisfied GL 88-20 requirements.
Changed PRA model methodology and Updated all Data	0	10/1999	BY1-4.98E-05 BY2-4.88E-05 BW1-4.86E-05 BW2-4.86E-05	BY1-4.48E-06 BY2-4.35E-06 BW1-3.78E-06 BW2-3.81E-06	PRA model was changed from the support state model to linked fault tree method. The changes involved extensive modifications to all event trees and fault trees. All data, including initiating event frequencies, equipment failure data, common cause failure (CCF) data and human error probabilities were updated using most recent industry sources. Plant-specific data was also updated.
One SX pump criteria incorporated	1	10/2000	BY1-4.55E-05 BY2-4.45E-05 BW1-4.61E-05 BW2-4.60E-05	BY1-5.41E-06 BY2-5.33E-06 BW1-4.89E-06 BW2-4.89E-06	The SX pump success criterion was changed from two pumps to one pump.
LOOP/DLOOP Event Tree revised	2	06/2001	BY1-4.81E-05 BY2-4.80E-05 BW1-4.60E-05 BW2-4.59E-05	BY1-5.29E-06 BY2-5.27E-06 BW1-4.96E-06 BW2-4.96E-06	The event tree was revised to remove extensive cutset recoveries performed as post processing. Revision 2 of PRA model was documented as an interim model and was not released as a working model.

Table F.2-1
Byron/Braidwood PRA Model Update History

Model change description	Rev.	Date	CDF	LERF	Comments
Internal flooding analysis revised and incorporation of plant mods to CV pump lube oil cooler	3	06/2001	BY1-5.56E-05 BY2-5.53E-05 BW1-3.15E-05 BW2-3.14E-05	BY1-6.26E-06 BY2-6.24E-06 BW1-4.65E-06 BW2-4.65E-06	Previous revisions did not include the results of internal flooding analysis. A fire hose connection from FP system to the CV pump lube oil cooler was made available as an alternate cooling water source. This mod removed a complete dependency of CV pumps on SX system. FP and VA system models were added as a result of this change.
Incorporated a plant mod at Byron (not applicable to Byron)	3a	08/2001	BY1-5.50E-05 BY2-5.48E-05 BW1-3.15E-05 BW2-3.14E-05	BY1-6.15E-06 BY2-6.13E-06 BW1-4.60E-06 BW2-4.60E-06	This mod includes removal of automatic control of 1(2)SX173 and 1(2)SX178 air operated valves, which provide cooling water to AF pump 1B. This mod removed AF pump 1B dependency on Instrument Air.
RPS and CCW system logic revised	3b	Not Available	Not Available	Not Available	The changes include system logic enhancements and corrections identified during the previous PRA revision. The model revision was performed in support of Westinghouse Owners Group ATWS sensitivity study. This revision was not issued.
System Model and Containment Failure updates	4	02/2002	BY1-5.27E-05 BY2-5.20E-05 BW1-3.12E-05 BW2-3.12E-05	BY1-5.41E-06 BY2-6.15E-06 BW1-4.57E-06 BW2-4.93E-06	Made significant model enhancements to the following systems: reactor protection system (RPS), engineered safety feature actuation system (ESFAS), CCW, PORVs, AFW and instrument power. The changes were system specific and included changes to address issues such as the need to remove instrument power for the PORVs for non-ATWS conditions, adding 3-of-4 common cause failure terms for the AF-005 valves, and the re-development of the RPS fault trees. Also, the Containment Failure likelihood was updated.

Table F.2-1
Byron/Braidwood PRA Model Update History

Model change description	Rev.	Date	CDF	LERF	Comments
Inverter LCO AOT Extension	4B	10/2002	BY1-5.36E-05 BY2-5.26E-05 BW1-3.26E-05 BW2-3.24E-05	BY1-4.85E-06 BY2-5.49E-06 BW1-4.06E-06 BW2-4.31E-06	Modifications to support more efficient model updates in the future and other miscellaneous issues to support the 120VAC Inverter limiting condition for operation (LCO) AOT Extension Application. Multiple detailed modeling changes were performed to address known issues. For example, the small LOCA and transient accident modeling logic was changed, the pump signal modeling for CC, SX, and CV was changed, and the CCW fault tree was revised to update how the Unit 0 heat exchanger was credited.
Address miscellaneous model issues and updated data.	5	12/2002	BY1-4.91E-05 BY2-4.68E-05 BW1-3.84E-05 BW2-3.83E-05	BY1-4.41E-06 BY2-4.82E-06 BW1-4.20E-06 BW2-4.45E-06	Changed model to address several model issues and incorporate values from updated failure and unavailability data, operator action human error probabilities (HEPs), and support system initiating event frequencies.
New SX Success Criteria and Loss of SX frequency. Address quality issues for periodic update.	5A	05/2003	BY1-6.43E-05 BY2-6.34E-05 BW1-5.78E-05 BW2-5.75E-05	BY1-4.93E-06 BY2-5.87E-06 BW1-5.04E-06 BW2-5.78E-06	Revised the model and data to address the PRA quality issues raised by CR#00142080 (1/30/03) against Rev. 5 model. Re-evaluated the plant-specific data, performed full convergence analysis and a human failure dependency analysis. Incorporated new SX success criteria. This model is used to support the SX technical specification (TS) CT (Completion Time) Extension (one-time relief) application.
Automatic Quantification using PSALink.	5B	06/2003	BY1-6.15E-05 BY2-6.06E-05 BW1-5.43E-05 BW2-5.39E-05	BY1-4.65E-06 BY2-5.52E-06 BW1-4.74E-06 BW2-5.39E-06	Revised the model so that automatic quantification can be performed using ORAM-Sentinel and PSALINK program.

Table F.2-1
Byron/Braidwood PRA Model Update History

Model change description	Rev.	Date	CDF	LERF	Comments
Conditional LOOP events	5E	Not Available	BY1-5.79E-05 BY2-5.72E-05 BW1-5.46E-05 BW2-5.38E-05	BY1-4,72E-06 BY2-5.62E-06 BW1-4.99E-06 BW2-5.75E-06	Model revised to incorporate conditional dual unit LOOP for most all initiators, updated some LERF binning, changed modeling of ESFAS testing, added RWST switchover channel testing and common cause. Other minor changes.
Incorporation of component spurious operation	5F	12/2006	BY1-5.75E-05 BY2-5.70E-05 BW1-5.42E-05 BW2-5.36E-05	BY1-4.71E-06 BY2-5.62E-06 BW1-4.98E-06 BW2-5.75E-06	Model revisions to the Byron/Byron PRA to deal with potential spurious operation of key components that were not accounted for in the full power internal events (FPIE) model in order to obtain more realistic results for the Byron Fire PRA activities.

Table F.2-1
Byron/Braidwood PRA Model Update History

Model change description	Rev.	Date	CDF	LERF	Comments
Periodic Update	6	07/2007	BY1-5.9E-05 BY2-5.9E-05 BW1-3.1E-05 BW2-3.6E-05	BY1-3.2E-06 BY2-4.4E-06 BW1-2.9E-06 BW2-3.9E-06	Periodic Model Update. Model revisions included changes to AFW success criteria based on new MAAP 4.0 analyses, revisions to HEPs to reflect new procedure changes and operator interviews, revision of the flooding analysis based on HEP changes, incorporation of updated data analyses, explicit modeling of ISLOCA sequences, expansion of CCF treatment for Byron SX tower modeling, incorporation of modeling changes to allow for multiple SX or CC pumps and/or heat exchangers to be out of service online, addition of ventilation modeling for motor-driven AF pumps, correction of emergency boration logic, incorporation of the new Byron air compressor configuration, accounting for instrument bus auto transfer features (both installed and future modifications), incorporation of logic to require operators to start another CC pump or reduce loads if a CC pump fails after two RH heat exchangers are in service on one CC pump, addition of normally open manual valve in the SX system that may be closed for system maintenance or repair online, changes to the RPS logic to better reflect the signals that cause a trip relative to the initiators, changed AF auto start logic to include AMSAC signals, removed credit for the diesel-driven AF pump's SX booster pump on loss of SX events (such as CCF of all four strainers) that would result in flow blockage, and other issues in the Updating Requirement Evaluation (URE) database. Due to issues identified with this model, it was not considered a model of record.
RPS/ESFAS Application	6A	Not Available	Not Available	Not Available	An application specific model for RPS/ESFAS TS Change RAI Responses.

Table F.2-1
Byron/Braidwood PRA Model Update History

Model change description	Rev.	Date	CDF	LERF	Comments
Error Correction	6B	02/2008	BY1-6.0E-05 BY2-6.0E-05 BW1-3.6E-05 BW2-3.6E-05	BY1-3.1E-06 BY2-4.3E-06 BW1-2.9E-06 BW2-3.4E-06	Addressed the issues identified in model revision 6 and other issues during review of the R6B model. Due to issues identified with merging the flood model with the base model, which were identified while incorporating new Byron flood mitigation procedures, this model was not considered a model of record.
Flood Procedures	6C	05/2008	BY1-3.6E-05 BY2-3.6E-05 BW1-3.6E-05 BW2-3.5E-05	BY1-2.5E-06 BY2-3.1E-06 BW1-2.9E-06 BW2-3.4E-06	Incorporated new Byron flood procedure in support of B/B RTS/ESFAS TS changes. Performed benchmark tests to switch over to CAFTA 5.3 and PRAQUANT 5.0a.
RCP Seal LOCA Model	6D	12/2008	BY1-2.2E-05 BY2-2.2E-05 BW1-2.3E-05 BW2-2.3E-05	BY1-2.1E-06 BY2-2.3E-06 BW1-2.5E-06 BW2-2.7E-06	Revised RCP seal LOCA model for non-LOOP sequences. Incorporated URE-709 (Bleed & Feed Success Criteria), 711 (logic error correction), 712 (Revised BE name) and 715 (Correction of a logic issue in the MLOC-05 sequence).
AF Crosstie	6E	06/2009	BY1-1.7E-05 BY2-1.7E-05 BW1-1.6E-05 BW2-1.5E-05	BY1-1.2E-06 BY2-1.5E-06 BW1-1.4E-06 BW2-1.6E-06	Incorporated AF Unit Crosstie Modification at Byron. The similar modification will be expected to be completed at Byron in October 2009. The HEP changes from HRA migration to HRA Calculator 4.0 were also implemented.
Software Revision	6E1	Not Available	BY1-1.7E-05 BY2-1.7E-05 BW1-1.6E-05 BW2-1.5E-05	BY1-1.1E-06 BY2-1.4E-06 BW1-1.4E-06 BW2-1.6E-06	Re-quantified the results using FORTE 3.0c due to a memory error encountered with FORTE 2.2f at the truncation limits of 1E-11 for CDF and 1E-12 for LERF for some application cases. No modeling changes.
Addendum to identify key operator actions	6E2	03/2010	BY1-1.7E-05 BY2-1.7E-05 BW1-1.6E-05 BW2-1.5E-05	BY1-1.1E-06 BY2-1.4E-06 BW1-1.4E-06 BW2-1.6E-06	Identified 12 operator actions as key assumptions to B/B PRA R6E1 model, based on the BB HRA. This was an addition to the model documentation and did not change or supersede the R6E1 model.

Table F.2-1
Byron/Braidwood PRA Model Update History

Model change description	Rev.	Date	CDF	LERF	Comments
Addendum to revise software quantification engine	6E3	05/2010	BY1-1.7E-05 BY2-1.7E-05 BW1-1.6E-05 BW2-1.5E-05	BY1-1.1E-06 BY2-1.4E-06 BW1-1.4E-06 BW2-1.6E-06	Document the B/B PRA results using FTREX 1.5 to enable the use of FTREX for Byron/Byron risk applications. The PRA model R6E was not changed, and the results from R6E1 and R6E3 are identical.
CC Split-train operation and updated Internal Flooding Analysis	6F	09/2011	BY1-2.53E-05 BY2-2.56E-05 BW1-4.02E-05 BW2-3.88E-05	BY1-1.33E-06 BY2-1.83E-06 BW1-1.75E-06 BW2-2.22E-06	Unscheduled update to incorporate operator actions to split the CC trains under most conditions. This is expected to be a temporary condition until plant modifications are completed that will support a return to the assumed conditions where the CC trains are not normally split. Also includes ongoing working model changes and the updated internal flooding model.
2011 Periodic Update	BB011a	06/2012	BY1-4.17E-05 BY2-4.03E-05 BW1-4.26E-05 BW2-4.26E-05	BY1-2.57E-06 BY2-3.21E-06 BW1-2.67E-06 BW2-3.28E-06	Periodic Update, including new data analysis, new HRA dependency analysis, and new pre-initiator HRA. Nearly 400 UREs addressed. Model also removes credit for operator action to crosstie AFW. Model naming scheme modified to match new Exelon guidance.
2012 MSPI Update	BB011b	11/2012	BY1-3.97E-05 BY2-3.82E-05 BW1-3.57E-05 BW2-3.51E-05	BY1-2.55E-06 BY2-3.19E-06 BW1-2.52E-06 BW2-3.08E-06	Emergent model update with improved modeling of CC and SX to support improved mitigating systems performance index (MSPI) calculations. Model includes credit for a new operator action to manipulate SX007 valves on loss of power and a new recovery action to use the 0CC pump to provide decay heat removal in key sequences.
2012 Level 2 Update	BB011b1	12/2012	BY1-3.97E-05 BY2-3.82E-05 BW1-3.57E-05 BW2-3.51E-05	BY1-1.07E-06 BY2-1.02E-06 BW1-1.05E-06 BW2-1.04E-06	This is an application specific model that was developed to support the SAMA analysis. The LERF model was replaced with a Level 2 Model based on the methodology in WCAP-16341-P.

Table F.2-2
Byron PRA Top Ranking Accident Sequences to CDF

Sequence ID	Accident Sequence Description	Contribution to CDF
SLOC-18	Small LOCA with failure of High Pressure Injection via Charging Pumps and Safety Injection Pumps; AF fails, but Steam Generators are fed from the Motor Driven or Startup Feedwater Pump. LOCAs for this sequence are due to Loss of SX or internal flood initiators. Key operator actions that contribute to this sequence are failures to isolate internal floods in time to prevent failure of the SX pumps and failure to recover RCP seal cooling.	25-26%
SLOC-06	Small LOCA with failure to establish ECCS recirculation cooling and successful cooldown and depressurization. Most of this sequence is due to RCP Seal LOCAs following a Loss of CCW. The dominant operator action which contributes to this sequence is failure to align the CV pump to a cool suction source.	20-21%
SLOC-09	Small LOCA with failure of High Pressure Injection via Charging Pumps and Safety Injection Pumps. This sequence is dominated by induced RCP Seal LOCAs, primarily from Loss of SX and internal flood initiators. Operator actions which contribute to this sequence are failure to open the SX crosstie valves, failure to align FP for CV pump cooling, and failure to isolate internal flood initiators. Dependent operator actions related to Loss of SX are key contributors.	20%
TRAN-04	Transient with failure of all feed to the Steam Generators and failure to establish ECCS high pressure recirculation cooling after successful high pressure injection via the charging pumps. The dominant initiating events associated with this sequence are Loss of SX and internal flooding scenarios. The key operator actions which contribute to this sequence are failure to restore feedwater from the main feedwater pumps and failure to establish the AFW cross-tie.	17-20%
SLOC-02	Small LOCA with failure to establish ECCS recirculation cooling and successful cooldown and depressurization. Essentially all of this sequence is due to random non-isolable small LOCAs. Induced RCP Seal LOCAs are negligible contributors. The dominant operator action which contributes to this sequence is failure to secure the RH pumps in the mini-flow mode (resulting in their failure).	4%
SGTR-04	Steam Generator Tube Rupture with short term failure to depressurize the primary and long term failure to do the same. Risk from this sequence is dominated by the dependent human actions to cooldown the RCS and terminate the break flow.	3%
TRAN-05	This is a transient with failure of Auxiliary Feedwater and failure of Motor Driven and Startup Feedwater Pumps. HPI is provided by the centrifugal charging pumps (CCPs), but feed and bleed fails due to failure of the PORVs to open due to operator failure.	2%

Table F.2-2
Byron PRA Top Ranking Accident Sequences to CDF

Sequence ID	Accident Sequence Description	Contribution to CDF
TRAN-09	This is a transient with failure of Auxiliary Feedwater, failure of Motor Driven and Startup Feedwater Pumps, and failure to establish Bleed and Feed using Charging Pumps and Safety Injection Pumps. The key initiating events associated with this sequence are Loss of SX and internal flooding. The SX pumps are the most risk significant components in this sequence. Operator actions which contribute to this sequence are failure to establish feedwater from the main feedwater system and failure to mitigate internal flooding events.	2%
SLOC-25	Small LOCA with failure of all feedwater and high pressure injection. Key initiating events include Loss of SX and internal flooding. Key operator actions include recovery from the Loss of SX and mitigation of the flooding events.	2%
LOOP-65	Station Blackout (SBO) with failure of all AFW. Offsite power is recovered prior to core damage and High Pressure Injection is established, but ECCS recirculation fails. The dominant initiating event is a Loss of SX followed by a consequential LOOP. Without SX cooling, there is no way to remove decay heat.	1%
	Total Contribution to CDF by Top 10 Sequences	>99%

Table F.2-3
Byron Important Operator Actions Based On CDF

Important Operator Actions	Important Sequences/Scenarios
Joint action to align cooling to the 0CC HX and provide cooling to the CV pumps for loss of CC (16% of CDF)	This is a joint event representing the failure of operators to first fail to align SX cooling water to the 0CC HX, followed by another dependent failure to align FP cooling and a cool suction source to the CV pumps in order to maintain RCP seal cooling.
Joint action to start a standby pump, establish an SX crosstie, and provide cooling to the CV pumps following loss of SX (14% of CDF)	This is a joint event representing the failure of operators to first fail to start a standby pump (typically SX), followed by failure to crosstie SX. Without SX, RCP seal cooling will be lost unless the CV pumps can be provided with cooling from the FP system and a cool suction source. The third failure in this combination fails that cooling to the CV pumps.
Recover SX crosstie between units (13% of CDF)	Upon Loss of SX, operators need to recover SX by establishing the SX crosstie to the opposite unit. If no RCP seal failure occurs, a later chance to recover the crosstie is credited, which is modeled by this action.
Recover FP cooling to CV pumps for FP internal flood (9% of CDF)	This action models the recovery of FP cooling to the CV pumps for the purposes of high pressure injection following an FP internal flood where seal injection was previously lost. It is not credited if the FP piping break occurred in a location which prevent recovery or if the RCP seals fail and lead to a large Seal LOCA.
Restore feedwater as a source of secondary side cooling (8% of CDF)	Upon failure of AFW to provide cooling water to the steam generators, operators have the opportunity to utilize the main feedwater or startup feedwater pumps to provide another source of feedwater. Failure results in a complete loss of feedwater to the steam generators. This is exacerbated by the current loss of credit for the AFW crosstie.
Mitigate FP Internal Flood Event (7% of CDF)	Following a Fire Protection System rupture in the Aux Building, operators need to terminate the flooding event (requires turning off the Diesel Driven FP Pump at the Circ Water Pump House) to prevent flood damage to the SX system or need to align alternate cooling to the CV pumps to maintain RCS inventory control. Failure leads to a Loss of all RCP Seal Cooling and a high probability of an RCP Seal LOCA which can't be mitigated due to the loss of the SX pumps and other essential equipment in the Aux Building.
Align CV pump suction to RWST upon loss of SX (5% of CDF)	Upon loss of SX, cooling to the CV pumps must be established by aligning FP and realigning the CV pump suction to use the RWST as a cool suction source. Failing to do so results in loss of seal injection to the RCP(s). Loss of SX also fails the CC system that fails RCP Thermal Barrier Cooling. This has a high probability of leading to an RCP Seal LOCA.

Table F.2-4
Mapping of Level 1 Sequences to PDS

CDF Seq. ID	PDS	CDF Seq. ID	PDS	CDF Seq. ID	PDS	CDF Seq. ID	PDS	CDF Seq. ID	PDS	CDF Seq. ID	PDS
ATWS-02	NHA	LODC-05	NHN	LOOP-36	NHN	LOOP-65	NHN	SGTR-25	B-N	SLOC-04	NHA
ATWS-04	NHA	LOOP-04	NHA	LOOP-37	NHN	LOOP-66	NHN	SGTR-27	B-N	SLOC-06	NHA
ATWS-06	NHA	LOOP-05	NHA	LOOP-39	NHA	LOOP-67	NHN	SGTR-28	B-N	SLOC-08	NHA
ATWS-07	NHN	LOOP-07	NHA	LOOP-40	NHA	LOOP-68	NHN	SGTR-29	B-N	SLOC-09	NHA
ATWS-08	NHA	LOOP-08	NHA	LOOP-42	NHN	LOOP-69	NHN	SGTR-30	BHA	SLOC-11	NHA
ATWS-10	NHA	LOOP-10	NHN	LOOP-43	NHN	MLOC-03	NLN	SLBI-03	NHN	SLOC-13	NHA
ATWS-11	NHA	LOOP-11	NHN	LOOP-44	NHN	MLOC-04	NLA	SLBI-04	NHN	SLOC-15	NHA
ATWS-13	NHA	LOOP-12	NHN	LOOP-46	NHN	SGTR-03	B-A	SLBI-05	NHN	SLOC-17	NHA
ATWS-14	NHA	LOOP-16	NHA	LOOP-47	NHN	SGTR-04	B-A	SLBI-07	NHN	SLOC-18	NHA
ATWS-15	NHN	LOOP-17	NHA	LOOP-48	NHN	SGTR-06	B-A	SLBI-08	NHN	SLOC-20	NHN
ATWS-16	NHA	LOOP-20	NHA	LOOP-50	NHN	SGTR-07	B-A	SLBI-10	NHN	SLOC-21	NHN
1ILOC-01	B--	LOOP-21	NHA	LOOP-51	NHN	SGTR-10	B-A	SLBI-11	NHN	SLOC-23	NHN
1ILOC-02	B--	LOOP-23	NHA	LOOP-52	NHN	SGTR-11	B-A	SLBI-12	NHN	SLOC-24	NHN
1ILOC-03	B--	LOOP-24	NHA	LOOP-54	NHA	SGTR-13	B-A	SLBI-13	NHN	SLOC-25	NHN
1ILOC-04	B--	LOOP-26	NHA	LOOP-55	NHA	SGTR-14	B-A	SLBO-03	NHN	SLOC-26	NHN
1ILOC-05	B--	LOOP-27	NHA	LOOP-56	NHA	SGTR-15	B-A	SLBO-04	NHN	TRAN-04	NHN
LLOC-02	NLA	LOOP-29	NHA	LOOP-58	NHA	SGTR-18	B-A	SLBO-05	NHN	TRAN-05	NHN
LLOC-03	NLA	LOOP-31	NHN	LOOP-59	NHA	SGTR-19	B-A	SLBO-07	NHN	TRAN-07	NHN
LLOC-04	NLA	LOOP-32	NHN	LOOP-60	NHA	SGTR-21	B-A	SLBO-08	NHN	TRAN-08	NHN

Table F.2-4
Mapping of Level 1 Sequences to PDS

CDF Seq. ID	PDS
LODC-03	NHN
LODC-04	NHN

CDF Seq. ID	PDS
LOOP-33	NHN
LOOP-35	NHN

CDF Seq. ID	PDS
LOOP-62	NHA
LOOP-63	NHA

CDF Seq. ID	PDS
SGTR-22	B-A
SGTR-24	B-N

CDF Seq. ID	PDS
SLBO-09	NHN
SLOC-02	NHA

CDF Seq. ID	PDS
TRAN-09	NHN
XLOC-00	NLA

Table F.2-5
Correlation of PDS to Sequences

L2 Sequence	NHA	NHN	NLA	NLN	B--	B-A	BHA	B-N
Intact01			X	X				
Intact02	X							
Intact03		X						
Intact04		X						
Intact05		X						
Late01			X	X				
Late02			X	X				
Late03			X	X				
Late04	X							
Late05	X							
Late06	X							
Late07		X						
Late06		X						
Late07		X						
Late08		X						
Late09		X						
Late10		X						
Late11		X						
Late12		X						
Late13		X						
Late14		X						
Late15		X						
Late16		X						
LERF01			X	X				
LERF02	X							
LERF03		X						
LERF04		X						
LERF05		X						
LERF06		X						

Table F.2-5
Correlation of PDS to Sequences

L2 Sequence	NHA	NHN	NLA	NLN	B--	B-A	BHA	B-N
LERF07		X						
LERF08		X						
LERF09	X	X	X	X				
LERF10						X	X	
LERF11					X			X
SERF01		X						
SERF02						X	X	

Table F.2-6
Representative Sequences

Release Category	Dominant L2 Sequences	Representative Sequence Discussion
LERF-ISLOCA	LERF11-ISLOCA: 100%	The Level 1 1ILOC-03 sequence is the dominant contributor and is used to characterize the release category. This sequence is a break in the RHR discharge line outside containment followed by successful injection, but core damage ensues as there is no water in the sump for recirculation mode. ILOC-04, the other top contributor, is similar, but the break is in the RHR suction line. ISLOCA in the RHR discharge line (800 gpm break), successful scram, successful injection, recirculation unavailable, core damage, containment bypass.
LERF-CI	LERF09: 100%	There are many different contributions to this release category due to its inclusive nature, but a vast majority includes failure of the recirculation mode after successful injection. Approximately 60% of the total contribution comes from small LOCA scenarios (both small LOCA initiators and RCP seal LOCAs that evolve from other initiating events). The remaining 40% is comprised mostly of loss of SX and Flooding events. Medium LOCAs are small contributors and are almost all recirculation failures. A truly representative sequence for this release category would be a small LOCA with recirculation failure, but to address the faster evolving contributors with injection failures, the seal LOCA with F&B failure is used. Loss of SX, successful scram, RCP seal LOCA, injection failure, core damage, containment isolation failure.
LERF-CFE	LERF02: 75% LERF03: 25%	The main difference between sequences LERF02 and LERF03 with respect to equipment availability is that AFW is available for LERF02 while it is not for LERF03. Both sequences include a mixture of injection and recirculation failures. Because LERF03 scenarios may evolve more quickly, they are used as the representative sequence as injection failure cases. Loss of SX, successful scram, no AFW, FW not restored, seal cooling successful, operator fail to initiate feed and bleed injection, core damage, successful operator action to depressurize the RCS prior to vessel failure or tube rupture, vessel melt, and containment failure due to hydrogen burn.

Table F.2-6
Representative Sequences

Release Category	Dominant L2 Sequences	Representative Sequence Discussion
LERF-SGTR-AFW	LERF10: 100%	Over 80% of the contributors are the result of operator failure to cool down the RCS in time to prevent passing water through the SG PORVs followed by operator failure to cool down the RCS to terminate SGTR break flow before RWST depletion. An additional 3% of the contribution is from failure to cool down the RCS in time to prevent passing water through the SG PORVs followed by operator failure to establish shutdown cooling. The consequences of these scenarios are similar and the larger contributor is chose as representative. SGTR, successful scram, SG isolation successful, failure to cool down RCS before passing water through the SG PORV, stuck open SG PORV, RCS injection successful, failure to cool down the RCS before RWST depletion, core damage, release through tubes.
LERF-SGTR-NOAFW	LERF11: 100%	The contributing scenarios are dominated by common cause failure of AFW followed by failure to restore main feedwater (MFW). SGTR, scram successful, AFW fails, FW not restored, injection successful, RWST depletes, core damage, release through tubes.
LERF-ISGTR	LERF08: ~99% LERF07: ~1%	Most of the induced tube rupture scenarios are pressure induced tube ruptures (LERF08), but thermally induced ruptures (LEFF07) are also represented in the cutsets. The TI-SGTR contribution to LERF is small relative to the PI-SGTR due to likelihood of hot leg failure near the time of TI-SGTR (eliminates release pathway). Both scenarios, however, are dominated by transient initiators with AFW unavailability, most of which lead to recirculation failures. Feed and Bleed failures are smaller contributors, but because of the potential impact on the source terms, the Feed and Bleed failure scenario is chosen as the representative case. Loss of SX, successful scram, AFW unavailable, operators fail to align alt FW and fail to align F&B, core damage, pressure induced tube rupture occurs.
LATE-BMT-AFW	LATE04: ~92% LATE01: ~1%	For both the LATE04 and LATE01 sequences, most of the contributors are LOCA events (including seal LOCAs) with recirculation failures. The availability of water on the containment floor impacts the probability of the basemat meltthrough, but has a negligible impact on the source term itself. For the basemat failure releases, the differences in LOCA size also have a minimal impact on the results. The largest frequency contributor is chosen as the representative sequence, which are the small LOCAs. Small LOCA, successful scram, AFW available, injection successful, recirculation mode failure, core damage, containment heat removal success (RCFCs), CS success, basemat melt through.

Table F.2-6
Representative Sequences

Release Category	Dominant L2 Sequences	Representative Sequence Discussion
LATE-BMT-NOAFW	LATE07: ~88% LATE08: ~12%	The difference in the two dominant Level 2 sequences is related to operation of Containment Spray, which determines if there is a water pool in the reactor cavity when the core relocates to the containment. The scenarios for both sequences are essentially the same, most being transients with AFW failure followed by a mixture of either injection or recirculation mode failures. For this case, the scenarios with the feed and bleed failures are chosen as representative to capture any potential timing issues for evacuation. General transient event, successful scram, AFW CCF to run, failure to restore FW, failure to initiate feed and bleed, core damage, no PI-SGTR, op depressurizes late, no early containment failure at vessel breach (VB), containment heat removal (CHR) successful, CS successful, basemat failure.
LATE-CHR-AFW	LATE06: >99.9%	Late06 accounts for almost all of the contributions to this release category frequency. Over 95% of the contribution to the release category is from LOSW events or events that lead to SX failure, followed by a seal LOCA. The other contributions are almost all scenarios that result in a seal LOCA in a different manner. Recirculation and injection failures are both represented, but most are injection failures. LOSW, successful scram, AFW failed, startup FW OK, failure to align alternate seal cooling, failure to align SX X-tie, seal LOCA, injection failure, core damage, no containment failure at VB, CHR fails with long term containment overpressurization (COP).
LATE-CHR-NOAFW	LATE09: >99%	Late09 accounts for almost all of the contributions to this release category frequency. Over 97% of the release category frequency is from LOSW events or events that lead to SX failure. These are generally followed by the unavailability of FW/Condensate and recirculation mode; injection failures contribute less than 10% of the frequency. LOSW (all SX pumps CCF), successful scram, AFW failure from lack of SX cooling, failure to restore FW, SX X-tie not available, CHR not available for recirc, core damage, operator depressurizes late, no containment failure at VB, CHR fails with long term COP.
SERF-SGTR -TISGTR-HLF	SERF01: 100%	The SERF01 sequence is comprised of mostly feed and bleed failures with some recirculation failures after failure of AFW. The more rapidly evolving feed and bleed failures are chosen as the representative sequences. Loss of 125 DC bus 111, successful scram, failure of AFW, failure of feed and bleed, core damage, late depressurization failure, TI-SGTR occurs, Hot leg fails at about the same time as TI-SGTR, no early containment failure, CHR success, CS success, no basemat failure.

Table F.2-6
Representative Sequences

Release Category	Dominant L2 Sequences	Representative Sequence Discussion
SERF-SGTR-AFW-SC	SERF02: 100%	The SERF02 sequence is mostly comprised (72% based on the Unit 2 results that correctly include 2RX-JHEP33-HOADA) of SGTR events with failure the operators to cool down the RCS before overfilling the SG (opens a steam generator PORV for a LOCA) and subsequent operator error to cool down the RCS to terminate the break flow before depleting the RWST. The cases including 2RX-JHEP33-HOADA (about 8%) are SGTR events with operator failures to shut down dead headed RHR pumps (fails RH) and failure to reduce ECCS injection (to prevent lifting the SG safety valves). SGTR, successful scram, operator fails to cool down the RCS, SG overfill causes stuck open PORV, operator fails to cool down the RCS to terminate break flow before the RWST is depleted, recirculation mode is unavailable, core damage, operators maintain SG level over the top of the SG tubes for release scrubbing.
INTACT	INTACT02: ~85% INTACT03: ~13% INTACT01: ~1%	Most of the intact contribution comes from small LOCA scenarios (including induced Small LOCAs) with recirculation failures. For intact containment scenarios, the path to core damage has a negligible impact on the source term. Small LOCA, successful scram, AFW available, injection successful, recirculation failure, core damage, containment intact.

Table F.2-7
Byron Source Term Summary

	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW(1)	LERF-SGTR-NOAFW	LERF-ISGTR	LATE-BMT-AFW(2)	LATE-BMT-NOAFW	LATE-CHR-AFW(3)	LATE-CHR-NOAFW(4)	SERF-SGTR-TISGTR-HLF	SERF-SGTR-AFW-SC(5)	INTACT
MAAP Case	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12b	13a
Run Duration	72 hr	72 hr	72 hr	200 hr	200 hr	800 hr	144 hr	144 hr	200 hrs	1600 hrs	72 hrs	200 hrs	72 hrs
Time after Scram when GE is declared	6.91	5.93	3.16	87.00	0.50	3.16	12.17	3.14	5.93	3.14	3.17	84.60	12.17
Fission Product Group:													
1) Noble													
Total Release Fraction	1.00E+00	9.80E-01	1.00E+00	8.10E-01	3.00E-01	1.00E+00	1.00E+00	1.00E+00	1.00E+00	1.00E+00	5.10E-01	7.90E-01	2.70E-03
Total Plume 1 Release Fraction	9.70E-1	4.30E-1	9.10E-1	4.40E-1	2.70E-1	5.00E-2	2.00E-4	4.00E-4	4.00E-3	7.00E-2	5.10E-1	4.20E-1	3.00E-4
Start of Plume 1 Release (hr)	7.00	6.00	5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40
End of Plume 1 Release (hr)	8.00	11.00	8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	3.00E-2	5.00E-1	9.00E-2	8.00E-2	0.00E+0	9.50E-1	4.50E-3	3.90E-3	9.96E-1	9.30E-1	0.00E+0	1.30E-1	4.00E-4
Start of Plume 2 Release (hr)	8.00	11.00	8.00	89.00	25.00	17.00	17.00	13.00	60.75	36.50	4.00	87.00	18.00
End of Plume 2 Release (hr)	12.00	21.00	13.00	93.00	35.00	27.00	27.00	23.00	70.75	46.50	14.00	93.00	28.00
Total Plume 3 Release Fraction	0.00E+0	5.00E-2	0.00E+0	2.90E-1	3.00E-2	0.00E+0	9.95E-1	9.96E-1	0.00E+0	0.00E+0	0.00E+0	2.40E-1	2.00E-3
Start of Plume 3 Release (hr)	12.00	30.00	19.00	93.00	35.00	90.00	90.00	90.00	90.00	90.00	14.00	93.00	28.00
End of Plume 3 Release (hr)	22.00	40.00	29.00	98.00	45.00	100.00	100.00	95.00	100.00	100.00	24.00	95.00	38.00
2) CsI													
Total Release Fraction	7.80E-01	1.40E-02	3.00E-01	9.70E-02	4.10E-02	1.90E-01	6.80E-05	7.40E-04	1.40E-02	2.40E-01	5.80E-02	1.80E-02	3.20E-05
Total Plume 1 Release Fraction	7.10E-1	9.00E-3	1.40E-1	5.30E-2	3.80E-2	1.00E-3	2.70E-5	2.00E-5	2.00E-5	2.00E-4	5.80E-2	9.00E-3	2.70E-5
Start of Plume 1 Release (hr)	7.00	6.00	5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40

Table F.2-7
Byron Source Term Summary

	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW(1)	LERF-SGTR-NOAFW	LERF-ISGTR	LATE-BMT-AFW(2)	LATE-BMT-NOAFW	LATE-CHR-AFW(3)	LATE-CHR-NOAFW(4)	SERF-SGTR-TISGTR-HLF	SERF-SGTR-AFW-SC(5)	INTACT
MAAP Case	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12b	13a
Run Duration	72 hr	72 hr	72 hr	200 hr	200 hr	800 hr	144 hr	144 hr	200 hrs	1600 hrs	72 hrs	200 hrs	72 hrs
Time after Scram when GE is declared	6.91	5.93	3.16	87.00	0.50	3.16	12.17	3.14	5.93	3.14	3.17	84.60	12.17
Fission Product Group:													
End of Plume 1 Release (hr)	8.00	11.00	8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	2.00E-2	3.00E-3	1.30E-1	3.00E-3	2.00E-3	1.10E-1	7.00E-6	5.00E-5	7.00E-3	1.30E-1	0.00E+0	0.00E+0	2.00E-6
Start of Plume 2 Release (hr)	8.00	11.00	8.00	89.00	25.00	17.00	17.00	13.00	60.75	36.50			18.00
End of Plume 2 Release (hr)	12.00	21.00	13.00	93.00	35.00	27.00	27.00	23.00	70.75	46.50			28.00
Total Plume 3 Release Fraction	5.00E-2	2.00E-3	3.00E-2	4.10E-2	1.00E-3	7.90E-2	3.40E-5	6.70E-4	7.00E-3	1.10E-1	0.00E+0	9.00E-3	3.00E-6
Start of Plume 3 Release (hr)	12.00	30.00	19.00	93.00	35.00	90.00	90.00	90.00	90.00	90.00		93.00	28.00
End of Plume 3 Release (hr)	22.00	40.00	29.00	98.00	45.00	100.00	100.00	95.00	100.00	100.00		95.00	38.00
3) TeO2													
Total Release Fraction	7.10E-01	1.90E-02	1.10E-01	6.30E-02	3.30E-02	2.00E-01	2.90E-05	1.10E-04	8.70E-05	1.10E-01	4.40E-02	9.50E-03	3.00E-05
Total Plume 1 Release Fraction	6.20E-1	1.60E-2	6.00E-2	3.80E-2	3.20E-2	1.00E-3	2.60E-5	2.00E-5	8.00E-6	1.00E-4	4.30E-2	5.40E-3	2.60E-5
Start of Plume 1 Release (hr)	7.00	6.00	5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40
End of Plume 1 Release (hr)	8.00	11.00	8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	5.00E-2	2.00E-3	3.00E-2	1.00E-3	0.00E+0	1.19E-1	1.00E-6	1.00E-5	3.30E-5	1.30E-3	1.00E-3	2.00E-4	3.00E-6
Start of Plume 2 Release (hr)	8.00	11.00	8.00	89.00		17.00	17.00	13.00	60.75	36.50	4.00	87.00	18.00
End of Plume 2 Release (hr)	12.00	21.00	13.00	93.00		27.00	27.00	23.00	70.75	46.50	14.00	93.00	28.00
Total Plume 3 Release Fraction	4.00E-2	1.00E-3	2.00E-2	2.40E-2	1.00E-3	8.00E-2	2.00E-6	8.00E-5	4.60E-5	1.09E-1	0.00E+0	3.90E-3	1.00E-6

Table F.2-7
Byron Source Term Summary

	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW(1)	LERF-SGTR-NOAFW	LERF-ISGTR	LATE-BMT-AFW(2)	LATE-BMT-NOAFW	LATE-CHR-AFW(3)	LATE-CHR-NOAFW(4)	SERF-SGTR-TISGTR-HLF	SERF-SGTR-AFW-SC(5)	INTACT
MAAP Case	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12b	13a
Run Duration	72 hr	72 hr	72 hr	200 hr	200 hr	800 hr	144 hr	144 hr	200 hrs	1600 hrs	72 hrs	200 hrs	72 hrs
Time after Scram when GE is declared	6.91	5.93	3.16	87.00	0.50	3.16	12.17	3.14	5.93	3.14	3.17	84.60	12.17
Fission Product Group:													
Start of Plume 3 Release (hr)	12.00	30.00	19.00	93.00	35.00	90.00	90.00	90.00	90.00	90.00		93.00	28.00
End of Plume 3 Release (hr)	22.00	40.00	29.00	98.00	45.00	100.00	100.00	95.00	100.00	100.00		95.00	38.00
4) SrO													
Total Release Fraction	1.10E-01	3.00E-04	3.00E-03	9.90E-03	1.60E-04	7.90E-04	3.20E-06	2.90E-06	3.00E-05	2.60E-04	8.50E-05	8.00E-04	3.20E-07
Total Plume 1 Release Fraction	9.60E-02	2.30E-4	2.60E-3	1.00E-3	7.00E-5	1.00E-5	1.60E-6	2.20E-6	2.00E-8	2.00E-6	8.40E-5	1.50E-4	2.80E-7
Start of Plume 1 Release (hr)	7.00	6.00	5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40
End of Plume 1 Release (hr)	8.00	11.00	8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	5.00E-03	3.00E-5	1.00E-4	2.10E-3	9.00E-5	7.80E-4	1.50E-6	1.00E-7	3.00E-8	5.00E-6	1.00E-6	1.70E-4	3.00E-8
Start of Plume 2 Release (hr)	8.00	11.00	8.00	89.00	25.00	17.00	17.00	13.00	60.75	36.50	4.00	87.00	18.00
End of Plume 2 Release (hr)	12.00	21.00	13.00	93.00	35.00	27.00	27.00	23.00	70.75	46.50	14.00	93.00	28.00
Total Plume 3 Release Fraction	0.00	4.00E-5	3.00E-4	6.80E-3	0.00E+0	0.00E+0	1.00E-7	6.00E-7	3.00E-5	2.53E-4	0.00E+0	4.80E-4	1.00E-8
Start of Plume 3 Release (hr)		30.00	19.00	93.00			90.00	90.00	90.00	90.00		93.00	28.00
End of Plume 3 Release (hr)		40.00	29.00	98.00			100.00	95.00	100.00	100.00		95.00	38.00
5) MoO2													
Total Release Fraction	1.50E-01	1.70E-03	3.40E-02	4.60E-02	2.80E-03	3.30E-04	4.80E-06	1.20E-05	2.10E-06	1.20E-04	7.20E-03	4.60E-03	2.40E-06
Total Plume 1 Release Fraction	1.10E-1	1.60E-3	3.30E-2	2.10E-2	2.50E-3	4.00E-5	4.70E-6	1.20E-5	1.30E-6	4.00E-5	7.10E-3	3.10E-3	2.10E-6

Table F.2-7
Byron Source Term Summary

	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW(1)	LERF-SGTR-NOAFW	LERF-ISGTR	LATE-BMT-AFW(2)	LATE-BMT-NOAFW	LATE-CHR-AFW(3)	LATE-CHR-NOAFW(4)	SERF-SGTR-TISGTR-HLF	SERF-SGTR-AFW-SC(5)	INTACT
MAAP Case	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12b	13a
Run Duration	72 hr	72 hr	72 hr	200 hr	200 hr	800 hr	144 hr	144 hr	200 hrs	1600 hrs	72 hrs	200 hrs	72 hrs
Time after Scram when GE is declared	6.91	5.93	3.16	87.00	0.50	3.16	12.17	3.14	5.93	3.14	3.17	84.60	12.17
Fission Product Group:													
Start of Plume 1 Release (hr)	7.00	6.00	5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40
End of Plume 1 Release (hr)	8.00	11.00	8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	4.00E-2	1.00E-4	1.00E-3	4.00E-3	3.00E-4	2.90E-4	1.00E-7	0.00E+0	8.00E-7	8.00E-5	1.00E-4	3.00E-4	2.00E-7
Start of Plume 2 Release (hr)	8.00	11.00	8.00	89.00	25.00	17.00	17.00		60.75	36.50	4.00	87.00	18.00
End of Plume 2 Release (hr)	12.00	21.00	13.00	93.00	35.00	27.00	27.00		70.75	46.50	14.00	93.00	28.00
Total Plume 3 Release Fraction	0.00E+0	0.00E+0	0.00E+0	2.10E-2	0.00E+0	0.00E+0	0.00E+0	0.00E+0	0.00E+0	0.00E+0	0.00E+0	1.20E-3	1.00E-7
Start of Plume 3 Release (hr)				93.00								93.00	28.00
End of Plume 3 Release (hr)				98.00								95.00	38.00
6) CsOH													
Total Release Fraction	7.70E-01	1.10E-02	6.10E-02	8.70E-02	2.70E-02	2.90E-01	5.00E-05	3.50E-04	4.50E-03	1.70E-01	3.10E-02	1.70E-02	2.90E-05
Total Plume 1 Release Fraction	7.00E-1	8.00E-3	3.40E-2	4.90E-2	2.60E-2	5.00E-4	2.60E-5	1.00E-5	7.00E-6	7.00E-5	3.10E-2	8.00E-3	2.60E-5
Start of Plume 1 Release (hr)	7.00	6.00	5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40
End of Plume 1 Release (hr)	8.00	11.00	8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	2.00E-2	1.00E-4	1.20E-2	3.00E-3	1.00E-3	7.00E-2	2.00E-6	2.00E-5	2.20E-3	2.20E-2	0.00E+0	0.00E+0	2.00E-6
Start of Plume 2 Release (hr)	8.00	11.00	8.00	89.00	25.00	17.00	17.00	13.00	60.75	36.50			18.00
End of Plume 2 Release (hr)	12.00	21.00	13.00	93.00	35.00	27.00	27.00	23.00	70.75	46.50			28.00

Table F.2-7
Byron Source Term Summary

	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW(1)	LERF-SGTR-NOAFW	LERF-ISGTR	LATE-BMT-AFW(2)	LATE-BMT-NOAFW	LATE-CHR-AFW(3)	LATE-CHR-NOAFW(4)	SERF-SGTR-TISGTR-HLF	SERF-SGTR-AFW-SC(5)	INTACT
MAAP Case	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12b	13a
Run Duration	72 hr	72 hr	72 hr	200 hr	200 hr	800 hr	144 hr	144 hr	200 hrs	1600 hrs	72 hrs	200 hrs	72 hrs
Time after Scram when GE is declared	6.91	5.93	3.16	87.00	0.50	3.16	12.17	3.14	5.93	3.14	3.17	84.60	12.17
Fission Product Group:													
Total Plume 3 Release Fraction	5.00E-2	2.90E-3	1.50E-2	3.50E-2	0.00E+0	2.20E-1	2.20E-5	3.20E-4	2.30E-3	1.48E-1	0.00E+0	9.00E-3	1.00E-6
Start of Plume 3 Release (hr)	12.00	30.00	19.00	93.00		90.00	90.00	90.00	90.00	90.00		93.00	28.00
End of Plume 3 Release (hr)	22.00	40.00	29.00	98.00		100.00	100.00	95.00	100.00	100.00		95.00	38.00
7) BaO													
Total Release Fraction	1.20E-01	5.50E-04	1.10E-02	3.70E-02	2.30E-03	5.70E-04	3.00E-06	4.30E-06	1.40E-05	1.40E-04	3.10E-03	2.80E-03	1.50E-06
Total Plume 1 Release Fraction	1.20E-1	4.70E-4	1.10E-2	7.00E-3	2.00E-3	6.00E-5	2.10E-6	3.80E-6	9.00E-8	1.00E-5	3.10E-3	1.10E-3	1.40E-6
Start of Plume 1 Release (hr)	7.00	6.00	5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40
End of Plume 1 Release (hr)	8.00	11.00	8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	0.00E+0	6.00E-5	0.00E+0	6.00E-3	3.00E-4	5.00E-4	7.00E-7	0.00E+0	1.00E-7	2.00E-5	0.00E+0	5.00E-4	1.00E-7
Start of Plume 2 Release (hr)		11.00		89.00	25.00	17.00	17.00		60.75	36.50		87.00	18.00
End of Plume 2 Release (hr)		21.00		93.00	35.00	27.00	27.00		70.75	46.50		93.00	28.00
Total Plume 3 Release Fraction	0.00E+0	2.00E-5	0.00E+0	2.40E-2	0.00E+0	1.00E-5	2.00E-7	5.00E-7	1.40E-5	1.10E-4	0.00E+0	1.20E-3	0.00E+0
Start of Plume 3 Release (hr)		30.00		93.00		90.00	90.00	90.00	90.00	90.00		93.00	
End of Plume 3 Release (hr)		40.00		98.00		100.00	100.00	95.00	100.00	100.00		95.00	
8) La2O3													
Total Release Fraction	3.60E-03	1.90E-04	4.20E-04	4.50E-04	1.10E-05	8.00E-05	4.90E-07	4.00E-07	1.30E-06	7.30E-06	7.40E-06	4.10E-05	2.00E-08

Table F.2-7
Byron Source Term Summary

	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW(1)	LERF-SGTR-NOAFW	LERF-ISGTR	LATE-BMT-AFW(2)	LATE-BMT-NOAFW	LATE-CHR-AFW(3)	LATE-CHR-NOAFW(4)	SERF-SGTR-TISGTR-HLF	SERF-SGTR-AFW-SC(5)	INTACT
MAAP Case	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12b	13a
Run Duration	72 hr	72 hr	72 hr	200 hr	200 hr	800 hr	144 hr	144 hr	200 hrs	1600 hrs	72 hrs	200 hrs	72 hrs
Time after Scram when GE is declared	6.91	5.93	3.16	87.00	0.50	3.16	12.17	3.14	5.93	3.14	3.17	84.60	12.17
Fission Product Group:													
Total Plume 1 Release Fraction	1.60E-3	1.60E-4	3.70E-4	2.00E-5	7.00E-6	3.00E-7	1.40E-7	2.50E-7	1.00E-9	1.00E-7	7.30E-6	3.00E-6	1.80E-8
Start of Plume 1 Release (hr)	7.00	6.00	5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40
End of Plume 1 Release (hr)	8.00	11.00	8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	1.90E-3	3.00E-5	1.00E-5	1.00E-5	4.00E-6	8.00E-5	3.40E-7	2.00E-8	1.00E-9	1.00E-7	1.00E-7	4.00E-6	2.00E-9
Start of Plume 2 Release (hr)	8.00	11.00	8.00	89.00	25.00	17.00	17.00	13.00	60.75	36.50	4.00	87.00	18.00
End of Plume 2 Release (hr)	12.00	21.00	13.00	93.00	35.00	27.00	27.00	23.00	70.75	46.50	14.00	93.00	28.00
Total Plume 3 Release Fraction	1.00E-4	0.00E+0	4.00E-5	4.20E-4	0.00E+0	0.00E+0	1.00E-8	1.30E-7	1.30E-6	7.10E-6	0.00E+0	3.40E-5	0.00E+0
Start of Plume 3 Release (hr)	12.00		19.00	93.00			90.00	90.00	90.00	90.00		93.00	
End of Plume 3 Release (hr)	22.00		29.00	98.00			100.00	95.00	100.00	100.00		95.00	
9) CeO2													
Total Release Fraction	4.20E-02	3.30E-04	2.10E-03	3.10E-03	2.10E-05	1.80E-03	8.00E-06	7.40E-06	6.00E-05	3.20E-04	1.10E-05	2.50E-04	1.80E-07
Total Plume 1 Release Fraction	1.30E-2	1.80E-4	1.10E-3	2.00E-4	1.40E-5	1.00E-6	2.10E-6	4.60E-6	4.00E-9	1.00E-7	1.10E-5	2.00E-5	1.60E-7
Start of Plume 1 Release (hr)	7.00	6.00	5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40
End of Plume 1 Release (hr)	8.00	11.00	8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	2.90E-2	4.00E-5	0.00E+0	1.00E-4	7.00E-6	1.80E-3	5.70E-6	5.00E-7	2.00E-9	2.00E-7	0.00E+0	2.00E-5	2.00E-8
Start of Plume 2 Release (hr)	8.00	11.00		89.00	25.00	17.00	17.00	13.00	60.75	36.50		87.00	18.00

Table F.2-7
Byron Source Term Summary

	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW(1)	LERF-SGTR-NOAFW	LERF-ISGTR	LATE-BMT-AFW(2)	LATE-BMT-NOAFW	LATE-CHR-AFW(3)	LATE-CHR-NOAFW(4)	SERF-SGTR-TISGTR-HLF	SERF-SGTR-AFW-SC(5)	INTACT
MAAP Case	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12b	13a
Run Duration	72 hr	72 hr	72 hr	200 hr	200 hr	800 hr	144 hr	144 hr	200 hrs	1600 hrs	72 hrs	200 hrs	72 hrs
Time after Scram when GE is declared	6.91	5.93	3.16	87.00	0.50	3.16	12.17	3.14	5.93	3.14	3.17	84.60	12.17
Fission Product Group:													
End of Plume 2 Release (hr)	12.00	21.00		93.00	35.00	27.00	27.00	23.00	70.75	46.50		93.00	28.00
Total Plume 3 Release Fraction	0.00E+0	1.10E-4	1.00E-3	2.80E-3	0.00E+0	0.00E+0	2.00E-7	2.30E-6	6.00E-5	3.20E-4	0.00E+0	2.10E-4	0.00E+0
Start of Plume 3 Release (hr)		30.00	19.00	93.00			90.00	90.00	90.00	90.00		93.00	
End of Plume 3 Release (hr)		40.00	29.00	98.00			100.00	95.00	100.00	100.00		95.00	
10) Sb (Grouped with TeO2)													
Total Release Fraction	5.70E-01	3.10E-02	2.90E-01	6.10E-02	2.40E-02	2.50E-01	3.20E-03	2.10E-04	1.90E-02	2.00E-01	1.50E-02	8.00E-03	2.00E-05
Total Plume 1 Release Fraction	4.60E-01	4.00E-03	1.80E-01	3.10E-02	1.70E-02	2.00E-04	2.00E-05	4.00E-05	8.00E-06	1.00E-04	1.50E-02	4.40E-03	1.40E-05
Start of Plume 1 Release (hr)	7.00	6.00	5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40
End of Plume 1 Release (hr)	8.00	11.00	8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	4.00E-02	0.00E+00	2.00E-02	5.00E-03	5.00E-03	5.00E-02	1.00E-05	1.00E-05	6.00E-03	3.00E-02	0.00E+00	4.00E-04	3.00E-06
Start of Plume 2 Release (hr)	8.00		8.00	89.00	25.00	17.00	17.00	13.00	60.75	36.50		87.00	18.00
End of Plume 2 Release (hr)	12.00		13.00	93.00	35.00	27.00	27.00	23.00	70.75	46.50		93.00	28.00
Total Plume 3 Release Fraction	7.00E-02	2.70E-02	9.00E-02	2.50E-02	2.00E-03	2.00E-01	3.17E-03	1.60E-04	1.30E-02	1.70E-01	0.00E+00	3.20E-03	3.00E-06
Start of Plume 3 Release (hr)	12.00	30.00	19.00	93.00	35.00	90.00	90.00	90.00	90.00	90.00		93.00	28.00
End of Plume 3 Release (hr)	22.00	40.00	29.00	98.00	45.00	100.00	100.00	95.00	100.00	100.00		95.00	38.00
11) Te2 (Grouped with TeO2)													

Table F.2-7
Byron Source Term Summary

	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW(1)	LERF-SGTR-NOAFW	LERF-ISGTR	LATE-BMT-AFW(2)	LATE-BMT-NOAFW	LATE-CHR-AFW(3)	LATE-CHR-NOAFW(4)	SERF-SGTR-TISGTR-HLF	SERF-SGTR-AFW-SC(5)	INTACT
MAAP Case	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12b	13a
Run Duration	72 hr	72 hr	72 hr	200 hr	200 hr	800 hr	144 hr	144 hr	200 hrs	1600 hrs	72 hrs	200 hrs	72 hrs
Time after Scram when GE is declared	6.91	5.93	3.16	87.00	0.50	3.16	12.17	3.14	5.93	3.14	3.17	84.60	12.17
Fission Product Group:													
Total Release Fraction	2.00E-04	2.00E-06	8.00E-05	0.00E+00	1.40E-11	0.00E+00	8.80E-07	9.50E-09	2.50E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total Plume 1 Release Fraction	0.00E+00	9.00E-07	1.00E-06	0.00E+00	0.00E+00	0.00E+00	3.00E-08	2.00E-11	2.00E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Plume 1 Release (hr)	7.00	6.00	5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40
End of Plume 1 Release (hr)	8.00	11.00	8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	1.90E-04	8.00E-07	7.00E-06	0.00E+00	5.00E-12	0.00E+00	1.00E-08	1.00E-11	7.00E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Plume 2 Release (hr)	8.00	11.00	8.00		25.00		17.00	13.00	60.75				
End of Plume 2 Release (hr)	12.00	21.00	13.00		35.00		27.00	23.00	70.75				
Total Plume 3 Release Fraction	1.00E-05	3.00E-07	7.20E-05	0.00E+00	9.00E-12	0.00E+00	8.40E-07	9.47E-09	1.80E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)	12.00	30.00	19.00		35.00		90.00	90.00	90.00				
End of Plume 3 Release (hr)	22.00	40.00	29.00		45.00		100.00	95.00	100.00				
12) UO2 (Grouped with CeO2)													
Total Release Fraction	2.40E-04	8.70E-07	2.20E-05	0.00E+00	2.20E-14	2.50E-05	7.30E-08	1.50E-07	2.20E-07	4.10E-06	0.00E+00	0.00E+00	0.00E+00
Total Plume 1 Release Fraction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	9.00E-09	4.00E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Plume 1 Release (hr)			5.00	87.00	24.00	3.50	12.50	3.40	6.00	3.50	3.50	85.00	12.40
End of Plume 1 Release (hr)			8.00	89.00	25.00	4.50	17.00	13.00	9.00	13.50	4.00	87.00	18.00
Total Plume 2 Release Fraction	1.70E-04	3.00E-11	1.00E-07	0.00E+00	1.70E-14	2.50E-05	4.60E-08	1.00E-08	0.00E+00	1.00E-11	0.00E+00	0.00E+00	0.00E+00

Table F.2-7
Byron Source Term Summary

	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW(1)	LERF-SGTR-NOAFW	LERF-ISGTR	LATE-BMT-AFW(2)	LATE-BMT-NOAFW	LATE-CHR-AFW(3)	LATE-CHR-NOAFW(4)	SERF-SGTR-TISGTR-HLF	SERF-SGTR-AFW-SC(5)	INTACT
MAAP Case	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12b	13a
Run Duration	72 hr	72 hr	72 hr	200 hr	200 hr	800 hr	144 hr	144 hr	200 hrs	1600 hrs	72 hrs	200 hrs	72 hrs
Time after Scram when GE is declared	6.91	5.93	3.16	87.00	0.50	3.16	12.17	3.14	5.93	3.14	3.17	84.60	12.17
Fission Product Group:													
Start of Plume 2 Release (hr)	8.00	11.00	8.00		25.00	17.00	17.00	13.00		36.50			
End of Plume 2 Release (hr)	12.00	21.00	13.00		35.00	27.00	27.00	23.00		46.50			
Total Plume 3 Release Fraction	7.00E-05	8.70E-07	2.19E-05	0.00E+00	5.00E-15	0.00E+00	1.80E-08	1.00E-07	2.20E-07	4.10E-06	0.00E+00	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)	12.00	30.00	19.00		35.00		90.00	90.00	90.00	90.00			
End of Plume 3 Release (hr)	22.00	40.00	29.00		45.00		100.00	95.00	100.00	100.00			

(1) LERF-SGTR-AFW: All three plume start times and GE time were reduced by 50 hours to conform to MACCS2 input limits.
(2) LATE-BMT-AFW: Plume 3 start time reduced from 107 hours to 90 hours to conform to MACCS2 input limits.
(3) LATE-CHR-AFW: Plume 3 start time reduced from 120 hours to 90 hours to conform to MACCS2 input limits.
(4) LATE-CHR-NOAFW: Plume 3 start time reduced from 126 hours to 90 hours to conform to MACCS2 input limits.

(5) SERF-SGTR-AFW-SC: All three plume start times and GE time were reduced by 40 hours to conform to MACCS2 input limits.

Table F.2-8
Detailed Release Category Results

Endstate	BY Unit 1		BY Unit 2	
	Freq (/yr)	Percent	Freq (/yr)	Percent
INTACT	1.16E-05	27.6%	1.17E-05	29.1%
SERF-TISGTR-HLF	6.49E-09	0.0%	6.50E-09	0.0%
SERF-SGTR-AFW-SC	1.38E-06	3.3%	1.55E-06	3.8%
LATE-BMMT-AFW	5.30E-07	1.3%	5.14E-07	1.3%
LATE-BMMT-NOAFW	7.95E-08	0.2%	8.63E-08	0.2%
LATE-CHR-AFW	1.89E-05	45.1%	1.85E-05	45.8%
LATE-CHR-NOAFW	8.35E-06	19.9%	6.94E-06	17.2%
LERF-ISLOCA	3.40E-07	0.8%	3.40E-07	0.8%
LERF-CI	3.67E-07	0.9%	3.52E-07	0.9%
LERF-CFE	3.55E-08	0.1%	3.41E-08	0.1%
LERF-SGTR-AFW	5.49E-08	0.1%	6.18E-08	0.2%
LERF-SGTR-NOAFW	8.57E-10	0.0%	8.57E-10	0.0%
LERF-ISGTR	2.69E-07	0.6%	2.31E-07	0.6%
Total	4.19E-05	100.0%	4.03E-05	100.0%

Table F.3-1
County Growth Rates 2000 – 2030

County	Growth Rate 2000 - 2030 Percentage
Illinois	
Boone	24.6%
Bureau	14.8%
Carroll	6.1%
DeKalb	39.4%
Henry	6.3%
Jo Daviess	32.5%
Kane	67.8%
Kendall	55.7%
La Salle	26.8%
Lee	7.8%
McHenry	70.2%
Ogle	24.7%
Stephenson	5.5%
Whiteside	12.1%
Winnebago	29.0%
Iowa	
Clinton	0.0%(1)
Jackson	0.0%(2)
Wisconsin	
Green	33.4%
Lafayette	3.8%
Rock	18.4%
Walworth	39.8%

(1) Calculated Clinton County growth rate was -3.4%. Zero growth is assumed.

(2) Calculated Jackson County growth rate was -2.0%. Zero growth is assumed.

Table F.3-2
Estimated Population Distribution within
a 10-Mile Radius of Byron, Year 2046

Sector	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles	10-mile Total(1)
N	0	2648	737	1010	1550	1231	5946
NNE	2	58	27	5533	3669	2323	9291
NE	0	8	36	1088	238	2043	1373
ENE	11	63	381	64	155	4270	678
E	0	0	0	97	53	1068	155
ESE	0	14	6	0	34	1140	60
SE	25	0	12	36	27	411	107
SSE	0	24	18	21	141	954	212
S	0	72	11	16	200	344	308
SSW	16	7	58	85	1362	4709	1538
SW	0	44	84	900	2076	7428	3115
WSW	0	8	532	1197	86	9791	1835
W	0	7	33	68	308	605	429
WNW	0	407	12	7	0	1362	440
NW	0	0	240	36	62	552	353
NNW	0	0	119	310	27	528	472
Total(1)	54	3360	2306	10468	9988	38759	26312

(1) Population projections developed in electronic spreadsheet calculation and totals may differ slightly due to rounding of individual values.

Table F.3-3
Estimated Population Distribution within a 50-Mile Radius of Byron, Year 2046

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile Total(1)
N	5946	6308	5696	12283	16600	48063
NNE	9291	64680	57178	80691	89403	303564
-NE	1373	176552	90883	9505	45774	326127
ENE	678	8637	36188	26709	113802	190280
E	155	3768	10526	34756	234146	284414
ESE	60	1925	72838	28637	66464	171058
SE	107	17986	3397	4753	45592	72239
SSE	212	2094	1641	16079	5067	26039
S	308	2384	5172	2750	11763	22712
SSW	1538	11387	1635	3599	7251	30109
SW	3115	13937	35349	11918	6658	78394
WSW	1835	4647	3388	6658	26660	52967
W	429	1125	3042	4530	8257	17975
WNW	440	3603	3573	3645	6030	18639
NW	353	1583	34296	7950	6218	50937
NNW	472	4644	6399	8011	21210	41248
Total(1)	26312	325260	371201	262474	710895	1734765

(1) Population projections developed in electronic spreadsheet calculation and totals may differ slightly due to rounding of individual values.

Table F.3-4
County Specific Land Use And Economic Parameters Inputs

County	Fraction Farm	Fraction Dairy	Farm Sales ($/hectare)	Farm Property Value ($/hectare)	Non-Farm Property Value ($/person)
Illinois					
Boone	0.76	0.074	1,466	13,492	211,408
Bureau	0.86	0.002	1,566	11,058	225,984
Carroll	0.93	0.062	1,929	10,042	213,874
DeKalb	0.92	0.013	2,013	12,637	203,355
Henry	0.93	0.002	1,497	10,768	219,909
Jo Daviess	0.73	0.174	1,199	10,927	253,565
Kane	0.58	0.018	2,544	13,291	246,480
Kendall	0.81	0.008	1,532	11,800	223,356
LaSalle	0.89	0.001	1,263	11,455	219,164
Lee	0.85	0.002	1,338	11,761	206,626
McHenry	0.56	0.067	1,793	13,774	268,236
Ogle	0.76	0.015	1,744	12,365	219,394
Stephenson	0.94	0.172	1,804	10,552	227,190
Whiteside	0.93	0.024	1,711	10,430	217,680
Winnebago	0.56	0.051	1,209	12,013	221,467
Iowa					
Clinton	0.89	0.046	1,434	9,300	220,742
Jackson	0.73	0.094	1,218	7,756	202,765
Wisconsin					
Green	0.82	0.557	1,514	9,749	235,318
Lafayette	0.85	0.459	1,581	9,619	198,295
Rock	0.75	0.223	1,403	11,010	213,731
Walworth	0.82	0.557	1,514	11,806	223,153

Table F.3-5
Byron MACCS2 Generic Economic Parameters

Variable	Description	Value
DPRATE(1)	Property depreciation rate (per yr)	0.20
DSRATE(2)	Investment rate of return (per yr)	0.07
EVACST(3)	Daily cost for a person who has been evacuated ($/person-day)	56.43
RELCST(3)	Daily cost for a person who is relocated ($/person-day)	56.43
POPCST(3)	Population relocation cost ($/person)	10,450
CDFRM0(3)	Cost of farm decontamination for two levels of decontamination ($/hectare) (5)	1,176 2,613
CDNFRM(3)	Cost of non-farm decontamination per resident person for various levels of decontamination ($/person) (5)	6,270 16,720
TIMDEC(1)	Decontamination time for each level(5)	2 & 4 months
DLBCST(3)	Average cost of decontamination labor ($/man-year)	73,150
TFWKF(1)	Time decontamination workers spend in farm land contaminated areas(5)	1/10 1/3
TWWNF(1)	Time decontamination workers spend in non-farm land contaminated areas(5)	1/3 1/3
VALWF0(4)	Value of farm wealth ($/hectare)	11,444
VALWNF(4)	Value of non-farm wealth ($/person)	231,318

(1) DPRATE uses NUREG/CR-4551 value (NRC 1990b).

(2) DSRATE based on NUREG/BR-0058 (NRC 2004a).

(3) These parameters use the NUREG/CR-4551 values (NRC 1990b), updated to July 2012 using the consumer price index.

(4) VALWF0 and VALWNF are based on 2007 National Agriculture Census (USDA 2009) and Bureau of Economic Analysis 2007 data (BEA 2012), updated to the July 2012 using the consumer price index.

(5) Two decontamination levels are modeled, consistent with NUREG/CR-4551 (NRC 1990b). The first value is associated with a dose reduction factor of 3. The second value is associated with a dose reduction factor of 15.

Table F.3-6
Byron MACCS2 End of Cycle Core Inventory

Entry	Nuclide	Activity (Bq)	Entry	Nuclide	Activity (Bq)
1	Co-58	3.39E+16	31	Te-131m	5.09E+17
2	Co-60	2.59E+16	32	Te-132	5.05E+18
3	Kr-85	3.79E+16	33	I-131	3.55E+18
4	Kr-85m	1.14E+18	34	I-132	5.13E+18
5	Kr-87	2.25E+18	35	I-133	7.34E+18
6	Kr-88	3.18E+18	36	I-134	8.15E+18
7	Rb-86	8.60E+15	37	I-135	6.85E+18
8	Sr-89	3.86E+18	38	Xe-133	7.16E+18
9	Sr-90	2.98E+17	39	Xe-135	2.03E+18
10	Sr-91	5.22E+18	40	Cs-134	7.04E+17
11	Sr-92	5.49E+18	41	Cs-136	2.00E+17
12	Y-90	3.12E+17	42	Cs-137	4.08E+17
13	Y-91	4.72E+18	43	Ba-139	6.76E+18
14	Y-92	5.51E+18	44	Ba-140	6.53E+18
15	Y-93	6.14E+18	45	La-140	6.69E+18
16	Zr-95	6.05E+18	46	La-141	6.17E+18
17	Zr-97	6.19E+18	47	La-142	6.05E+18
18	Nb-95	6.10E+18	48	Ce-141	5.97E+18
19	Mo-99	6.72E+18	49	Ce-143	5.93E+18
20	Tc-99m	5.88E+18	50	Ce-144	4.53E+18
21	Ru-103	5.44E+18	51	Pr-143	5.78E+18
22	Ru-105	3.71E+18	52	Nd-147	2.44E+18
23	Ru-106	1.84E+18	53	Np-239	6.87E+19
24	Rh-105	3.39E+18	54	Pu-238	1.36E+16
25	Sb-127	3.78E+17	55	Pu-239	1.02E+15
26	Sb-129	1.13E+18	56	Pu-240	1.19E+15
27	Te-127	3.73E+17	57	Pu-241	4.71E+17
28	Te-127m	4.87E+16	58	Am-241	5.21E+14
29	Te-129	1.11E+18	59	Cm-242	1.47E+17
30	Te-129m	1.66E+17	60	Cm-244	1.61E+16

Table F.3-7
MACCS2 Release Groups vs. Byron MAAP Release Groups

MACCS2 Release Groups	Byron MAAP Release Groups
Xe/Kr	1 – noble gases
I	2 – CsI
Cs	6 & 2 – CsOH and CsI(3)
Te	3, 10 & 11- TeO_2, Sb(2) & Te_2 (1)
Sr	4 – SrO
Ru	5 – MoO_2 (Mo is in Ru MACCS category)
La	8 – La_2O_3
Ce	9 & 12 – CeO_2 & UO_2 (1)
Ba	7 – BaO

(1) These release fractions are typically negligible compared to others in the group.

(2) The mass of Sb in the core is typically much less than the mass of Te.

(3) The mass of Cs contained in CsI is typically much less than the mass of Cs contained in CsOH, and is assumed to be negligible for this group.

Table F.3-8
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Source Term	Release Category	MAAP Case	MAAP Case Justification and Description	CsI RF[(1)]	Tcd [(2)] (Hrs)	Tvf [(3)] (Hrs)	Tcf [(4)] (Hrs)	Tend [(5)] (Hrs)
ST1	LERF-ISLOCA	1a	Sequence Contributors: LERF11-ISLOCA (100%). The Level 1 1ILOC-03 sequence is the dominant contributor and is used to characterize the release category. This sequence is a break in the RHR discharge line outside containment followed by successful injection, but core damage ensues as there is no water in the sump for recirculation mode ILOC-04, the other top contributor, is similar, but the break is in the RHR suction line.. MAAP Case: ISLOCA in the RHR discharge line (800 gpm break), successful scram, successful injection, recirculation unavailable, core damage, containment bypass..	0.78	6.91	9.65	Bypass	72

Table F.3-8
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Source Term	Release Category	MAAP Case	MAAP Case Justification and Description	CsI RF[1]	Tcd [2] (Hrs)	Tvf [3] (Hrs)	Tcf [4] (Hrs)	Tend [5] (Hrs)
ST2	LERF-CI	2a	Sequence Contributors: LERF09 (100%). There are many different contributions to this release category due to its inclusive nature, but a vast majority include failure of the recirculation mode after successful injection. Approximately 60% of the total contribution comes from small LOCA scenarios (both small LOCA initiators and RCP seal LOCAs that evolve from other initiating events). The remaining 40% is comprised mostly of loss of SX and Flooding events. Medium LOCAs are small contributors and are almost all recirculation failures. A truly representative sequence for this release category would be a small LOCA with recirculation failure, but to address the faster evolving contributors with injection failures, the seal LOCA with F&B failure is used. MAAP Case: Loss of SX, successful scram, RCP seal LOCA, injection failure, core damage, containment isolation failure.	1.4E-2	5.93	8.67	ISLOCA	72

Table F.3-8
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Source Term	Release Category	MAAP Case	MAAP Case Justification and Description	CsI RF(1)	Tcd (2) (Hrs)	Tvf (3) (Hrs)	Tcf (4) (Hrs)	Tend (5) (Hrs)
ST3	LERF-CFE	3a	Sequence Contributors: LERF02 (75%), LERF03 (25%). The main difference between sequences LERF02 and LERF03 with respect to equipment availability is that AFW is available for LERF02 while it is not for LERF03. Both sequences include a mixture of injection and recirculation failures. Because LERF03 scenarios may evolve more quickly, they are used as the representative sequence as injection failure cases. MAAP Case: Loss of SX, successful scram, no AFW, FW not restored, seal cooling successful, operator fail to initiate feed and bleed injection, core damage, successful operator action to depressurize the RCS prior to vessel failure or tube rupture, vessel melt, and containment failure due to hydrogen burn.	0.30	3.16	5.11	5.11	72

Table F.3-8
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Source Term	Release Category	MAAP Case	MAAP Case Justification and Description	CsI RF[(1)]	Tcd [(2)] (Hrs)	Tvf [(3)] (Hrs)	Tcf [(4)] (Hrs)	Tend [(5)] (Hrs)
ST4	LERF-SGTR-AFW	4a	Sequence Contributors: LERF10 (100%). Over 80% of the contributors are the result of operator failure to cool down the RCS in time to prevent passing water through the SG PORVs followed by operator failure to cool down the RCS to terminate SGTR break flow before RWST depletion. An additional 3% of the contribution is from failure to cool down the RCS in time to prevent passing water through the SG PORVs followed by operator failure to establish shutdown cooling. The consequences of these scenarios are similar and the larger contributor is chose as representative.. MAAP Case: SGTR, successful scram, SG isolation successful, failure to cool down RCS before passing water through the SG PORV, stuck open SG PORV, RCS injection successful, failure to cool down the RCS before RWST depletion, core damage, release through tubes.	9.7E-2	137.0	155.19	NA	200
ST5	LERF-SGTR-NOAFW	5a	Sequence Contributors: LERF11(100%). The contributing scenarios are dominated by common cause failure of AFW followed by failure to restore MFW. MAAP Case: SGTR, scram successful, AFW fails, FW not restored, injection successful, RWST depletes, core damage, release through tubes.	4.1E-2	23.82	31.13	NA	200

Table F.3-8
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Source Term	Release Category	MAAP Case	MAAP Case Justification and Description	CsI RF(1)	Tcd (2) (Hrs)	Tvf (3) (Hrs)	Tcf (4) (Hrs)	Tend (5) (Hrs)
ST6	LERF-ISGTR	6a	Sequence Contributors: LERF08 (99%), LERF07 (1%). Most of the induced tube rupture scenarios are pressure induced tube ruptures (LERF08), but thermally induced ruptures (LEFF07) are also represented in the cutsets. The TI-SGTR contribution to LERF is small relative to the PI-SGTR due to likelihood of hot leg failure near the time of TI-SGTR (eliminates release pathway). Both scenarios, however, are dominated by transient initiators with AFW unavailability, most of which lead to recirculation failures. Feed and Bleed failures are smaller contributors, but because of the potential impact on the source terms, the Feed and Bleed failure scenario is chosen as the representative case. MAAP Case: Loss of SX, successful scram, AFW unavailable, operators fail to align alt FW and fail to align F&B, core damage, pressure induced tube rupture occurs.	0.19	3.16	7.39	17.23	800

Table F.3-8
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Source Term	Release Category	MAAP Case	MAAP Case Justification and Description	CsI RF[1]	Tcd [2] (Hrs)	Tvf [3] (Hrs)	Tcf [4] (Hrs)	Tend [5] (Hrs)
ST7	LATE-BMT-AFW	7a	Sequence Contributors: Late04 (92%), Late01 (1%). For both the LATE04 and LATE01 sequences, most of the contributors are LOCA events (including seal LOCAs) with recirculation failures. The availability of water on the containment floor impacts the probability of the basemat meltthrough, but has a negligible impact on the source term itself. For the basemat failure releases, the differences in LOCA size also have a minimal impact on the results. The largest frequency contributor is chosen as the representative sequence, which are the small LOCAs. MAAP Case: Small LOCA, successful scram, AFW available, injection successful, recirculation mode failure, core damage, containment heat removal success (RCFCs), CS success, basemat melt through.	6.8E-5	12.17	15.22	107.40	144

Table F.3-8
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Source Term	Release Category	MAAP Case	MAAP Case Justification and Description	CsI RF[1]	Tcd [2] (Hrs)	Tvf [3] (Hrs)	Tcf [4] (Hrs)	Tend [5] (Hrs)
ST8	LATE-BMT-NOAFW	8a	Sequence Contributors: Late07 (88%), Late08 (12%). The difference in the two dominant Level 2 sequences is related to operation of Containment Spray, which determines if there is a water pool in the reactor cavity when the core relocates to the containment. The scenarios for both sequences are essentially the same, most being transients with AFW failure followed by a mixture of either injection or recirculation mode failures. For this case, the scenarios with the feed and bleed failures are chosen as representative to capture any potential timing issues for evacuation.. MAAP Case: General transient event, successful scram, AFW CCF to run, failure to restore FW, failure to initiate feed and bleed, core damage, no PI-SGTR, op depressurizes late, no early containment failure at vessel breach, CHR successful, CS successful, basemat failure.	7.4E-4	3.14	6.88	90.10	144

Table F.3-8
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Source Term	Release Category	MAAP Case	MAAP Case Justification and Description	CsI RF(1)	Tcd (2) (Hrs)	Tvf (3) (Hrs)	Tcf (4) (Hrs)	Tend (5) (Hrs)
ST9	LATE-CHR-AFW	9a	Sequence Contributors: Late06 accounts for almost all of the contributions to this release category frequency. Over 95% of the contribution to the release category is from LOSW events or events that lead to SX failure, followed by a seal LOCA. The other contributions are almost all scenarios that result in a seal LOCA in a different manner. Recirculation and injection failures are both represented, but most are injection failures. MAAP Case: LOSW, successful scram, AFW failed, startup FW OK, failure to align alternate seal cooling, failure to align SX X-tie, seal LOCA, injection failure, core damage, no containment failure at VB, CHR fails with long term COP.	1.4E-2	5.93	8.88	60.78	200
ST10	LATE-CHR-NOAFW	10a	Sequence Contributors: Late09 accounts for almost all of the contributions to this release category frequency. Over 97% of the release category frequency is from LOSW events or events that lead to SX failure. These are generally followed by the unavailability of FW/Condensate and recirculation mode; injection failures contribute less than 10% of the frequency. MAAP Case: LOSW (all SX pumps CCF), successful scram, AFW failure from lack of SX cooling, failure to restore FW, SX X-tie not available, CHR not available for recirc, core damage, operator depressurizes late, no containment failure at VB, CHR fails with long term COP.	0.24	3.14	10.12	36.50	1600

Table F.3-8
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Source Term	Release Category	MAAP Case	MAAP Case Justification and Description	CsI RF[(1)]	Tcd [(2)] (Hrs)	Tvf [(3)] (Hrs)	Tcf [(4)] (Hrs)	Tend [(5)] (Hrs)
ST11	SERF-SGTR - TISGTR-HLF	11a	The SERF01 sequence is comprised of mostly feed and bleed failures with some recirculation failures after failure of AFW. The more rapidly evolving feed and bleed failures are chosen as the representative sequences. MAAP Case: Loss of 125 DC bus 111, successful scram, failure of AFW, failure of feed and bleed, core damage, late depressurization failure, TI-SGTR occurs, Hot leg fails at about the same time as TI-SGTR, no early containment failure, CHR success, CS success, no basemat failure.	5.8E-2	3.17	6.69	NA	72
ST12	SERF-SGTR-AFW-SC	12b	Sequence Contributors: The SERF02 sequence is mostly comprised (72% based on the Unit 2 results that correctly include 2RX-JHEP33-HOADA) of SGTR events with failure the operators to cool down the RCS before overfilling the SG (opens a steam generator PORV for a LOCA) and subsequent operator error to cool down the RCS to terminate the break flow before depleting the RWST. The cases including 2RX-JHEP33-HOADA (about 8%) are SGTR events with operator failures to shut down dead headed RHR pumps (fails RH) and failure to reduce ECCS injection (to prevent lifting the SG safety valves).. MAAP Case: SGTR, successful scram, operator fails to cool down the RCS, SG overfill causes SO PORV, operator fails to cool down the RCS to terminate break flow before the RWST is depleted, recirculation mode is unavailable, core damage, operators maintain SG level over the top of the SG tubes for release scrubbing.	1.8E-2	124.6	142.79	NA	200

Table F.3-8
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Source Term	Release Category	MAAP Case	MAAP Case Justification and Description	CsI RF[1]	Tcd [2] (Hrs)	Tvf [3] (Hrs)	Tcf [4] (Hrs)	Tend [5] (Hrs)
ST13	INTACT	13a	Most of the intact contribution comes from small LOCA scenarios (including induced Small LOCAs) with recirculation failures. For intact containment scenarios, the path to core damage has a negligible impact on the source term. MAAP case: Small LOCA, successful scram, AFW available, injection successful, recirculation failure, core damage, containment intact.	3.2E-5	12.17	15.13	NA	72

Notes:
[1] CsI RF – Cesium Iodide release fraction to the environment at the end of the run
[2] Tcd - Time of core damage (maximum core temperature >1800°F)
[3] Tvf - Time of vessel breach
[4] Tcf – Time of containment failure
[5] Tend – Time at end of run. MAAP cases were run to achieve a plateau of the release fractions, with primary attention paid to CsI and CsOH release fractions.

Table F.3-9
MACCS2 Base Case Mean Results Unit 1

Source Term	Release Category	Dose (p-rem)	Offsite Economic Cost ($)	Freq. (/yr)	Dose-Risk (p-rem/yr)	OECR ($/yr)
ST1	LERF-ISLOCA	1.30E+07	3.48E+10	3.40E-07	4.42E+00	1.18E+04
ST2	LERF-CI	9.30E+05	4.51E+09	3.67E-07	3.41E-01	1.66E+03
ST3	LERF-CFE	2.50E+06	1.64E+10	3.55E-08	8.88E-02	5.82E+02
ST4	LERF-SGTR-AFW	2.39E+06	1.83E+10	5.49E-08	1.31E-01	1.00E+03
ST5	LERF-SGTR-NOAFW	7.79E+05	6.47E+09	8.57E-10	6.68E-04	5.54E+00
ST6	LERF-ISGTR	2.59E+06	3.05E+10	2.69E-07	6.97E-01	8.20E+03
ST7	LATE-BMT-AFW	3.08E+04	4.20E+07	5.30E-07	1.63E-02	2.23E+01
ST8	LATE-BMT-NOAFW	8.00E+04	1.82E+08	7.95E-08	6.36E-03	1.45E+01
ST9	LATE-CHR-AFW	5.56E+05	1.89E+09	1.89E-05	1.05E+01	3.57E+04
ST10	LATE-CHR-NOAFW	2.13E+06	2.24E+10	8.35E-06	1.78E+01	1.87E+05
ST11	SERF-SGTR-TISGTR-HLF	9.50E+05	6.75E+09	6.49E-09	6.17E-03	4.38E+01
ST12	SERF-SGTR-AFW-SC	9.62E+05	6.05E+09	1.38E-06	1.33E+00	8.35E+03
ST13	INTACT	1.08E+04	1.02E+07	1.16E-05	1.25E-01	1.18E+02
	FREQUENCY WEIGHTED TOTALS			**4.19E-05**	**3.55E+01**	**2.55E+05**

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%SXIE	9.60E-01	1.852	Indicator for SX Initiating Event	SX impacts several critical functions and systems and multiple SAMAs are potentially relevant. For failure of all SX pumps (both units) to run (a majority contributor), most contributors include operator failures such that additional actions would provide limited benefit. A diesel driven SX pump with an auto start function could be used to mitigate CCF failures of the SX pumps. To maximize benefit, backup manual controls would have to be included in the MCR (SAMA 1). For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). For the contributors in which the failure of SX is due to the failure to start the standby SX pump, automating the start of the standby SX pump on failure of the running pump is a potential solution (SAMA 3). Instead of replacing the PDP to protect the RCP seals, a passive means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4). Another potential means of mitigating this scenario would be to modify the Startup FW pump to auto start and align on low SG level (using the AMSAC SG level signal) (SAMA 5).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
FLAG-CCHTX0-U2	5.00E-01	1.476	CCW HTX 0 ALIGNED TO UNIT 2	This event is a plant configuration flag that represents conditions when the 0HX is aligned to the non-accident unit. Over 55% of the contributors including this flag are related to the operator actions linked with preventing seal LOCAs, such as starting the standby SX/CCW pump, providing alternate cooling to the charging pumps, performing the SX cross-tie. Loss of SX evolutions leading to seal LOCAs can be addressed by replacing the PDP with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4). Automating the start of the standby SX pump would also reduce some of these contributors and may be viable if combined with flooding sensors that would prevent auto start in flooding scenarios (SAMA 3). Fire protection system flooding in the Aux Building is another contributor, which could be mitigated by installing fire protection pump controls in the MCR (SAMA 8) or by installing flow restrictors in the fire protection lines (SAMA 9).
0SX01AB2AB-CPMFRIE	2.15E-04	1.45	FAILURE OF ALL SX PUMPS (1A/1B/2A/2B) TO RUN DUE TO CCF (4/4)	These events represent a loss of all SX due to common cause pump failure. A diesel driven SX pump could be used to mitigate CCF failures of the SX pumps. To maximize benefit, controls would have to be included in the MCR (SAMA 1). For cases in which no seal LOCA occurs, secondary side heat removal can prevent core damage. The top contributor including SX pump CCF is the failure to recover FW for heat removal (about 40%). A potential means of mitigating this scenario would be tomodify the Startup FW pump to auto start and align on low SG level (using the AMSAC SG level signal) (SAMA 5). For cases with seal LOCAS, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
FLAG-CCHTX0-U1	5.00E-01	1.425	CCW HTX 0 ALIGNED TO UNIT 1	This event is a plant configuration flag that represents conditions when the 0HX is aligned to the accident unit. Over 55% of the contributors including this flag are related to the operator actions linked with preventing seal LOCAs, such as starting the standby SX/CCW pump, providing alternate cooling to the charging pumps, performing the SX cross-tie. Loss of SX evolutions leading to seal LOCAs can be addressed by replacing the PDP with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4). Automating the start of the standby SX pump would also reduce some of these contributors and may be viable if combined with flooding sensors that would prevent auto start in flooding scenarios (SAMA 3). Fire protection system flooding in the Aux Building is another contributor, which could be mitigated by installing fire protection pump controls in the MCR (SAMA 8) or by installing flow restrictors in the fire protection lines (SAMA 9).
%CCIE	9.60E-01	1.257	Indicator for CCInitiating Event	These initiating events essentially all lead to RCP seal LOCAs and over 99% are related to the failure to establish a cool suction source for the charging pumps. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Installation of "no leak" RCP seals is another option (SAMA 4).
SEAL-U1-TRANS	2.10E-01	1.256	UNIT 1 SEAL LOCA OCCURRED - NON-LOOP SEQUENCES	Over 99% of the non-LOOP seal LOCA contributors include the failure to establish a cool suction source for the charging pump for Loss of CCW initiating events. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Installation of "no leak" RCP seals is another option (SAMA 4).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1RX-JHEP44-HOADA	5.00E-03	1.186	JOINT HEP FOR 1CV-ALL---HPMOA AND 0CC-SXHTX0-HHXOA	Over 99% of the contributors including this event are related to loss of component cooling water initiators. The JHEP event represents the failure of the operators to align a cool suction source for the charging pumps in conjunction with a subsequent failure to align the 0 CC Hx to the accident unit. These failures result in the loss of RCP seal cooling. These scenarios can be addressed by replacing the PDP with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4).
1CC01A-----HXFFIE	5.34E-03	1.18	CCW HTX 1CC01A - LOSS OF FUNCTION	Over 80% of the contribution for this event comes from its combination with 1RX-JHEP32-HOADA, which represents failure to align a cool suction source for the charging pumps and failure to align the "0" heat exchanger to the unit. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1RX-JHEP05-HOADA	3.30E-04	1.163	JHEP - 1RC-PUMPS--HPMOA/0SX-XTIE---HMVOA/(1FP-PRI-7X-HMVOA OR 1CV-ALL---HPMOA)	This JHEP represents the failure of 4 different actions: starting the standby CCW/CCP/SX pump (it is the SX pump for these contributors), aligning the inter-unit SX cross-tie, aligning fire protection water to charging pump lube oil cooling, and establishing a cool suction source for the charging pumps. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Automating the start of the standby SX pump would also reduce these contributors and may be viable if combined with flooding sensors that would prevent auto start in flooding scenarios (SAMA 3). Automating the SX X-tie is not suggested given that certain failures in the SX system could fail the non-accident unit if the X-tie is performed without consideration of the failure scenario. Installation of "no leak" RCP seals is another option (SAMA 4).
0VA1SUPP---PNMM	2.10E-02	1.147	UNIT 1 VA SUPPLY PLENUM MAINTENANCE	For loss of SX scenarios, the Auxiliary Building HVAC system must be available to provide backup pump cubicle cooling even if fire protection is aligned as an alternte lube oil cooling supply. Installation of the "no-leak" RCP seals would prevent these scenarios (SAMA 4).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
0SX-XTIE-D-HMVRA	3.60E-01	1.146	RECOV OF LOSS OF SX SEAL LOCA (COND PROB OF 0SX-XTIE-D-HMVRA + 0.21 SEAL FAIL)	This is a composite event that represents the probability that either the seal LOCA is too large for the CVCS to mitigate, or that the SX cross-tie is not performed in time to support injection with CVCS (to prevent core damage). Main contributors include dependent operator action groups that include failures related to aligning alternate charging pump cooling, starting the standby SX pumps, and aligning the SX X-tie to prevent the seal LOCA. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Automating the start of the standby SX pump would also reduce these contributors and may be viable if combined with flooding sensors that would prevent auto start in flooding scenarios (SAMA 3). An alternate means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4). Automating the SX X-tie is not suggested given that certain failures in the SX system could fail the non-accident unit if the X-tie is performed without consideration of the failure scenario.
1SX01PB-----PMFRIE	3.19E-02	1.129	FAILURE OF PUMP 1B TO RUN RANDOMLY	Over 85% of the contribution for this event comes from its combination with JHEP 1RX-JHEP05-HOADA. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Automating the start of the standby SX pump would also reduce these contributors and may be viable if combined with flooding sensors that would prevent auto start in SX flooding scenarios (SAMA 3). Automating the SX X-tie is not suggested given that certain failures in the SX system could fail the non-accident unit if the X-tie is performed without consideration of the failure scenario. Installation of "no leak" RCP seals is another option (SAMA 4).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1FP-PRI-7F-HMVRA	4.50E-01	1.095	RECOV OF LOSS OF SX SEAL LOCA (1FP-PRI-7D-HMVRA + 0.21 + 0.1 FP BREAK LOCATION)	These events represent a combination of conditions that preclude recovery of high pressure injection to prevent core damage in fire protection flooding events (alignment fails, break is too large, or break is in a location that precludes use of the FP system). Mitigation of the initiating event could be accomplished by providing shutdown switch for the fire protection pumps in the main control room, which would simplify the action and provide significant time margin for the operators to terminate the flood before critical equipment is lost (SAMA 8). An alternate strategy would be to place flow restrictors in the fire protection pipes to prevent high flow flooding events (SAMA 9). To prevent the seal LOCAs, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Installation of "no leak" RCP seals is another option (SAMA 4).
1FW-FWR--EHSYOA	1.40E-02	1.083	OPERATORS FAIL TO EXECUTE FW RESTORATION	Over 95% of the contribution from this event is related to two cutsets, both of which are hardware failures that lead to loss of all SX. In these cases, there are no seal LOCAs, but lack of secondary side heat removal requires primary side makeup and when the RWST is depleted, recirc fails due to lack of SX/CC/RHR cooling. If the operators fail to restore feedwater after a loss of SX initiating event, CD ensues due to dependencies. In this case, they are longer term failures, but modifying the Startup FW pump to auto start and align on low SG level (using the AMSAC SG level signal) is a potential means of mitigating this scenario (SAMA 5). A diesel driven SX pump with an auto start function could be used to mitigate CCF failures of the SX pumps. To maximize benefit, backup manual controls would have to be included in the MCR (SAMA 1).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
FLMITIG-M3-T1-FP	6.94E-03	1.069	FAILURE TO MITIGATE >3700 GPM FP FLOOD FOR T1 SCENARIO	The events represent the failure to mitigate the fire protection flooding scenarios. Mitigation of the initiating event could be accomplished by providing shutdown switch for the fire protection pumps in the main control room, which would simplify the action and provide significant time margin for the operators to terminate the flood before critical equipment is lost (SAMA 8). An alternate strategy would be to place flow restrictors in the fire protection pipes to prevent high flow flooding events (SAMA 9). To prevent seal LOCAs, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Installation of "no leak" RCP seals is another option (SAMA 4). Floods that flow into the Aux Building impact the SX pump rooms via ductwork from the Aux Building drain sump room. Altering the ductwork to eliminate communication between the rooms would help extend the time that is available to mitigate Aux Building flooding events (SAMA 10).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%FL1FPM3A0----T1	7.58E-04	1.065	UNIT 1 MAJOR FLOOD (>3,700GPM) FROM FIRE PROTECTION INTO AUX BLDG - COMMON AREA	The top 2 cutsets, only differentiated by the heat exchanger alignment, contribute over 97% of the risk for this event. The scenarios include failure to mitigate the flooding event followed by the failure high pressure injection to provide makeup for the seal LOCA (1FP-PRI-7F-HMVRA). Mitigation of the initiating event could be accomplished by providing shutdown switch for the fire protection pumps in the main control room, which would simplify the action and provide significant time margin for the operators to terminate the flood before critical equipment is lost (SAMA 8). An alternate strategy would be to place flow restrictors in the fire protection pipes to prevent high flow flooding events (SAMA 9). To prevent seal LOCAs, which are a dominant consequence of the flood mitigation failure, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Installation of "no leak" RCP seals is another option (SAMA 4). Floods that flow into the Aux Building impact the SX pump rooms via ductwork from the Aux Building drain sump room. Altering the ductwork to eliminate communication between the rooms would help extend the time that is available to mitigate Aux Building flooding events (SAMA 10).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%APIE	9.60E-01	1.063	Indicator for AP Initiating Event	About 75% of the contribution for this event comes from its combination with 1RX-JHEP05-HOADA or some combination of the events in this dependent action. This 1RX-JHEP05-HOADA represents the failure of 4 different actions: starting the standby CCW/CCP/SX pump (it is the SX pump for these contributors), aligning the inter-unit SX cross-tie, aligning fire protection water to charging pump lube oil cooling, and establishing a cool suction source for the charging pumps. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Automating the start of the standby SX pump would also reduce these contributors and may be viable if combined with flooding sensors that would prevent auto start in flooding scenarios (SAMA 3). Automating the SX X-tie is not suggested given that certain failures in the SX system could fail the non-accident unit if the X-tie is performed without consideration of the failure scenario. Installation of "no leak" RCP seals is another option (SAMA 4). For the SBO contributors, implementation of the DMS would proivide a means of maintaining heat removal and inventory control indefinitely (SAMA 11).
1CV-ALL----HPMOA	1.00E-02	1.056	OPERATORS FAIL TO ESTABLISH COOL SUCTION SOURCE FOR CHARGING PUMP	This action represents failure to transfer charging pump suction to the RWST on loss of cooling to the letdown heat exchanger. It is mostly combined with CCW and SX pump failures and pump maintenance unavailabilities, which ultimately lead to seal LOCAs. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Installation of "no leak" RCP seals is another option (SAMA 4).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1AP142------BSLPIE	2.12E-03	1.049	BUS 142 FAILS	Over 97% of the contribution for this event comes from its combination with 1RX-JHEP05-HOADA or some combination of the events in this dependent action. This 1RX-JHEP05-HOADA represents the failure of 4 different actions: starting the standby CCW/CCP/SX pump (it is the SX pump for these contributors), aligning the inter-unit SX cross-tie, aligning fire protection water to charging pump lube oil cooling, and establishing a cool suction source for the charging pumps. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Automating the start of the standby SX pump would also reduce these contributors and may be viable if combined with flooding sensors that would prevent auto start in flooding scenarios (SAMA 3). Automating the SX X-tie is not suggested given that certain failures in the SX system could fail the non-accident unit if the X-tie is performed without consideration of the failure scenario. Installation of "no leak" RCP seals is another option (SAMA 4). In addition, failure of the AFW cross-tie is a minor contributor, which could be reduced by resolving the regulatory issues related to its use (SAMA 15).
%RC-SLOC1-N-PSIE	1.41E-03	1.037	SMALL LOCA INITIATING EVENT (NON-ISOLABLE)	Over 73% of the contribution from the SLOCA initiating event is related to the failure to stop the RH pumps when they are on min-flow without CC cooling to the RH heat exchangers. A potential enhancement may be to establish CC to the RH heat exchanger when the RH pumps start (SAMA 7).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1AP-BOTHSAT-TRMM	6.25E-03	1.036	BOTH U1 SAT OOS FOR TM - 141 PWR VIA 241; 142 PWR VIA 242; 156 - 159 ON UAT	1AP-BOTHSAT-TRMM represents the failure of the UAT to provide power to the 143 bus when both U1 SATs are in maintenance. About 95% of the contribution for this event comes from its combination with loss of service water events, which ultimately results in all SG makeup and RCS injection/heat removal capability. These contributors could be addressed by precluding simultaneous maintenance on both unit SATs or by providing contingency procedures to direct the power alignments required to operate the Startup Feedwater pump (SAMA 12). Alternatively, replacing the PDP with a self cooled high pressure injection pump with auto start capability would provide a means of maintaining RCP seal injection. For heat removal, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13).
1RX-JHEP28-HOADA	3.30E-04	1.029	JOINT HEP FOR 1RC-DS-SGTRHDVOA AND 1RC-LCD—-HSYOA	This event represents the dependent failure combination of performing RCS cooldown in time to prevent SG overfill (stuck open PORV) followed by failure to cool the RCS down in time to terminate break flow before the RWST is depleted. These events lead directly to core damage. Because of the operator dependence issues in the scenarios including this event, SAMAs requiring manual action would provide limited benefit. A potential means of mitigating these scenarios would be to provide an automated RWST makeup system to ensure injection can be maintained to the RCS for an indefinite period. A source of boration is assumed to be required to prevent recriticality, which could occur in some conditions if unborated water is used for RCS makeup (SAMA 14).
1RH-SP-X-—HPMOA	7.30E-04	1.028	OPERATORS FAIL TO STOP RH PUMPS	Over 94% of the contribution for this event comes from its combination with the small LOCA initiating event. This contribution is related to the failure to stop the RH pumps when they are on min-flow without CC cooling to the RH heat exchangers. A potential enhancement may be to establish CC to the RH heat exchanger when the RH pumps start (SAMA 7).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1FP-PRI-7D-HMVRA	3.50E-01	1.026	RECOV OF LOSS OF SX SEAL LOCA (COND PROB OF 1FP-PRI-7D-HMVRA + 0.21 SEAL FAIL)	This is a composite event that represents the probability that either the seal LOCA is too large for the CVCS to mitigate, or that the operators fail to align alternate cooling to the charging pumps in time to protect the RCP seals. Over 55% of the contribution is related to a fire protection system flood in the Aux Building common area. This event could be mitigated by installing fire protection pump controls in the MCR (SAMA 8) or by installing flow restrictors in the fire protection lines (SAMA 9). Another 30% of the contribution is associated with common cause failure of the SX pumps to run with a consequential seal LOCA. A diesel driven SX pump could be used to mitigate CCF failures of the SX pumps. To maximize benefit, controls would have to be included in the MCR (SAMA 1). For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Installation of "no leak" RCP seals is another means of preventing seal LOCAs (SAMA 4).
1AF-XTIE--EHXVOA	1.00E+00	1.023	OPERATORS FAIL TO EXECUTE AF CROSSTIE FROM OPPOSITE UNIT	This event represents failure of the AFW X-tie, which is assumed to always fail due to regulatory issues. The AFW cross-tie is currently physically in place at the site, but credit cannot be taken for the x-tie capability until permission to fully implement it is granted. Competing the implementation of the AFW X-tie would address the contributors related to this event (SAMA 15).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1SX01AB----HXFFIE	5.65E-03	1.021	SX PUMP 1B OIL COOLER FAILS DURING OPERATION	Over 88% of the contribution for this event comes from its combination with the dependent failure combination 1RX-JHEP05-HOADA. This JHEP represents the failure of 4 different actions: starting the standby CCW/CCP/SX pump (it is the SX pump for these contributors), aligning the inter-unit SX cross-tie, aligning fire protection water to charging pump lube oil cooling, and establishing a cool suction source for the charging pumps. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Automating the start of the standby SX pump would also reduce these contributors and may be viable if combined with flooding sensors that would prevent auto start in flooding scenarios (SAMA 3). Automating the SX X-tie is not suggested given that certain failures in the SX system could fail the non-accident unit if the X-tie is performed without consideration of the failure scenario. Installation of "no leak" RCP seals is another option (SAMA 4).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1CV-ALL-D–HPMRA	3.60E-01	1.019	RECOV OF LOSS OF SX SEAL LOCA (COND PROB OF 1CV-ALL-D-HPMRA + 0.21 SEAL FAIL)	This event represents the probability that either the operators fail to swap the charging pumps to a cool suction source in time to support CCP injection or that the resulting seal LOCA is too large for CCP makeup. Over 90% of the risk is related to scenarios in which all SX pumps fail due to common cause. For these cases, flow from another source needs to be established to the SX piping to cool the loads. A diesel driven SX pump could be used to mitigate CCF failures of the SX pumps. To maximize benefit, controls would have to be included in the MCR (SAMA 1). For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Automating the start of the standby SX pump would also reduce these contributors and may be viable if combined with flooding sensors that would prevent auto start in flooding scenarios (SAMA 3). Installation of "no leak" RCP seals is another means of preventing seal LOCAs (SAMA 4).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
0AP-DLOOP-GT	2.40E-03	1.019	CONDITIONAL PROBABILITY OF DLOOP GIVEN GENERAL TRANSIENT	Over 75% of the contribution for this event comes from its combination with loss of all SX events. A diesel driven SX pump could be used to mitigate CCF failures of the SX pumps. To maximize benefit, controls would have to be included in the MCR. There would be some dependence issues related to using this system, but starting a standby diesel SX pump may be faster and easier than restoring FW for heat removal (SAMA 1). For consequential LOOP paths, RCP seal protection can be pursued, but FW restoration in not available and an alternate form of heat removal is required. Replacinf the PDP with a self cooled high pressure injection pump with auto start capability would provide a means of maintaining RCP seal injection. For heat removal, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). For the SBO contributors, implementation of the DMS would proivide a means of maintaining heat removal and inventory control indefinitely (SAMA 11).
1RX-JHEP13-HOADA	6.50E-04	1.016	JOINT HEP FOR 1RC-PUMPS--HPMOA AND 0SX-XTIE—HMVOA	This event represents the failure of the operators to start the standby SX pump after failure of the running pump and the dependent failure to subsequently align the SX cross-tie. A potential means of mitigating these events is automating the start of the standby SX pump on failure of the running pump (SAMA 3). Alternatively, installing "no leak" RCP seals would help ensure RCS inventory is maintained long enough for the operators to restore FW and perform a coodown (SAMA 4).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
FLMITIG-M3-T1-WS	3.90E-03	1.016	FAILURE TO MITIGATE >3700 WS FLOOD FOR T1 SCENARIO	This event represents the failure to mitigate a flood in the non-essential service water system (>3700 gpm), which includes flood termination before water damage to the SX pumps can occur and for aligning fire protection to the charging pumps for lube oil cooling. The short time frame available for flood termination precludes success of the manual action to shut the WS pumps off even though it is a 1 minute MCR action. Including logic to trip the WS pumps on high flow conditions is a potential means of mitigating the WS flood (SAMA 16). For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Floods that flow into the Aux Building impact the SX pump rooms via ductwork from the Aux Building drain sump room. Altering the ductwork to eliminate communication between the rooms would help extend the time that is available to mitigate Aux Building flooding events (SAMA 10).
1RX-JHEP32-HOADA	4.90E-04	1.016	JOINT HEP FOR 0CC-HTX0—HHXOA AND 1CV-ALL—HPMOA	Over 85% of the contribution for this event comes from its combination with 1CC01A-----HXFFIE, which is the loss of function of the 1CC01A HX. Failure to align the "0" HX in conjunction with failure to align a cool suction source to the charging pumps results in core damage. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Given that all scenarios including this JHEP are seal LOCA scenarios, installation of "no leak" RCP seals is another option to reduce the frequency of these contributors (SAMA 4).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1RX-JHEP22-HOADA	2.40E-03	1.015	JOINT HEP FOR 0SX-XTIE---HMVOA AND (1FP-PRI-7X-HMVOA OR 1CV-ALL---HPMOA)	This dependent failure combination represents the failure to align the SX cross-tie and either the failure to align a cool suction source to the charging pumps or to align fire protection to the charging pump lube oil coolers. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). The top 50% of the contributors include evolutions in which SX is lost due to failure of the running pump and failure or maintenance unavailability of the remaining pump. A diesel driven SX pump could be used to mitigate CCF failures of the SX pumps. To maximize benefit, controls would have to be included in the MCR (SAMA 1).
%FL1WSM3A0---T1	4.23E-04	1.015	UNIT 1 MAJOR FLOOD (>3,700GPM) FROM NORMAL SERVICE WATER INTO AUX BLDG - COMMON	This event represents a flood in the non-essential service water system (>3700 gpm). Over 96% of the contribution comes from a single cutset, which includes the event to mitigate the flood (FLMITIG-M3-T1-WS). Including logic to trip the WS pumps on high flow conditions is a potential means of terminating the WS flood before it damages critical equipment (SAMA 16). For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Floods that flow into the Aux Building impact the SX pump rooms via ductwork from the Aux Building drain sump room. Altering the ductwork to eliminate communication between the rooms would help extend the time that is available to mitigate Aux Building flooding events (SAMA 10).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1AP-142-1—TRMM	2.76E-02	1.015	SAT 142-1 IS UNAVAILABLE DUE TO MAINTENANCE (141 PWR SUPPLIED FROM SAT 142-2)	The unavailability of system auxiliary transformer (SAT) 142-1 fails the power supply to the Startup Feedwater pump and also to the (2/4 condensate pumps (A and C) (fast bus transfer inhibited). Failure of the remaining credited FW pump (FW01PA) or one additional condensate pump fails the Alternate FW function. Over 95% of the contributors including the 1AP-142-1—TRMM event also total loss of SX that leads to unavailability of AFW and another failure that leads to the unavaiability of Alternate FW (no heat removal). To mitigate these events, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). Currently, no credit is taken for manually aligning power to the non-Class 1E buses to restore power to the FW system, which is likely conservative.
1AP-142-2—TRMM	2.76E-02	1.015	SAT 142-2 IS UNAVAILABLE DUE TO MAINTENANCE	The unavailability of SAT 142-2 fails the power supply to the Startup Feedwater pump and also to the (2/4 condensate pumps (A and C) (fast bus transfer inhibited). Failure of the remaining credited FW pump (FW01PA) or one additional condensate pump fails the Alternate FW function. Over 95% of the contributors including the 1AP-142-2—TRMM event also total loss of SX that leads to unavailability of AFW and another failure that leads to the unavaiability of Alternate FW (no heat removal). To mitigate these events, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). Currently, no credit is taken for manually aligning power to the non-Class 1E buses to restore power to the FW system, which is likely conservative.

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%FL1SX-MA0---T2	1.65E-04	1.013	UNIT 1 MAJOR FLOOD (>2000GPM) FROM SX INTO AUX BLDG - COMMON AREA	This event represents a flood in the essential service water system (>2000 gpm) in the Auxiliary Building, which results in loss of SX and a seal LOCA. Over 65% of the contribution is related to the failure to perform the flood mitigation task of terminating the event before the water level is high enough to fail the charging pumps (among other equipment). This task is for flood termination and alignment of alternate charging pump cooling, which is dominated by failure to align alternate charging pump cooling. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Floods that flow into the Aux Building impact the SX pump rooms via ductwork from the Aux Building drain sump room. Altering the ductwork to eliminate communication between the rooms would help extend the time that is available to mitigate Aux Building flooding events (SAMA 10).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
0AP-DLOOP-SC	6.70E-01	1.013	FRACTION OF CONDITIONAL LOOPS THAT ARE SWITCHYARD-CENTERED	The largest single contributor (about 40%) including this event is initiated by a CCF of all SX pumps. A diesel driven SX pump could be used to mitigate CCF failures of the SX pumps. To maximize benefit, controls would have to be included in the MCR (SAMA 1). There would be some dependence issues related to using this system, but starting a standby diesel SX pump may be faster and easier than restoring FW for heat removal. For consequential LOOP paths, RCP seal protection can be pursued, but FW restoration in not available and an alternate form of heat removal is required. Replacinf the PDP with a self cooled high pressure injection pump with auto start capability would provide a means of maintaining RCP seal injection. For heat removal, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). For the SBO contributors, implementation of the DMS would proivide a means of maintaining heat removal and inventory control indefinitely (SAMA 11).
%DC-LODC111-BSIE	5.39E-04	1.013	LOSS OF DC BUS 111 INITIATING EVENT	Over 87% of the contribution for this event comes from its combination with the failure to perform the AFW X-tie. Loss of DC buss 111 in conjunction with maintenance of the AFW B pump is a dominant contributor to the loss of the AFW function. Competing the implementation of the AFW X-tie would address the contributors related to this event (SAMA 15).
%FW-GTR-1---HWIE	7.05E-01	1.012	GENERAL TRANSIENT INITIATING EVENT	The largest contributor to the cutsets including this event (about 50%) is the failure to diagnose the need for seconday cooling (after failure of AFW). A potential means of mitigating this scenario would be to modify the Startup FW pump to auto start and align on low SG level (using the AMSAC SG level signal). Another 10% is related to the failure of the AFW cross-tie, which can be addressed by completing the modification (SAMA 15).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%SP-BB-A-SXPRB-1	1.21E-03	1.012	GLOBAL SPRAY SCENARIO UNIT 1 BYRON AND BRAIDWOOD IN AUX BLDG - SX PUMP ROOM B	The "B" SX pump is failed by direct spray from a pipe break within the pump room. Pump damage could potentially be prevented by installing spray shields on the SX pump, but even if the pump is protected, the event would lead to a forced shutdown without the "B" SX pump when the break is discovered. A manual trip is preferable to an automatic trip, but the benefit of the spray shield is questionable. Over 84% of the contribution including this initiating event is associated with dependent failure event 1RX-JHEP05-HOADA. The PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Installation of "no leak" RCP seals is another option (SAMA 4). Automating the start of the standby SX pump (SAMA 3) would provide a means of supplying SX to required loads, but depending on where the pipe break is, the SX system may be shut down for evaluation and this capability would provide no benefit.
1AF01PB----PDFR	9.58E-03	1.012	DIESEL-DRIVEN PUMP 1AF01PB RANDOM FAILURE TO RUN	About 60% of the contribution from this event includes failure of the AFW X-tie, which is typically combined with loss of DC buss 111 (which fails the motor driven AFW (MDAFW) pump and FW condensate) or bus 141 (which also fails MDAFW and FW Condensate after div 1 battery depletion). The AFW cross-tie is currently physically in place at the site, but credit cannot be taken for the x-tie capability until regulatory issues are resolved and implementation is finalized. Competing the implementation of the AFW X-tie would address the contributors related to this event (SAMA 15).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1FW-FRH1—HSGOA	1.10E-03	1.012	OPERATORS FAIL RECOGNIZE THE CUE TO SECONDARY COOLING	These events represent the failure to recognize the need to align an alternate heat removal source (AFW X-tie, FW Restoration, or bleed and feed) after failure of AFW. The action itself is relatively reliable, has an alarmed cue, and clear procedure guidance. A larger contributor to the cognitive element is that the procedure step is not graphically distinct, but changing the procedure to include an emphasis on the step is not judged to provide more than an academic benefit. Nearly 50% of the contribution is related to total loss of SX due to pump CCF and strainer plugging. A diesel driven SX pump with suction from the WS forebay with an auto start function could be used to mitigate CCF failures of the SX pumps. To maximize benefit, backup manual controls would have to be included in the MCR and the pump discharge suction strainers would have to be replaced by suctions strainers of an alternate type (SAMA 1). Accessibility of the strainers may allow manual clearing of debris in the event of a clogging event.
1CC01PA-B--CPMFRIE	2.18E-04	1.011	CCW PUMPS 1CC01PA & 1CC01PB FAIL TO RUN DUE TO CCF (2/4)	Over 98% of the contribution for this event comes from a single cutset that includes the failure to establish a cool suction source for the charging pumps on loss of CC. The PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Installation of "no leak" RCP seals is another option (SAMA 4).
1SX004——MVOCIE	3.90E-04	1.011	1SX004 MOV TRANSFERS CLOSED	100% of the contributors including this event are related to loss of component cooling water initiators. The event represents the transfer closed of the Unit specific CC HX inlet valve, which then requires alignment of the 0 CC Hx to the accident unit. These failures result in the loss of RCP seal cooling and a subsequent seal LOCA. These scenarios can be addressed by replacing the PDP with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1SX007-----MVOCIE	3.90E-04	1.011	1SX007 MOV TRANSFERS CLOSED	100% of the contributors including this event are related to loss of component cooling water initiators. The event represents the transfer closed of the Unit specific CC HX outlet valve, which then requires alignment of the 0 CC Hx to the accident unit. These failures result in the loss of RCP seal cooling and a subsequent seal LOCA. These scenarios can be addressed by replacing the PDP with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4).
FLMITIG--G-T1-FP	2.23E-04	1.011		The event represents failure to terminate the fire protection flood in the aux building. The scenarios including this event could be mitigated by installing fire protection pump controls in the MCR (SAMA 8) or by installing flow restrictors in the fire protection lines (SAMA 9). For fire protection breaks, there is a chance that the break is in an area that would preclude use of the fire protection system as an alternate cooling source for charging pump lube oil cooling, but for those cases in which the break does not prevent use of the system, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" seals (SAMA 4). Floods that flow into the Aux Building impact the SX pump rooms via ductwork from the Aux Building drain sump room. Altering the ductwork to eliminate communication between the rooms would help extend the time that is available to mitigate Aux Building flooding events (SAMA 10).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%FL1FP-GA0—T1	3.99E-03	1.01	UNIT 1 GENERAL FLOOD (100-2000GPM) FROM FIRE PROTECTION INTO AUX BLDG - COMMON A	The event represents failure to terminate the fire protection flood in the aux building. The scenarios including this event could be mitigated by installing fire protection pump controls in the MCR (SAMA 8) or by installing flow restrictors in the fire protection lines (SAMA 9). For fire protection breaks, there is a chance that the break is in an area that would preclude use of the fire protection system as an alternate cooling source for charging pump lube oil cooling, but for those cases in which the break does not prevent use of the system, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" seals (SAMA 4). Floods that flow into the Aux Building impact the SX pump rooms via ductwork from the Aux Building drain sump room. Altering the ductwork to eliminate communication between the rooms would help extend the time that is available to mitigate Aux Building flooding events (SAMA 10).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
FLMITIG-M2-T1-FP	2.19E-03	1.01		The event represents failure to terminate the fire protection flood in the aux building. The scenarios including this event could be mitigated by installing fire protection pump controls in the MCR (SAMA 8) or by installing flow restrictors in the fire protection lines (SAMA 9). For fire protection breaks, there is a chance that the break is in an area that would preclude use of the fire protection system as an alternate cooling source for charging pump lube oil cooling, but for those cases in which the break does not prevent use of the system, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" seals (SAMA 4). Floods that flow into the Aux Building impact the SX pump rooms via ductwork from the Aux Building drain sump room. Altering the ductwork to eliminate communication between the rooms would help extend the time that is available to mitigate Aux Building flooding events (SAMA 10).
1CD05PD----PMMM	2.87E-02	1.01	MAINTENANCE UNAVAILABILTY OF CD/CB PUMP CD05PD/CB01PD	Over 80% of the contributors including this event are the result of two loss of SX cutsets, one with its combination with maintenance on the 141-1 SAT and the other with the 142-2 SAT. Each of the maintenance events prevents the fast transfer to the bus powering the "A" and "C" condensate/condensate booster pumps to the remaining SAT on a trip, which results in failure of the alternate FW capability. To mitigate these events, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). Currently, no credit is taken for manually aligning power to the non-Class 1E buses to restore power to the FW system, which is likely conservative. Providing an alternate, diesel driven SX pump is another potential means of mitigating the events (SAMA 1).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%FL1FPM2A0—T1	3.77E-04	1.01	UNIT 1 MAJOR FLOOD M2 (3,700GPM) FROM FIRE PROTECTION INTO AUX BLDG - COMMON ARE	The event represents failure to terminate the fire protection flood in the aux building. The scenarios including this event could be mitigated by installing fire protection pump controls in the MCR (SAMA 8) or by installing flow restrictors in the fire protection lines (SAMA 9). For fire protection breaks, there is a chance that the break is in an area that would preclude use of the fire protection system as an alternate cooling source for charging pump lube oil cooling, but for those cases in which the break does not prevent use of the system, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" seals (SAMA 4). Floods that flow into the Aux Building impact the SX pump rooms via ductwork from the Aux Building drain sump room. Altering the ductwork to eliminate communication between the rooms would help extend the time that is available to mitigate Aux Building flooding events (SAMA 10).
1FP-PRI-7X-HMVOA	4.60E-03	1.009	OPERATORS FAIL TO ALIGN FP SEAL COOLING - SX NON-PIPE FAILURE INITIATOR	Over 94% of the contribution for this event comes from its combination with the Loss of SX initiating event, either all pumps on both units or al SX strainer on both units. A diesel driven SX pump with an auto start function could be used to mitigate CCF failures of the SX pumps. To maximize benefit, backup manual controls would have to be included in the MCR (SAMA 1). Another potential means of mitigating this scenario would be to modify the Startup FW pump to auto start and align on low SG level (using the AMSAC SG level signal) (SAMA 5). For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" seals (SAMA 4).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1RX-JHEP47-HOADA	3.30E-04	1.009	JOINT HEP FOR 1RC-PUMPS--HPMOA AND 0SX005----HMVOA AND 1FP-PRI-7X-HMVOA	Over 85% of the contribution for this event comes from its combination with 1CC01A-----HXFFIE, which is the loss of function of the 1CC01A HX. Failure to align the "0" HX in conjunction with failure to align a cool suction source to the charging pumps results in core damage. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Given that all scenarios including this JHEP are seal LOCA scenarios, installation of "no leak" RCP seals is another option to reduce the frequency of these contributors (SAMA 4).
1RX-JHEP48-HOADA	3.30E-04	1.009	JOINT HEP FOR 1RC-PUMPS--HPMOA AND 0SX005----HMVOA AND 1CV-ALL----HPMOA	Over 85% of the contribution for this event comes from its combination with 1CC01A-----HXFFIE, which is the loss of function of the 1CC01A HX. Failure to align the "0" HX in conjunction with failure to align a cool suction source to the charging pumps results in core damage. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Given that all scenarios including this JHEP are seal LOCA scenarios, installation of "no leak" RCP seals is another option to reduce the frequency of these contributors (SAMA 4).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
FLMITIG--M-T2-SX	2.09E-03	1.009	FAILURE TO MITIGATE >2000 GPM SX FLOOD FOR T2 SCENARIO	This event represents the failure to mitigate a flood in the essential service water system (>2000 gpm) in the Auxiliary Building, which results in loss of SX and a seal LOCA. The contribution is represented by a single cutset. Failure to perform the flood mitigation task of terminating the event before the water level is high enough to fail the charging pumps (among other equipment) or failure to align alternate charging pump lube oil cooling results in core damage. This task is for flood termination and alignment of alternate charging pump cooling, which is dominated by failure to align alternate charging pump cooling. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" seals (SAMA 4).
1SI-HPR----HSYOA	6.80E-03	1.009	OPERATORS FAIL TO ESTABLISH HIGH PRESSURE RECIRC (SLOW EVENT)	There is not a single dominant event related to the scenarios that include this event, but failure of the AFW system is the condition that drives the need for recirculation mode. 38% of the contribution is directly tied to the failure of the AFW X-tie. Completing the implementation of the AFW X-tie would address the contributors related to this event (SAMA 15). Failure of the AFW system requires transition to an alternate method of heat removal, however, if the startup FW pump is enhanced to autostart on AFW failure, the importance of the action to manually align the startup feedwater would be reduced (SAMA 5). The current configuration requires a manual restart of MFW as a backup heat removal source. Automating swap to recirculation mode is an additional potential enhancement (SAMA 29).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%RC-SGTR1-B-HXIE	8.44E-04	1.009	STEAM GENERATOR TUBE RUPTURE IN S/G 1B	Over 70% of the contribution from this event is tied to the dependent human failure combination of failing to cool the RCS in time to prevent opening a SG PORV (lead to stuck open PORV) and the subsequent failure to cool the RCS to terminate flow from the break before RWST depletion. Installing an automated RWST makeup system that would extend the time available to perform the cooldown would provide additional time for action and, if the actuation is alarmed, it would provide an additional cue to perform the RCS cooldown (SAMA 14).
%RC-SGTR1-C-HXIE	8.44E-04	1.009	STEAM GENERATOR TUBE RUPTURE IN S/G 1C	Over 70% of the contribution from this event is tied to the dependent human failure combination of failing to cool the RCS in time to prevent opening a SG PORV (lead to stuck open PORV) and the subsequent failure to cool the RCS to terminate flow from the break before RWST depletion. Installing an automated RWST makeup system that would extend the time available to perform the cooldown would provide additional time for action and, if the actuation is alarmed, it would provide an additional cue to perform the RCS cooldown (SAMA 14).
%RC-SGTR1-A-HXIE	8.44E-04	1.009	STEAM GENERATOR TUBE RUPTURE IN S/G 1A	Over 70% of the contribution from this event is tied to the dependent human failure combination of failing to cool the RCS in time to prevent opening a SG PORV (lead to stuck open PORV) and the subsequent failure to cool the RCS to terminate flow from the break before RWST depletion. Installing an automated RWST makeup system that would extend the time available to perform the cooldown would provide additional time for action and, if the actuation is alarmed, it would provide an additional cue to perform the RCS cooldown (SAMA 14).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%RC-SGTR1-D-HXIE	8.44E-04	1.009	STEAM GENERATOR TUBE RUPTURE IN S/G 1D	Over 70% of the contribution from this event is tied to the dependent human failure combination of failing to cool the RCS in time to prevent opening a SG PORV (lead to stuck open PORV) and the subsequent failure to cool the RCS to terminate flow from the break before RWST depletion. Installing an automated RWST makeup system that would extend the time available to perform the cooldown would provide additional time for action and, if the actuation is alarmed, it would provide an additional cue to perform the RCS cooldown (SAMA 14).
0SX-MU-LVL-HMVOA	5.30E-03	1.008	OPERATORS FAIL TO RESTORE LEVEL TO SX TOWER BASIN	Normally, Circulating Water provides makeup to the SX basins, but on loss of offsite power, the Circ Water pumps are unavailable. The SX makeup pumps and Well Water pumps also provide automated basin makeup, but the Well Water level control system includes a non-emergency power dependence. For LOOP events in which the SX makeup pumps fail (essentially all the relevant contributors), the operators must manually control SX basin level. The action iteslf is relativley reliable with an alarmed cue and clear procedures. No procedure enhancements have been identified that would significatnly improve the reliabitlity of this action. For LOOP scenarios without SX, no heat removal mechanisms are available, but SAMAs that require additional opertor actions would have limited benefit due to human dependence issues. In order to provide heat removal capability for these conditions, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1SX01PA----PMMM	5.90E-03	1.008	SX PUMP 1A UNAVAILABLE DUE TO MAINTENANCE	About 70% of the contribution for this event comes from its combination with 1RX-JHEP22-HOADA or some combination of the events in this dependent failure combination. 1RX-JHEP22-HOADA represents the failure to align the SX cross-tie and either the failure to align a cool suction source to the charging pumps or to align fire protection to the charging pump lube oil coolers. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). A diesel driven SX pump could be used to mitigate CCF failures of the SX pumps. To maximize benefit, controls would have to be included in the MCR (SAMA 1).
1AP141------BSLPIE	2.12E-03	1.008	BUS 141 FAILS	About 30% of the cases include unavailability of the "B" train AFW pump and failure of the AFW X-tie. Competing the implementation of the AFW X-tie would address these contributors (SAMA 15). About 65% of the contributors are cases in which seal cooling is lost followed by the on set of a seal LOCA. The DMS would provide a means of addressing these contributors (SAMA 11).
1AF01PB----PDMM	7.12E-03	1.007	AF DIESEL-DRIVEN PUMP 1AF01PB UNAVAILABLE DUE TO MAINTENANCE	About 45% of the contribution from this event includes failure of the AFW X-tie in conjunction with loss of DC buss 111 (which fails the MDAFWpump and FW condensate). The AFW cross-tie is currently physically in place at the site, but credit cannot be taken for the x-tie capability until regulatory issues are resolved and implementation is finalized. Competing the implementation of the AFW X-tie would address the contributors related to this event (SAMA 15).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1SX01A-1B--CPMFRIE	2.93E-04	1.007	FAILURE OF SX PUMPS 1A & 1B TO RUN DUE TO COMMON CAUSE	Over 95% of the contribution for this event comes from its combination with 1RX-JHEP22-HOADA or some combination of the events in this dependent failure combination. 1RX-JHEP22-HOADA represents the failure to align the SX cross-tie and either the failure to align a cool suction source to the charging pumps or to align fire protection to the charging pump lube oil coolers. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). A diesel driven SX pump could be used to mitigate CCF failures of the SX pumps. To maximize benefit, controls would have to be included in the MCR (SAMA 1).
1FW01PA----PMMM	1.36E-02	1.007	MAINTENANCE UNAVAILABILITY OF PUMP FW01PA	Over 96% are initiated by common cause failure of all SX pumps followed by failure of the MFW system to provide heat removal. Because most of those failures include unavailability of the startup feedwater pump, SAMA 2 is not an option. Providing an alternate, diesel driven SX pump is a potential means of reducing the risk of this scenario (SAMA 1). A potentially more cost effective solution would be to modify the AFW pumps to be self cooled in conjunction with the replacement of the PDP with a self cooled, auto start pump that would protect the RCP seals (SAMA 13). Implementation of the DMS is another potential means of addressing these scenarios (SAMA 11).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%FW-LMFW1---HWIE	6.90E-02	1.007	TOTAL LOSS OF MAIN FEEDWATER	The failure evolutions initiated by the total loss of MFW initiator are diverse and there is no single dominant contributor to risk. One of the larger contributors is the a joint HEP representing the failure to manually initiate AFW and the subsequent failure to diagnose the need to align alternate heat removal. The independent action to align alternate heat removal is relatively reliable, has an alarmed cue, and clear procedure guidance. However, the dependent action chain begins with AFW start, which has a short available time for response and a relatively high HEP that drives the JHEP. Given the longer time frame available for starting Feed and Bleed, the importance of the action may be conservative. However, the AMSAC low level logic could be used to provide a backup start signal for AFW to mitigate these scenarios (SAMA 17). Automating swap to recirculation mode is an additional potential enhancement (SAMA 29). Alternatively, installing an automated RWST makeup system that would extend the time available to perform the transition to recirculation. If the actuation is alarmed, it would provide an additional cue to perform the action (SAMA 14).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%RCS-RHR-DISCHIE	9.16E-07	1.007	FREQ OF EXPOSING RHR PUMP DISCHARGE HEADERS TO RCS PRESSURE	This event is a piping overpressurization event that leads to ISLOCA scenarios and core damage (and containment bypass). Over 99% of the contribution is due to a single cutset that represents the conditional probability of a leak when the RHR line is subjected to high pressure. Potential enhancements include installing pressure monitoring instrumentation in the RHR lines or replacing the MOV in the suction line with a valve capable of closing against RCS pressure. Success of the pressure monitoring instruments is predicted on a leak before break failure mode that would allow sufficient time to shut down the reactor and depressuirze the RCS before both check valves fail. For the large flow breaks represented by this event, it is not clear that pressure monitoring would provide adequate warning to mitigate the event and it is not consided to be a comprehensive means of reducing the frequency of these events. The ISLOCA analysis indicates that the isolation MOVs in the cold and hot legs are not designed to close against RCS pressure. A potential means of addressing these ISLOCA scenarios would be to replace MOVs _SI8809A, _SI8809B, and _SI8840 with valves that could be used to terminate an ISLOCA event (SAMA 19).
LEAK-800-150	2.80E-01	1.006	CONDITIONAL PROB OF LEAK 800 GPM GIVEN LEAK IS AT LEAST 150 GPM	This event represent the probability that an ISLOCA occurs given exposure the RHR line to overpressure conditions, 100% of which leads directly to core damage (and containment bypass). The ISLOCA analysis indicates that the isolation MOVs in the cold and hot legs are not designed to close against RCS pressure. A potential means of addressing these ISLOCA scenarios would be to replace MOVs _SI8809A, _SI8809B, and _SI8840 with valves that could be used to terminate an ISLOCA event (SAMA 19).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1AF01PA-B--CPMFR	8.20E-05	1.006	AF PUMPS FAIL TO RUN DUE TO CCF (2/2)	Over 35% of the contribution is related to the failure to recognize the need to start an alternate heat removal system after AFW failure. Failure of the AFW system requires transition to an alternate method of heat removal, however, if the Startup FW pump is modified to auto start and align on low SG level (using the AMSAC SG level signal), the risk of this scenario could be reduced (SAMA 5). The current configuration requires a manual restart of MFW as a backup heat removal source. Other contributors include failure to perform the AFW X-tie and alignment of high pressure recirculation mode. The AFW X-tie is currently physically in place at the site, but credit cannot be taken for the x-tie capability until permission to fully implement it is granted. Completing the implementation of the AFW X-tie would address the contributors related to this event (SAMA 15). For the cases that include failure to swap to recirculation, this action is only required because of loss of AFW. Making the AFW X-tie available would also address most of these cases.
FLMITIG-FPCVCOOL	3.90E-03	1.006	FAILURE TO ALIGN FP COOLING TO CV PUMP LUBE OIL COOLER	This event represents the failure to align fire protection to alternate charging pump lube oil cooling for general flooding in the Auxiliary Building, many of which are SX system flood events. For these cases, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" seals (SAMA 4).
1CC01PAB2A-CPMFRIE	1.04E-04	1.005	CCW PUMPS 1CC01PA/1CC01PB/2CC01PA FAIL TO RUN DUE TO CCF (3/4)	Over 98% of the contribution for this event comes from its combination with the failure to align a cool suction source to the charging pump. The PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
1CC01PAB2B-CPMFRIE	1.04E-04	1.005	CCW PUMPS 1CC01PA/1CC01PB/2CC01PB FAIL TO RUN DUE TO CCF (3/4)	Over 98% of the contribution for this event comes from its combination with the failure to align a cool suction source to the charging pump. The PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2).
1FWTRAIN-1AHOEXM	1.00E-02	1.005	1FW01PA PUMP TRAIN RESTORATION FAILURE POST T/M	This event represents a pre-initiator restoration error of FW01PA pump when it is in standby mode. Most of the contributors are loss os SX scenarios that also include the failure or unavailability of the startup FW pump such that all primary and secondary side heat removal is failed. To mitigate these events, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13).
1RH01PB—PMMM	8.79E-03	1.005	RH PUMP 1RH01PB UNAVAILABLE DUE TO MAINTENANCE	One on the larger contributors (about 33%) is related to failure of the AFW X-tie. Completing the implementation of the AFW X-tie would address the contributors related to this event (SAMA 15). Failure of the AFW system requires transition to an alternate method of heat removal, however, if the Startup FW pump is modified to auto start and align on low SG level (using the AMSAC SG level signal), the risk from this scenario could be reduced (SAMA 5). The current configuration requires a manual restart of MFW as a backup heat removal source. An additional 18% of the contributors are due to seal LOCAs caused by failure to align a cool suction source to the charging pumps on loss of CCW. For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" seals (SAMA 4).

Table F.5-1
Byron Level 1 IE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAS
%SY-WRDLOOP-DLIE	2.87E-03	1.005	DUAL UNIT WEATHER-RELATED LOSS OF OFFSITE POWER (SUSTAINED)	Many of these LOOP events include failures of the SX makeup system, which leads to loss of SX. In conjunction with the loop event, loss of SX fails all heat removal. To mitigate these events, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). Implementing the DMS would provide a means of mitigating these evens for cases when opertor failures do not fail the SX basin makeup function (benefit for about 75% of the cases).

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%SXIE	9.60E-01	1.496	Indicator for SX Initiating Event	Addressed in the Level 1 importance list.
0SX01AB2AB-CPMFRIE	2.15E-04	1.386	FAILURE OF ALL SX PUMPS (1A/1B/2A/2B) TO RUN DUE TO CCF (4/4)	Addressed in the Level 1 importance list.
1L2-SGT-VF-PISGR	2.80E-02	1.334	PRESSURE-INDUCED STEAM GENERATOR TUBE RUPTURE	About 83% of the contributors are loss of SX initiators or events that lead to loss of SX followed by unavailability of main FW. A diesel driven SX pump with an auto start function could be used to mitigate CCF failures of the SX pumps. To maximize benefit, backup manual controls would have to be included in the MCR (SAMA 1). For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). For the contributors in which the failure of SX is due to the failure to start the standby SX pump, automating the start of the standby SX pump on failure of the running pump is a potential solution (SAMA 3). Instead of replacing the PDP to protect the RCP seals, a passive means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4). Another potential means of mitigating this scenario would be to modify the Startup FW pump to auto start and align on low SG level (using the AMSAC SG level signal) (SAMA 5). For the induced tube rupture event itself, the condition of the SG tubes does play a role in the determination of the failure probability, but SG replacement is already in progress at the site and no additional changes are suggested.
%RCS-RHR-DISCHIE	9.16E-07	1.319	FREQ OF EXPOSING RHR PUMP DISCHARGE HEADERS TO RCS PRESSURE	Addressed in the Level 1 importance list.
LEAK-800-150	2.80E-01	1.316	CONDITIONAL PROB OF LEAK 800 GPM GIVEN LEAK IS AT LEAST 150 GPM	Addressed in the Level 1 importance list.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1RH-FAILS	1.00E+00	1.268	RH PUMPS FAIL DURING RECIRC MODE (WITH CS IN RECIRCULATION MODE)	These failures are essentially all related to containment isolation failure scenarios. There are a number of isolation failure mechanisms, the largest of which is an operator error related to the failure to close the path between the RWST and the containment sump (1CI-RWST---HMVOA at 47%). The operator action evaluation is based on closing the required valves as part of the transition to recirculation mode and does not credit the additional isolation tasks that would close the relevant release pathway that are performed in the SACRG-1 procedure. The SACRG-1 isolation tasks, which are directed by a different procedure, based on different cues, and taken at a different time than the credited isolation actions could be credited to reduce the risk associated with this event. No additional procedural changes are considered to be required. The scenarios leading to the containment isolation failures include the same contributors reviewed in the Level 1 importance list (e.g., %SXIE 48%, %CCIE 22%, %APIE 9%, %FL1FPM3A0----T1 7%) and the same SAMAs are applicable. No additional SAMAs are suggested.
FLAG-CCHTX0-U2	5.00E-01	1.134	CCW HTX 0 ALIGNED TO UNIT 2	Addressed in the Level 1 importance list.
1FW-FWR--EHSYOA	1.40E-02	1.12	OPERATORS FAIL TO EXECUTE FW RESTORATION	Addressed in the Level 1 importance list.
FLAG-CCHTX0-U1	5.00E-01	1.12	CCW HTX 0 ALIGNED TO UNIT 1	Addressed in the Level 1 importance list.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1CI-RWST---HMVOA	3.00E-03	1.111	OPERATORS FAIL TO CLOSE MOV SI8806 OR CV112D/E OR SI8813/8920 OR 8814	This event represents a containment isolation failure due to an operator error related to the failure to close the path between the RWST and the containment sump. The operator action evaluation is based on closing the required valves as part of the transition to recirculation mode and does not credit the additional isolation tasks that would close the relevant release pathway that are performed in the SACRG-1 procedure. The SACRG-1 isolation tasks, which are directed by a different procedure, based on different cues, and taken at a different time than the credited isolation actions could be credited to reduce the risk associated with this event. No additional procedural changes are considered to be required. The scenarios leading to the containment isolation failures include the same contributors reviewed in the Level 1 importance list (e.g., %SXIE 50%, %CCIE 23%, %FL1FPM3A0----T1 7%, %APIE 6%) and the same SAMAs are applicable. No additional SAMAs are suggested.
1CI-CLASS-A-PNFF	2.30E-03	1.084	CLASS A PENTRATION FAILURE	This event represents a containment isolation failure due to any/all penetration failures and is not associated with any specific penetration failure or weakness. This type of a general event does not provide meaningful insight into a specific enhancement that could be made to the penetration itself. The frequency of the scenarios that lead to core damage, however, can be reduced. All contributors above at least 2%of the portion of the CDF that includes this event are included in the L1 importance review, including %SXIE 49%, %CCIE 22%, %FL1FPM3A0----T1 7%, %APIE 6%. SAMAs related to these events would be relevant to reducing the risk of the scenarios that include 1CI-CLASS-A-PNFF.
1FP-PRI-7D-HMVRA	3.50E-01	1.079	RECOV OF LOSS OF SX SEAL LOCA (COND PROB OF 1FP-PRI-7D-HMVRA + 0.21 SEAL FAIL)	Addressed in the Level 1 importance list.
%CCIE	9.60E-01	1.076	Indicator for CCInitiating Event	Addressed in the Level 1 importance list.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SEAL-U1-TRANS	2.10E-01	1.076	UNIT 1 SEAL LOCA OCCURRED - NON-LOOP SEQUENCES	Addressed in the Level 1 importance list.
FLMITIG-M3-T1-WS	3.90E-03	1.075	FAILURE TO MITIGATE >3700 WS FLOOD FOR T1 SCENARIO	Addressed in the Level 1 importance list.
%RCS-RHR-SUCT-IE	4.58E-07	1.065	FREQUENCY OF HAVING RCS PRESSURE IN THE RHR SUCTION LINE	This event is a piping overpressurization event that leads to ISLOCA scenarios, core damage, and containment bypass. Over 98% of the contribution is due to a single cutset that represents the conditional probability of a leak that is at least 1700 gpm given a leak of 150 gpm when the RHR line is subjected to high pressure. The leak path is due to failure of two MOVs that are in series between the RHR pump suction and the RCS hot leg. There are currently no other valves in the suction path line that could be used to isolate flow. Potential enhancements include installing pressure monitoring instrumentation in the RHR lines or installing an emergency isolation valve in the suction line. Success of the pressure monitoring instruments is predicted on a leak before break failure mode that would allow sufficient time to shut down the reactor and depressurize the RCS before both isolation valves fail. For the large flow breaks represented by this event, it is not clear that pressure monitoring would provide adequate warning to mitigate the event and it is not considered to be a comprehensive means of reducing the frequency of these events. Therefore, installing an emergency isolation valve is suggested as a means of mitigating this sequence (SAMA 21).

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
LEAK-1700-150	1.40E-01	1.064	CONDITIONAL PROB OF LEAK 1700 GPM GIVEN LEAK IS AT LEAST 150 GPM	This event represents the conditional probability of a leak that is at least 1700 gpm given a leak of 150 gpm when the RHR line is subjected to high pressure. The leak path is due to failure of two MOVs that are in series between the RHR pump suction and the RCS hot leg. There are currently no other valves in the suction path line that could be used to isolate flow. Potential enhancements include installing pressure monitoring instrumentation in the RHR lines or installing an emergency isolation valve in the suction line. Success of the pressure monitoring instruments is predicted on a leak before break failure mode that would allow sufficient time to shut down the reactor and depressurize the RCS before both isolation valves fail. For the large flow breaks represented by this event, it is not clear that pressure monitoring would provide adequate warning to mitigate the event and it is not considered to be a comprehensive means of reducing the frequency of these events. Therefore, installing an emergency isolation valve is suggested as a means of mitigating this sequence (SAMA 21).
1RX-JHEP44-HOADA	5.00E-03	1.059	JOINT HEP FOR 1CV-ALL—-HPMOA AND 0CC-SXHTX0-HHXOA	Addressed in the Level 1 importance list.
1CC01A——HXFFIE	5.34E-03	1.056	CCW HTX 1CC01A - LOSS OF FUNCTION	Addressed in the Level 1 importance list.
1RX-JHEP05-HOADA	3.30E-04	1.055	JHEP - 1RC-PUMPS--HPMOA/0SX-XTIE—HMVOA/(1FP-PRI-7X-HMVOA OR 1CV-ALL—-HPMOA)	Addressed in the Level 1 importance list.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1AF-SGFLOODHPVOA	4.10E-02	1.054	Operator Maintains Faulted SG Full of Water for Fission Product Scrubbing	This action is proceduralized, is based on appropriate and clear cues, is simple to perform, and the procedure includes a step that validates performance of the action. While the action is relatively reliable, it is influenced by the high stress of the scenario, which results in the HEP being dominated by a large execution failure term associated with a simple level adjustment action. No procedural changes have been identified that would significantly improve the assessed reliability of the action. Over 80% of the contributors including this action also include the joint HEP 1RX-JHEP28-HOADA. This event represents the dependent failure combination of performing RCS cooldown in time to prevent SG overfill (stuck open PORV) followed by failure to cool the RCS down in time to terminate break flow before the RWST is depleted. These events lead directly to core damage. Because of the operator dependence issues in the scenarios including this event, SAMAs requiring manual action would provide limited benefit. A potential means of mitigating these scenarios would be to provide an automated RWST makeup system to ensure injection can be maintained to the RCS for an indefinite period. A source of boration is assumed to be required to prevent recriticality, which could occur in some conditions if unborated water is used for RCS makeup (SAMA 14).

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%FL1WSM3A0HVACT1	3.85E-05	1.052	UNIT 1 MAJOR FLOOD (>3,700GPM) FROM NORMAL SERVICE WATER INTO AUX BLDG - HVAC 45	This event is included in single cutset which is a normal service water flooding scenario in the Aux Building with failure to provide alternate lube oil cooling to the charging pumps. Including logic to trip the WS pumps on high flow conditions is a potential means of terminating the WS flood before it damages critical equipment (SAMA 16). For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Floods that flow into the Aux Building impact the SX pump rooms via ductwork from the Aux Building drain sump room. Altering the ductwork to eliminate communication between the rooms would help extend the time that is available to mitigate Aux Building flooding events (SAMA 10).
1AP-BOTHSAT-TRMM	6.25E-03	1.05	BOTH U1 SAT OOS FOR TM - 141 PWR VIA 241; 142 PWR VIA 242; 156 - 159 ON UAT	Addressed in the Level 1 importance list.
0VA1SUPP—-PNMM	2.10E-02	1.046	UNIT 1 VA SUPPLY PLENUM MAINTENANCE	Addressed in the Level 1 importance list.
0SX-XTIE-D-HMVRA	3.60E-01	1.046	RECOV OF LOSS OF SX SEAL LOCA (COND PROB OF 0SX-XTIE-D-HMVRA + 0.21 SEAL FAIL)	Addressed in the Level 1 importance list.
1RX-JHEP28-HOADA	3.30E-04	1.045	JOINT HEP FOR 1RC-DS-SGTRHDVOA AND 1RC-LCD—-HSYOA	Addressed in the Level 1 importance list.
1SX01PB—-PMFRIE	3.19E-02	1.042	FAILURE OF PUMP 1B TO RUN RANDOMLY	Addressed in the Level 1 importance list.
%APIE	9.60E-01	1.039	Indicator for AP Initiating Event	Addressed in the Level 1 importance list.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1CICS001AB-HMVOA	1.10E-03	1.037	OPERATORS FAIL TO CLOSE RWST SUCTION MOV UPON SWITCH TO RECIRC	This event represents a containment isolation failure due to an operator error related to the failure to close the path between the RWST and the containment sump. The failure results in an open path between the RWST and the containment sump (from the sump through _SI8811A/B, _CS009A/B, and _CS001A/B to the RWST). The containment isolation assessment does not credit the additional isolation tasks that would close the relevant release pathway (by closing _SI8811A/B) that are performed in the SACRG-1 procedure. If this action were credited, these contributors would be reduced. No additional procedural changes are considered to be required. The scenarios leading to the containment isolation failures include the same contributors reviewed in the Level 1 importance list (e.g., %SXIE 50%, %CCIE 23%, %FL1FPM3A0---T1 7%, %APIE 5%) and the same SAMAs are applicable. No additional SAMAs are suggested.
1FP-PRI-7F-HMVRA	4.50E-01	1.035	RECOV OF LOSS OF SX SEAL LOCA (1FP-PRI-7D-HMVRA + 0.21 + 0.1 FP BREAK LOCATION)	Addressed in the Level 1 importance list.
1CS001A----MVOO	1.00E-03	1.033	CS PUMP RWST SUCTION MOV CS001A FAILS TO CLOSE	This event represents a containment isolation failure due to a valve failure. The failure results in an open path between the RWST and the containment sump (from the sump through _SI8811A, _CS009A, and _CS001A to the RWST). The containment isolation assessment does not credit the additional isolation tasks that would close the relevant release pathway (by closing _SI8811A) that are performed in the SACRG-1 procedure. If this action were credited, these contributors would be reduced. No additional procedural changes are considered to be required. The scenarios leading to the containment isolation failures include the same contributors reviewed in the Level 1 importance list (e.g., %SXIE 51%, %CCIE 23%, %FL1FPM3A0---T1 7%, %APIE 5%) and the same SAMAs are applicable. No additional SAMAs are suggested.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1CS001B----MVOO	1.00E-03	1.033	CS PUMP RWST SUCTION MOV CS001B FAILS TO CLOSE	This event represents a containment isolation failure due to a valve failure. The failure results in an open path between the RWST and the containment sump (from the sump through _SI8811B, _CS009B, and _CS001B to the RWST). The containment isolation assessment does not credit the additional isolation tasks that would close the relevant release pathway (by closing _SI8811B) that are performed in the SACRG-1 procedure. If this action were credited, these contributors would be reduced. No additional procedural changes are considered to be required. The scenarios leading to the containment isolation failures include the same contributors reviewed in the Level 1 importance list (e.g., %SXIE 51%, %CCIE 23%, %FL1FPM3A0---T1 7%, %APIE 5%) and the same SAMAs are applicable. No additional SAMAs are suggested.
1AP142-----BSLPIE	2.12E-03	1.032	BUS 142 FAILS	Addressed in the Level 1 importance list.
1AF-XTIE--EHXVOA	1.00E+00	1.03	OPERATORS FAIL TO EXECUTE AF CROSSTIE FROM OPPOSITE UNIT	Addressed in the Level 1 importance list.
FLMITIG-M3-T1-FP	6.94E-03	1.026	FAILURE TO MITIGATE >3700 GPM FP FLOOD FOR T1 SCENARIO	Addressed in the Level 1 importance list.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1L2-CNT-VF-CFE4	1.00E-03	1.026	Early Cont Failure due to Direct Containment Heating, Hydrogen Burn, or Stm Expl	Over 99% of the contributors including this event are either small LOCAs or RCP seal LOCAs with AFW available. The early containment failure mechanisms include direct containment heating (DCH), hydrogen burn, and ex-vessel steam explosion. DCH is included because in the scenarios where AFW is available (all cases with event 1L2-CNT-VF-CFE4), RCS pressure is assumed to be reduced to the point where ISGTR is avoided, but not below 200 psig where DCH could be avoided. The SARCG-1 procedure would direct depressurization, but this is not credited in the Level 2 model. Even if depressurization were credited and DCH could be avoided, the early containment failure probability for would remain the same for model as all early containment failure modes are assigned the same failure probability for Byron (based on the WCAP guidance). The most effective means of addressing the risk related to this event is to prevent core damage. The contributors are mainly seal LOCAs (95%). For cases in which aligning alternate cooling to the charging pump fails, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Installation of "no leak" RCP seals is another option (SAMA 4).
%FL1FPM3A0----T1	7.58E-04	1.024	UNIT 1 MAJOR FLOOD (>3,700GPM) FROM FIRE PROTECTION INTO AUX BLDG - COMMON AREA	Addressed in the Level 1 importance list.
%FL1WSM3A0----T1	4.23E-04	1.021	UNIT 1 MAJOR FLOOD (>3,700GPM) FROM NORMAL SERVICE WATER INTO AUX BLDG - COMMON	Addressed in the Level 1 importance list.
1AP-142-1---TRMM	2.76E-02	1.02	SAT 142-1 IS UNAVAILABLE DUE TO MAINTENANCE (141 PWR SUPPLIED FROM SAT 142-2)	Addressed in the Level 1 importance list.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1AP-142-2—TRMM	2.76E-02	1.02	SAT 142-2 IS UNAVAILABLE DUE TO MAINTENANCE	Addressed in the Level 1 importance list.
0AP-DLOOP-GT	2.40E-03	1.019	CONDITIONAL PROBABILITY OF DLOOP GIVEN GENERAL TRANSIENT	Addressed in the Level 1 importance list.
1CV-ALL----HPMOA	1.00E-02	1.017	OPERATORS FAIL TO ESTABLISH COOL SUCTION SOURCE FOR CHARGING PUMP	Addressed in the Level 1 importance list.
1AF01PB-----PDFR	9.58E-03	1.016	DIESEL-DRIVEN PUMP 1AF01PB RANDOM FAILURE TO RUN	Addressed in the Level 1 importance list.
%DC-LODC111-BSIE	5.39E-04	1.015	LOSS OF DC BUS 111 INITIATING EVENT	Addressed in the Level 1 importance list.
1FW-FRH1—HSGOA	1.10E-03	1.015	OPERATORS FAIL RECOGNIZE THE CUE TO SECONDARY COOLING	Addressed in the Level 1 importance list.
%FW-GTR-1—HWIE	7.05E-01	1.015	GENERAL TRANSIENT INITIATING EVENT	Addressed in the Level 1 importance list.
%RCP-HX-RUPT--IE	1.22E-03	1.014	FREQUENCY OF RCP HEAT EXCHANGER RUPTURE	This event represents in ISLOCA caused by failure of the RCP Thermal Barrier HX (tubes within the RCP rupture) and failure to isolate the component cooling return lines that can transport RCS inventory outside containment. The isolation failures include both a valve failure for the automatic isolation and failure of the manual backup isolation action. Additional manual actions to mitigate the event are likely to provide limited benefit due to dependence issues. A potential means of mitigating this event would be to install the same isolation logic used on valve _CC685 on valve_CC9438 (SAMA 22).
1CD05PD-----PMMM	2.87E-02	1.013	MAINTENANCE UNAVAILABILTY OF CD/CB PUMP CD05PD/CB01PD	Addressed in the Level 1 importance list.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%RC-SGTR1-A-HXIE	8.44E-04	1.013	STEAM GENERATOR TUBE RUPTURE IN S/G 1A	Addressed in the Level 1 importance list.
%RC-SGTR1-B-HXIE	8.44E-04	1.013	STEAM GENERATOR TUBE RUPTURE IN S/G 1B	Addressed in the Level 1 importance list.
%RC-SGTR1-C-HXIE	8.44E-04	1.013	STEAM GENERATOR TUBE RUPTURE IN S/G 1C	Addressed in the Level 1 importance list.
%RC-SGTR1-D-HXIE	8.44E-04	1.013	STEAM GENERATOR TUBE RUPTURE IN S/G 1D	Addressed in the Level 1 importance list.
1CC685-----MVOO	1.05E-03	1.013	MOV 1CC685 - FAILS TO CLOSE	This event represents failure to close of the RCP Thermal Barrier Cooling return line isolation valve. The event is tied to the ISLOCA initiating event %RCP-HX-RUPT--IE. The isolation failures include both a valve failure for the automatic isolation and failure of the manual backup isolation action. Additional manual actions to mitigate the event are likely to provide limited benefit due to dependence issues. A potential means of mitigating this event would be to install the same isolation logic used on valve _CC685 on valve_CC9438 (SAMA 22).
1CC9519---HXVOA	1.00E-02	1.013	OPERATOR ACTION TO CLOSE MANUAL VALVE 1CC9519	This action is tied to the ISLOCA initiating event %RCP-HX-RUPT--IE. Currently, this action is a screening value that represents failure to manually isolate the flow in the CC system coming from the thermal barrier HX break and details related to this action are limited. The isolation failures include both a valve failure for the automatic isolation and failure of the manual backup isolation action. Additional manual actions to mitigate the event are likely to provide limited benefit due to dependence issues. A potential means of mitigating this event would be to install the same isolation logic used on valve _CC685 on valve_CC9438 (SAMA 22).
0AP-DLOOP-SC	6.70E-01	1.013	FRACTION OF CONDITIONAL LOOPS THAT ARE SWITCHYARD-CENTERED	Addressed in the Level 1 importance list.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%RC-SLOC1-N-PSIE	1.41E-03	1.011	SMALL LOCA INITIATING EVENT (NON-ISOLABLE)	Addressed in the Level 1 importance list.
1RH-SP-X---HPMOA	7.30E-04	1.011	OPERATORS FAIL TO STOP RH PUMPS	Addressed in the Level 1 importance list.
1AF01PB-----PDMM	7.12E-03	1.01	AF DIESEL-DRIVEN PUMP 1AF01PB UNAVAILABLE DUE TO MAINTENANCE	Addressed in the Level 1 importance list.
1SI-HPR----HSYOA	6.80E-03	1.009	OPERATORS FAIL TO ESTABLISH HIGH PRESSURE RECIRC (SLOW EVENT)	Addressed in the Level 1 importance list.
1FW01PA-----PMMM	1.36E-02	1.009	MAINTENANCE UNAVAILABILITY OF PUMP FW01PA	Addressed in the Level 1 importance list.
1AF01PA-B--CPMFR	8.20E-05	1.009	AF PUMPS FAIL TO RUN DUE TO CCF (2/2)	Addressed in the Level 1 importance list.
1L2-CNT-VF-CFE2	1.00E-03	1.008	Early Cont Failure due to Hydrogen Burn	The scenarios that include this event are essentially all cases in which the operators successfully depressurize the RCS before TI-SGTR and RPV breach. The low pressure conditions preclude all early containment failure modes but hydrogen explosions. While this failure mode is considered to be highly unlikely for the Byron containment design, the event is included in the Level 2 model as a potentially conservative representation of the evolution. A potential means of mitigating early containment failure due to hydrogen detonations would be to install a passive hydrogen ignition system (SAMA 23).
%FW-LMFW1---HWIE	6.90E-02	1.008	TOTAL LOSS OF MAIN FEEDWATER	Addressed in the Level 1 importance list.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1RX-JHEP64-HOADA	8.70E-03	1.008	JOINT HEP FOR 1AF-STARTFWHPMOA AND 1FW-FRH1—HSGOA	This dependent human failure event represents the failure to start AWF on failure of the auto start function and subsequent failure to diagnose the need to align alt heat removal such as FW restoration, AFW X-tie, or B&F cooling. The independent action to align alternate heat removal is relatively reliable, has an alarmed cue, and clear procedure guidance. However, the dependent action chain begins with AFW start, which has a short available time for response and a relatively high HEP that drives the JHEP. Given the longer time frame available for starting Feed and Bleed, the importance of the action may be conservative. However, the AMSAC low level logic could be used to provide a backup start signal for AFW to mitigate these scenarios (SAMA 17).
1SX01AB-----HXFFIE	5.65E-03	1.007	SX PUMP 1B OIL COOLER FAILS DURING OPERATION	Addressed in the Level 1 importance list.
1CV-ALL-D--HPMRA	3.60E-01	1.007	RECOV OF LOSS OF SX SEAL LOCA (COND PROB OF 1CV-ALL-D-HPMRA + 0.21 SEAL FAIL)	Addressed in the Level 1 importance list.
1FWTRAIN-1AHOEXM	1.00E-02	1.007	1FW01PA PUMP TRAIN RESTORATION FAILURE POST T/M	Addressed in the Level 1 importance list.
1RX-JHEP13-HOADA	6.50E-04	1.006	JOINT HEP FOR 1RC-PUMPS–HPMOA AND 0SX-XTIE—HMVOA	Addressed in the Level 1 importance list.
1AF01PA-----PMMM	2.12E-03	1.006	AF MOTOR-DRIVEN PUMP 1AF01PA UNAVAILABLE DUE TO MAINTENANCE	Over 73% of the contributors include either the independent failure of 1FW-FRH1—HSGOA or a joint HEP that includes the action. A potential means of mitigating this scenario woudl be to modify the Startup FW pump to auto start and align on low SG level (using the AMSAC SG level signal) (SAMA 5). Another contributor in a dependent action chain (about 38%) is for the action to refill the diesel driven AFW pump fuel oil day tank. Automating the refuel function is a potential means of reducing the contribution of these events (SAMA 18).

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1AP141——BSLPIE	2.12E-03	1.006	BUS 141 FAILS	Addressed in the Level 1 importance list.
1RX-JHEP17-HOADA	3.60E-05	1.006	JOINT HEP FOR 1AF01PB-FO-HXVOA AND 1FW-FRH1—HSGOA	These are long term scenarios in which diesel driven AFW fuel oil refill fails followed by failure to recognize the need for alternate heat removal. Automating the refuel function is a potential means of reducing the contribution of these events (SAMA 18).
%CD-LCND1—HWIE	5.26E-02	1.005	LOSS OF CONDENSER HEAT SINK	There is not a single dominant event related to the scenarios that include this event, but failure of the AFW system is the condition that drives the need for recirculation mode. Completing the implementation of the AFW X-tie would potentially address many of the contributors related to this event (SAMA 15); 34% alone are linked to CCF of the AFW pumps to run. Given the loss of the condenser initiating event, use of MFW is not an option for this scenario. Failure to swap to recirc mode is another contributor at about 37% of the total for this event. Installing an automated RWST makeup system that would extend the time available to perform the transition to recirculation and, if the actuation is alarmed, it would provide an additional cue to perform the action (SAMA 14).
1RX-JHEP32-HOADA	4.90E-04	1.005	JOINT HEP FOR 0CC-HTX0—HHXOA AND 1CV-ALL—HPMOA	Addressed in the Level 1 importance list.
1AF01PA—PMFS	1.28E-03	1.005	MOTOR-DRIVEN PUMP 1AF01PA RANDOM FAILURE TO START	About 60% of the contributors including this event result in PI-SGTR. A large majority of those cases include the failure to restore FW to operation after AFW failure. If FW was restored, RCS pressure would be reduced to avoid the PI-SGTR event. A potential means of mitigating the PI-SGTR scenarios would be to modify the Startup FW pump to auto start and align on low SG level (using the AMSAC SG level signal) (SAMA 5). For the remaining contributors, which include containment isolation failures, SAMA 5 is also a means of avoiding core damage by restoring secondary side heat removal.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1FW016-----AVMM	7.61E-03	1.005	MAINTENANCE UNAVAILABILITY CONTROL VALVE FW016	This event represents the maintenance unavailability of the motor driven MFW pump flow control valve. All events are total loss of SX events (both units) so that the unavailability of the FW016 valve fails all heat removal capability when combined with a failure of the startup FW pump. Also, about 75% of the contributors including this event result in PI-SGTR. If FW was restored, RCS pressure would be reduced to avoid the PI-SGTR event. For these scenarios, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13).
1FW02P----PMMM	1.36E-02	1.005	MFW MD START UP PUMP FW02P UNAVAILABLE DUE TO MAINTENANCE	Over 99% of the contribution for this event comes from its combination with the Loss of SX initiating event, either all pumps on both units or al SX strainer on both units. A diesel driven SX pump with an auto start function could be used to mitigate CCF failures of the SX pumps. To maximize benefit, backup manual controls would have to be included in the MCR (SAMA 1). Also, about 79% of the contributors including this event result in PI-SGTR. If SG makeup was restored, RCS pressure would be reduced to avoid the PI-SGTR event. For these scenarios, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13).

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1AP131X1M2--CBOO	2.50E-03	1.005	FEED BREAKER 131X1M2 FROM MCC 131X1 FAIL TO CLOSE	These failures, in combination with specific breaker failures, result in the loss of power to the Safety Injection minimum flow valves. For cases in which recirculation mode initiates successfully but subsequently fails due RHR pump failures, loss of power to the _SI8813, _SI8814, and SI8820 valves can result in a containment isolation failure. However, the current containment isolation analysis does not take credit for the additional isolation tasks that would close the relevant release pathway (by closing _SI8811A/B) that are performed in the SACRG-1 procedure. If this action were credited, these contributors would be reduced. No additional procedural changes are considered to be required. The contributors that lead to core damage are those that have been treated in the level 1 importance, including the failure to align alternate cooling or a cool suction source for the charging pumps. Over 70% of the contributors are RCS Seal LOCAs, which could be addressed by providing a self cooled, auto start seal injection pump (SAMA 2) or by installing "no leak" RCP seals (SAMA 4).
1RX-JHEP22-HOADA	2.40E-03	1.005	JOINT HEP FOR 0SX-XTIE---HMVOA AND (1FP-PRI-7X-HMVOA OR 1CV-ALL---HPMOA)	Addressed in the Level 1 importance list.

Table F.5-2a
Byron LERF FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1CD05PDCBPDHOEXM	1.00E-02	1.005	1CD05PD/1CB01PD PUMP TRAIN RESTORATION FAILURE POST T/M (STANDBY ONLY)	About 90% of the contributors including this event are related to the unavailability of either the 141-1 SAT or the 142-2 SAT. Each of the maintenance events prevents the fast transfer to the bus powering the "A" and "C" condensate/condensate booster pumps to the remaining SAT on a trip, which results in failure of the alternate FW capability. To mitigate these events, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). Currently, no credit is taken for manually aligning power to the non-Class 1E buses to restore power to the FW system, which is likely conservative. Providing an alternate, diesel driven SX pump is another potential means of mitigating the events (SAMA 1).
1RX-JHEP47-HOADA	3.30E-04	1.005	JOINT HEP FOR 1RC-PUMPS--HPMOA AND 0SX005----HMVOA AND 1FP-PRI-7X-HMVOA	Addressed in the Level 1 importance list.
1RX-JHEP48-HOADA	3.30E-04	1.005	JOINT HEP FOR 1RC-PUMPS--HPMOA AND 0SX005----HMVOA AND 1CV-ALL----HPMOA	Addressed in the Level 1 importance list.

Table F.5-2b
Byron Late FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%SXIE	9.60E-01	2.994	Indicator for SX Initiating Event	Addressed in the Level 1 importance list.
0SX01AB2AB-CPMFRIE	2.15E-04	1.814	FAILURE OF ALL SX PUMPS (1A/1B/2A/2B) TO RUN DUE TO CCF (4/4)	Addressed in the Level 1 importance list.
FLAG-CCHTX0-U2	5.00E-01	1.522	CCW HTX 0 ALIGNED TO UNIT 2	Addressed in the Level 1 importance list.
FLAG-CCHTX0-U1	5.00E-01	1.442	CCW HTX 0 ALIGNED TO UNIT 1	Addressed in the Level 1 importance list.
1RX-JHEP05-HOADA	3.30E-04	1.253	JHEP - 1RC-PUMPS--HPMOA/0SX-XTIE---HMVOA/(1FP-PRI-7X-HMVOA OR 1CV-ALL—-HPMOA)	Addressed in the Level 1 importance list.
0VA1SUPP—-PNMM	2.10E-02	1.228	UNIT 1 VA SUPPLY PLENUM MAINTENANCE	Addressed in the Level 1 importance list.
0SX-XTIE-D-HMVRA	3.60E-01	1.226	RECOV OF LOSS OF SX SEAL LOCA (COND PROB OF 0SX-XTIE-D-HMVRA + 0.21 SEAL FAIL)	Addressed in the Level 1 importance list.
1SX01PB----PMFRIE	3.19E-02	1.198	FAILURE OF PUMP 1B TO RUN RANDOMLY	Addressed in the Level 1 importance list.
1FP-PRI-7F-HMVRA	4.50E-01	1.143	RECOV OF LOSS OF SX SEAL LOCA (1FP-PRI-7D-HMVRA + 0.21 + 0.1 FP BREAK LOCATION)	Addressed in the Level 1 importance list.
1FW-FWR—EHSYOA	1.40E-02	1.124	OPERATORS FAIL TO EXECUTE FW RESTORATION	Addressed in the Level 1 importance list.
FLMITIG-M3-T1-FP	6.94E-03	1.102	FAILURE TO MITIGATE >3700 GPM FP FLOOD FOR T1 SCENARIO	Addressed in the Level 1 importance list.

Table F.5-2b
Byron Late FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%FL1FPM3A0----T1	7.58E-04	1.097	UNIT 1 MAJOR FLOOD (>3,700GPM) FROM FIRE PROTECTION INTO AUX BLDG - COMMON AREA	Addressed in the Level 1 importance list.
%APIE	9.60E-01	1.087	Indicator for AP Initiating Event	Addressed in the Level 1 importance list.
1AP142------BSLPIE	2.12E-03	1.073	BUS 142 FAILS	Addressed in the Level 1 importance list.
1AP-BOTHSAT-TRMM	6.25E-03	1.053	BOTH U1 SAT OOS FOR TM - 141 PWR VIA 241; 142 PWR VIA 242; 156 - 159 ON UAT	Addressed in the Level 1 importance list.
1FP-PRI-7D-HMVRA	3.50E-01	1.037	RECOV OF LOSS OF SX SEAL LOCA (COND PROB OF 1FP-PRI-7D-HMVRA + 0.21 SEAL FAIL)	Addressed in the Level 1 importance list.
1CV-ALL----HPMOA	1.00E-02	1.032	OPERATORS FAIL TO ESTABLISH COOL SUCTION SOURCE FOR CHARGING PUMP	Addressed in the Level 1 importance list.
1SX01AB-----HXFFIE	5.65E-03	1.03	SX PUMP 1B OIL COOLER FAILS DURING OPERATION	Addressed in the Level 1 importance list.
1CV-ALL-D--HPMRA	3.60E-01	1.028	RECOV OF LOSS OF SX SEAL LOCA (COND PROB OF 1CV-ALL-D-HPMRA + 0.21 SEAL FAIL)	Addressed in the Level 1 importance list.
0AP-DLOOP-GT	2.40E-03	1.025	CONDITIONAL PROBABILITY OF DLOOP GIVEN GENERAL TRANSIENT	Addressed in the Level 1 importance list.
1RX-JHEP13-HOADA	6.50E-04	1.024	JOINT HEP FOR 1RC-PUMPS--HPMOA AND 0SX-XTIE---HMVOA	Addressed in the Level 1 importance list.

Table F.5-2b
Byron Late FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1RX-JHEP22-HOADA	2.40E-03	1.022	JOINT HEP FOR 0SX-XTIE---HMVOA AND (1FP-PRI-7X-HMVOA OR 1CV-ALL---HPMOA)	Addressed in the Level 1 importance list.
FLMITIG-M3-T1-WS	3.90E-03	1.022	FAILURE TO MITIGATE >3700 WS FLOOD FOR T1 SCENARIO	Addressed in the Level 1 importance list.
%FL1WSM3A0----T1	4.23E-04	1.021	UNIT 1 MAJOR FLOOD (>3,700GPM) FROM NORMAL SERVICE WATER INTO AUX BLDG - COMMON	Addressed in the Level 1 importance list.
1AP-142-1---TRMM	2.76E-02	1.021	SAT 142-1 IS UNAVAILABLE DUE TO MAINTENANCE (141 PWR SUPPLIED FROM SAT 142-2)	Addressed in the Level 1 importance list.
1AP-142-2---TRMM	2.76E-02	1.021	SAT 142-2 IS UNAVAILABLE DUE TO MAINTENANCE	Addressed in the Level 1 importance list.
1L2-CNT-VF-BMMTW	5.00E-02	1.021	Probability of BMMT with water in the cavity	These scenarios are those in which core damage has occurred, early containment failure has not occurred, the RCFS have provided containment heat removal, and containment spray has functioned to transfer water to the containment floor. Changes such as flooded rubble beds and core catchers are not suggested since they have been analyzed many times and determined not to be cost beneficial. A potential means of reducing these types of releases would be to install a reactor cavity flooding mechanism that could rapidly transfer water to the cavity at a depth that would provide adequate cooling for the lower part of the RPV (SAMA 24).
%FL1SX-MA0----T2	1.65E-04	1.019	UNIT 1 MAJOR FLOOD (>2000GPM) FROM SX INTO AUX BLDG - COMMON AREA	Addressed in the Level 1 importance list.

Table F.5-2b
Byron Late FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%SP-BB-A-SXPRB-1	1.21E-03	1.017	GLOBAL SPRAY SCENARIO UNIT 1 BYRON AND BRAIDWOOD IN AUX BLDG - SX PUMP ROOM B	Addressed in the Level 1 importance list.
0AP-DLOOP-SC	6.70E-01	1.017	FRACTION OF CONDITIONAL LOOPS THAT ARE SWITCHYARD-CENTERED	Addressed in the Level 1 importance list.
FLMITIG--G-T1-FP	2.23E-04	1.016	FAILURE TO MITIGATE <2000 GPM FP FLOOD FOR T1 SCENARIO	Addressed in the Level 1 importance list.
%CCIE	9.60E-01	1.015	Indicator for CCInitiating Event	Addressed in the Level 1 importance list.
SEAL-U1-TRANS	2.10E-01	1.015	UNIT 1 SEAL LOCA OCCURRED - NON-LOOP SEQUENCES	Addressed in the Level 1 importance list.
%FL1FP-GA0----T1	3.99E-03	1.015	UNIT 1 GENERAL FLOOD (100-2000GPM) FROM FIRE PROTECTION INTO AUX BLDG - COMMON A	Addressed in the Level 1 importance list.
FLMITIG-M2-T1-FP	2.19E-03	1.015	FAILURE TO MITIGATE >2700 GPM FP FLOOD FOR T1 SCENARIO	Addressed in the Level 1 importance list.
1CD05PD-----PMMM	2.87E-02	1.014	MAINTENANCE UNAVAILABILTY OF CD/CB PUMP CD05PD/CB01PD	Addressed in the Level 1 importance list.
%FL1FPM2A0----T1	3.77E-04	1.014	UNIT 1 MAJOR FLOOD M2 (3,700GPM) FROM FIRE PROTECTION INTO AUX BLDG - COMMON ARE	Addressed in the Level 1 importance list.
1FP-PRI-7X-HMVOA	4.60E-03	1.013	OPERATORS FAIL TO ALIGN FP SEAL COOLING - SX NON-PIPE FAILURE INITIATOR	Addressed in the Level 1 importance list.

Table F.5-2b
Byron Late FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1RX-JHEP47-HOADA	3.30E-04	1.013	JOINT HEP FOR 1RC-PUMPS--HPMOA AND 0SX005-----HMVOA AND 1FP-PRI-7X-HMVOA	Addressed in the Level 1 importance list.
1RX-JHEP48-HOADA	3.30E-04	1.013	JOINT HEP FOR 1RC-PUMPS--HPMOA AND 0SX005-----HMVOA AND 1CV-ALL----HPMOA	Addressed in the Level 1 importance list.
1AF-XTIE--EHXVOA	1.00E+00	1.013	OPERATORS FAIL TO EXECUTE AF CROSSTIE FROM OPPOSITE UNIT	Addressed in the Level 1 importance list.
FLMITIG--M-T2-SX	2.09E-03	1.013	FAILURE TO MITIGATE >2000 GPM SX FLOOD FOR T2 SCENARIO	Addressed in the Level 1 importance list.
0SX-MU-LVL-HMVOA	5.30E-03	1.012	OPERATORS FAIL TO RESTORE LEVEL TO SX TOWER BASIN	Addressed in the Level 1 importance list.
1SX01PA-----PMMM	5.90E-03	1.012	SX PUMP 1A UNAVAILABLE DUE TO MAINTENANCE	Addressed in the Level 1 importance list.
1RX-JHEP44-HOADA	5.00E-03	1.012	JOINT HEP FOR 1CV-ALL----HPMOA AND 0CC-SXHTX0-HHXOA	Addressed in the Level 1 importance list.
1CC01A------HXFFIE	5.34E-03	1.011	CCW HTX 1CC01A - LOSS OF FUNCTION	Addressed in the Level 1 importance list.
1SX01A-1B--CPMFRIE	2.93E-04	1.01	FAILURE OF SX PUMPS 1A & 1B TO RUN DUE TO COMMON CAUSE	Addressed in the Level 1 importance list.
1FW01PA-----PMMM	1.36E-02	1.01	MAINTENANCE UNAVAILABILITY OF PUMP FW01PA	Addressed in the Level 1 importance list.
1FW-FRH1---HSGOA	1.10E-03	1.009	OPERATORS FAIL RECOGNIZE THE CUE TO SECONDARY COOLING	Addressed in the Level 1 importance list.

Table F.5-2b
Byron Late FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
FLMITIG-FPCVCOOL	3.90E-03	1.009	FAILURE TO ALIGN FP COOLING TO CV PUMP LUBE OIL COOLER	Addressed in the Level 1 importance list.
%SY-WRDLOOP-DLIE	2.87E-03	1.008	DUAL UNIT WEATHER-RELATED LOSS OF OFFSITE POWER (SUSTAINED)	Addressed in the Level 1 importance list.
1FWTRAIN-1AHOEXM	1.00E-02	1.007	1FW01PA PUMP TRAIN RESTORATION FAILURE POST T/M	Addressed in the Level 1 importance list.
0SX02PB----PDFS	1.94E-02	1.006	SX MAKEUP PUMP-0B FAILS TO START RANDOMLY	Normally, Circulating Water provides makeup to the SX basins, but on loss of offsite power, the Circ Water pumps are unavailable. The SX makeup pumps and Well Water pumps also provide automated basin makeup, but the Well Water level control system includes a non-emergency power dependence. For LOOP events in which the SX makeup pumps fail (over 70% of the contributors), the operators must manually control SX basin level. The action iteslf is relativley reliable with an alarmed cue and clear procedures. No procedure enhancements have been identified that would significatnly improve the reliabitlity of this action. For LOOP scenarios without SX, no heat removal mechanisms are available, but SAMAs that require additional opertor actions would have limited benefit due to human dependence issues. In order to provide heat removal capability for these conditions, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13).
%FW-GTR-1---HWIE	7.05E-01	1.006	GENERAL TRANSIENT INITIATING EVENT	Addressed in the Level 1 importance list.

Table F.5-2b
Byron Late FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1FW02P------PMMM	1.36E-02	1.006	MFW MD START UP PUMP FW02P UNAVAILABLE DUE TO MAINTENANCE	Over 97% of the contribution for this event comes from its combination with the Loss of SX initiating event, either all pumps on both units or al SX strainer on both units. A diesel driven SX pump with an auto start function could be used to mitigate CCF failures of the SX pumps. To maximize benefit, backup manual controls would have to be included in the MCR (SAMA 1). Alternatively, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). The DMS could also provide a means of alternate SG makeup and RCS seal protection, if required (SAMA 11).
1FW016------AVMM	7.61E-03	1.005	MAINTENANCE UNAVAILABILITY CONTROL VALVE FW016	This event represents the maintenance unavailability of the motor driven MFW pump flow control valve. Over 99% of the contributors including this event are total loss of SX events (both units) so that the unavailability of the FW016 valve fails all heat removal capability when combined with a failure of the startup FW pump. For these scenarios, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). The DMS could also provide a means of alternate SG makeup and RCS seal protection, if required (SAMA 11).
0AP-DLOOP-PC	2.20E-01	1.005	FRACTION OF CONDITIONAL LOOPS THAT ARE PLANT-CENTERED	Over 75% of the contributors including this event are loss of SX event with consequential LOOP, which ultimately fails all heat removal capability. For these cases, RCP seal protection can be pursued, but FW restoration is not available and an alternate form of heat removal is required. Replacing the PDP with a self cooled high pressure injection pump with auto start capability would provide a means of maintaining RCP seal injection. For heat removal, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). For the SBO contributors, implementation of the DMS would proivide a means of maintaining heat removal and inventory control indefinitely (SAMA 11).

Table F.5-2b
Byron Late FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
0FP03PA----PMMM	2.62E-02	1.005	FP MOTOR DRIVEN FIRE PUMP 0FP03PA - UNAVAILABLE DUE TO MAINTENANCE	These scenarios including this event are all seal LOCA events caused by loss of normal SX cooling and failure of the fire system to provide alternate seal cooling. A diesel driven SX pump with an auto start function could be used to mitigate CCF failures of the SX pumps. To maximize benefit, backup manual controls would have to be included in the MCR (SAMA 1). Alternatively, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). Instead of replacing the PDP to protect the RCP seals, a passive means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4).
1AP141------BSLPIE	2.12E-03	1.005	BUS 141 FAILS	Addressed in the Level 1 importance list.
0SX02PA----PDFS	1.94E-02	1.005	SX MAKEUP PUMP-0A FAILS TO START RANDOMLY (DIESEL-DRIVEN)	Normally, Circulating Water provides makeup to the SX basins, but on loss of offsite power, the Circ Water pumps are unavailable. The SX makeup pumps and Well Water pumps also provide automated basin makeup, but the Well Water level control system includes a non-emergency power dependence. For LOOP events in which the SX makeup pumps fail (over 78% of the contributors), the operators must manually control SX basin level. The action iteslf is relativley reliable with an alarmed cue and clear procedures. No procedure enhancements have been identified that would significatnly improve the reliabitlity of this action. For LOOP scenarios without SX, no heat removal mechanisms are available, but SAMAs that require additional opertor actions would have limited benefit due to human dependence issues. In order to provide heat removal capability for these conditions, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13).

Table F.5-2b
Byron Late FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
1RC-UBR2—2WRUB	1.52E-01	1.005	CORE UNCOVERY BEFORE POWER RECOVERY AFTER WEATHER-RELATED LOOP OR DLOOP - UBR2	The scenatios including this event are essentially all SBOs with seal LOCA events. For these contributors, implementation of the DMS would proivide a means of maintaining heat removal and inventory control indefinitely (SAMA 11).
1CD05PDCBPDHOEXM	1.00E-02	1.005	1CD05PD/1CB01PD PUMP TRAIN RESTORATION FAILURE POST T/M (STANDBY ONLY)	About 90% of the contributors including this event are related to the unavailability of either the 141-1 SAT or the 142-2 SAT. Each of the maintenance events prevents the fast transfer to the bus powering the "A" and "C" condensate/condensate booster pumps to the remaining SAT on a trip, which results in failure of the alternate FW capability. To mitigate these events, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). Currently, no credit is taken for manually aligning power to the non-Class 1E buses to restore power to the FW system, which is likely conservative. Providing an alternate, diesel driven SX pump is another potential means of mitigating the events (SAMA 1).
0SX01AB2AB-CPMFR	5.89E-07	1.005	FAILURE OF ALL SX PUMPS (1A/1B/2A/2B) TO RUN DUE TO CCF (4/4)	These events represent a loss of all SX due to common cause pump failure (but not as an initiating event). A diesel driven SX pump could be used to mitigate CCF failures of the SX pumps. To maximize benefit, controls would have to be included in the MCR (SAMA 1). For cases in which no seal LOCA occurs, secondary side heat removal can prevent core damage. In order to provide heat removal capability for these conditions, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). For cases with seal LOCAS, the PDP could be replaced with a self-cooled high pressure injection pump with the capability to auto start on loss of charging flow (SAMA 2). An alternate means of preventing a seal LOCA would be to install "no leak" RCP seals (SAMA 4).

Table F.5-2b
Byron Late FPIE Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
0SX02PB----PDMM	2.67E-02	1.005	SX MAKEUP PUMP-0B UNAVAILABLE DUE TO MAINTENANCE (BYRON)	Normally, Circulating Water provides makeup to the SX basins, but on loss of offsite power, the Circ Water pumps are unavailable. The SX makeup pumps and Well Water pumps also provide automated basin makeup, but the Well Water level control system includes a non-emergency power dependence. For LOOP events in which the SX makeup pumps fail (about 65% of the contributors), the operators must manually control SX basin level. The action iteslf is relativley reliable with an alarmed cue and clear procedures. No procedure enhancements have been identified that would significatnly improve the reliabitlity of this action. For LOOP scenarios without SX, no heat removal mechanisms are available, but SAMAs that require additional opertor actions would have limited benefit due to human dependence issues. In order to provide heat removal capability for these conditions, the AFW output flow can be routed to the lube oil coolers to eliminate the SX cooling dependence (SAMA 13). For the loss of DC buss 111 initiating event (17%), the impact is similar and SAMA 13 is also applicable. The DMS could also mitigate these scenarios (SAMA 11).

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
1	Diesel Driven SX Pump	In order to mitigate CCF failure of the SX pumps, a diesel driven pump could be installed in a flood safe location with suction from the WS forebay that includes a suction strainer of an alternate design that is accessible for manual cleaning (in place of the pump discharge strainers). Auto start capability would be required to increase the benefit of the SAMA, but water level interlocks for critical rooms (e.g., SX pump rooms, Aux Building sump) may be required to prevent auto start in SX flooding evolutions.	Byron Level 1 Importance Review	Due to space and exhaust issues, a diesel driven system will require an additional structure to house the pump and diesel engine combination. Limerick estimated the cost of a diesel driven suppression pool cooling system (housed in a dedicated building) to be $25,600,000 in 1989 (PECO 1989). The Limerick enhancement is considered to be similar in scope to this SAMA and it is used as the basis for the cost estimate. Using the CPI to scale to cost to 2011 dollars, the result is $46,430,968 (224.9/124.0 *$25,600,000) (USDL 2012).	As the implementation cost is greater than the MACR, this SAMA has screened from further analysis.
2	Replace the Positive Displacement Pump with a Self Cooled, Auto Start Pump	Loss of SX requires swap of the charging pump suction source to the RWST as well as alignment of an alternate lube oil cooling source to maintain RCP seal injection. Replacing the positive displacement pump with a self cooled pump with the capability to auto start on loss of charging and SX flow would provide a means of seal cooling on loss of the normal pumps. Providing an automatic transfer switch to allow power from either division would enhance the SAMA's capability.	Byron Level 1 Importance Review	Exelon estimates the cost of this SAMA to be $5,751,110.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
3	Auto Start of Standby SX Pump	Automating the start of the standby SX pump would help reduce the reliance of operators to maintain cooling to critical loads. Use of flooding interlocks could be used to prevent auto actuation in flooding scenarios.	Byron Level 1 Importance Review	Exelon estimates the cost of this SAMA to be $1,130,300.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
4	Install "No Leak" RCP Seals	For loss of RCP seal cooling scenarios, a passive means of reducing the probability of an RCP seal LOCA is to replace the existing pump seals with "no leak" seals (e.g., Westinghouse "shield" seals) that are less likely to fail on loss of cooling.	Byron Level 1 Importance Review	Exelon estimates the cost of this SAMA to be $12,230,000.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
5	Modify the Startup Feedwater Pump to Start Using the AMSAC SG Low-Low-Low Level signal to Mitigate AFW Failure	For accident sequences in which main feedwater has tripped and AFW has failed to start, it is necessary to manually restart the FW system for continued SG makeup. By modifying the startup feedwater pump to auto start and align on low steam generator level, the need for operator intervention after AFW failure is essentially eliminated. Use of the AMSAC low-low-low SG level signal is an additional benefit that mitigate start signal failures.	Byron Level 1 Importance Review	Exelon estimates the cost of this SAMA to be $657,200.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
6	Not Used.				
7	Establish Flow to the RH HX on RH Pump Start	To prevent overheating the RH pumps when they are operating on min-flow without CC cooling to the heat exchangers, procedure EP-0 (and potentially others) could be changed to direct the operators to align CC to the RH HX when the RH pumps start. This precludes the need for the operators to rely on a continuous action statement to protect the RH pumps if secondary side cooling is not established.	Byron Level 1 Importance Review	Procedure changes are estimated to cost $100,000 per site.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
8	Install Kill Switches for the Fire Protection Pumps in the MCR	Currently, it is not possible to terminate all flow from the fire protection system in the MCR. In the event of a flood caused by a fire protection system break, the availability of controls in the MCR that would allow the operators to shut down the fire protection pumps would increase the likelihood that the flood could be terminated before critical equipment is damaged.	Byron Level 1 Importance Review	Exelon estimates the cost of this SAMA to be $338,830.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
9	Install Flow Restrictors in Fire Protection Pipes	Large breaks in the fire protection systems are significant contributors to plant risk. Installing flow restrictors in the auxiliary building piping would increase the time available to respond to these flooding events. Locating flow restrictors outside the auxiliary building upstream of valves 0FP209A, 0FP209B, and FP033 would provide adequate protection for auxiliary building floods.	Byron Level 1 Importance Review	Exelon estimates the cost of this SAMA to be $349,300.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
10	Alter Ductwork Between the Aux Bldg Sump Drain Room and the SX Pump Room	Currently, the ductwork between the Auxiliary Building Sump Drain Room and the SX Pump Rooms provides a flowpath for flood water when the Auxiliary Building Sump Drain Room fills with water (at a depth of about 12 feet). Water then flows through the ductwork to the SX pump room and damages the SX pumps. Eliminating this pathway will increase the time available to mitigate the flooding event by precluding SX pump damage from the flooding event.	Byron Level 1 Importance Review	Exelon estimates the cost of this SAMA to be $1,320,300.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
11	Implement DMS	The diverse and flexible coping strategies (FLEX) guide identifies different means of addressing required plant functions in extreme accident conditions, but for the SAMA analysis a specific approach, called the Diverse Mitigation System (DMS), is proposed. A portable 480V AC generator is proposed as a means of supporting long term AFW operation by means of maintaining instrumentation and control power for the system by energizing the buses used for the battery chargers. A portable, engine driven SG makeup pump would provide an alternate means of SG makeup, with injection connections available on different divisions. Fire protection should provide both CST makeup and a suction source connection for the portable SG makeup pump. Use of high temperature RCP seals would limit primary system leakage and the positive displacement pump could be replaced by one that could be powered by the portable generator for long term RCS makeup. A means of providing borated makeup to the RWST is also required, which could potentially be performed using the fire protection system and an eductor. Finally, a connection point to an outside source would have to be provide for the containment spray system for long term spray capability in an SBO.	Byron Level 1 Importance Review	For this application, the cost is based on a reduced scope of the DMS that accounts only for the alternate 480V AC power source, alternate SG makeup pump, and "no-leak" RCP seals. Ginna estimated the cost of a skid mounted 480V AC generator to be $400,000 (RG&E 2002). An additional $400,000 is assumed for the cost of the portable, engine driven SG makeup pump to address conditions where the AFW pumps are unavailable. This is combined with the cost of SAMA 4 to yield a total of $13,030,000.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
12	Modify Practices for SAT Maintenance or Enhance Procedures	For on-line SAT maintenance, a single SAT can provide power to the loads normally supplied by both SATs on a given unit. However, in order to align this configuration, there is a transition period during which both SATs are unable to provide power to any bus. For loss of SX events, this condition is critical because it eliminates the ability to provide power to the Feedwater system for heat removal, which is the only heat removal mechanism available without SX (due to system dependencies). Precluding on-line SAT maintenance is a potential means of reducing this on-line risk. Alternatively, procedures from the Braidwood site that are no longer used at Byron could be modified to serve as contingency procedures for these maintenance evolutions. Braidwood has procedures to provide power to the buses required to power the Startup Feedwater pump, but they are not clearly linked to address the SAT maintenance scenario. Providing clear contingency procedures to perform the required power alignment could help reduce the risk of these scenarios.	Byron Level 1 Importance Review	Exelon plant personnel estimate that moving the SAT maintenance to an outage would require 1 week of additional time each outage at a cost of about $1 million a day. For a two year cycle over 20 years, the total additional time would be 70 days for a total of $70 million.	As the implementation cost is greater than the MACR, this SAMA has screened from further analysis.
13	Alternate AFW Cooling with Seal Protection	For loss of SX events with consequential LOOP, the AFW lube oil coolers are unavailable and the AFW pumps are assumed to fail. The AFW discharge flow could be routed back to the lube oil coolers to provide a self-cooling mechanism that would eliminate the SX dependence. The cooling water return path could potentially be returned to the AFW pump discharge path. For RCP seal protection, replacing the positive displacement pump with a self cooled pump with the capability to auto start on loss of charging flow and/or high seal injection water temp would provide a success path.	Byron Level 1 Importance Review	Ginna estimated the cost of the AFW change to be $200,000 (RG&E 2002). This is used with the cost of SAMA 2 to get a the total of $5,951,110 for this SAMA.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
14	Automated RWST Makeup	For SGTR scenarios in which cooldown has failed, installing an automated RWST makeup system could provide an means of maintaining injection indefinitely. The makeup pump should be powered from a diesel backed bus. A boron source is required to ensure criticality does not occur. Including an alarm that identifies system actuation would provide an additional cue to address plant issues that have led to RWST depletion.	Byron Level 1 Importance Review	TMI estimated the cost of a similar SAMA to be $3,800,000 (Exelon 2008a).	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
15	Resolve Regulatory Issues and Complete Implementation of the Inter Unit AFW Cross-tie	The inter unit AFW cross-tie is in place at the site, but regulatory issues must be resolved before it can be considered "implemented". Once the process is complete, it will allow one unit to use the other unit's AFW system to provide SG makeup. The cross-tie valve requires local, manual action for operation.	Byron Level 1 Importance Review	Not Applicable	No significant expenditures are required to complete this enhancement, but the modification was not official at the time of the SAMA development and it is not credited in the PRA model of record. Retained for Phase 2 as a sensitivity analysis to demonstrate how crediting the cross-tie will impact the SAMA analysis.
16	Install High Flow Sensors On the Non-Essential Service Water System	Installing flow sensors in the WS lines with logic to trip the pumps on high flow conditions is a potential means of terminating WS flood events before critical systems are damaged.	Byron Level 1 Importance Review	Exelon estimates the cost of this SAMA to be $993,800.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
17	Use AMASC for Alternate LOW SG Level AFW Initiation	For non-ATWS, the AMSAC logic could be used to provide a backup initiation signal for AFW. This would mitigate failures of the normal SSPS initiation system.	Byron Level 1 Importance Review	Exelon estimates the cost of this SAMA to be $981,730.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
18	Automate Refill of the Diesel Driven AFW Pump Fuel Oil Day Tank	The action to refill the diesel driven AFW pump fuel oil day tank is currently a manual action. Level sensors in the tank could be used to control a fill valve on the gravity feed line to automate the function, which would potentially improve system reliability.	Byron Level 1 Importance Review	Exelon estimates the cost of this SAMA to be $1,608,680.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
19	Replace MOVs in the RHR Discharge Line with Valves that Can Isolate an ISLOCA Event	For cases in which the check valves fail in the RHR discharge line and an ISLOCA occurs, the event could be terminated if the containment isolation valves were capable of closing after the ISLOCA has occurred. Replacing the existing valves (MOVs _SI8809A, _SI8809B, and _SI8840) with an alternate design could provide this capability.	Byron Level 1 Importance Review	Wolf Creek Estimated $600,000 for two valves (WCNOC 2006), so $900,000 is assumed for the three valve change required for Byron.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
20	Disallow On-Line RHR HX Maintenance	For cases in which one RHR HX is out of service for maintenance, the plant is vulnerable to single failure events for certain initiating events that require heat removal (for example LOCAs). Preventing on-line maintenance of the RHR heat exchangers would prevent the associated core damage scenarios.	Byron Level 1 Importance Review	Exelon plant personnel estimate that moving the RHR maintenance to an outage would require 2-3 days of additional time each outage at a cost of about $1 million a day. For a two year cycle over 20 years, the total additional time would be 20-30 days for a total of $20 million to $30 million. $20 million is used here.	As the implementation cost is greater than the MACR, this SAMA has screened from further analysis.

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
21	Install an Emergency Isolation Valve in each of the RHR Suction Lines	For cases in which the two motor operated isolation valves in the RHR suction line fail and result in the overpressurization of the low pressure RHR piping, a LOCA outside containment can occur if the RHR piping breaks. In the event of a piping break, having an additional, normally open MOV located on the high pressure piping capable of closing against RCS pressure would provide a means of terminating the ISLOCA event.	Byron LERF Importance Review	For installing four new MOVs in the high pressure injection system (rather than replacing valves), TMI estimated a cost of $3,150,000 (Exelon 2008a). For the two valves required by this SAMA, this cost is divided by two to yield about $1,600,000.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
22	Install the Same High Flow Isolation Logic Used on Valve _CC685 on Valve _CC9438	In the event that an RCP Thermal Barrier Cooling heat exchangers breaks, the current in-containment relief valves are designed to relieve pressure at 2485 psig, which would be within the capacity of the piping up to the isolation boundary. However, if the Thermal Barrier Cooling Hx were to break and the isolation valve failed to close, the CC system could be over pressurized and inventory could be transferred outside containment through the 150 psid relief valves. A potential means of mitigating this event would be to install the same isolation logic used on valve _CC685 on valve_CC9438.	Byron LERF Importance Review	A similar valve logic change was estimated to be $250,000 in the Harris SAMA analysis (CPL 2006).	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
23	Install a Passive Hydrogen Ignition System	For accident scenarios resulting in the generation of hydrogen in quantities sufficient to cause significant hydrogen detonations, containment failure is possible. A potential means of preventing these containment failure scenarios would be to install a passive hydrogen ignition system.	Byron LERF Importance Review	Calvert Cliffs estimated the cost of this enhancement to be $760,000 (BGE 1998).	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
24	Provide a Reactor Vessel Exterior Cooling System	This SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head can be submerged in water. For Byron, use of existing emergency power is adequate to address the highest contributors.	Byron Late Release Importance Review	Calvert Cliffs estimated the cost of this enhancement to be $2,500,000 (BGE 1998), but it included its own power source. The cost is reduced by a factor of 2 to account for the use of existing power emergency power at Byron ($1,250,000).	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
25	Install a Filtered Containment Vent	This SAMA would provide a means of preventing long term containment overpressure failures by relieving pressure through a scrubbed release path. While post core damage venting is undesirable, a controlled scrubbed release is preferable to an unscrubbed release through a containment break.	General Late Release Mitigation Method	Information for PWRs is limited, but the Limerick SAMDA analysis provided costs that ranged from $5.7 million to $11.3 million (PECO 1989). $5.7 million is used for this analysis.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
26	DMS Using a Dedicated Generator, Self Cooled Charging Pump, and a Portable AFW Pump	This SAMA represents an alternate configuration of the DMS in which seal LOCAs are prevented using a seal injection system rather than by "no leak" seals. A dedicated 480V AC generator is proposed as a means of supporting long term SG makeup by maintaining the buses used for the battery chargers for SG level instrumentation and for powering a self-cooled primary side seal injection pump. A portable, engine driven SG makeup pump would provide an alternate means of SG makeup, with injection connections available on different divisions. Fire protection should provide both CST makeup and a suction source connection for the portable SG makeup pump A means of providing borated makeup to the RWST is also required, which could potentially be performed using the fire protection system and an eductor. Finally, a connection point to an outside source would have to be provided for the containment spray system for long term spray capability in an SBO.	Industry SAMA Review	For this application, the cost estimate is derived from a reduced scope of equipment for simplicity. DC Cook estimated the cost of an RCP seal injection system with a dedicated deisel to be $2,000,000 (I&M 2003). The RCP seal injection DG is also assumed to support SG level instrumentation. To account for the cost of a portable SG makeup pump, the cost of a portable generator from Ginna (RG&E 2002) is used as a surrogate ($400,000). The total cost of the SAMA is $2,400,000.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
27	Protect RH, SI, and CVCS Cubicle Cooling Fan Cables in Fire Zone 11.3-0.	While most of the equipment damage in the dominant fire scenario in zone 11.3-0 is related to the loss of MCC 132X1 (the ignition source), protecting the cables related to the RH, SI, and CVCS pump cubicle cooling fans may reduce the likelihood that room cooling will be failed for those pumps.	Byron Fire Results	Salem estimated the cost of installing cable wrap and fire barriers to maintain divisional separation to be $975,000 (PSEG 2009). While each fire barrier installation is unique, this is used as a rough estimate of the Byron cost.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
28	Install Fire Barriers around MCC 134X	Fires that start in this MCC are exacerbated by the propagation of the fire to nearby equipment. Installation of fire barriers to protect the equipment could mitigate the consequences of the fires.	Byron Fire Results	Salem estimated the cost of installing cable wrap and fire barriers to maintain divisional separation to be $975,000 (PSEG 2009). While each fire barrier installation is unique, this is used as a rough estimate of the Byron cost.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
29	Automate Swap to Recirculation Mode	Fully automating the swap to recirculation mode and removing the operator from the process can improve the reliability of the action.	Byron Fire Results and Level 1 Importance Review	V.C. Summer estimated to cost of this enhancement to be $1,225,000 (SCE&GC 2002).	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.
30	Protect AFW Cables in the Aux Building General Area, Elevation 383'	Fires initiating in the AFW 1A pump result in damage to the AFW 1B and 2A pumps. Protecting the AFW cables in these areas will improve the potential for pumps 1B and 2A to remain available in these scenarios for SG makeup.	Byron Fire Results	Salem estimated the cost of installing cable wrap and fire barriers to maintain divisional separation to be $975,000 (PSEG 2009). While each fire barrier installation is unique, this is used as a rough estimate of the Byron cost.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.

Table F.5-3
Byron Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
31	Protect Cables for 2AF013A, B, and D in the Aux Building General Area, Elevation 426'	Fires in this are (initiated in MCC 234X, for example) can fail both trains of AFW. Protecting the cables that are vulnerable (A, B, and D in the important scenario), would help preserve the AFW function.	Byron Fire Results	Salem estimated the cost of installing cable wrap and fire barriers to maintain divisional separation to be $975,000 (PSEG 2009). While each fire barrier installation is unique, this is used as a rough estimate of the Byron cost.	As the implementation cost is less than the MACR, this SAMA has been retained for Phase 2 analysis.

Table F.6-1
Byron Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
2	Replace the Positive Displacement Pump with a Self Cooled, Auto Start Pump	Loss of SX requires swap of the charging pump suction source to the RWST as well as alignment of an alternate lube oil cooling source to maintain RCP seal injection. Replacing the positive displacement pump with a self cooled pump with the capability to auto start on loss of charging and SX flow would provide a means of seal cooling on loss of the normal pumps. Providing an automatic transfer switch to allow power from either division would enhance the SAMA's capability.	Byron Level 1 Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".
3	Auto Start of Standby SX Pump	Automating the start of the standby SX pump would help reduce the reliance of operators to maintain cooling to critical loads. Use of flooding interlocks could be used to prevent auto actuation in flooding scenarios.	Byron Level 1 Importance Review	This SAMA's net value is positive and is classified as potentially "cost beneficial".
4	Install "No Leak" RCP Seals	For loss of RCP seal cooling scenarios, a passive means of reducing the probability of an RCP seal LOCA is to replace the existing pump seals with "no leak" seals (e.g., Westinghouse "shield" seals) that are less likely to fail on loss of cooling.	Byron Level 1 Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".

Table F.6-1
Byron Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
5	Modify the Startup Feedwater Pump to Start Using the AMSAC SG Low-Low-Low Level signal to Mitigate AFW Failure	For accident sequences in which main feedwater has tripped and AFW has failed to start, it is necessary to manually restart the FW system for continued SG makeup. By modifying the startup feedwater pump to auto start and align on low steam generator level, the need for operator intervention after AFW failure is essentially eliminated. Use of the AMSAC low-low-low SG level signal is an additional benefit that mitigate start signal failures.	Byron Level 1 Importance Review	This SAMA's net value is positive and is classified as potentially "cost beneficial".
6	Not Used.			
7	Establish Flow to the RH HX on RH Pump Start	To prevent overheating the RH pumps when they are operating on min-flow without CC cooling to the heat exchangers, procedure EP-0 (and potentially others) could be changed to direct the operators to align CC to the RH HX when the RH pumps start. This precludes the need for the operators to rely on a continuous action statement to protect the RH pumps if secondary side cooling is not established.	Byron Level 1 Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".

Table F.6-1
Byron Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
8	Install Kill Switches for the Fire Protection Pumps in the MCR	Currently, it is not possible to terminate all flow from the fire protection system in the MCR. In the event of a flood caused by a fire protection system break, the availability of controls in the MCR that would allow the operators to shut down the fire protection pumps would increase the likelihood that the flood could be terminated before critical equipment is damaged.	Byron Level 1 Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".
9	Install Flow Restrictors in Fire Protection Pipes	Large breaks in the fire protection systems are significant contributors to plant risk. Installing flow restrictors in the auxiliary building piping would increase the time available to respond to these flooding events. Locating flow restrictors outside the auxiliary building upstream of valves 0FP209A, 0FP209B, and FP033 would provide adequate protection for auxiliary building floods.	Byron Level 1 Importance Review	This SAMA's net value is positive and is classified as potentially "cost beneficial".
10	Alter Ductwork Between the Aux Bldg Sump Drain Room and the SX Pump Room	Currently, the ductwork between the Auxiliary Building Sump Drain Room and the SX Pump Rooms provides a flowpath for flood water when the Auxiliary Building Sump Drain Room fills with water (at a depth of about 12 feet). Water then flows through the ductwork to the SX pump room and damages the SX pumps. Eliminating this pathway will increase the time available to mitigate the flooding event by precluding SX pump damage from the flooding event.	Byron Level 1 Importance Review	This SAMA's net value is positive and is classified as potentially "cost beneficial".

Table F.6-1
Byron Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
11	Implement DMS	The diverse and flexible coping strategies (FLEX) guide identifies different means of addressing required plant functions in extreme accident conditions, but for the SAMA analysis a specific approach, called the Diverse Mitigation System (DMS), is proposed. A portable 480V AC generator is proposed as a means of supporting long term AFW operation by means of maintaining instrumentation and control power for the system by energizing the buses used for the battery chargers. A portable, engine driven SG makeup pump would provide an alternate means of SG makeup, with injection connections available on different divisions. Fire protection should provide both CST makeup and a suction source connection for the portable SG makeup pump. Use of high temperature RCP seals would limit primary system leakage and the positive displacement pump could be replaced by one that could be powered by the portable generator for long term RCS makeup. A means of providing borated makeup to the RWST is also required, which could potentially be performed using the fire protection system and an eductor. Finally, a connection point to an outside source would have to be provide for the containment spray system for long term spray capability in an SBO.	Byron Level 1 Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".
13	Alternate AFW Cooling with Seal Protection	For loss of SX events with consequential LOOP, the AFW lube oil coolers are unavailable and the AFW pumps are assumed to fail. The AFW discharge flow could be routed back to the lube oil coolers to provide a self-cooling mechanism that would eliminate the SX dependence. The cooling water return path could potentially be returned to the AFW pump discharge path. For RCP seal protection, replacing the positive displacement pump with a self cooled pump with the capability to auto start on loss of charging flow and/or high seal injection water temp would provide a success path.	Byron Level 1 Importance Review	This SAMA's net value is positive and is classified as potentially "cost beneficial".

Table F.6-1
Byron Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
14	Automated RWST Makeup	For SGTR scenarios in which cooldown has failed, installing an automated RWST makeup system could provide an means of maintaining injection indefinitely. The makeup pump should be powered from a diesel backed bus. A boron source is required to ensure criticality does not occur. Including an alarm that identifies system actuation would provide an additional cue to address plant issues that have led to RWST depletion.	Byron Level 1 Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".
15	Resolve Regulatory Issues and Complete Implementation of the Inter Unit AFW Cross-tie	The inter unit AFW cross-tie is in place at the site, but regulatory issues must be resolved before it can be considered "implemented". Once the process is complete, it will allow one unit to use the other unit's AFW system to provide SG makeup. The cross-tie valve requires local, manual action for operation.	Byron Level 1 Importance Review	This SAMA's net value is positive and is classified as potentially "cost beneficial".
16	Install High Flow Sensors On the Non-Essential Service Water System	Installing flow sensors in the WS lines with logic to trip the pumps on high flow conditions is a potential means of terminating WS flood events before critical systems are damaged.	Byron Level 1 Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".

Table F.6-1
Byron Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
17	Use AMASC for Alternate LOW SG Level AFW Initiation	For non-ATWS, the AMSAC logic could be used to provide a backup initiation signal for AFW. This would mitigate failures of the normal SSPS initiation system.	Byron Level 1 Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".
18	Automate Refill of the Diesel Driven AFW Pump Fuel Oil Day Tank	The action to refill the diesel driven AFW pump fuel oil day tank is currently a manual action. Level sensors in the tank could be used to control a fill valve on the gravity feed line to automate the function, which would potentially improve system reliability.	Byron Level 1 Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".
19	Replace MOVs in the RHR Discharge Line with Valves that Can Isolate an ISLOCA Event	For cases in which the check valves fail in the RHR discharge line and an ISLOCA occurs, the event could be terminated if the containment isolation valves were capable of closing after the ISLOCA has occurred. Replacing the existing valves (MOVs _SI8809A, _SI8809B, and _SI8840) with an alternate design could provide this capability.	Byron Level 1 Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".

Table F.6-1
Byron Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
21	Install an Emergency Isolation Valve in each of the RHR Suction Lines	For cases in which the two motor operated isolation valves in the RHR suction line fail and result in the overpressurization of the low pressure RHR piping, a LOCA outside containment can occur if the RHR piping breaks. In the event of a piping break, having an additional, normally open MOV located on the high pressure piping capable of closing against RCS pressure would provide a means of terminating the ISLOCA event.	Byron LERF Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".
22	Install the Same High Flow Isolation Logic Used on Valve _CC685 on Valve _CC9438	In the event that an RCP Thermal Barrier Cooling heat exchangers breaks, the current in-containment relief valves are designed to relieve pressure at 2485 psig, which would be within the capacity of the piping up to the isolation boundary. However, if the Thermal Barrier Cooling Hx were to break and the isolation valve failed to close, the CC system could be over pressurized and inventory could be transferred outside containment through the 150 psid relief valves. A potential means of mitigating this event would be to install the same isolation logic used on valve _CC685 on valve_CC9438.	Byron LERF Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".
23	Install a Passive Hydrogen Ignition System	For accident scenarios resulting in the generation of hydrogen in quantities sufficient to cause significant hydrogen detonations, containment failure is possible. A potential means of preventing these containment failure scenarios would be to install a passive hydrogen ignition system.	Byron LERF Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".

Table F.6-1
Byron Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
24	Provide a Reactor Vessel Exterior Cooling System	This SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head can be submerged in water. For Byron, use of existing emergency power is adequate to address the highest contributors.	Byron Late Release Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".
25	Install a Filtered Containment Vent	This SAMA would provide a means of preventing long term containment overpressure failures by relieving pressure through a scrubbed release path. While post core damage venting is undesirable, a controlled scrubbed release is preferable to an unscrubbed release through a containment break.	General Late Release Mitigation Method	This SAMA's net value is positive and is classified as potentially "cost beneficial".
26	DMS Using a Dedicated Generator, Self Cooled Charging Pump, and a Portable AFW Pump	This SAMA represents an alternate configuration of the DMS in which seal LOCAs are prevented using a seal injection system rather than by "no-leak" seals. A dedicated 480V AC generator is proposed as a means of supporting long term SG makeup by maintaining the buses used for the battery chargers for SG level instrumentation and for powering a self-cooled primary side seal injection pump. A portable, engine driven SG makeup pump would provide an alternate means of SG makeup, with injection connections available on different divisions. Fire protection should provide both CST makeup and a suction source connection for the portable SG makeup pump. A means of providing borated makeup to the RWST is also required, which could potentially be performed using the fire protection system and an eductor. Finally, a connection point to an outside source would have to be provided for the containment spray system for long term spray capability in an SBO.	Industry SAMA Review	This SAMA's net value is positive and is classified as potentially "cost beneficial".

Table F.6-1
Byron Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
27	Protect RH, SI, and CVCS Cubicle Cooling Fan Cables in Fire Zone 11.3-0.	While most of the equipment damage in the dominant fire scenario in zone 11.3-0 is related to the loss of MCC 132X1 (the ignition source), protecting the cables related to the RH, SI, and CVCS pump cubicle cooling fans may reduce the likelihood that room cooling will be failed for those pumps.	Byron Fire Results	This SAMA's net value is positive and is classified as potentially "cost beneficial".
28	Install Fire Barriers around MCC 134X	Fires that start in this MCC are exacerbated by the propagation of the fire to nearby equipment. Installation of fire barriers to protect the equipment could mitigate the consequences of the fires.	Byron Fire Results	This SAMA's net value is negative and is classified as not "cost beneficial".
29	Automate Swap to Recirculation Mode	Fully automating the swap to recirculation mode and removing the operator from the process can improve the reliability of the action.	Byron Fire Results and Level 1 Importance Review	This SAMA's net value is negative and is classified as not "cost beneficial".

Table F.6-1
Byron Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
30	Protect AFW Cables in the Aux Building General Area, Elevation 383'	Fires initiating in the AFW 1A pump result in damage to the AFW 1B and 2A pumps. Protecting the AFW cables in these areas will improve the potential for pumps 1B and 2A to remain available in these scenarios for SG makeup.	Byron Fire Results	This SAMA's net value is negative and is classified as not "cost beneficial".
31	Protect Cables for 2AF013A, B, and D in the Aux Building General Area, Elevation 426'	Fires in this are (initiated in MCC 234X, for example) can fail both trains of AFW. Protecting the cables that are vulnerable (A, B, and D in the important scenario), would help preserve the AFW function.	Byron Fire Results	This SAMA's net value is positive and is classified as potentially "cost beneficial".

Table F.7-1
Generic Economic Sensitivity Case Values

Variable	Description	Base Case Value	Sensitivity Value
DPRATE[(1)]	Property depreciation rate (per yr)	0.20	0.20
DSRATE[(2)]	Investment rate of return (per yr)	0.07	0.07
EVACST[(3)]	Daily cost for a person who has been evacuated ($/person-day)	56.43	112.86
RELCST[(3)]	Daily cost for a person who is relocated ($/person-day)	56.43	112.86
POPCST[(3)]	Population relocation cost ($/person)	10,450	20,900
CDFRM0[(3)]	Cost of farm decontamination for two levels of decontamination ($/hectare)[(5)]	1,176 2,613	2,352 5,226
CDNFRM[(3)]	Cost of non-farm decontamination per resident person for various levels of decontamination ($/person)[(5)]	6,270 16,720	12,540 33,440
TIMDEC[(1)]	Decontamination time for each level[(5)]	2 & 4 months	2 & 12 months
DLBCST[(3)]	Average cost of decontamination labor ($/man-year)	73,150	146,300
TFWKF[(1)]	Time decontamination workers spend in farm land contaminated areas[(5)]	1/10 1/3	¼ 1/4
TWWNF[(1)]	Time decontamination workers spend in non-farm land contaminated areas[(5)]	1/3 1/3	1/4 1/4
VALWF0[(4)]	Value of farm wealth ($/hectare)	11,444	11,444
VALWNF[(4)]	Value of non-farm wealth ($/person)	231,318	231,318

(1) DPRATE uses NUREG/CR-4551 value (NRC 1990b).

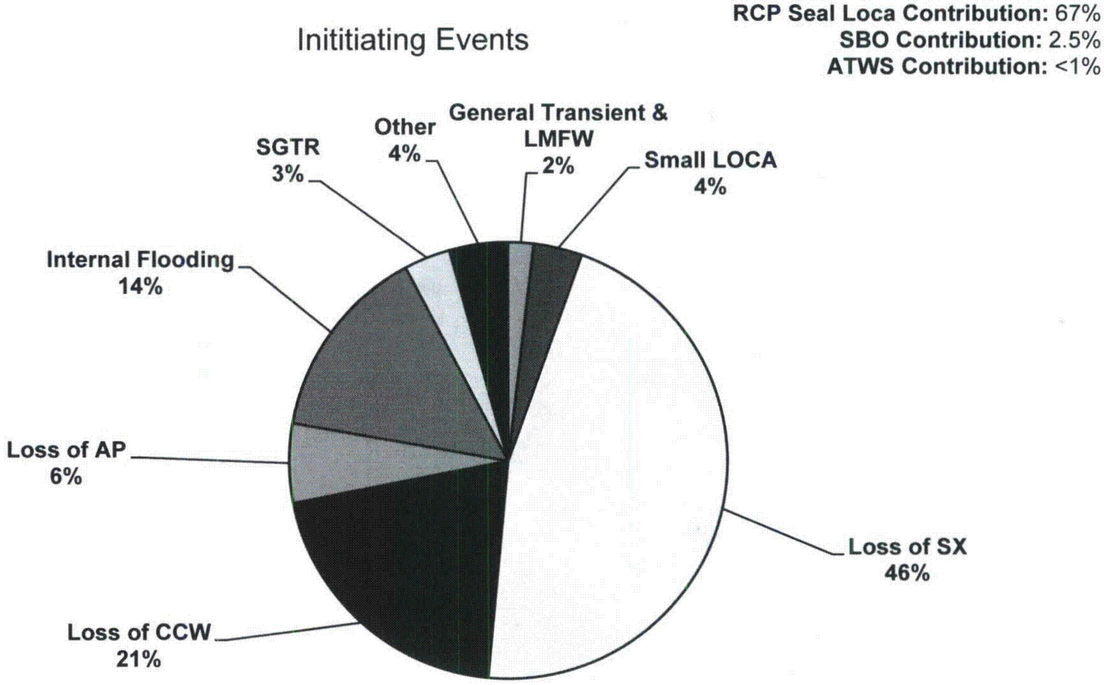
(2) DSRATE based on NUREG/BR-0058 (NRC 2004a).

(3) These parameters use the NUREG/CR-4551 values (NRC 1990b), updated to July 2012 using the consumer price index for base case. They are increased by a factor of 2 for sensitivity.

(4) VALWF0 and VALWNF are site specific values based on 2007 National Agriculture Census (USDA 2009) and Bureau of Economic Analysis 2007 data (BEA 2012), updated to the July 2012 using the consumer price index. They are not revised for the sensitivity case.

(5) Two decontamination levels are modeled, consistent with NUREG/CR-4551 (NRC 1990b). The first value is associated with a dose reduction factor of 3. The second value is associated with a dose reduction factor of 15. The dose reduction factors of 3 and 15 are not revised for the sensitivity case.

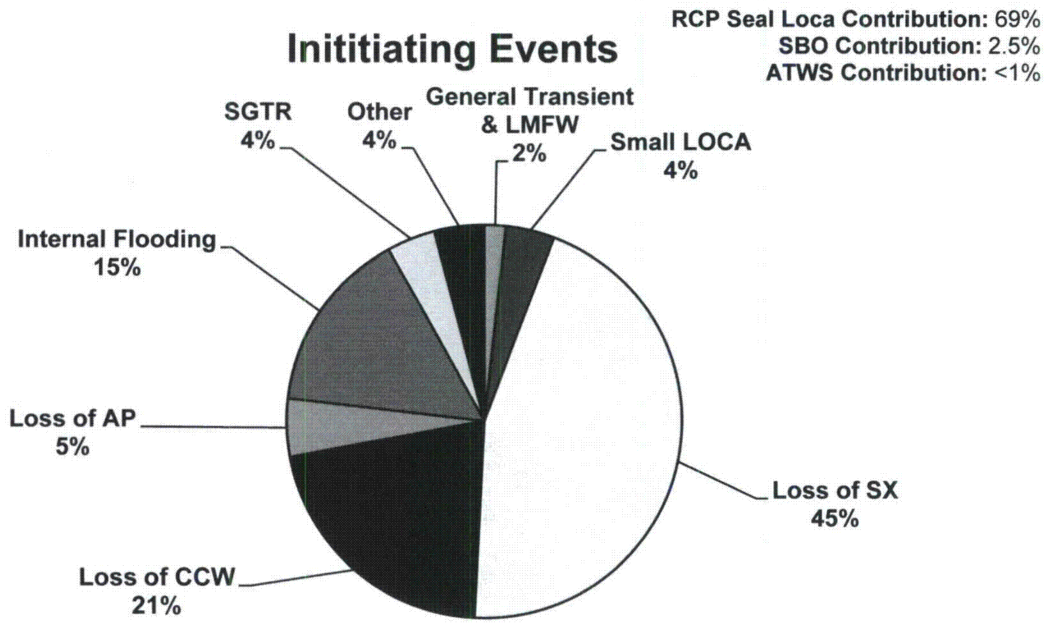
F.10 FIGURES



Initiating event[3]	CDF Contribution (based on percent contribution)
LOSS OF SX	1.83E-05
LOSS OF CCW	8.34E-06
INTERNAL FLOODING	5.56E-06
LOSS OF AP	2.38E-06
SMALL LOCA	1.59E-06
OTHER	1.59E-06
SGTR	1.19E-06
GEN TRANSIENT &LMFW	7.94E-07
TOTAL	3.97E-05

Figure F.2-1
Byron Unit 1 Contribution to CDF by Initiating Event

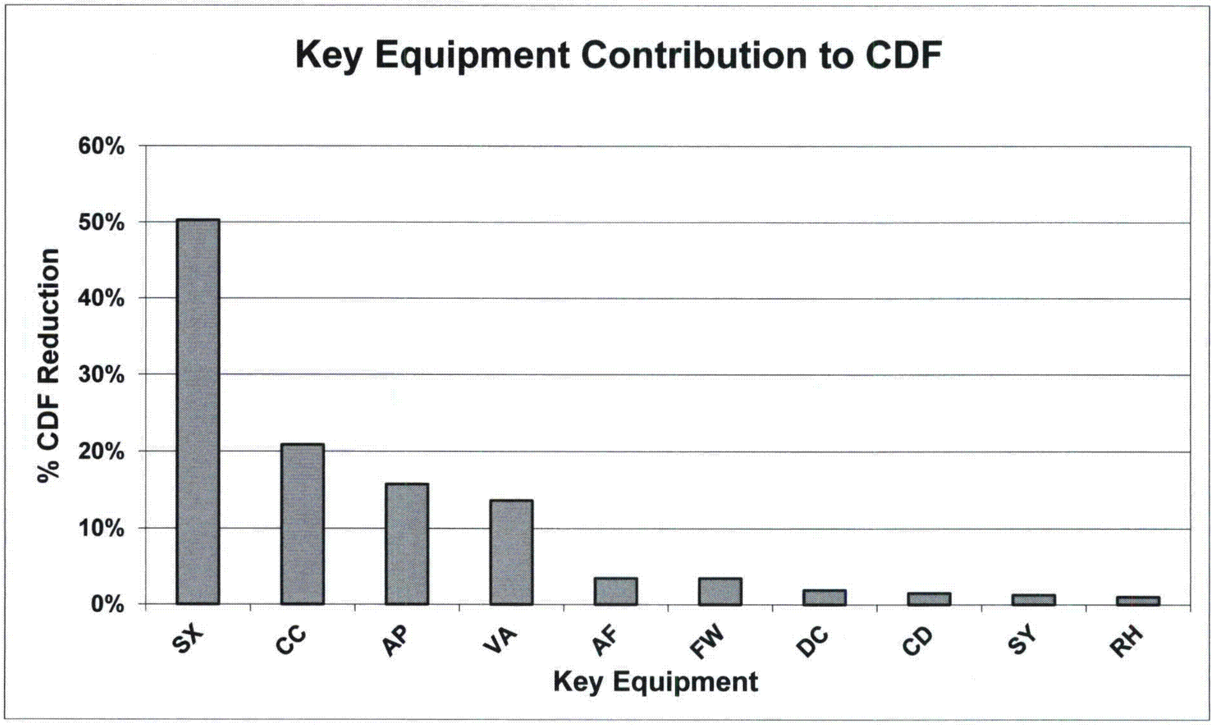
[3] The contributions from the consequential events are RCP seal LOCA: 2.66E-05, SBO: 9.93E-07, ATWS: <3.97E-07.



INITIATING EVENT[4]	CDF CONTRIBUTION
LOSS OF SX	1.72E-05
SMALL LOCA	8.02E-06
INTERNAL FLOODING	5.73E-06
LOSS OF CCW	1.91E-06
OTHER	1.53E-06
SGTR	1.53E-06
MEDIUM LOCA	1.53E-06
LOSS OF AP	7.64E-07
GEN TRANSIENT &LMFW	1.72E-05
TOTAL	3.82E-05

Figure F.2-2
Byron Unit 2 Contribution to CDF by Initiating Event

[4] The contributions from the consequential events are RCP seal LOCA: 2.64E-05, SBO: 9.55E-07, ATWS: <3.82E-07.



Legend		
System Acronym	System Name	
SX	F.10.1.1	ESSENTIAL SERVICE WATER
CC	F.10.1.2	COMPONENT COOLING WATER
AP	F.10.1.3	AUXILIARY ELECTRIC POWER
AF	F.10.1.4	AUXILIARY FEEDWATER
FW	F.10.1.5	MAIN FEEDWATER
DC	F.10.1.6	DC POWER
SY	F.10.1.7	SWITCHYARD
RH	F.10.1.8	RESIDUAL HEAT REMOVAL
VA	F.10.1.9	AUXILIARY BUILDING HVAC
DG	F.10.1.10	DIESEL GENERATORS

Figure F.2-3
Unit 1 Fusell-Veselly by System based on CDF

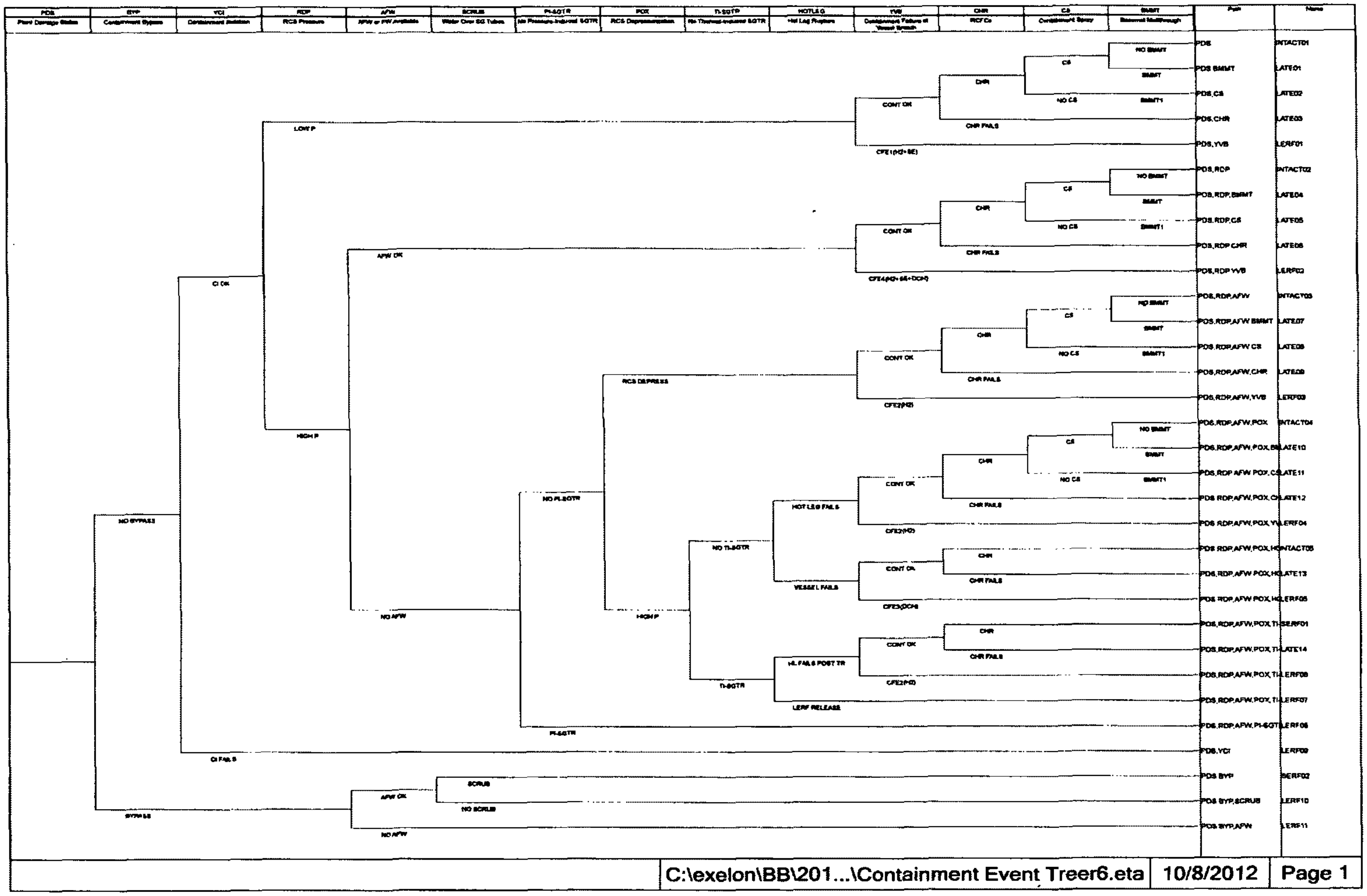


Figure F.2-4
Containment Event Tree

F.11 REFERENCES[5]

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BGE 1998	BGE (Baltimore Gas and Electric). 1998. Calvert Cliffs Application for License Renewal, Attachment 2 of Appendix F - Severe Accident Mitigation Alternatives Analysis. April.
BLS 2012	BLS (U.S. Dept. of Labor, Bureau of Labor Statistics). 2012, Accessed August at www.bls.gov/data/.
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Entergy 2007	Entergy (Entergy Nuclear Indian Point 2, LLC). 2007. Appendix E - Applicant's Environmental Report; Operating License Renewal Stage; Indian Point Energy Center Unit 2. Attachment E - Severe Accident Mitigation Alternatives Analysis. April.

[5] URLs delineated in some references may no longer be valid.

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Appendix G

Clean Water Act §401 Water Quality Certification

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Exelon Generation

Michael P. Gallagher

July 2, 2012
Byron Ltr 2012-0071

Mr. Dan Heacock, Facility Evaluation Unit Manager
Illinois Environmental Protection Agency, Bureau of Water
Post Office Box 19276
Springfield, IL 62794-9276

Subject: Application for Clean Water Act Section 401 Certification associated with Renewal of Byron Generating Station Units 1 & 2 Operating Licenses

Dear Mr. Heacock:

In 2013, Exelon Generation Company (Exelon) plans to file an application with the U.S. Nuclear Regulatory Commission (NRC) for renewal of the Byron Generating Station, Units 1 and 2 operating licenses for 20 additional years beyond the currently licensed terms. No operational changes that would alter discharges or discharge pollutant loads from the Byron units during the extended operating terms would result from license renewal. Also, no construction is being proposed in connection with the license renewals.

In accordance with Section 401 of the federal Clean Water Act, the applicant for a federal license, such as renewed licenses for the Byron units, must provide the licensing agency with a certification by the state where the discharge would originate, indicating that applicable state water quality standards would not be violated as a result of discharges from the licensed facility. Thus, Exelon is filing the enclosed application requesting certification from the Illinois Environmental Protection Agency that renewal of the Byron operating licenses would not violate state water quality standards.

On March 14, 2012, Exelon attended a pre-submittal meeting with you and other IEPA staff. The enclosed application was prepared consistent with input received at the meeting, IEPA regulations in 35 Ill. Adm. Code Part 302, and corresponding IEPA guidance. As instructed, copies of the application are being submitted in parallel to the Illinois Department of Natural Resources (IDNR) and the U.S. Army Corps of Engineers.

If there are questions, please feel free to contact either John Petro at (630) 657-3209 or Nancy Ranek at (610) 765-5369.

Respectfully,

Michael P. Gallagher

Michael P. Gallagher
Vice President, License Renewal Projects
Exelon Generation Company, LLC

Illinois Environmental Protection Agency, Bureau of Water
July 2, 2012
Page 2

Enclosure

cc: Illinois Department of Natural Resources (IDNR) (enclosure w/ attachments)
U.S. Army Corps of Engineers (enclosure w/ attachments)
Illinois Emergency Management Agency - Division of Nuclear Safety (enclosure *wo/* attachments)
Illinois Emergency Management Agency (Byron Representative) (enclosure *wo/* attachments)

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, ROCK ISLAND DISTRICT
PO BOX 2004 CLOCK TOWER BUILDING
ROCK ISLAND, ILLINOIS 61204-2004

rec'd 10/8/2012 TPR

REPLY TO
ATTENTION OF

October 2, 2012

Operations Division

SUBJECT: Request for Letter of No Objection for Renewal of Section 401 Water Quality Certification for Byron Generating Station Units 1 and 2 Operating Licenses located in Byron, Ogle County, Illinois.

Nancy L. Ranek
License Renewal Environmental Lead
Exelon Generation, LLC
200 Exelon Way, KSA/2-E
Kennett Square, PA 19348

Dear Ms. Ranek:

This is in response to your July 3, 2012 request that the U.S. Army Corps of Engineers issue a letter of no objection to the above referenced activity.

Following a review of the information you furnished to this office and assuming your project is conducted only as set forth in the information provided, this office has determined that the subject project does not require a Department of the Army (DA) permit to complete the proposed renewal action. It is our understanding the Exelon is coordinating the renewal of their Section 401 Water Quality Certification for Byron Generating Station Units 1 and 2 Operating Licenses located in Byron, Ogle County, Illinois, and there is no actual project or proposed work associated with this request. Specifically, there is not work of activities in, over, or under a navigable waterway that affect the course, condition, capacity or location of navigation regulated pursuant to Section 10 of the Rivers and Harbors Act of 1899. In addition, there is no discharge of dredged or fill material into waters of the U.S., including wetlands, regulated pursuant to Section 404 of the Federal Water Pollution Control Act of 1972 (Clean Water Act). Please be aware that any unpermitted discharge into an area within the jurisdiction of this office may result in civil or criminal enforcement under the Clean Water Act, 33 U.S.C. Sec. 1319.

This determination is valid for a period of 5 years from the date of this letter and covers only your proposal to renew your Section 401 Water Quality Certification for Byron Generating Station Units 1 and 2 Operating Licenses located in Byron, Ogle county, Illinois.

Should you have any questions, please contact our Regulatory Branch by letter, or telephone me at 309/794-5369.

Sincerely,

Jeff Sniadach

Jeffrey W. Sniadach
Project Manager
Enforcement Section

Copy Furnished:

Mr. Dan Heacock
Illinois Environmental Protection Agency
Watershed Management Section, Permit Sec. 15
1021 North Grand Avenue East
Post Office Box 19276
Springfield, Illinois 62794-9276
Epa.401.bow@illinois.gov (email copy)

Illinois Department of
Natural Resources

Pat Quinn, Governor

One Natural Resources Way Springfield, Illinois 62702-1271
http://dnr.state.il.us

Marc Miller, Acting Director

July 10, 2012

SUBJECT: Application for Permit # 20125045
Byron Generating Station
Units 1 & 2 Operating Licenses
Rock River, Ogle County

Mr. Michael P. Gallagher
Vice President, License Renewal Projects
200 Exelon Way
Kennett Square, PA 19348

Dear Mr. Gallagher:

Thank you for the July 5, 2012 submittal of the subject application for an Illinois Department of Natural Resources/Office of Water Resources (IDNR/OWR) permit. The submittal informs us of your plans to file an application with the U.S. Nuclear Regulatory Commission for renewal of the operating license for the Byron Generating Station, Units 1 and 2.

Given that no construction will occur which requires review under our Part 3700 Floodway Construction nor our Part 3704 Public Water rules, we have determined that an IDNR/OWR permit is not required.

For your information, continued operation of the site is subject to all conditions of IDNR/OWR Permit No. 15001, issued April 7, 1977 to Commonwealth Edison, your predecessor at the generating site.

Please feel free to contact me at 217/524-1047 if you have any questions.

Sincerely,

Mark McCauley
Senior Permit Engineer

MLM:crw
cc: John R. Petro
Byron Generating Station