4.21 TABLES

TABLE 4-1
CATEGORY 1 ISSUES THAT ARE NOT APPLICABLE TO RNP[a]

Issues	Basis for Inapplicability to RNP
Surface Water Quality, Hydrology, and Use (for all plants)	
1. Impacts of refurbishment on surface water quality	Issue applies to activity, refurbishment, that RNP will not undertake.
2. Impacts of refurbishment on surface water use	Issue applies to activity, refurbishment, that RNP will not undertake.
4. Altered salinity gradients	Issue applies to discharge to a natural water body that has a salinity gradient to alter, not to a freshwater river as at RNP.
12. Water use conflicts (plants with once-through cooling systems)	Issue applies to heat dissipation system, once-through, that RNP does not have.
Aquatic Ecology (for all plants)	
14. Refurbishment	Issue applies to activity, refurbishment, that RNP will not undertake.
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)	
28. Entrainment of fish and shellfish in early life stages	Issue applies to heat dissipation system, cooling towers, that RNP does not have.
29. Impingement of fish and shellfish	Issue applies to heat dissipation system, cooling towers, that RNP does not have.
30. Heat shock	Issue applies to heat dissipation system, cooling towers, that RNP does not have.
Groundwater Use and Quality	
31. Impacts of refurbishment on groundwater use and quality	Issue applies to activity, refurbishment, which RNP will not undertake.
32. Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	Issue applies to a plants that withdraw less than 100 gpm. RNP withdraws more than 100 gpm.
36. Groundwater quality degradation (Ranney wells)	Issue applies to a heat dissipation system feature, Ranney wells, that RNP does not have.
37. Groundwater quality degradation (saltwater intrusion)	Issue applies to plants located in coastal areas. RNP is located inland.
38. Groundwater quality degradation (cooling ponds in salt marshes)	Issue applies to plants located in coastal areas. RNP is located inland.

TABLE 4-1 (Cont'd)
CATEGORY 1 ISSUES THAT ARE NOT APPLICABLE TO RNP[a]

Issues	Basis for Inapplicability to RNP
Terrestrial Resources	
41. Cooling tower impacts on crops and ornamental vegetation	Issue applies to heat dissipation system, cooling towers, that RNP does not have.
42. Cooling tower impacts on native plants	Issue applies to heat dissipation system, cooling towers, that RNP does not have.
43. Bird collisions with cooling towers	Issue applies to a plant feature, natural draft cooling towers, that RNP does not have.
Human Health	
54. Radiation exposures to the public during refurbishment	Issue applies to activity, refurbishment, that RNP will not undertake.
55. Occupational radiation exposures during refurbishment	Issue applies to activity, refurbishment, that RNP will not undertake.
56. Microbiological organisms (occupational health)	Issue applies to a plant feature, cooling towers, that RNP does not have.
Socioeconomics	
72. Aesthetic impacts (refurbishment)	Issue applies to activity, refurbishment, that RNP will not undertake.

< = less than
gpm = gallons per minute
NRC = U. S. Nuclear Regulatory Commission
a. NRC listed the issues in Table B-1 of 10 CFR 51, Appendix B. CP&L added issue numbers for organization and clarity.

TABLE 4-2
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
	Surface Water Quality, Hydrology, and Use (for all plants)	
3. Altered current patterns at intake and discharge structures	SMALL. Altered current patterns have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.	4.4.2/4-52
5. Altered thermal stratification of lakes	SMALL. Generally, lake stratification has not been found to be a problem at operating nuclear power plants and is not expected to be a problem during the license renewal term.	4..4.2.2/4-53
6. Temperature effects on sediment transport capacity	SMALL. These effects have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.	4..4.2.2/4-53
7. Scouring caused by discharged cooling water	SMALL. Scouring has not been found to be a problem at most operating nuclear power plants and has caused only localized effects at a few plants. It is not expected to be a problem during the license renewal term.	4.4.2.2/4-53
8. Eutrophication	SMALL. Eutrophication has not been found to be a problem at operating nuclear power plants and is not expected to be a problem during the license renewal term.	4.4.2.2/4-53
9. Discharge of chlorine or other biocides	SMALL. Effects are not a concern among regulatory and resource agencies, and are not expected to be a problem during the license renewal term.	4.4.2.2/4-53
10. Discharge of sanitary wastes and minor chemical spills	SMALL. Effects are readily controlled through NPDES permit and periodic modifications, if needed, and are not expected to be a problem during the license renewal term.	4.4.2.2/4-53
11. Discharge of other metals in waste water	SMALL. These discharges have not been found to be a problem at operating nuclear power plants with cooling-tower-based heat dissipation systems and have been satisfactorily mitigated at other plants. They are not expected to be a problem during the license renewal term.	4.4.2.2/4-53

TABLE 4-2 (Cont'd)
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
	Aquatic Ecology (for all plants)	
15. Accumulation of contaminants in sediments or biota	SMALL. Accumulation of contaminants has been a concern at a few nuclear power plants, but has been satisfactorily mitigated by replacing copper alloy condenser tubes with those of another metal. It is not expected to be a problem during the license renewal term.	4.4.2.2/4-53 4.4.3/4-56
16. Entrainment of phytoplankton and zooplankton	SMALL. Entrainment of phytoplankton and zooplankton has not been found to be a problem at operating nuclear power plants and is not expected to be a problem during the license renewal term.	4.4.3/4-56
17. Cold shock	SMALL. Cold shock has been satisfactorily mitigated at operating nuclear plants with once-through cooling systems, has not endangered fish populations or been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds, and is not expected to be a problem during the license renewal term.	4.4.3/4-56
18. Thermal plume barrier to migrating fish	SMALL. Thermal plumes have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.	4.4.3/4-56
19. Distribution of aquatic organisms	SMALL. Thermal discharge may have localized effects, but is not expected to affect the larger geographical distribution of aquatic organisms.	4.4.3/4-56
20. Premature emergence of aquatic insects	SMALL. Premature emergence has been found to be a localized effect at some operating nuclear power plants, but has not been a problem and is not expected to be a problem during the license renewal term.	4.4.3/4-56
21. Gas supersaturation (gas bubble disease)	SMALL. Gas supersaturation was a concern at a small number of operating nuclear power plants with once-through cooling systems, but has been satisfactorily mitigated. It has not been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds and is not expected to be a problem during the license renewal term.	4.4.3/4-56

TABLE 4-2 (Cont'd)
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
22. Low dissolved oxygen in the discharge	SMALL. Low dissolved oxygen has been a concern at one nuclear power plant with a once-through cooling system, but has been effectively mitigated. It has not been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds and is not expected to be a problem during the license renewal term.	4.4.3/4-56
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	SMALL. These types of losses have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.	4.4.3/4-56
24. Stimulation of nuisance organisms (e.g., shipworms)	SMALL. Stimulation of nuisance organisms has been satisfactorily mitigated at the single nuclear power plant with a once-through cooling system where previously it was a problem. It has not been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds and is not expected to be a problem during the license renewal term.	4.4.3/4-56
	Terrestrial Resources	
44. Cooling pond impacts on terrestrial resources	SMALL. Impacts of cooling ponds on terrestrial ecological resources are considered to be of small significance at all sites.	4.4.4/4-58
45. Power line right-of-way management (cutting and herbicide application)	SMALL. The impacts of right-of-way maintenance on wildlife are expected to be of small significance at all sites.	4.5.6.1/4-71
46. Bird collision with power lines	SMALL. Impacts are expected to be of small significance at all sites.	4.5.6.2/4-74
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	SMALL. No significant impacts of electromagnetic fields on terrestrial flora and fauna have been identified. Such effects are not expected to be a problem during the license renewal term.	4.5.6.3/4-77

TABLE 4-2 (Cont'd)
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
48. Floodplains and wetlands on power line right of way	SMALL. Periodic vegetation control is necessary in forested wetlands underneath power lines and can be achieved with minimal damage to the wetland. No significant impact is expected at any nuclear power plant during the license renewal term.	4.5.7/4-81
	Air Quality	
51. Air quality effects of transmission lines	SMALL. Production of ozone and oxides of nitrogen is insignificant and does not contribute measurably to ambient levels of these gases.	4.5.2/4-62
	Land Use	
52. Onsite land use	SMALL. Projected onsite land use changes required during refurbishment and the renewal period would be a small fraction of any nuclear power plant site and would involve land that is controlled by the applicant.	3.2/3-1
53. Power line right-of-way	SMALL. Ongoing use of power line right of ways would continue with no change in restrictions. The effects of these restrictions are of small significance.	4.5.3/4-62
	Human Health	
58. Noise	SMALL. Noise has not been found to be a problem at operating plants and is not expected to be a problem at any plant during the license renewal term.	4.3.7/4-49
60. Electromagnetic fields, chronic effects	UNCERTAIN. Biological and physical studies of 60-Hz electromagnetic fields have not found consistent evidence linking harmful effects with field exposures. However, research is continuing in this area and a consensus scientific view has not been reached.	4.5.4.2/4-67
61. Radiation exposures to public (license renewal term)	SMALL. Radiation doses to the public will continue at current levels associated with normal operations.	4.6.2/4-87
62. Occupational radiation exposures (license renewal term)	SMALL. Projected maximum occupational doses during the license renewal term are within the range of doses experienced during normal operations and normal maintenance outages, and	4.6.3/4-95

TABLE 4-2 (Cont'd)
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
	would be well below regulatory limits.	
	Socioeconomics	
64. Public services: public safety, social services, and tourism and recreation	SMALL. Impacts to public safety, social services, and tourism and recreation are expected to be of small significance at all sites.	3.7.4/3-14 (refurbishment – public services) 3.7.4.3/3-18 (refurbishment – safety) 3.7.4.4/3-19 (refurbishment – social) 3.7.4.6/3-20 (refurbishment – tourism, recreation) 4.7.3/4-104 (renewal – public services) 4.7.3.3/4-106 (renewal – safety) 4.7.3.4/4-107 (renewal – social) 4.7.3.6/4-107 (renewal – tourism, recreation)
67. Public services, education (license renewal term)	SMALL. Only impacts of small significance are expected.	4.7.3.1/4-106
73. Aesthetic impacts (license renewal term)	SMALL. No significant impacts are expected during the license renewal term.	4.7.6/4-111
74. Aesthetic impacts of transmission lines (license renewal term)	SMALL. No significant impacts are expected during the license renewal term.	4.5.8/4-83

TABLE 4-2 (Cont'd)
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
	Postulated Accidents	
75. Design basis accidents	SMALL. The NRC staff has concluded that the environmental impacts of design basis accidents are of small significance for all plants.	5.3.2/5-11 (design basis) 5.5.1/5-114 (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)	SMALL. Offsite impacts of the uranium fuel cycle have been considered by the Commission in Table S-3 of this part. Based on information in the GEIS, impacts on individuals from radioactive gaseous and liquid releases including radon-222 and technetium-99 are small.	6.2.4/6-27 6.6/6-87
78. Offsite radiological impacts (collective effects)	The 100-year environmental dose commitment to the U.S. population from the fuel cycle, high-level waste and spent fuel disposal excepted, is calculated to be about 14,800 person rem, or 12 cancer fatalities, for each additional 20-year power reactor operating term. Much of this, especially the contribution of radon releases from mines and tailing piles, consists of tiny doses summed over large populations. This same dose calculation can theoretically be extended to include many tiny doses over additional thousands of years as well as doses outside the U.S. The result of such a calculation would be thousands of cancer fatalities from the fuel cycle, but this result assumes that even tiny doses have some statistical adverse health effect, which will not ever be mitigated (for example, no cancer cure in the next thousand years), and that these dose projections over thousands of years are meaningful. However, these assumptions are questionable. In particular, science cannot rule out the possibility that there will be no cancer fatalities from these tiny doses. For perspective, the doses are very small fractions of regulatory limits, and even smaller fractions of natural background exposure to the same populations.	6.2.4/6-27 6.6/6-88

TABLE 4-2 (Cont'd)
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
78. Offsite radiological impacts (collective effects) (Continued)	Nevertheless, despite all the uncertainty, some judgment as to the regulatory NEPA implications of these matters should be made and it makes no sense to repeat the same judgment in every case. Even taking the uncertainties into account, the Commission concludes that these impacts are acceptable in that these impacts would not be sufficiently large to require the NEPA conclusion, for any plant, that the option of extended operation under 10 CFR Part 54 should be eliminated. Accordingly, while the Commission has not assigned a single level of significance for the collective effects of the fuel cycle, this issue is considered Category 1.	
79. Offsite radiological impacts (spent fuel and high-level waste disposal)	For the high-level waste and spent fuel disposal component of the fuel cycle, there are no current regulatory limits for offsite releases of radionuclides for the current candidate repository site. However, if we assume that limits are developed along the lines of the 1995 National Academy of Sciences (NAS) report, "Technical Bases for Yucca Mountain Standards," and that in accordance with the Commission's Waste Confidence Decision, 10 CFR 51.23, a repository can and likely will be developed at some site which will comply with such limits, peak doses to virtually all individuals will be 100 millirem per year or less. However, while the Commission has reasonable confidence that these assumptions will prove correct, there is considerable uncertainty since the limits are yet to be developed, no repository application has been completed or reviewed, and uncertainty is inherent in the models used to evaluate possible pathways to the human environment. The NAS report indicated that 100 millirem per year should be considered as a starting point for limits for individual doses, but notes that some measure of consensus exists among national and international bodies that the limits should be a fraction of the 100 millirem per year. The lifetime individual risk from 100 millirem annual dose limit is about 310^{-3}.	6.2.4/6-28 6.6/6-88

TABLE 4-2 (Cont'd)
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
79. Offsite radiological impacts (spent fuel and high-level waste disposal) (Continued)	Estimating cumulative doses to populations over thousands of years is more problematic. The likelihood and consequences of events that could seriously compromise the integrity of a deep geologic repository were evaluated by the U.S. Department of Energy in the "Final Environmental Impact Statement: Management of Commercially Generated Radioactive Waste," October 1980. The evaluation estimated the 70-year whole-body dose commitment to the maximum individual and to the regional population resulting from several modes of breaching a reference repository in the year of closure, after 1,000 years, after 100,000 years, and after 100,000,000 years. Subsequently, the NRC and other federal agencies have expended considerable effort to develop models for the design and for the licensing of a high-level waste repository, especially for the candidate repository at Yucca Mountain. More meaningful estimates of doses to population may be possible in the future as more is understood about the performance of the proposed Yucca Mountain repository. Such estimates would involve very great uncertainty, especially with respect to cumulative population doses over thousands of years. The standard proposed by the NAS is a limit on maximum individual dose. The relationship of potential new regulatory requirements, based on the NAS report, and cumulative population impacts has not been determined, although the report articulates the view that protection of individuals will adequately protect the population for a repository at Yucca Mountain. However, (EPA's) generic repository standards in 40 CFR part 191 generally provide an indication of the order of magnitude of cumulative risk to population that could result from the licensing of a Yucca Mountain repository, assuming the ultimate standards will be within the range of standards now under consideration. The standards in 40 CFR part 191 protect the population by imposing "containment requirements" that limit the cumulative amount of radioactive material released over 10,000 years. The cumulative release limits	

TABLE 4-2 (Cont'd)
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
79. Offsite radiological impacts (spent fuel and high-level waste disposal) (Continued)	are based on EPA's population impact goal of 1,000 premature cancer deaths worldwide for a 100,000 metric tonne (MTHM) repository. Nevertheless, despite all the uncertainty, some judgment as to the regulatory NEPA implications of these matters should be made and it makes no sense to repeat the same judgment in every case. Even taking the uncertainties into account, the Commission concludes that these impacts are acceptable in that these impacts would not be sufficiently large to require the NEPA conclusion, for any plant, that the option of extended operation under 10 CFR part 54 should be eliminated. Accordingly, while the Commission has not assigned a single level of significance for the impacts of spent fuel and high-level waste disposal, this issue is considered Category 1.	
80. Nonradiological impacts of the uranium fuel cycle	SMALL. The nonradiological impacts of the uranium fuel cycle resulting from the renewal of an operating license for any plant are found to be small.	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) 6.6/6-90 (conclusion)
81. Low-level waste storage and disposal	SMALL. The comprehensive regulatory controls that are in place, and the low public doses being achieved at reactors, ensure that the radiological impacts to the environment will remain small during the term of a renewed license. The maximum additional onsite land that may be required for low-level waste storage during the term of a renewed license and associated impacts will be small. Nonradiological impacts on air and water will be negligible. The radiological and nonradiological environmental impacts of long-term disposal of low-level waste from any individual plant at licensed sites are small. In addition, the Commission concludes that there is reasonable assurance that sufficient low-level waste disposal capacity will be made available when needed for facilities to be decommissioned consistent with NRC decommissioning requirements.	6.4.2/6-36 ("low-level" definition) 6.4.3/6-37 (low-level volume) 6.4.4/6-48 (renewal effects) 6.6/6-90 (conclusion)

TABLE 4-2 (Cont'd)
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
82. Mixed waste storage and disposal	SMALL. The comprehensive regulatory controls and the facilities and procedures that are in place ensure proper handling and storage, as well as negligible doses and exposure to toxic materials for the public and the environment at all plants. License renewal will not increase the small, continuing risk to human health and the environment posed by mixed waste at all plants. The radiological and nonradiological environmental impacts of long-term disposal of mixed waste from any individual plant at licensed sites are small. In addition, the Commission concludes that there is reasonable assurance that sufficient mixed waste disposal capacity will be made available when needed for facilities to be decommissioned consistent with NRC decommissioning requirements.	6.4.5/6-63 6.6/6-91 (conclusion)
83. Onsite spent fuel	SMALL. The expected increase in the volume of spent fuel from an additional 20 years of operation can be safely accommodated on site with small environmental effects through dry or pool storage at all plants if a permanent repository or monitored retrievable storage is not available.	6.4.6/6-70 6.6/6-91 (conclusion)
84. Nonradiological waste	SMALL. No changes to generating systems are anticipated for license renewal. Facilities and procedures are in place to ensure continued proper handling and disposal at all plants.	6.5/6-86 6.6/6-92 (conclusion) Addendum 1
85. Transportation	SMALL. The impacts of transporting spent fuel enriched up to 5 percent uranium-235 with average burnup for the peak rod to current levels approved by NRC up to 62,000 MWd/MTU and the cumulative impacts of transporting high-level waste to a single repository, such as Yucca Mountain, Nevada are found to be consistent with the impact values contained in 10 CFR 51.52(c), Summary Table S-4-Environmental Impact of Transportation of Fuel and Waste to and from One Light-Water-Cooled Nuclear Power Reactor. If fuel enrichment or burnup conditions are not met, the applicant must submit an assessment of the implications for the environmental impact values reported in §51.52.	Ref. NRC 1996a

TABLE 4-2 (Cont'd)
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
	Decommissioning	
86. Radiation doses	SMALL. Doses to the public will be well below applicable regulatory standards regardless of which decommissioning method is used. Occupational doses would increase no more than 1 man-rem caused by buildup of long-lived radionuclides during the license renewal term.	7.3.1/7-15
87. Waste management	SMALL. Decommissioning at the end of a 20-year license renewal period would generate no more solid wastes than at the end of the current license term. No increase in the quantities of Class C or greater than Class C wastes would be expected.	7.3.2/7-19 (impacts) 7.4/7-25 (conclusions)
88. Air quality	SMALL. Air quality impacts of decommissioning are expected to be negligible either at the end of the current operating term or at the end of the license renewal term.	7.3.3/7-21 (air) 7.4/7-25 (conclusion)
89. Water quality	SMALL. The potential for significant water quality impacts from erosion or spills is no greater whether decommissioning occurs after a 20-year license renewal period or after the original 40-year operation period, and measures are readily available to avoid such impacts.	7.3.4/7-21 (water) 7.4/7-25 (conclusion)
90. Ecological resources	SMALL. Decommissioning after either the initial operating period or after a 20-year license renewal period is not expected to have any direct ecological impacts.	7.3.5/7-21 (ecological) 7.4/7-25 (conclusion)
91. Socioeconomic impacts	SMALL. Decommissioning would have some short-term socioeconomic impacts. The impacts would not be increased by delaying decommissioning until the end of a 20-year relicense period, but they might be decreased by population and economic growth.	7.3.7/7-24 (socioeconomic) 7.4/7-25 (conclusion)

TABLE 4-2 (Cont'd)
CATEGORY 1 AND "NA" ISSUES THAT ARE APPLICABLE TO RNP[a]

Issue	NRC Findings[b]	GEIS (NRC 1996a) (Section/Page)
	Environmental Justice	
92. Environmental Justice	NONE. The need for and the content of an analysis of environmental justice will be addressed in plant-specific reviews.	Not in GEIS

CFR = Code of Federal Regulations
EPA = U.S. Environmental Protection Agency
GEIS = Generic Environmental Impact Statement
Hz = Hertz
NA = Not applicable
NEPA = National Environmental Policy Act
NPDES = National Pollutant Discharge Elimination System
NRC = U.S. Nuclear Regulatory Commission

a. NRC listed the issues in Table B-1 of 10 CFR 51 Appendix B. CP&L added issue numbers for organization and clarity.

b. NRC has defined SMALL to mean that, for the issue, environmental effects are not detectable or are so minor that they would neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, NRC has concluded that those impacts that do not exceed permissible levels in the NRC's regulations are considered small. (10 CFR 51, Appendix B, Table B-1, Footnote 3).

c. NRC published, on September 3, 1999, a GEIS addendum in support of its rulemaking that re-categorized Issue 85 from 2 to 1.

TABLE 4-3
RESULTS OF INDUCED CURRENT ANALYSIS

Transmission Line	Voltage (kV)	Limiting Case Peak Electric Field Strength (kV/meter)	Limiting Case Induced Current (milliamperes)
Rockingham (as far as Society Hill)[a]	230	2.23	2.08
Darlington[b]	230	4.09	2.85
Florence (as far as Society Hill)[a]	230	2.23	2.08
Sumter[b]	230	4.09	2.85

a. At a location where the towers carry both Rockingham and Florence lines.
b. At a location where the towers carry both Darlington and Sumter lines.

4.22 REFERENCES

Note to reader: Some web pages cited in this document are no longer available, or are no longer available through the original URL addresses. Hard copies of cited web pages are available in CP&L 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 CP&L have been given for these pages, even though they may not be directly accessible.

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5.0 ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

5.1 DISCUSSION

NRC

"...The environmental report must contain any new and significant information regarding the environmental impacts of license renewal of which the applicant is aware." 10 CFR 51.53(c)(3)(iv)

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants and provides for license renewal, requiring a license renewal application that includes an environmental report (10 CFR 54.23). NRC regulations, 10 CFR 51, prescribe the environmental report content and identify the specific analyses the applicant must perform. In an effort to streamline the environmental review, NRC has resolved most of the environmental issues generically and only requires an applicant's analysis of the remaining issues.

While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those environmental issues that have been generically resolved [10 CFR 51.53(c)(3)(i)], the regulations do require that an applicant identify any new and significant information of which the applicant is aware [10 CFR 51.53(c)(3)(iv)]. The purpose of this requirement is to alert NRC staff to such information, so the staff can determine whether to seek the Commission's approval to waive or suspend application of the rule with respect to the affected generic analysis. NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) conclusions (NRC 1996).

Carolina Power and Light Company (CP&L) expects that new and significant information would include:

- Information that identifies a significant environmental issue not covered in the GEIS and codified in the regulation, or
- Information that was not covered in the GEIS analyses and that leads to an impact finding different from that codified in the regulation.

NRC does not specifically define the term "significant." For the purpose of its review, CP&L used guidance available in Council on Environmental Quality (CEQ) regulations. The National Environmental Policy Act authorizes CEQ to establish implementing regulations for federal agency use. NRC requires license renewal applicants to provide NRC with input, in the form of an environmental report, that NRC will use to meet National Environmental Policy Act requirements as they apply to license renewal (10 CFR 51.10). CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), focus on significant environmental issues (40 CFR 1502.1), and eliminate from detailed study issues that are not significant [40 CFR 1501.7(a)(3)]. The CEQ guidance includes a lengthy definition of "significantly" that requires consideration of the context of the action and the intensity or severity of the impact(s) (40 CFR 1508.27). CP&L expects that moderate or large impacts, as defined by NRC, would be significant. Chapter 4 presents the NRC definitions of "moderate" and "large" impacts.

The new and significant assessment process that CP&L used during preparation of this license renewal application included: (1) interviews with CP&L subject experts on the validity of the conclusions in the GEIS as they relate to Robinson Nuclear Plant (RNP), (2) an extensive review of documents related to environmental issues at RNP, (3) correspondence with state and federal agencies to determine if the agencies had concerns not addressed in the GEIS, (4) a review of internal procedures for reporting to the NRC events that could have environmental impacts, and (5) credit for the oversight provided by inspections of plant facilities by state and federal regulatory agencies.

CP&L is aware of no new and significant information regarding the environmental impacts of RNP Unit 2 license renewal.

5.2 REFERENCES

NRC (U.S. Nuclear Regulatory Commission). 1996. *Public Comments on the Proposed 10 CFR 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response.* Volumes 1 and 2. NUREG-1529. Washington, DC. May.

6.0 SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 LICENSE RENEWAL IMPACTS

Carolina Power & Light (CP&L) has reviewed the environmental impacts of renewing the Robinson Nuclear Plant (RNP) operating license and has concluded that impacts would be small and would not require mitigation. This environmental report documents the basis for CP&L's conclusion. Chapter 4 incorporates by reference U.S. Nuclear Regulatory Commission (NRC) findings for the 49 Category 1 issues that apply to RNP, all of which have impacts that are small (Table 4-2). The rest of Chapter 4 analyzes Category 2 issues, all of which are either not applicable or have impacts that would be small. Table 6-1 identifies the impacts that RNP license renewal would have on resources associated with Category 2 issues.

6.2 MITIGATION

NRC

"The report must contain a consideration of alternatives for reducing adverse impacts...for all Category 2 license renewal issues..." 10 CFR 51.53(c)(3)(iii)

"The environmental report shall include an analysis that considers and balances...alternatives available for reducing or avoiding adverse environmental effects..." 10 CFR 51.45(c) as incorporated by 10 CFR 51.53(c)(2) and 10 CFR 51.45(c)

Impacts of license renewal are small and would not require mitigation. Current operations include mitigation and monitoring activities that would continue during the license renewal term. CP&L performs routine mitigation and monitoring activities to ensure the safety of workers, the public, and the environment. These activities include the radiological environmental monitoring program, continuous emissions monitoring, effluent chemistry monitoring, effluent toxicity testing, and monitoring of Lake Robinson water quality.

6.3 UNAVOIDABLE ADVERSE IMPACTS

NRC

The environmental report shall discuss any "...adverse environmental effects which cannot be avoided should the proposal be implemented..." 10 CFR 51.45(b)(2) as adopted by 10 CFR 51.53(c)(2)

This environmental report adopts by reference NRC findings for applicable Category 1 issues, including discussions of any unavoidable adverse impacts (Table 4-2). CP&L examined 21 Category 2 issues and identified the following unavoidable adverse impacts of license renewal:

- Waste heat that results from operation of the plant is discharged to Lake Robinson and affects its thermal pattern. This additional heat loading is likely to cause a small reduction in productivity of fish, phytoplankton, and benthos. The additional heat is released to the atmosphere over the impoundment and slightly increases the consumption of water due to increased evaporation accompanying the added heat load.

- Procedures for the disposal of sanitary, chemical, and radioactive wastes are intended to reduce adverse impacts from these sources to acceptably low levels. A small impact will be present as long as the plant is in operation. Solid radioactive wastes are a product of the operation of Unit 2 and long-term disposal of these materials must be considered.

- Operation of RNP results in a very small increase in radioactivity in the air and water. However, fluctuations in natural background radiation may be expected to exceed the small incremental increase in dose to the local population. Operation of RNP also establishes a very low probability risk of accidental radiation exposure to inhabitants of the area.

- Some fish are impinged on the traveling screens at the intake structure.

- Some larval fish and shellfish are entrained at the intake structure.

6.4 IRREVERSIBLE AND IRRETRIEVABLE RESOURCE COMMITMENTS

NRC

The environmental report shall discuss any "...irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented..." 10 CFR 51.45(b)(5) as adopted by 10 CFR 51.53(c)(2)

Continued operation of RNP for the license renewal term will result in irreversible and irretrievable resource commitments, including the following:

- nuclear fuel, which is used in the reactor and is converted to radioactive waste;
- land required to dispose of spent nuclear fuel, low-level radioactive wastes generated as a result of plant operations; and sanitary wastes generated from normal industrial operations;
- elemental materials that will become radioactive; and
- materials used for the normal industrial operations of the plant that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms.

6.5 SHORT-TERM USE VERSUS LONG-TERM PRODUCTIVITY OF THE ENVIRONMENT

NRC

The environmental report shall discuss the "...relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity..." 10 CFR 51.45(b)(4) as adopted by 10 CFR 51.53(c)(2)

The current balance between short-term use and long-term productivity at the RNP site was established when the plant began operating in the early 1970s. The Final Environmental Statement (NRC 1975) evaluated the impacts of constructing and operating RNP in rural Darlington County, South Carolina. Short-term use of natural resources would include land and water. The area surrounding the plant site is chiefly rural and at least half is agricultural. Approximately 200 acres of the site is devoted to the production of electrical energy via the nuclear power plant. This includes the area occupied by buildings, structures, and landscaping around the RNP site proper and the 100-acre area required for the discharge canal (NRC 1975). The 2,250-acre Lake Robinson was previously constructed for the coal-fired plant. Transmission line construction required over 1,000 acres of pasture or cultivated land (including timber production) that also resulted in the alteration of natural wildlife habitats. Land areas disturbed during construction of the plant, but not used, have been replanted with native grasses, trees, and shrubs (NRC 1975). Regarding water usage, the increased consumption of water from Lake Robinson due to the added heat load from operation of the plant is less than the daily flow of Black Creek. This is not a permanent loss to the environment, but only a small change in water distribution (NRC 1975).

With respect to decommissioning, many environmental disturbances would cease when Unit 2 is shut down, and a balancing of the biota would occur. Thus, the "trade-off" between the production of electricity and small changes in the local environment is reversible. Experience with other experimental, developmental, and commercial nuclear plants has demonstrated the feasibility of decommissioning and dismantling such plants sufficiently to restore a site to its former use (NRC 1975). The degree of dismantlement, as with most abandoned industrial plants, will take into account the intended new use of the site and a balance among health and safety considerations, salvage values, and environmental impact. However, decisions on the ultimate disposition of these lands have not yet been made. Continued operation for an additional 20 years would not alter this conclusion.

6.6 TABLE

TABLE 6-1
ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL AT RNP

No.	Issue	Environmental Impact
	Surface Water Quality, Hydrology, and Use (for all plants)	
13	Water use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow)	**Small.** Evaporative losses from Lake Robinson would be approximately 10 percent of the upstream annual mean flow and 17 percent of the lowest annual mean flow of Black Creek, which would have little or no effect on Black Creek and its riparian ecological communities.
	Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)	
25	Entrainment of fish and shellfish in early life stages	**Small.** CP&L has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements to provide best available technology to minimize entrainment.
26	Impingement of fish and shellfish	**Small.** CP&L has a current NPDES permit which constitutes compliance with CWA Section 316(b) requirements to provide best available technology to minimize impingement.
27	Heat shock	**Small.** CP&L has a CWA Section 316(a) variance for facility-specific thermal discharge limits.
	Groundwater Use and Quality	
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use > 100 gpm)	**Small.** From the end of the current license period (2010) to the end of the relicensing period (2030), the incremental increase in drawdown is projected to be approximately one foot.
34	Groundwater use conflicts (plants using cooling towers or cooling ponds withdrawing makeup water from a small river)	**Small.** Cooling water is pumped from a small impoundment and not directly from Black Creek. Loss of water due to evaporation, which is 10 percent of the upstream flow, would be distributed evenly across Lake Robinson.
35	Groundwater use conflicts (Ranney wells)	**None.** This issue does not apply because RNP does not use Ranney wells.
39	Groundwater quality degradation (cooling ponds at inland sites)	**Small.** Water table and artesian conditions exist at the site. The water table aquifer will discharge locally to Black Creek and Lake Robinson. The static head of the artesian groundwater underlying the site is approximately 80 feet above the impoundment level, generally preventing leakage from the impoundment to the artesian aquifer.
	Terrestrial Resources	
40	Refurbishment impacts	**None.** No impacts are expected because RNP will not undertake refurbishment.
	Threatened or Endangered Species	
49	Threatened or endangered species	**Small.** With the exception of occasional bald eagle sightings, there are no known occurrences of threatened or endangered species at RNP. CP&L has no plans to alter current natural resource management practices.

TABLE 6-1 (CONT'D) ENVIRONMENTAL IMPACTS RELATED TO LICENSE RENEWAL AT RNP

No.	Issue	Environmental Impact
		Air Quality
50	Air quality during refurbishment (non-attainment and maintenance areas)	**None**. No impacts are expected because RNP will not undertake refurbishment.
		Human Health
57	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	**Small.** Given the thermal characteristics of Lake Robinson in the vicinity of the discharge outfall and the disinfection of the sewage treatment plant effluent, CP&L does not expect plant operations to stimulate growth or reproduction of thermophilic microorganisms.
59	Electromagnetic fields, acute effects (electric shock)	**Small.** The largest modeled induced current under the RNP transmission lines would be less than 5.0 milliamperes. Therefore, the RNP transmission lines conform to the National Electric Safety Code® provisions for preventing electric shock from induced current.
		Socioeconomics
63	Housing impacts	**Small.** NRC concluded that housing impacts would be small in medium and high population areas having no growth control measures. RNP is located in a medium population area that does not have growth control measures.
65	Public services: public utilities	**Small.** CP&L anticipates no additional plant water use or employment.
66	Public services: education (refurbishment)	**None**. No impacts are expected because RNP will not undertake refurbishment.
68	Offsite land use (refurbishment)	**None**. No impacts are expected because RNP will not undertake refurbishment.
69	Offsite land use (license renewal term)	**Small.** No plant-induced changes to offsite land use are expected from license renewal. Impacts from continued operation would be positive.
70	Public services: transportation	**Small.** CP&L anticipates no additional employment.
71	Historic and archeological resources	**Small.** Continued operation of RNP would not require construction at the site or new transmission lines. CP&L is not currently aware of plant-related impacts affecting archeological or historic sites of significance within the area. Therefore, CP&L concludes that license renewal would not adversely affect historic or archeological resources.
		Postulated Accidents
76	Severe accidents	**Small.** No severe accident mitigation alternatives related to license renewal (i.e., related to plant aging management) were found to be cost beneficial.

6.7 REFERENCES

NRC (U.S. Nuclear Regulatory Commission). 1975. *Final Environmental Statement related to the operation of H. B. Robinson Nuclear Steam-Electric Plant, Unit 2.* Carolina Power and Light Company. Docket No. 50-261. NUREG-75/024. April. Washington, DC.

7.0 ALTERNATIVES TO THE PROPOSED ACTION

NRC

The environmental report shall discuss "Alternatives to the proposed action…." 10 CFR 51.45(b)(3), as adopted by reference at 10 CFR 51.53(c)(2).

"...The report is not required to include discussion of need for power or economic costs and benefits of ... alternatives to the proposed action except insofar as such costs and benefits are either essential for a determination regarding the inclusion of an alternative in the range of alternatives considered or relevant to mitigation...." 10 CFR 51.53(c)(2).

"While many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable..." (NRC 1996a).

"...The consideration of alternative energy sources in individual license renewal reviews will consider those alternatives that are reasonable for the region, including power purchases from outside the applicant's service area...." (NRC 1996b).

Chapter 7 evaluates alternatives to H. B. Robinson Nuclear Plant (RNP) Unit 2 license renewal. The chapter identifies actions that Carolina Power and Light Company (CP&L) might take, and associated environmental impacts, if the U.S. Nuclear Regulatory Commission (NRC) did not renew the plant operating license. The chapter also addresses some of the actions that CP&L has considered, but would not take, and identifies CP&L bases for determining that such actions would be unreasonable.

CP&L divided its alternatives discussion into two categories, "no-action" and "alternatives that meet system generating needs." In considering the level of detail and analysis that it should provide for each category, CP&L relied on the NRC decision-making standard for license renewal:

"...the NRC staff, adjudicatory officers, and Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that preserving the option of license renewal for energy planning decision makers would be unreasonable." [10 CFR 51.95(c)(4)].

CP&L has determined that the environmental report would support NRC decision making, as long as the document provides sufficient information to clearly indicate whether an alternative would have a smaller, comparable, or greater environmental impact than the proposed action. Providing additional detail or analysis serves no function if it only brings to light additional adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality, which provide that the consideration of alternatives (including the proposed action) should enable reviewers to evaluate their comparative merits (40 CFR 1500-1508). CP&L believes that Chapter 7 provides sufficient detail about alternatives to establish the basis for necessary comparisons to the Chapter 4 discussion of impacts from the proposed action.

In characterizing environmental impacts from alternatives, CP&L has used the same definitions of "small," "moderate," and "large" that are presented in the introduction to Chapter 4.

7.1 NO-ACTION ALTERNATIVE

CP&L is using "no-action alternative" to refer to a scenario in which NRC does not renew the RNP operating license. Components of this alternative include replacing the generating capacity of RNP and decommissioning the facility, as described below.

CP&L supplies as much as 54.5 terawatt hours of electricity to its 1.4-million customer base in North and South Carolina (CP&L 2000b). A terawatt hour is one billion kilowatt hours. RNP Unit 2 provides approximately 6.2 terawatt hours or about 11 percent of the electricity CP&L provides to its customers (PSC 2000). CP&L believes that any alternative would be unreasonable if it did not include replacing this capacity. Replacement could be accomplished by (1) building new generating capacity, (2) purchasing power from the wholesale market, or (3) reducing power requirements through demand reduction. Section 7.2.1 describes each of these possibilities in detail, and Section 7.2.2 describes environmental impacts from feasible alternatives.

The *Generic Environmental Impact Statement* (GEIS) (NRC 1996a) defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license. NRC-evaluated decommissioning options include immediate decontamination and dismantlement (DECON), and safe storage of the stabilized and defueled facility (SAFSTOR) for a period of time, followed by decontamination and dismantlement. Regardless of the option chosen, decommissioning must be completed within a 60-year period. Under the no-action alternative, CP&L would continue operating RNP until the current license expires, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of a larger reactor (the "reference" pressurized-water reactor is the 1,175-megawatt electrical [MWe] Trojan Nuclear Plant). This description bounds decommissioning activities that CP&L would conduct at RNP.

As the GEIS notes, NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts include: occupational and public radiation dose; impacts of waste management; impacts to air and water quality; and ecological, economic, and socioeconomic impacts. NRC indicated in the *Final Generic Environmental Impact Statement on Decommissioning* (NRC 1988) that the environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations. CP&L adopts by reference the NRC conclusions regarding environmental impacts of decommissioning.

CP&L notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. CP&L will have to decommission RNP regardless of the NRC decision on license renewal; license renewal would only postpone decommissioning for another 20 years. NRC has established in the GEIS that the timing of decommissioning operations does not substantially influence the environmental impacts of decommissioning. CP&L adopts by reference the NRC findings (10 CFR 51, Appendix B, Table B-1, Decommissioning) to the effect that delaying decommissioning until after the renewal term would have small environmental impacts. The discriminators between the proposed action and the no-action alternative lie within the choice of generation replacement options to be part of the no-action alternative. Section 7.2.2 analyzes the impacts from these options.

CP&L concludes that the decommissioning impacts under the no-action alternative would not be substantially different from those occurring following license renewal, as identified in the GEIS (NRC 1996a) and in the decommissioning generic environmental impact statement (NRC 1988). These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs.

7.2 ALTERNATIVES THAT MEET SYSTEM GENERATING NEEDS

Although RNP is located in South Carolina, 88 percent of CP&L's electrical energy generation is in North Carolina. Therefore, power generation in both states is of interest for this evaluation. The current mix of power generation options in the Carolinas is one indicator of what have been considered to be feasible alternatives within the CP&L service area.

South Carolina's electric utility industry had a total generating capacity of 17,627 MWe in 1998. As Figure 7-1 indicates, this capacity includes units fueled by coal (34.1 percent); nuclear (36.5 percent); petroleum (1.7 percent); gas (0.1 percent); dual-fired (e.g., petroleum/gas) (8.0 percent); and hydroelectric (19.6 percent). Approximately 489 MWe (2.7 percent of the State's generating capability) was from non-utility sources (EIA 2000a). South Carolina's non-utility generators also use a variety of energy sources.

In 1998, North Carolina's electric utility industry had a total generating capacity of 21,020 MWe. As Figure 7-2 indicates, this capacity includes units fueled by coal (59.2 percent); nuclear (22.3 percent); petroleum (1.7 percent); gas (0.5 percent); dual-fired (8.8 percent); and hydroelectric (7.5 percent). Approximately 1,825 MWe (8 percent of the State's generating capability) was from non-utility sources (EIA 2000b). North Carolina's non-utility generators also use a variety of energy sources.

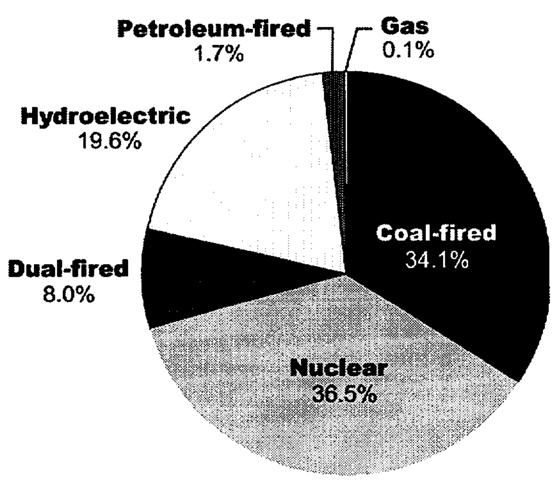

FIGURE 7-1. SOUTH CAROLINA UTILITY GENERATING CAPABILITY, 1998

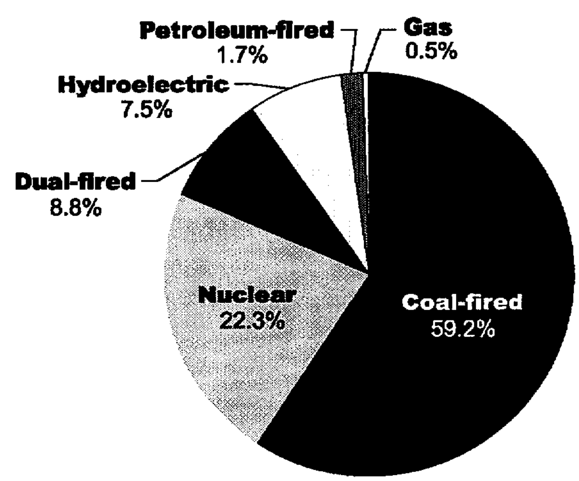

FIGURE 7-2. NORTH CAROLINA UTILITY GENERATING CAPABILITY, 1998

Based on 1998 generation data, South Carolina utility companies produced 84 terawatt hours of electricity. As shown in Figure 7-3, utilities' generation utilization in South Carolina was dominated by nuclear (57.7 percent), followed by coal (38.4 percent), hydroelectric (3.0 percent), gas (0.5 percent), and petroleum (0.4 percent).

Approximately 2.8 terawatt hours of electricity (3.3 percent of the State's generation) was provided by non-utility sources (EIA 2000a).

Based on 1998 generation data, utility companies in North Carolina produced 113 terawatt hours of electricity. As Figure 7-4 depicts, utilities' generation utilization in North Carolina was dominated by coal (61.0 percent), followed by nuclear (34.3 percent), hydroelectric (3.6 percent), gas (0.8 percent), and petroleum (0.3 percent). Approximately 8 terawatt hours of electricity (6.8 percent of the State's generation) was provided by non-utility sources (EIA 2000b).

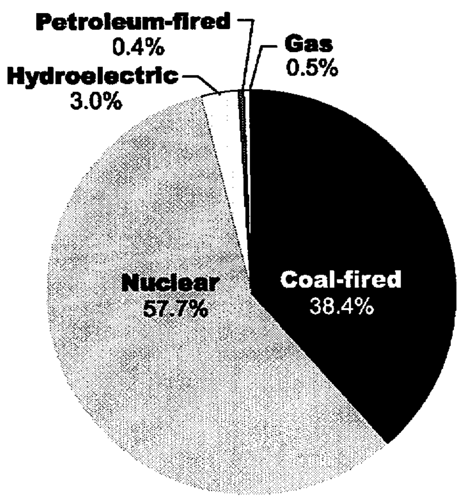

FIGURE 7-3. SOUTH CAROLINA UTILITY GENERATION UTILIZATION, 1998

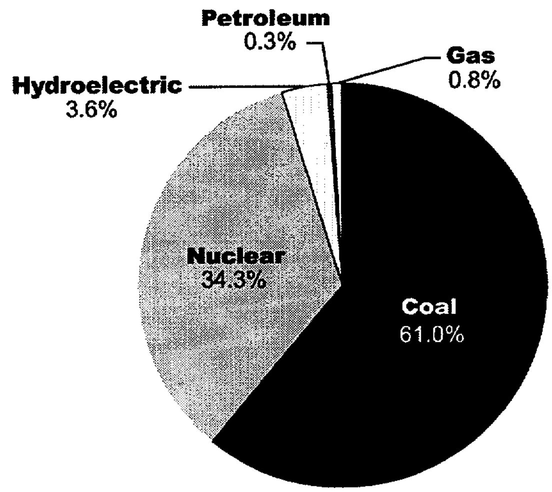

FIGURE 7-4. NORTH CAROLINA UTILITY GENERATION UTILIZATION, 1998

The difference between capacity and utilization is the result of preferential usage. For example, in North Carolina, nuclear energy represented 22.3 percent of utilities' installed capability, but produced 34.3 percent of the electricity generated by utilities (EIA 2000b, Tables 4 and 5, respectively). This reflects North Carolina's preferential reliance on nuclear energy as a base-load generating source. South Carolina also shows a preference for reliance on nuclear energy as a base-load generating source, with nuclear energy representing 36.5 percent utilities' installed capability and 57.7 percent of the electricity generated by utilities (EIA 2000a).

CP&L summer generation capability, including jointly owned capacity, is 10,961 MWe. Figure 7-5 illustrates the CP&L energy capacity mix for summer capability. Forty-eight (48) percent of CP&L's capacity comes from coal, 29 percent from nuclear, 21 percent from combustion turbines, and 2 percent from hydroelectric (CP&L 2000a). The CP&L share of energy supplied by these units in 1999 (excluding purchases) was 51.7 terawatt hours. Figure 7-6 illustrates the CP&L utilization by fuel type. Coal power generated 55 percent, nuclear 43 percent, hydroelectric generated 1 percent, and 1 percent was generated in combustion turbines (CP&L 2000b).

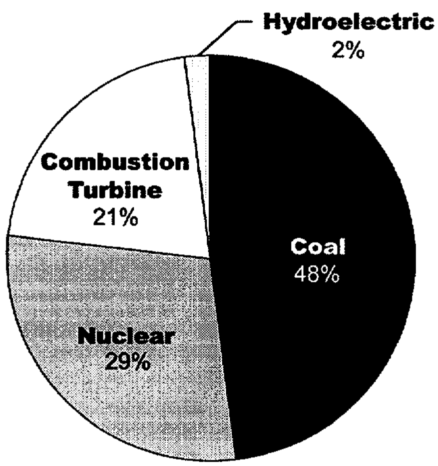

FIGURE 7-5. CP&L ENERGY CAPABILITY

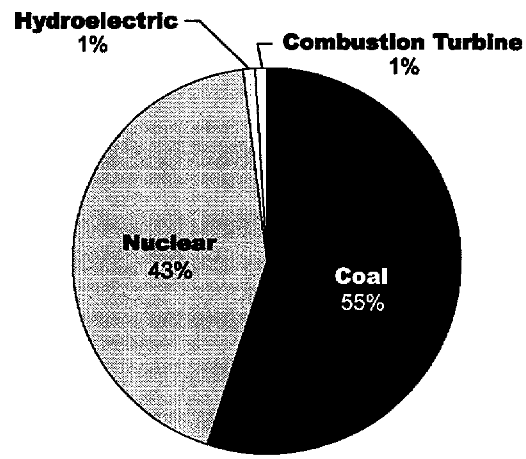

FIGURE 7-6. CP&L GENERATION BY FUEL TYPE

Similar to North and South Carolina, CP&L's utilization reflects a preference for nuclear energy as a base-load generating source. Nuclear energy represented 29 percent of CP&L's installed capacity, but produced 43 percent of the electricity generated by (CP&L 2000a and CP&L 2000b).

7.2.1 ALTERNATIVES CONSIDERED

Technology Choices

CP&L routinely conducts evaluations of alternative generating technologies. The most recent study evaluated 17 technologies; of these, 10 are commercially available and only 5 are mature, proven technologies (CP&L 2000a). Based on these reviews, CP&L identified candidate technologies that would be capable of replacing the net base-load capacity, 683 MWe, (CP&L 2001a) of the nuclear unit at RNP.

A cost-benefit analysis revealed that simple-cycle combustion turbines are the most economical commercially available technology for peaking service. For base-load service (like RNP), the most economical commercially available technology is combined-cycle combustion turbines, followed by units fired by pulverized coal (CP&L 2000a). Based on these evaluations, CP&L has concluded that feasible new plant systems that could replace the capacity of the RNP nuclear unit are limited to pulverized coal and combined-cycle units. CP&L would use gas as the primary fuel in its combined-cycle turbine because of its economical and environmental advantages over petroleum. Approximately 85 percent of CP&L combustion turbine capacity is fired primarily by gas (CP&L 2000a). Manufacturers now have large standard-size combined-cycle gas turbines that are economically attractive and suitable for high-capacity base-load operation.

Mixture

NRC indicated in the GEIS that, while many methods are available for generating electricity and a huge number of combinations or mixes can be assimilated to meet system needs, such expansive consideration would be too unwieldy, given the purposes of the alternatives analysis. Therefore, NRC determined that a reasonable set of alternatives should be limited to analysis of single discrete electrical generation sources and only those electric generation technologies that are technically reasonable and commercially viable (NRC 1996a). Consistent with the NRC determination, CP&L has not evaluated mixes of generating sources. The impacts from coal- and gas-fired generation presented in this chapter would bound the impacts from any generation mixture of the two technologies.

Deregulation

Nationally, the electric power industry has been undergoing a transition from a regulated monopoly structure to a competitive market environment. Efforts to deregulate the electric utility industry began with passage of the National Energy Policy Act of 1992. Provisions of this act required electric utilities to allow open access to their transmission lines and encouraged development of a competitive wholesale market for electricity. The Act did not mandate competition in the retail market, leaving that decision to the states (NEI 2000).

Over the past few years, deregulation of the electric utility industry has received considerable attention in the Carolinas. The legislatures of both North and South Carolina have been studying the issue of electric power industry restructuring, or deregulation, since 1997. Some bills have been introduced, but no bill has gone beyond subcommittee. It is uncertain what action the state legislatures will take and when that might be (CP&L 2000c).

If the electric power industry in the Carolinas is deregulated, retail competition would replace the electric utilities' mandate to serve the public, and electricity customers in the area would be able to choose among competing power suppliers, including those located outside the region (CP&L 2001b). As such, electric generation would be based on the customers' needs and preferences, the lowest price, or the best combination of prices, services, and incentives.

This potential major source of competition for construction and operation of power plants would affect the selection of alternatives for RNP license renewal. With the prospect of hundreds of suppliers being licensed to sell electricity in the Carolinas, CP&L could not control demand and would not remain competitive if it offered extensive conservation and load modification incentives. North and South Carolina would ensure that the operation of generating units of incumbent utilities would not inhibit the development of competition within the Carolinas. Therefore, it is not clear whether

CP&L or another supplier would construct new generating units to replace those at RNP, if its license were not renewed. Regardless of which entities construct and operate the replacement power supply, certain environmental parameters would be constant among these alternative power sources. Therefore, Chapter 7 discusses the impacts of reasonable alternatives to RNP without regard to whether they would be owned by CP&L.

Alternatives

The following sections present fossil-fuel-fired generation (Section 7.2.1.1) and purchased power (Section 7.2.1.2) as reasonable alternatives to license renewal. Section 7.2.1.3 discusses reduced demand and presents the basis for concluding that it is not a reasonable alternative to license renewal. Section 7.2.1.4 discusses other alternatives that CP&L has determined are not reasonable and CP&L bases for these determinations.

7.2.1.1 Construct and Operate Fossil-Fuel-Fired Generation

CP&L analyzed locating hypothetical new coal- and gas-fired units at the existing RNP site and at an undetermined greenfield site. CP&L concluded that RNP is the preferred site for new construction because this approach could minimize environmental impacts by building on previously disturbed land and by making the most use possible of existing facilities, such as transmission lines, roads and parking areas, office buildings, and components of the cooling system. This is particularly true at the RNP site because it includes both pulverized coal- and gas-fired capacity. Locating hypothetical units at the existing site has, therefore, been applied to the coal- and gas-fired units.

For comparability, CP&L selected gas- and coal-fired units of equal electric power and capacity factors. A scenario of, for example, one unit with a net capacity of 683 MWe could be assumed to replace the 683-MWe RNP net capacity. However, CP&L's experience indicates that, although customized unit sizes can be built, using standardized sizes is more economical. For example, a manufacturer's standard-sized units include a gas-fired combined-cycle plant of 585-MWe net capacity, where the generator is arranged between gas and steam turbines on a single shaft. The plant consists of two 189-megawatt (MW) gas turbines and 207 MW of heat recovery capacity. For comparability, CP&L set the net power of the coal-fired unit equal to the gas-fired plant (585 MWe). Although this provides less capacity than the existing unit, it ensures against overestimating environmental impacts from the alternatives. The shortfall in capacity could be replaced by other methods (see Mixture in Section 7.2.1).

It must be emphasized, however, that these are hypothetical scenarios. CP&L does not have plans for such construction at RNP.

Coal-Fired Generation

NRC has evaluated coal-fired generation alternatives for the Calvert Cliffs Nuclear Power Plant (NRC 1999a) and for the Oconee Nuclear Station (NRC 1999b). For Oconee, NRC analyzed 2,500 MWe of coal-fired generation capacity. CP&L has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed substantially more generating capacity than the 585 MWe discussed in this analysis. In defining the RNP coal-fired alternative, CP&L has used site- and South Carolina-specific input and has scaled from the NRC analysis, where appropriate.

Table 7-1 presents the basic coal-fired alternative emission control characteristics. CP&L based its emission control technology and percent control assumptions on alternatives that the U.S. Environmental Protection Agency (EPA) has identified as being available for minimizing emissions (EPA 1998). For the purposes of analysis, CP&L has assumed that coal and lime (calcium hydroxide) would be delivered by rail via the rail line that is used for the existing coal-fired Unit 1.

<u>Gas-Fired Generation</u>

CP&L's current emphasis on combined-cycle units fueled primarily by gas is evidenced by its plan to construct 525 MWe of gas-fired combined-cycle capacity in Effingham County, Georgia (CP&L 2000d). CP&L has chosen to evaluate gas-fired generation using combined-cycle turbines because it has determined that the technology is mature, economical, and feasible. As indicated, a manufacturer's standard unit size (585 MWe net) is available and economical. Therefore, CP&L has analyzed 585 MW of net power, consisting of two 189-MW gas-fired combustion turbines and heat-recovery boiler capacity of 207 MW, to be located on RNP property. Table 7-2 presents the basic gas-fired alternative characteristics. CP&L would ensure gas availability through its holding company, Progress Energy, Inc.

7.2.1.2 Purchase Power

CP&L has evaluated conventional and prospective power supply options that could be reasonably implemented before the current RNP license expires in 2010. CP&L has entered into long-term purchase contracts with several utilities to provide firm capacity and energy. CP&L presumes that this capacity might be available for purchase after the year 2010 to meet future demand. Because these contracts are part of CP&L's current and future capacity, however, CP&L does not consider these power purchases a feasible option for the purchase power alternative.

In 1999, South Carolina exported 48.8 terawatt-hours of electricity (EIA 2001). North Carolina, on the other hand, imported 17.8 terawatt-hours of electricity in 1999 (EIA 2001). Therefore, in 1999, approximately 31.0 terawatt-hours of electricity were exported from the Carolinas. Some of the exported power may be the result of purchase contracts, which would prevent CP&L from using this power to replace RNP generation. However, CP&L cannot rule out the possibility that power would be available for purchase as an alternative to RNP license renewal. Therefore, CP&L has analyzed purchased power as a reasonable alternative.

CP&L assumes that the generating technology used to produce purchased power would be one of those that NRC analyzed in the GEIS. For this reason, CP&L is adopting by reference the GEIS description of the alternative generating technologies as representative of the purchase power alternative. Of these technologies, facilities fueled by coal and combined-cycle facilities fueled by natural gas are the most cost effective for providing base-load capacity. Given the amount of electricity generated by RNP, CP&L believes that it is reasonable to assume that new capacity would have to be built for the purchased-power alternative.

7.2.1.3 Reduce Demand

In the past, CP&L has offered demand-side management (DSM) programs that either conserve energy or allow the company to reduce customers' load requirements during periods of peak demand. CP&L's DSM programs fall into three categories (CP&L 2001c):

Conservation Programs

- Educational programs that encourage the wise use of energy

Energy Efficiency Programs

- Discounted residential rates for homes that meet specific energy efficiency standards
- Incentive programs that encourage customers to replace old, inefficient appliances or equipment with new high-efficiency appliances or equipment.

Load Management Programs

- Standby Generator Program – encourages customers to let CP&L switch loads to the customer's standby generators during periods of peak demand
- Interruptible Service Program – encourages customers to allow blocks of their load to be interrupted during periods of peak demand
- Time-of-Use Pricing – encourages customers to discontinue usage during specific times.

CP&L annually projects both the summer and winter peak power (in MW) and annual energy requirements (in gigawatt-hours) impacts of DSM. Projections for future DSM represent substantial decreases in the DSM initiatives that were in effect during past years. The market conditions which provided initial support for utility-sponsored conservation and load management efforts during the late 1970s and early 1980s can be broadly characterized by:

1. increasing long-term marginal prices for capacity and energy production resources;
2. forecasts projecting increasing demand for electricity across the nation;

3. general agreement that conditions (1) and (2) would continue for the foreseeable future;

4. limited competition in the generation of electricity;

5. economies of scale in the generation of electricity, which supported the construction of large central power plants; and

6. the use of average embedded cost as the basis for setting electricity prices within a regulated context.

These market and regulatory conditions would undergo dramatic changes in a deregulated market. Changes that have significantly impacted the cost effectiveness of utility-sponsored DSM can be described as follows:

1. a decline in generation costs, due primarily to technological advances that have reduced the cost of constructing new generating units (e.g., combustion turbines);

2. national energy legislation that has encouraged wholesale competition through open access to the transmission grid, as well as state legislation designed to facilitate retail competition.

The utility planning environment features shorter planning horizons, lower reserve margins, and increased reliance on market prices to direct utility resource planning. The changes occurring in the industry have greatly reduced the number of cost-effective DSM alternatives.

Other significant changes include:

- The adoption of increasingly stringent national appliance standards for most major energy-using equipment and the adoption of energy efficiency requirements in state building codes. These mandates have further reduced the potential for cost-effective utility-sponsored measures.

- In states that are currently transitioning into deregulation, third parties are increasingly providing energy services and products in competitive markets at prices that reflect their value to the customer. Market conditions can be expected to continue this shift among providers of cost-effective load management.

For these reasons, CP&L determined that the remaining DSM programs, which are primarily directed toward load management, are not an effective substitute for any of its large base-load units operating at high-capacity factors, including RNP.

7.2.1.4 Other Alternatives

This section identifies alternatives that CP&L has determined are not reasonable and the CP&L bases for these determinations. CP&L accounted for the fact that RNP is a base-load generator and that any feasible alternative to RNP would also need to be able to generate base-load power. In performing this evaluation, CP&L relied heavily upon NRC's GEIS (NRC 1996a).

Wind

Wind power, by itself, is not suitable for large base-load generation. As discussed in Section 8.3.1 of the GEIS, wind has a high degree of intermittence, and average annual capacity factors for wind plants are relatively low (less than 30 percent). Wind power, in conjunction with energy storage mechanisms, might serve as a means of providing base-load power. However, current energy storage technologies are too expensive for wind power to serve as a large base-load generator.

Wind power is not a technically feasible alternative in the Carolinas. According to the Wind Energy Resource Atlas of the United States (NREL 1986), areas suitable for wind energy applications must be wind power class 3 or higher. South Carolina and North Carolina do not have sufficient wind resources for wind energy applications (NREL 1986). While some exposed ridge crests and mountain summits in the extreme northwestern part of South Carolina are wind power class 3 or higher, more than 99 percent of the land area in the State has a wind power class of 1. Nearly 87 percent of the land area in North Carolina is less than wind power class 3. Areas in North Carolina that are wind power class 3 or higher are confined to exposed ridge crests and mountain summits in western North Carolina and the barrier islands along the Atlantic coast. The geography of these wind power class 3 areas makes them unsuitable for utility-scale wind energy applications (NREL 1986).

The GEIS estimates a land-use requirement of 150,000 acres per 1,000 MWe for wind power. Therefore, replacement of RNP generating capacity (683 MWe net) with wind power, even assuming ideal wind conditions, would require dedication of about 160 square miles. Based on the lack of sufficient wind speeds and the amount of land needed to replace RNP, the wind alternative would require a large greenfield site, which would result in a large environmental impact. Additionally, wind plants have aesthetic impacts, generate noise, and harm birds.

CP&L has concluded that, due to the lack of area in the Carolinas having suitable wind speeds and the amount of land needed (approximately 160 square miles), wind power is not a reasonable alternative to RNP license renewal.

Solar

By its nature, solar power is intermittent. In conjunction with energy storage mechanisms, solar power might serve as a means of providing base-load power. However, current energy storage technologies are too expensive to permit solar power to serve as a large base-load generator. Even without storage capacity, solar power technologies (photovoltaic and thermal) cannot currently compete with conventional fossil-fueled technologies in grid-connected applications, due to high costs per kilowatt of capacity. (NRC 1996a).

Solar power is not a technically feasible alternative for baseload capacity in the Carolinas. North and South Carolina receive about 3.3 kilowatt hours of solar radiation per square meter per day, compared with 5 to 7.2 kilowatt hours per square meter per day in areas of the West, such as California, which are most promising for solar technologies (NRC 1996a).

Finally, according to the GEIS, land requirements for solar plants are high, at 35,000 acres per 1,000 MWe for photovoltaic and 14,000 acres per 1,000 MWe for solar thermal systems. Therefore, replacement of RNP generating capacity with solar power would require dedication of about 37 square miles for photovoltaic and 15 square miles for solar thermal systems. Neither type of solar electric system would fit at the RNP site, and both would have large environmental impacts at a greenfield site.

CP&L has concluded that, due to the high cost, limited availability of sufficient incident solar radiation, and amount of land needed (approximately 15 to 37 square miles), solar power is not a reasonable alternative to RNP license renewal.

Hydropower

A portion (about 5,000 MW) of utility generating capacity in the Carolinas is hydroelectric. As the GEIS points out in Section 8.3.4, hydropower's percentage of United States generating capacity in the Carolinas is expected to decline because hydroelectric facilities have become difficult to site as a result of public concern over flooding, destruction of natural habitat, and alteration of natural river courses. From 1998 to 1999, utilities reduced hydroelectric production by about 74 percent in South Carolina and 35 percent in North Carolina (EIA 2000c). According to the *U.S. Hydropower Resource Assessment for South Carolina* (INEL 1997a), there are no remaining sites in South Carolina that would be environmentally suitable for a large hydroelectric facility. Similarly, the *U.S. Hydropower Resource Assessment for North Carolina* (INEL 1997b), indicates that there are no environmentally suitable sites remaining in North Carolina that could be used for a large hydroelectric facility.

The GEIS estimates land use of 1,600 square miles per 1,000 MWe for hydroelectric power. Based on this estimate, replacement of RNP generating capacity would require flooding more than 1,090 square miles, resulting in a large impact on land use. Further, operation of a hydroelectric facility would alter aquatic habitats above and below the dam, which would impact existing aquatic communities.

CP&L has concluded that, due to the lack of suitable sites in the Carolinas and the amount of land needed (approximately 1,090 square miles), hydropower is not a reasonable alternative to RNP license renewal.

Geothermal

As illustrated by Figure 8.4 in the GEIS, geothermal plants might be located in the western continental United States, Alaska, and Hawaii, where hydrothermal reservoirs are prevalent. However, because there are no high-temperature geothermal sites in

North or South Carolina, CP&L concludes that geothermal is not a reasonable alternative to RNP license renewal.

Wood Energy

As discussed in the GEIS (NRC 1996a), the use of wood waste to generate electricity is largely limited to those states with significant wood resources. According to the U.S. Department of Energy, North and South Carolina are considered to have excellent wood resource potential (Walsh et al. 2000). The pulp, paper, and paperboard industries in states with adequate wood resources generate electric power by consuming wood and wood waste for energy, benefiting from the use of waste materials that could otherwise represent a disposal problem. However, the largest wood waste power plants are 40 to 50 MW in size.

Further, as discussed in Section 8.3.6 of the GEIS, construction of a wood-fired plant would have an environmental impact that would be similar to that for a coal-fired plant, although facilities using wood waste for fuel would be built on smaller scales. Like coal-fired plants, wood-waste plants require large areas for fuel storage, processing, and waste disposal (i.e., ash). Additionally, operation of wood-fired plants has environmental impacts, including impacts on the aquatic environment and air. Wood has a low heat content that makes it unattractive for base-load applications. It is also difficult to handle and has high transportation costs.

While wood resources are available in the Carolinas, CP&L has concluded that, due to the lack of an obvious environmental advantage, low heat content, handling difficulties, and high transportation costs, wood energy is not a reasonable alternative to RNP license renewal.

Municipal Solid Waste

As discussed in Section 8.3.7 of the GEIS, the initial capital costs for municipal solid waste plants are greater than for comparable steam turbine technology at wood-waste facilities. This is due to the need for specialized waste separation and handling equipment.

The decision to burn municipal solid waste to generate energy is usually driven by the need for an alternative to landfills, rather than by energy considerations. The use of landfills as a waste disposal option is likely to increase in the near term; however, it is unlikely that many landfills will begin converting waste to energy because of unfavorable economics, particularly with electricity prices declining.

Estimates in the GEIS suggest that the overall level of construction impacts from a waste-fired plant should be approximately the same as that for a coal-fired plant. Additionally, waste-fired plants have the same or greater operational impacts (including impacts on the aquatic environment, air, and waste disposal). Some of these impacts would be moderate, but still larger than the environmental effects of RNP license renewal.

CP&L has concluded that, due to the high costs and lack of obvious environmental advantages, burning municipal solid waste to generate electricity is not a reasonable alternative to RNP license renewal.

Other Biomass-Derived Fuels

In addition to wood and municipal solid waste fuels, there are several other concepts for fueling electric generators, including burning energy crops, converting crops to a liquid fuel such as ethanol (ethanol is primarily used as a gasoline additive), and gasifying energy crops (including wood waste). As discussed in the GEIS, none of these technologies has progressed to the point of being competitive on a large scale or of being reliable enough to replace a base-load plant such as RNP.

Further, estimates in the GEIS suggest that the overall level of construction impacts from a crop-fired plant should be approximately the same as that for a wood-fired plant. Additionally, crop-fired plants would have similar operational impacts (including impacts on the aquatic environment and air). These systems also have large impacts on land use, due to the acreage needed to grow the energy crops.

CP&L has concluded that, due to the high costs and lack of obvious environmental advantage, burning other biomass-derived fuels is not a reasonable alternative to RNP license renewal.

Petroleum

Both North and South Carolina have several petroleum (oil)-fired power plants; however, they produce less than one percent of the total power generated in the Carolinas. Petroleum-fired operation is more expensive than nuclear or coal-fired operation. In addition, future increases in petroleum prices are expected to make petroleum-fired generation increasingly more expensive than coal-fired generation. The high cost of petroleum has prompted a steady decline in its use for electricity generation. From 1998 to 1999, utilities reduced production of electricity by petroleum-fired plants by about 9 percent in South Carolina and 1 percent in North Carolina (EIA 2000c).

Also, construction and operation of an petroleum-fired plant would have environmental impacts. For example, Section 8.3.11 of the GEIS estimates that construction of a 1,000-MWe petroleum-fired plant would require about 120 acres. Additionally, operation of petroleum-fired plants would have environmental impacts (including impacts on the aquatic environment and air) that would be similar to those from a coal-fired plant.

CP&L has concluded that, due to the high costs and lack of obvious environmental advantage, petroleum-fired generation is not a reasonable alternative to RNP license renewal.

Fuel Cells

Phosphoric acid fuel cells are the most mature fuel cell technology, but they are only in the initial stages of commercialization. Two hundred turnkey plants have been installed in the United States, Europe, and Japan. Recent estimates suggest that a company would have to produce about 100 MW of fuel cell stacks annually to achieve a price of $1,000 to $1,500 per kilowatt. However, the current production capacity of fuel cell manufacturers only totals about 75 MW per year. CP&L believes that this technology has not matured sufficiently to support production for a facility the size of RNP. CP&L has concluded that, due to cost and production limitations, fuel cell technology is not a reasonable alternative to RNP license renewal.

Delayed Retirement

CP&L has no plans for retiring any of its fleet of nuclear plants and expects to need additional capacity in the near future. Fossil plants slated for retirement tend to be ones that are old enough to have difficulty in meeting today's restrictions on air contaminant emissions. In the face of increasingly stringent restrictions, delaying retirement in order to compensate for a plant the size of RNP would appear to be unreasonable without major construction to upgrade or replace plant components. CP&L concludes that the environmental impacts of such a scenario are bounded by its coal- and gas-fired alternatives.

7.2.2 ENVIRONMENTAL IMPACTS OF ALTERNATIVES

This section evaluates the environmental impacts of alternatives that CP&L has determined to be reasonable alternatives to RNP license renewal: coal-fired generation, gas-fired generation, and purchased power.

7.2.2.1 Coal-Fired Generation

NRC evaluated environmental impacts from coal-fired generation alternatives in the GEIS (NRC 1996a). NRC concluded that construction impacts could be substantial, due in part to the large land area required (which can result in natural habitat loss) and the large workforce needed. NRC pointed out that siting a new coal-fired plant where an existing nuclear plant is located would reduce many construction impacts. NRC identified major adverse impacts from operations as human health concerns associated with air emissions, waste generation, and losses of aquatic biota due to cooling water withdrawals and discharges.

The coal-fired alternative that CP&L has defined in Section 7.2.1.1 would be located at RNP. As noted previously, this site has an existing coal-fired unit.

Air Quality

Air quality impacts of coal-fired generation are considerably different from those of nuclear power. A coal-fired plant would emit oxides of sulfur (SO_x) and nitrogen (NO_x), particulate matter, and carbon monoxide, all of which are regulated pollutants. As

Section 7.2.1.1 indicates, CP&L has assumed a plant design that would minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. CP&L estimates the coal-fired alternative emissions to be as follows:

SO_x = 2,031 tons per year

NO_x = 447 tons per year

Carbon monoxide = 461 tons per year

Particulates:

Total suspended particulates = 80 tons per year

PM_{10} (particulates having a diameter of less than 10 microns) = 18 tons per year

Table 7-3 shows how CP&L calculated these emissions.

In 1998, emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) from South Carolina's generators ranked 17th and 32nd nationally, respectively (EIA 2000a). No South Carolina generators were cited in the Clean Air Act Amendments of 1990 to begin compliance in 1995 with stricter emission controls for SO_2 and NO_x. However, it is likely that South Carolina's Public Service Commission will need to design a State Implementation Plan for reducing ground-level ozone in response to a proposal released by the EPA in October 1998.

NRC did not quantify coal-fired emissions, but implied that air impacts would be substantial. NRC noted that adverse human health effects from coal combustion have led to important federal legislation in recent years and that public health risks, such as cancer and emphysema, have been associated with coal combustion. NRC also mentioned global warming and acid rain as potential impacts. CP&L concludes that federal legislation and large-scale concerns, such as global warming and acid rain, are indications of concerns about destabilizing important attributes of air resources. However, SO_2 emission allowances, NO_x emission offsets, low NO_x burners, overfire air, fabric filters or electrostatic precipitators, and scrubbers are regulatorily imposed mitigation measures. As such, CP&L concludes that the coal-fired alternative would have moderate impacts on air quality; the impacts would be clearly noticeable, but would not destabilize air quality in the area.

Waste Management

CP&L concurs with the GEIS assessment that the coal-fired alternative would generate substantial solid waste. The coal-fired plant would annually consume approximately 1,840,000 tons of coal having an ash content of 8.7 percent (Tables 7-3 and 7-1, respectively). After combustion, most (99.9 percent) of this ash, approximately 160,000 tons per year, would be collected and disposed of onsite. In addition, approximately 111,000 tons of scrubber sludge would be disposed of onsite each year (based on annual calcium hydroxide usage of nearly 37,000 tons). CP&L estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 145 acres (a square area with sides of approximately 2,500 feet). Table 7-4 shows how CP&L calculated ash and scrubber waste volumes. The RNP site is approximately 3,500 acres, excluding Lake Robinson. While only half this waste volume and land use would be attributable to the 20-year license renewal period alternative, the total numbers are pertinent as a cumulative impact.

CP&L believes that, with proper siting coupled with current waste management and monitoring practices, waste disposal would not destabilize any resources. There would be space within the site footprint for this disposal. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, CP&L believes that waste disposal for the coal-fired alternative would have moderate impacts; the impacts of increased waste disposal would be clearly noticeable, but would not destabilize any important resource, and further mitigation would be unwarranted.

Other Impacts

CP&L estimates that construction of the powerblock and coal storage area would impact 120 acres of land and associated terrestrial habitat. Because most of this construction would be in previously disturbed areas, impacts would be minimal. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Construction debris from clearing and grubbing could be disposed of onsite and municipal waste disposal capacity would be available. Socioeconomic impacts from the construction workforce would be minimal, because worker relocation would not be expected, due to the site's proximity to Florence and Columbia, South Carolina, 25 miles and 56 miles from the site, respectively. However, CP&L estimates a workforce of 110 for operations. The reduction in workforce would result in adverse socioeconomic impacts. Cultural resource impacts would be unlikely, due to the assumed previously disturbed nature of the site.

Impacts to aquatic resources and water quality would be minimal, due to the plant's use of the existing cooling water system that withdraws from and discharges to Lake Robinson. The additional stacks, boilers, and rail deliveries would increase the visual impact of the existing site. Socioeconomic impacts would result from a decrease in the operational workforce. CP&L believes these impacts would be small, due to RNP's proximity to Florence and Columbia.

CP&L notes the EPA has drafted regulations which, if completed in their current form, would require the coal-fired alternative cooling system to be closed-cycle (EPA 2000a). Addition of this technology to the alternative would involve constructing a natural draft cooling tower or mechanical cooling towers. Recirculation would reduce cooling water intake volume by approximately 90 percent.

CP&L believes that other construction and operation impacts would be small. In most cases, the impacts would be detectable, but they would not destabilize any important attribute of the resource involved. Due to the minor nature of these other impacts, mitigation would not be warranted beyond that previously mentioned.

7.2.2.2 Gas-Fired Generation

NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, focusing on combined-cycle plants. Section 7.2.1.1 presents CP&L's reasons for defining the gas-fired generation alternative as a combined-cycle plant on the RNP site. Land-use impacts from gas-fired units on RNP would be less than those from the coal-fired alternative. Reduced land requirements, due to construction on the existing site and a smaller facility footprint, would reduce impacts to ecological, aesthetic, and cultural resources as well. A smaller workforce could have adverse socioeconomic impacts. Human health effects associated with air emissions would be of concern. Aquatic biota losses due to cooling water withdrawals would be offset by the concurrent shutdown of the nuclear generators.

NRC has evaluated the environmental impacts of constructing and operating four 440-MW combined-cycle gas-fired units as an alternative to a nuclear power plant license renewal (NRC 1996a). This analysis is for a generating capacity approximately three times the RNP gas-fired alternatives analysis, because CP&L would install 585 MW of net power. CP&L has adopted the rest of the NRC analysis with necessary South Carolina- and CP&L-specific modifications noted.

<u>Air Quality</u>

Natural gas is a relatively clean-burning fossil fuel; the gas-fired alternative would release similar types of emissions, but in lesser quantities than the coal-fired alternative. Control technology for gas-fired turbines focuses on NO_x emissions. CP&L estimates the gas-fired alternative emissions to be as follows:

SO_x = 48 tons per year

NO_x = 153 tons per year

Carbon monoxide = 32 tons per year

Filterable Particulates = 27 tons per year (all particulates are PM_{10})

Table 7-5 shows how CP&L calculated these emissions.

The Section 7.2.2.1 discussion of regional air quality and Clean Air Act requirements is also applicable to the gas-fired generation alternative. NO_x effects on ozone levels, SO_2 allowances, and NO_x emission offsets could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, and regulatory requirements are less stringent, the emissions are still substantial. CP&L concludes that emissions from the gas-fired alternative located at RNP would noticeably alter local air quality, but would not destabilize regional resources (i.e., air quality). Air quality impacts would therefore be moderate, but substantially smaller than those of coal-fired generation.

Waste Management

Gas-fired generation would result in almost no waste generation, producing minor (if any) impacts. CP&L concludes that gas-fired generation waste management impacts would be small.

Other Impacts

Similar to the coal-fired alternative, the ability to construct the gas-fired alternative on the existing RNP site would reduce construction-related impacts. Because the existing gas supply to the site is for 15 MW of power, a new gas pipeline would be required for the two 189-MW gas turbine generators in this alternative. To the extent practicable, CP&L would route the pipeline along the existing, previously disturbed, right-of-way to minimize impacts. Approximately 1.5 miles of new pipeline construction would be required to connect RNP to the existing pipeline network connection at the Darlington County plant. A 16- to 24-inch-diameter pipeline would necessitate a 75-foot-wide corridor, resulting in the disturbance of approximately 13.5 acres. This new construction may also necessitate an upgrade of existing pipeline facilities between the Darlington County plant and the State-wide pipeline network. CP&L estimates that 50 acres would be needed for a plant site; this much previously disturbed acreage is available at RNP, reducing loss of terrestrial habitat. Aesthetic impacts, erosion and sedimentation, fugitive dust, and construction debris impacts would be similar to the coal-fired alternative, but smaller because of the reduced site size. Socioeconomic impacts of construction would be minimal. However, CP&L estimates a workforce of 25 for gas operations. The reduction in work force would result in adverse socioeconomic impacts. CP&L believes these impacts would be moderate and would be mitigated by the site's proximity to the metropolitan areas of Florence and Columbia.

7.2.2.3 Purchased Power

As discussed in Section 7.2.1.2, CP&L assumes that the generating technology used under the purchased power alternative would be one of those that NRC analyzed in the GEIS. CP&L is also adopting by reference the NRC analysis of the environmental impacts from those technologies. Under the purchased power alternative, therefore, environmental impacts would still occur, but they would likely originate from a power plant located elsewhere in the Carolinas. CP&L believes that imports from outside the Carolinas would not be required.

The purchased power alternative would include constructing up to 200 miles of high-voltage (i.e., 500-kilovolt) transmission lines to get power from the remote locations in the Carolinas to the CP&L network. CP&L believes most of the transmission lines could be routed along existing rights-of-way. CP&L assumes that the environmental impacts of transmission line construction would be moderate. As indicated in the introduction to Section 7.2.1.1, the environmental impacts of construction and operation of new coal- or gas-fired generating capacity for purchased power at a previously undisturbed greenfield site would exceed those of a coal- or gas-fired alternative located on the RNP site.

7.3 TABLES

TABLE 7-1
COAL-FIRED ALTERNATIVE

Characteristic	Basis
Unit size = 585 MW ISO rating net[a]	Calculated to be ≤ RNP Unit 2 net capacity – 683 MW
Unit size = 620 MW ISO rating gross[a]	Calculated based on 6 percent onsite power
Number of units = 1	
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions (EPA 1998)
Fuel type = bituminous, pulverized coal	Typical for coal used in South Carolina
Fuel heating value = 12,775 Btu/lb	1999 value for coal used in South Carolina (EIA 2000d)
Fuel ash content by weight = 8.7 percent	1999 value for coal used in South Carolina (EIA 2000d)
Fuel sulfur content by weight = 1.16 percent	1999 value for coal used in South Carolina (EIA 2000d)
Uncontrolled NO_x emission = 9.7 lb/ton Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, pre-NSPS with low-NO_x burner (EPA 1998)
Heat rate = 10,200 Btu/Kwh	Typical for coal-fired, single-cycle steam turbines (EIA 2000d)
Capacity factor = 0.85	Typical for large coal-fired units
NO_x control = low NO_x burners, overfire air and selective catalitic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NO_x emissions (EPA 1998)
Particulate control = fabric filters (baghouse-99.9 percent removal efficiency)	Best available for minimizing particulate emissions (EPA 1998)
SO_x control = Wet scrubber – lime (95 percent removal efficiency)	Best available for minimizing SO_x emissions (EPA 1998)

a. The difference between "net" and "gross" is electricity consumed onsite.

Btu = British thermal unit
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
Kwh = kilowatt hour
NSPS = New Source Performance Standard
Lb = pound
MW = megawatt
NO_X = nitrogen oxides
SO_x = oxides of sulfur

TABLE 7-2
GAS-FIRED ALTERNATIVE

Characteristic	Basis
Unit size = 585 MW ISO rating net:[a] Two 189-MW combustion turbines and a 207-MW heat recovery boiler	Manufacturer's standard size gas-fired combined-cycle plant that is ≤ RNP Unit 2 net capacity - 683 MW
Unit size = 608 MW ISO rating gross:[a] Two 196.5-MW combustion turbines 215-MW heat recovery boiler	Calculated based on 4 percent onsite power
Number of units = 1	
Fuel type = natural gas	Assumed
Fuel heating value = 1,025 Btu/ft^3	1999 value for gas used in South Carolina (EIA 2000d)
Fuel sulfur content = 0.0034 lb/MMBtu	Used when sulfur content is not available (EPA 2000b)
NO_x control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NO_x emissions (EPA 2000b)
Fuel NO_x content = 0.0109 lb/MMBtu	Typical for large SCR-controlled gas fired units with water injection (EPA 2000b)
Fuel CO content = 0.00226 lb/MMBtu	Typical for large SCR-controlled gas fired units (EPA 2000b)
Heat rate = 6,204 Btu/Kwh	Manufacturer's listed heat rate for this unit
Capacity factor = 0.85	Typical for large gas-fired base-load units

a. The difference between "net" and "gross" is electricity consumed onsite.

Btu = British thermal unit
ft^3 = cubic foot
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
Kwh = kilowatt hour
MM = million
MW = megawatt
NO_x = nitrogen oxides

TABLE 7-3
AIR EMISSIONS FROM COAL-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual coal consumption	$1\,\text{unit} \times \frac{620\,\text{MW}}{\text{unit}} \times \frac{10{,}200\,\text{Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\,\text{kW}}{\text{MW}} \times \frac{\text{lb}}{12{,}775\,\text{Btu}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times 0.85 \times \frac{24\,\text{hr}}{\text{day}} \times \frac{365\,\text{day}}{\text{yr}}$	1,843,292 tons of coal per year
SO_x[a,c]	$\frac{38 \times 1.28\,\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times (1 - 90/100) \times \frac{1{,}843{,}292\,\text{tons}}{\text{yr}}$	2,031 tons SO_x per year
NO_x[b, c]	$\frac{9.7\,\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times (1 - 95/100) \times \frac{1{,}843{,}292\,\text{tons}}{\text{yr}}$	447 tons NO_x per year
CO[c]	$\frac{0.5\,\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times \frac{1{,}843{,}292\,\text{tons}}{\text{yr}}$	461 tons CO per year
TSP[d]	$\frac{10 \times 8.7\,\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times (1 - 99.9/100) \times \frac{1{,}843{,}292\,\text{tons}}{\text{yr}}$	80 tons TSP per year
PM_{10}[d]	$\frac{2.3 \times 8.7\,\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times (1 - 99.9/100) \times \frac{1{,}843{,}292\,\text{tons}}{\text{yr}}$	18 tons PM_{10} per year

a. EPA 1998, Table 1.1-1.
b. EPA 1998, Table 1.1-2.
c. EPA 1998, Table 1.1-3.
d. EPA 1998, Table 1.1-4.

CO = carbon monoxide
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter less than 10 microns
SO_x = oxides of sulfur
TSP = total suspended particulates

TABLE 7-4
SOLID WASTE FROM COAL-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual SO_x generated[a]	$\frac{1{,}843{,}292 \text{ ton coal}}{\text{yr}} \times \frac{1.16 \text{ ton S}}{100 \text{ ton coal}} \times \frac{64.1 \text{ ton } SO_2}{32.1 \text{ ton S}}$	42,743 tons of SO_x per year
Annual SO_x removed	$\frac{42{,}743 \text{ ton } SO_2}{\text{yr}} \times (95/100)$	40,606 tons of SO_x per year
Annual ash generated	$\frac{1{,}843{,}292 \text{ ton coal}}{\text{yr}} \times \frac{8.70 \text{ ton ash}}{100 \text{ ton coal}} \times (99.9/100)$	160,206 tons of ash per year
Annual lime consumption[b]	$\frac{42{,}743 \text{ ton } SO_2}{\text{yr}} \times \frac{56.1 \text{ ton CaO}}{64.1 \text{ ton } SO_2}$	37,408 tons of CaO per year
Calcium sulfate[c]	$\frac{40{,}606 \text{ ton } SO_2}{\text{yr}} \times \frac{172 \text{ ton } CaSO_4 \bullet 2H_2O}{64.1 \text{ ton } SO_2}$	108,958 tons of $CaSO_4 \cdot 2H_2O$ per year
Annual scrubber waste[d]	$\frac{37{,}408 \text{ ton CaO}}{\text{yr}} \times \frac{(100-95)}{100} + 108{,}958 \text{ ton } CaSO_4 \bullet 2H_2O$	110,828 tons of scrubber waste per year
Total volume of scrubber waste[e]	$\frac{110{,}828 \text{ ton}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{144.8 \text{ lb}}$	61,244,731 ft^3 of scrubber waste
Total volume of ash[f]	$\frac{160{,}206 \text{ ton}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{100 \text{ lb}}$	128,164,798 ft^3 of ash
Total volume of solid waste	$61{,}244{,}731 \ ft^3 + 128{,}164{,}798 \ ft^3$	189,409,529 ft^3 of solid waste
Waste pile area (acres)	$\frac{189{,}409{,}529 \ ft^3}{30 \ ft} \times \frac{\text{acre}}{43{,}560 \ ft^2}$	145 acres of solid waste
Waste pile area (ft x ft square)	$\sqrt{(189{,}409{,}529 \ ft^3 / 30 ft)}$	2,513 feet by feet square of solid waste

Based on annual coal consumption of 1,843,292 tons per year (Table 7-3).

a. Calculations assume 100 percent combustion of coal.

b. Lime consumption is based on total SO_2 generated.

c. Calcium sulfate generation is based on total SO_2 removed.

d. Total scrubber waste includes scrubbing media carryover.

e. Density of $CaSO_4 \cdot 2H_2O$ is 144.8 lb/ft^3.

f. Density of coal bottom ash is 100 lb/ft^3 (FHA 2000).

S = sulfur
SO_x = oxides of sulfur
CaO = calcium oxide (lime)
$CaSO_4 \cdot 2H_2O$ = calcium sulfate dihydrate

TABLE 7-5
AIR EMISSIONS FROM GAS-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual gas consumption	$1\text{ unit}\times\frac{608\text{ MW}}{\text{unit}}\times\frac{6{,}204\text{ Btu}}{\text{kW}\times\text{hr}}\times\frac{1{,}000\text{ kW}}{\text{MW}}\times 0.85\times\frac{\text{ft}^3}{1{,}025\text{ Btu}}\times\frac{24\text{ hr}}{\text{day}}\times\frac{365\text{ day}}{\text{yr}}$	27,419,539,771 ft^3 per year
Annual Btu input	$\frac{27{,}419{,}539{,}771\text{ ft}^3}{\text{yr}}\times\frac{1025\text{ Btu}}{\text{ft}^3}\times\frac{\text{MM Btu}}{10^6\text{ Btu}}$	28,105,028 MMBtu per year
SO_x[a]	$\frac{0.0034\text{ lb}}{\text{MMBtu}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\frac{28{,}105{,}028\text{ MMBtu}}{\text{yr}}$	48 tons SO_x per year
NO_x[b]	$\frac{0.0109\text{ lb}}{\text{MMBtu}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\frac{28{,}105{,}028\text{ MMBtu}}{\text{yr}}$	153 tons NO_x per year
CO[b]	$\frac{0.0023\text{ lb}}{\text{MMBtu}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\frac{28{,}105{,}028\text{ MMBtu}}{\text{yr}}$	32 tons CO per year
TSP[a]	$\frac{0.0019\text{ lb}}{\text{MMBtu}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\frac{28{,}105{,}028\text{ MMBtu}}{\text{yr}}$	27 tons filterable TSP per year
PM_{10}[a]	$\frac{27\text{ tons TSP}}{\text{yr}}$	27 tons filterable PM_{10} per year

a. EPA 2000b, Table 3.1-1.
b. EPA 2000b, Table 3.1-2.

CO = carbon monoxide
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter less than 10 microns
SO_x = oxides of sulfur
TSP = total suspended particulates

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8.0 COMPARISON OF ENVIRONMENTAL IMPACTS OF LICENSE RENEWAL WITH THE ALTERNATIVES

NRC

"To the extent practicable, the environmental impacts of the proposal and the alternatives should be presented in comparative form..."
10 CFR 51.45(b)(3) as adopted by 51.53(c)(2)

Chapter 4 analyzes environmental impacts of H. B. Robinson Steam Electric Plant, Unit No. 2 (RNP) license renewal and Chapter 7 analyzes impacts from renewal alternatives. Table 8-1 summarizes environmental impacts of the proposed action (license renewal) and the alternatives, for comparison purposes. The environmental impacts compared in Table 8-1 are those that are either Category 2 issues for the proposed action, license renewal, or are issues that the *Generic Environmental Impact Statement* (GEIS) (NRC 1996) identified as major considerations in an alternatives analysis. For example, although the U. S. Nuclear Regulatory Commission (NRC) concluded that air quality impacts from the proposed action would be small (Category 1), the GEIS identified major human health concerns associated with air emissions from alternatives (Section 7.2.2). Therefore, Table 8-1 compares air impacts among the proposed action and the alternatives. Table 8-2 is a more detailed comparison of the alternatives.

8.1 TABLES

TABLE 8-1
IMPACTS COMPARISON SUMMARY

		No-Action Alternative			
Impact	**Proposed Action (License Renewal)**	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With Purchased Power**
Land Use	SMALL	SMALL	SMALL	SMALL	MODERATE
Water Quality	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Air Quality	SMALL	SMALL	MODERATE	MODERATE	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Threatened or Endangered Species	SMALL	SMALL	SMALL	SMALL	SMALL
Human Health	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Socioeconomics	SMALL	SMALL	SMALL	MODERATE	SMALL to MODERATE
Waste Management	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Aesthetics	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Cultural Resources	SMALL	SMALL	SMALL	SMALL	SMALL

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource. 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.

TABLE 8-2
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative With Coal-Fired Generation	 With Gas-Fired Generation	 With Purchased Power
		Alternative Descriptions		
RNP license renewal for 20 years, followed by decommissioning	Decommissioning following expiration of current RNP license. Adopting by reference, as bounding RNP decommissioning, GEIS description (NRC 1996, Section 7.1)	New construction at the RNP site.	New construction at the RNP site.	Would involve construction of new generation capacity in the state. Adopting by reference GEIS description of alternate technologies (Section 7.2.1.2)
		Use existing rail spur	Construct 1.5 miles of gas pipeline in a 75-foot-wide corridor. May include possible upgrades to existing pipelines.	
		Use existing switchyard and transmission lines	Use existing switchyard and transmission lines	Construct up to 200 miles of transmission lines
		One 585-MW (net) tangentially-fired, dry bottom unit; capacity factor 0.85	585 MW of net power, consisting of two 189-MW gas-fired combustion turbines and heat recovery capacity of 207 MW. (Combined-cycle turbines to be used.)	
		Existing RNP intake/ discharge canal system	Existing RNP intake/ discharge canal system	
		Pulverized bituminous coal, 12,775 Btu/pound; 10,200 Btu/kWh; 8.7% ash; 1.16% sulfur; 9.7 lb/ton nitrogen oxides; 1,843,292 tons coal/yr	Natural gas, 1,025 Btu/ft^3; 6,204 Btu/kWh; 0.0034 lb sulfur/MMBtu; 0.0109 lb NO_x/MMBtu; 27,419,539,771 ft^3 gas/yr	

TABLE 8-2 (Cont'd)
IMPACTS COMPARISON DETAIL

		No-Action Alternative		
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With Purchased Power**
		Low NO_x burners, overfire air and selective catalytic reduction (95% NO_x reduction efficiency). Wet scrubber – lime/limestone desulfurization system (95% SO_x removal efficiency); 37,408 tons limestone/yr Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency)	Selective catalytic reduction with steam/water injection	
435 workers		110 workers (Section 7.2.2.1)	25 workers (Section 7.2.2.2)	
Land Use Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 52, 53)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – 120 acres required for the powerblock and associated facilities. (Section 7.2.2.1)	SMALL – 50 acres for facility at RNP location; 13.5 acres for pipeline (Section 7.2.2.2). New gas pipeline would be built to connect with existing gas pipeline corridor.	MODERATE – most transmission facilities could be constructed along existing transmission corridors (Section 7.2.2.3) Adopting by reference GEIS description of land use impacts from alternate technologies (NRC 1996)

TABLE 8-2 (Cont'd)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
Water Quality Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 3, 5, 6, 7-11). Two Category 2 groundwater issues not applicable (Section 4.6, Issue 34; and Section 4.7, Issue 35). Evaporative loss from cooling pond would have minimal effect on biological communities (Section 4.1, Issue 13) and aquifer recharge or groundwater degradation (Section 4.8, Issue 39).	SMALL – Adopting by reference Category 1 issue finding (Table 4-2, Issue 89).	SMALL – Construction impacts minimized by use of best management practices. Operational impacts minimized by use of the existing cooling water system that withdraws from and discharges to Lake Robinson (Section 7.2.2.1)	SMALL – Reduced cooling water demands, inherent in combined-cycle design (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of water quality impacts from alternate technologies (NRC 1996,)
Air Quality Impacts				
SMALL – Adopting by reference Category 1 issue finding (Table 4-2, Issue 51). Category 2 issue not applicable (Section 4.11, Issue 50).	SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issue 88)	MODERATE – 2,031 tons SO_x/yr 447 tons NO_x/yr 461 tons CO/yr 80 tons TSP/yr 18 tons PM_{10}/yr (Section 7.2.2.1)	MODERATE – 48 tons SO_x/yr 153 tons NO_x/yr 32 tons CO/yr 27 tons PM_{10}/yr[a] (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of air quality impacts from alternate technologies (NRC 1996)

TABLE 8-2 (Cont'd)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
		Ecological Resource Impacts		
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 15-24, 44-48). One Category 2 issue not applicable (Section 4.9, Issue 40). RNP holds a current NPDES permit, which constitutes compliance with Clean Water Act Section 316(b) (Section 4.2, Issue 25; Section 4.3, Issue 26) and 316(a) (Section 4.4, Issue 27)	SMALL – Adopting by reference Category 1 issue finding (Table 4-2, Issue 90)	SMALL – 145 acres of forested land could be required for ash/sludge disposal over 20-year license renewal term. (Section 7.2.2.1)	SMALL – Construction of the pipeline could alter habitat. (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of ecological resource impacts from alternate technologies (NRC 1996)
		Threatened or Endangered Species Impacts		
SMALL – With the exception of occasional bald eagle sightings, no threatened or endangered species are known at the site or along the transmission corridors. (Section 4.10, Issue 49)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats

TABLE 8-2 (Cont'd)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
		Human Health Impacts		
SMALL – Category 1 issues (Table 4-2, Issues 58, 61, 62). Risk from microbiological organisms minimal due to low discharge temperatures (Section 4.12, Issue 57). Risk due to transmission-line induced currents minimal due to conformance with consensus code (Section 4.13, Issue 59)	SMALL – Adopting by reference Category 1 issue finding (Table 4-2, Issue 86)	MODERATE – Adopting by reference GEIS conclusion that risks such as cancer and emphysema from emissions are likely (NRC 1996)	SMALL – Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions (NRC 1996)	SMALL to MODERATE – Adopting by reference GEIS description of human health impacts from alternate technologies (NRC 1996)
		Socioeconomic Impacts		
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 64, 67). Two Category 2 issues are not applicable (Section 4.16, Issue 66 and Section 4.17.1, Issue 68). Location in medium population area with limited growth controls minimizes potential for housing impacts. Section 4.14, Issue 63). Plant contribution to county tax base is significant, and continued plant operation would benefit county (Section 4.17.2, Issue 69).	SMALL – Adopting by reference Category 1 issue finding (Table 4-2, Issue 91)	SMALL – Reduction in permanent work force at RNP could adversely affect surrounding counties, but would be mitigated by RNP's proximity to Florence and Columbia (Section 7.2.2.1).	SMALL to MODERATE – Reduction in permanent work force at RNP could adversely affect surrounding counties, but would be mitigated by RNP's proximity to Florence and Columbia (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of socioeconomic impacts from alternate technologies (NRC 1996)

TABLE 8-2 (Cont'd)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative		
		With Coal-Fired Generation	**With Gas-Fired Generation**	**With Purchased Power**
(Capacity of public water supply and transportation infrastructure minimizes potential for related impacts (Section 4.15, Issue 65 and Section 4.18, Issue 70)				
Waste Management Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 77-85)	SMALL – Adopting by reference Category 1 issue finding (Table 4-2, Issue 87)	MODERATE – 160,206 tons of coal ash and 110,828 tons of scrubber sludge would require 145 acres over 20-year license renewal term. Industrial waste generated annually (Section 7.2.2.1)	SMALL – Almost no waste generation (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of waste management impacts from alternate technologies (NRC 1996)
Aesthetic Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 73, 74)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – The coal-fired power block and the exhaust stack would be visible from Lake Robinson and from a moderate offsite distance (Section 7.2.2.1)	SMALL – Steam turbines and stacks would create visual impacts comparable to those from existing RNP facilities (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies (NRC 1996)

TABLE 8-2 (Cont'd)
IMPACTS COMPARISON DETAIL

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
Cultural Resource Impacts				
SMALL – SHPO consultation minimizes potential for impact (Section 4.19, Issue 71)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.1)	SMALL – 1.5 miles of pipeline construction in east-central SC could affect some cultural resources (Section 7.2.2.2)	SMALL – Adopting by reference GEIS description of cultural resource impacts from alternate technologies (NRC 1996)

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.
MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource. 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.

Btu = British thermal unit
ft^3 = cubic foot
gal = gallon
GEIS = Generic Environmental Impact Statement (NRC 1996)
kWh = kilowatt hour
lb = pound
MM = million
MW = megawatt
NO_x = nitrogen oxide
PM_{10} = particulates having diameter less than 10 microns
SHPO = State Historic Preservation Officer
SO_x = sulfur dioxide
TSP = total suspended particulates
yr = year

a. All TSP for gas-fired alternative is PM_{10}.

8.2 REFERENCES

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

9.0 STATUS OF COMPLIANCE

9.1 PROPOSED ACTION

NRC

"The environmental report shall list all federal permits, licenses, approvals and other entitlements which must be obtained in connection with the proposed action and shall describe the status of compliance with these requirements. The environmental report shall also include a discussion of the status of compliance with applicable environmental quality standards and requirements including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection." 10 CFR 51.45(d), as adopted by 10 CFR 51.53(c)(2)

9.1.1 GENERAL

Table 9-1 lists environmental authorizations that Carolina Power and Light Company (CP&L) has obtained for current Robinson Nuclear Plant (RNP) operations. In this context, CP&L uses "authorizations" to include any permits, licenses, approvals, or other entitlements. CP&L expects to continue renewing these authorizations during the current license period and through the U.S. Nuclear Regulatory Commission (NRC) license renewal period. Preparatory to applying for renewal of the RNP license to operate, CP&L conducted an assessment to identify any new and significant environmental information (Chapter 5). The assessment included interviews with CP&L subject experts, review of RNP environmental documentation, and communication with state and federal environmental protection agencies. Based on this assessment, CP&L concludes that RNP Unit 2 is in compliance with applicable environmental standards and requirements.

Table 9-2 lists additional environmental authorizations and consultations related to NRC renewal of the RNP license to operate. As indicated, CP&L anticipates needing relatively few such authorizations and consultations. Sections 9.1.2 through 9.1.5 discuss some of these items in more detail.

9.1.2 THREATENED OR ENDANGERED SPECIES

Section 7 of the Endangered Species Act (16 USC 1531 et seq.) requires federal agencies to ensure that agency action is not likely to jeopardize any species that is listed, proposed for listing as endangered, or threatened. Depending on the action involved, the Act requires consultation with the U.S. Fish and Wildlife Service (FWS) regarding effects on non-marine species, the National Marine Fisheries Service (NMFS) for marine species, or both. FWS and NMFS have issued joint procedural regulations at 50 CFR 402, Subpart B, that address consultation, and FWS maintains the joint list of threatened and endangered species at 50 CFR 17.

Although not required of an applicant by federal law or NRC regulation, CP&L has chosen to invite comment from federal and state agencies regarding potential effects that RNP license renewal might have. Appendix C includes copies of CP&L correspondence with FWS and the South Carolina Department of Natural Resources. CP&L did not consult with NMFS because species under the auspices of NMFS are not known to be in the RNP vicinity.

9.1.3 COASTAL ZONE MANAGEMENT PROGRAM COMPLIANCE

The federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on applicants for a federal license to conduct an activity that could affect a state's coastal zone (NRC 2001). RNP, located in Darlington County, is not within the South Carolina coastal resources (SCDHEC 2000) and, due to its distance (approximately 50 miles) from the coastal zone, is not expected to affect the South Carolina coastal zone. Certification from the South Carolina coastal zone management program is not necessary.

9.1.4 HISTORIC PRESERVATION

Section 106 of the National Historic Preservation Act (16 USC 470 et seq.) requires federal agencies having the authority to license any undertaking to, prior to issuing the license, take into account the effect of the undertaking on historic properties and to afford the Advisory Council on Historic Preservation an opportunity to comment on the undertaking. Council regulations provide for establishing an agreement with any State Historic Preservation Officer (SHPO) to substitute state review for Council review (35 CFR 800.7). Although not required of an applicant by federal law or NRC regulation, CP&L has chosen to invite comment by the South Carolina SHPO. Appendix E includes copies of CP&L correspondence with the SHPO regarding potential effects that RNP license renewal might have on historic or cultural resources. Based on the CP&L submittal and other information, the SHPO concurred with CP&L's conclusion that RNP license renewal would not affect known historic or archeological properties.

9.1.5 WATER QUALITY (401) CERTIFICATION

Federal Clean Water Act Section 401 requires applicants for a federal license to conduct an activity that might result in a discharge into navigable waters to provide the licensing agency a certification from the state that the discharge will comply with applicable Clean Water Act requirements (33 USC 1341). NRC has indicated in its *Generic Environmental Impact Statement for License Renewal* (NRC 1996) that issuance of a National Pollutant Discharge Elimination System (NPDES) permit implies certification by the state (NRC 1996). CP&L is applying to NRC for license renewal to continue RNP operations. Appendix B contains excerpts from the RNP NPDES permit.

Consistent with the GEIS, CP&L is providing evidence of the RNP NPDES permit as evidence of state water quality (401) certification.

9.2 ALTERNATIVES

NRC

"The discussion of alternatives in the report shall include a discussion of whether the alternatives will comply with such applicable environmental quality standards and requirements." 10 CFR 51.45(d), as required by 10 CFR 51.53(c)(2)

The coal, gas, and purchased power alternatives discussed in Section 7.2.1 probably could be constructed and operated to comply with applicable environmental quality standards and requirements. CP&L notes that increasingly stringent air quality protection requirements could make the construction of a large fossil-fueled power plant infeasible in many locations. CP&L also notes that the U.S. Environmental Protection Agency has proposed requirements (EPA 2000) that could affect the design of cooling water intake structures for new facilities. As drafted, the requirements would probably necessitate construction of cooling towers for the coal- and gas-fired alternatives.

9.3 TABLES

TABLE 9-1
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT RNP UNIT 2 OPERATIONS

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
		Federal Requirements to License Renewal			
U. S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10	License to operate	DPR – 23 - Unit 2	Issued 7/31/70 Expires 7/31/10	Operation of Unit 2
South Carolina Department of Health and Environmental Control	Clean Water Act (33 USC 1251 et seq.), Pollution Control Act of South Carolina (S.C. Code Sections 48-1-10 et seq., 1976)	National Pollutant Discharge Elimination System Permit	SC0002925	Issued 9/29/97 Expires 9/30/01 (Renewal application was submitted 3/30/01)	Contains effluent limits for H.B. Robinson Steam Electric Plant (i.e., nuclear and coal-fired units) discharges to Lake Robinson and Black Creek.
U.S. Department of the Interior, Bureau of Land Management	31 Stat. 790; 43 Stat. 959	Flooding of Government Lands permit	BLM-A-047130	Issued 8/6/58; no expiration date	Reservoir right-of-way for land in the Carolina Sandhills Wildlife Management Area
South Carolina Department of Health and Environmental Control, Bureau of Air Quality	Clean Air Act Title V (42 USC 7661 et seq.); SC Code of Regulations, 61-62; SC Pollution Control Act (Sections 48-1-50[5] and 48-1-110[a])	Part 70 Air Quality Permit	TV-0820-0002	Issued 12/21/99 Expires 3/31/04	Air emission source operation

TABLE 9-1 (Cont'd)
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT RNP UNIT 2 OPERATIONS

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
South Carolina Department of Health and Environmental Control	SC Code of Laws 48-1-10 et seq. And 44-1-140(11); SC Code of Regulations 61-70	Industrial Solid Waste Permit	163341-1601	Issued 4/20/94; environmental compliance review once every 5 years	Carolina Power and Light Company (CP&L) landfill wastes: construction rubble, paper products, & wood or products with metal scraps
South Carolina Department of Health and Environmental Control	SC Code of Laws 48-1-10 et seq. And 44-1-140(11); SC Code of Regulations 61-70	Industrial Solid Waste Permit	163341-1602	Issued 6/22/94; environmental compliance review once every 5 years	CP&L landfill wastes: packing material, dried empty paint cans, dried paint brushes, and spent water treatment demineralizer resin beads, asbestos
South Carolina Department of Health and Environmental Control	SC Code of Laws 44-2	Underground Storage Tank Registration	02635	Issued 7/31/01; Expires 7/31/02	Notification of underground storage tank serving an emergency diesel generator
U.S. Fish and Wildlife Service	16 USC 703-712	Federal Fish and Wildlife Permit, Depredation	MB789112-0	Issued 1/01/00; Expires 12/31/00	Removal and relocation of migratory bird nests
South Carolina Department of Natural Resources	SC Code of Laws 50-11-1180	Letter of Authorization, Depredation	No Number	Issued 1/18/00; Expires 12/31/00	Removal and relocation of migratory bird nests

TABLE 9-1 (Cont'd)
ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT RNP UNIT 2 OPERATIONS

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
South Carolina Department of Health and Environmental Control – Division of Radioactive Waste Management	South Carolina Radioactive Waste Transportation and Disposal Act (Act No. 429)	South Carolina Radioactive Waste Transport Permit	0042-39-01	Issued 12/18/2001 Expires 12/31/2002	Transportation of radioactive waste into the State of South Carolina
State of Tennessee Department of Environment and Conservation Division of Radiological Health	Tennessee Department of Environment and Conservation Rule 1200-2-10.32	Tennessee Radioactive Waste License-for-Delivery	T-SC003-L01	Issued 1/1/2002 Expires 12/31/2002	Transportation of radioactive waste into the State of Tennessee
U.S. Department of Transportation	49 USC 5108	Registration	052901 017 004J	Issued 5/30/01 Expires 6/30/02	Hazardous materials shipments

Note: Some permits also apply to Unit. 1

**TABLE 9-2
ENVIRONMENTAL AUTHORIZATIONS FOR
RNP UNIT 2 LICENSE RENEWAL[a]**

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License renewal	Environmental Report submitted in support of license renewal application
U.S. Fish and Wildlife Service	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires federal agency issuing a license to consult with the U.S. Fish and Wildlife Service (Appendix C)
South Carolina Department of Health and Environmental Control	Clean Water Act Section 401 (33 USC 1341)	Certification	State issuance of NPDES permit (Section 9.1.5) constitutes 401 certification
South Carolina Department of Archives and History	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Requires federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer (SHPO). SHPO has concurred that license renewal will not affect any sites listed or eligible for listing (Appendix E)

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

9.4 REFERENCES

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

EPA (U.S. Environmental Protection Agency). 2000. "National Pollutant Discharge Elimination System--Regulations Addressing Cooling Water Intake Structures for New Facilities; Proposed Rule." *Federal Register.* Vol. 65, No. 155. August 10.

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

NRC (U.S. Nuclear Regulatory Commission). 2001. *Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues*. NRR Office Instruction No. LIC-203. June 21.

SCDHEC (South Carolina Department of Health and Environmental Control). 2000. Ocean and Coastal Resource Management. Coastal Counties Map. Available at http://www.scdhec.net/ocrm/html/map.html. Accessed February 7, 2001.

APPENDIX A

NRC NEPA ISSUES FOR LICENSE RENEWAL OF NUCLEAR POWER PLANTS

Carolina Power and Light Company (CP&L) has prepared this environmental report in accordance with the requirements of U.S. Nuclear Regulatory Commission (NRC) regulation 10 CFR 51.53. NRC included in the regulation a list of National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants. Table A-1 lists these 92 issues and identifies the section in which CP&L addressed each issue in the environmental report. For organization and clarity, CP&L has assigned a number to each issue and uses the issue numbers throughout the environmental report.

TABLE

TABLE A-1
RNP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

	Issue	Category	Section of this Environmental Report
1.	Impacts of refurbishment on surface water quality	1	4.0
2.	Impacts of refurbishment on surface water use	1	4.0
3.	Altered current patterns at intake and discharge structures	1	4.0
4.	Altered salinity gradients	1	4.0
5.	Altered thermal stratification of lakes	1	4.0
6.	Temperature effects on sediment transport capacity	1	4.0
7.	Scouring caused by discharged cooling water	1	4.0
8.	Eutrophication	1	4.0
9.	Discharge of chlorine or other biocides	1	4.0
10.	Discharge of sanitary wastes and minor chemical spills	1	4.0
11.	Discharge of other metals in waste water	1	4.0
12.	Water use conflicts (plants with once-through cooling systems)	1	4.0
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
14.	Refurbishment impacts to aquatic resources	1	4.0
15.	Accumulation of contaminants in sediments or biota	1	4.0
16.	Entrainment of phytoplankton and zooplankton	1	4.0
17.	Cold shock	1	4.0
18.	Thermal plume barrier to migrating fish	1	4.0
19.	Distribution of aquatic organisms	1	4.0
20.	Premature emergence of aquatic insects	1	4.0
21.	Gas supersaturation (gas bubble disease)	1	4.0
22.	Low dissolved oxygen in the discharge	1	4.0
23.	Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.0
24.	Stimulation of nuisance organisms (e.g., shipworms)	1	4.0
25.	Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	4.2
26.	Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	4.3
27.	Heat shock for plants with once-through and cooling pond heat dissipation systems	2	4.4

TABLE A-1 (Cont'd)
RNP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

	Issue	Category	Section of this Environmental Report
28.	Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	4.0
29.	Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	4.0
30.	Heat shock for plants with cooling-tower-based heat dissipation systems	1	4.0
31.	Impacts of refurbishment on groundwater use and quality	1	4.0
32.	Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	4.0
33.	Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	4.5
34.	Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	4.6
35.	Groundwater use conflicts (Ranney wells)	2	4.7
36.	Groundwater quality degradation (Ranney wells)	1	4.0
37.	Groundwater quality degradation (saltwater intrusion)	1	4.0
38.	Groundwater quality degradation (cooling ponds in salt marshes)	1	4.0
39.	Groundwater quality degradation (cooling ponds at inland sites)	2	4.8
40.	Refurbishment impacts to terrestrial resources	2	4.9
41.	Cooling tower impacts on crops and ornamental vegetation	1	4.0
42.	Cooling tower impacts on native plants	1	4.0
43.	Bird collisions with cooling towers	1	4.0
44.	Cooling pond impacts on terrestrial resources	1	4.0
45.	Power line right-of-way management (cutting and herbicide application)	1	4.0
46.	Bird collisions with power lines	1	4.0
47.	Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.0
48.	Floodplains and wetlands on power line right-of-way	1	4.0
49.	Threatened or endangered species	2	4.10
50.	Air quality during refurbishment (non-attainment and maintenance areas)	2	4.11
51.	Air quality effects of transmission lines	1	4.0
52.	Onsite land use	1	4.0

TABLE A-1 (Cont'd)
RNP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

	Issue	Category	Section of this Environmental Report
53.	Power line right-of-way land use impacts	1	4.0
54.	Radiation exposures to the public during refurbishment	1	4.0
55.	Occupational radiation exposures during refurbishment	1	4.0
56.	Microbiological organisms (occupational health)	1	4.0
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
58.	Noise	1	4.0
59.	Electromagnetic fields, acute effects (electric shock)	2	4.13
60.	Electromagnetic fields, chronic effects	NA[b]	4.0
61.	Radiation exposures to public (license renewal term)	1	4.0
62.	Occupational radiation exposures (license renewal term)	1	4.0
63.	Housing impacts	2	4.14
64.	Public services: public safety, social services, and tourism and recreation	1	4.0
65.	Public services: public utilities	2	4.15
66.	Public services: education (refurbishment)	2	4.16
67.	Public services: education (license renewal term)	1	4.0
68.	Offsite land use (refurbishment)	2	4.17.1
69.	Offsite land use (license renewal term)	2	4.17.2
70.	Public services: transportation	2	4.18
71.	Historic and archaeological resources	2	4.19
72.	Aesthetic impacts (refurbishment)	1	4.0
73.	Aesthetic impacts (license renewal term)	1	4.0
74.	Aesthetic impacts of transmission lines (license renewal term)	1	4.0
75.	Design basis accidents	1	4.0
76.	Severe accidents	2	4.20
77.	Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4.0
78.	Offsite radiological impacts (collective effects)	1	4.0
79.	Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4.0
80.	Nonradiological impacts of the uranium fuel cycle	1	4.0
81.	Low-level waste storage and disposal	1	4.0
82.	Mixed waste storage and disposal	1	4.0
83.	Onsite spent fuel	1	4.0

TABLE A-1 (Cont'd)
RNP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

	Issue	Category	Section of this Environmental Report
84.	Nonradiological waste	1	4.0
85.	Transportation	1	4.0
86.	Radiation doses (decommissioning)	1	4.0
87.	Waste management (decommissioning)	1	4.0
88.	Air quality (decommissioning)	1	4.0
89.	Water quality (decommissioning)	1	4.0
90.	Ecological resources (decommissioning)	1	4.0
91.	Socioeconomic impacts (decommissioning)	1	4.0
92.	Environmental justice	NA[b]	2.6.2

a. Source: 10 CFR 51, Subpart A, Appendix A, Table B-1. (Issue numbers added to facilitate discussion.)

b. Not applicable. Regulation does not categorize this issue.

NEPA = National Environmental Policy Act.

APPENDIX B

NPDES PERMIT

The National Pollutant Discharge Elimination System (NPDES) permit for Carolina Power and Light Company's H. B. Robinson Steam Electric Plant is a large document. Only the cover page, providing the authority to discharge to Lake Robinson and Black Creek, and pages related to the Section 316(a) variance and Section 316 (b) determination are included in this Appendix.

DHEC

PROMOTE PROTECT PROSPER

South Carolina Department of Health
and Environmental Control

National Pollutant Discharge Elimination System Permit

for Discharge to Surface Waters

This Permit Certifies That

Carolina Power & Light Company
H.B. Robinson Steam Electric Plant

has been granted permission to discharge from a facility located at

Hartsville, South Carolina
Darlington County

to receiving waters named

Lake Robinson and Black Creek

in accordance with effluent limitations, monitoring requirements and other conditions set forth in Parts I, II, and III hereof. This permit is issued in accordance with the provisions of the Pollution Control Act of South Carolina (S.C. Code Sections 48-1-10 *et seq.*, 1976), Regulation 61-9 and with the provisions of the Federal Clean Water Act (PL 92-500), as amended, 33 U.S.C. 1251 *et seq.*, the "Act."

Marion F. Sadler, Jr., Director
Industrial, Agricultural, and Storm Water Permitting Division
Bureau of Water

Issued: *September 29, 1997*

Expires: *September 30, 2001*

Effective: *October 1, 1997*

Permit No.: *SC0002925*

Rationale TME/8/97
NPDES Permit No. SC0002925
CP&L Co./H.B. Robinson Steam Electric Plant
Darlington County

This is a renewal of the above referenced NPDES permit.

I. Project Description:

The Carolina Power & Light Company, H.B. Robinson Steam Electric Plant (hereinafter referred to as the Permittee), operates a nuclear and coal-fired steam electric power generating facility (SIC 4911). The electrical generating capacity of Unit 1 is rated at 185 megawatts MWe and Unit 2 is rated at 730 MWe. The facility is located at SC Highway 151 and 23 in Hartsville, South Carolina. The effluent discharge from this facility is subject to the Steam Electric Power Generating Point Source Category (40 CFR Part 423). This facility discharges effluent through the following outfalls and corresponding locations:

Outfall	Latitude	Longitude
001	34° 27' 30"	80° 09' 45"
002	34° 27' 30"	80° 09' 45"
003	34° 27' 30"	80° 09' 45"
005	34° 27' 30"	80° 09' 45"
006	34° 27' 30"	80° 09' 45"
007	34° 27' 30"	80° 09' 45"
008	34° 24' 00"	80° 09' 07"
009	34° 24' 00"	80° 09' 07"
011	34° 24' 00"	80° 09' 07"
013	34° 27' 30"	80° 09' 45"
014	34° 27' 30"	80° 09' 45"

The receiving waters are the Black Creek and Lake Robinson. The Black Creek is classified as Freshwaters by (Regulation 61-69). Lake Robinson, however, is not classified by SCDHEC; since Lake Robinson is a source of water to the Black Creek it shall be assumed to be similarly designated as a Freshwater. A Freshwater is suitable for primary contact recreation, secondary contact recreation, and as a source for drinking water after conventional treatment. A freshwaters are suitable for fishing and the survival and propagation of a balanced indigenous aquatic community of fauna and flora, as well as for industrial and agricultural uses.

II. General Information:

A. The facility contact and mailing address follows:

J. W. Moyer, General Manager
H.B. Robinson Steam Electric Plant
3581 West Entrance Road
Hartsville, South Carolina 29550

a) The sanitary sludge may only be disposed of to the ash pond during periods when ash is being sluiced into the ash pond.

b) A maximum of 10,000 gallons of sanitary sludge may be disposed of to the ash pond on a weekly basis. Also, when the surge, septic, and contact chambers are purged on a quarterly basis, a maximum of 24,000 additional gallons may be disposed of to the ash pond.

The Permittee will be required to obtain prior written approval for any other sludge disposal activities at this facility.

VI. Operator

The Permittee's present treatment system consists of sedimentation and neutralization. The highest classification of the operation of all treatment equipment is usually used to determine the operator requirement. Based on the wastewater treatment system classification, an operator with a Grade B-B or higher certification is required to accept the responsibility of inspections made by lower grade operators.

VII. Groundwater Monitoring

The Permittee shall monitor and report each of the four (4) groundwater monitoring wells semiannually for the following parameters:

Water Level, tenth/feet	Arsenic, total, mg/l
Total Dissolved Solids	Iron, total, mg/l
pH (field), standard units	Sulfate, mg/l
Specific Conductance (field), umhos/cm	Zinc, total, mg/l

VIII. Previous Biological Studies

A. 316(a)

Studies of the thermal effects of the discharge were provided in support of the 316(a) variance request with a June 30, 1976 316(a) Demonstration. On November 15, 1977, a determination was made that the protection and propagation of a balanced, indigenous population of fish, shellfish, and other aquatic organisms in and on Lake Robinson will be assured by the continued operation of the H.B. Robinson Steam Electric Plant in its present once-through mode. Additionally, since 1976, the Permittee has been conducting an annual environmental monitoring reports of the Lake Robinson impoundment. To date, the 1986 Annual Environmental Monitoring Report has noted the worst case conditions (low pool, high ambient temperature, high discharge temperature). On May 20, 1994, Consent Agreement 94-034-W, which regard the temperature limits for Outfall 001, was finalized. This Consent Agreement adjusts the thermal limitations of the previous 316(a) variance to allow more gradual seasonal temperature limitations. On January 16, 1996, a meeting was held to discuss the Daily Average and Daily Maximum Heat Discharge Limitation on page 2 of the permit, it was determined that the Heat

Discharge Limitations were not necessary and that the existing temperature limits would protect the receiving water body. With the August 27, 1996 renewal application, additional reports and studies were provided and requested that the 316(a) variance be renewed, and that the two week steps of the previous permit be reduced to monthly transition. The thermal limitations shown in the Conclusion of Section III.B Temperature of the rationale were the monthly agreed upon thermal limitations with the renewal of the 316(a) variance.

B. 316(b)
Section 316(b) of the CWA requires that the location, design, construction and capacity of a cooling water intake structure reflect the best technology available for minimizing environmental impact. In addition, Section 316(b) of the CWA requires that the location, design, construction, and capacity of a cooling water intake structure reflect the best technology available for minimizing environmental impacts. On November 15, 1977, a determination was made that the lake was sustaining good populations of fish, including bluegill, and does not appear to adversely impacted by impingement. Also, the location, design, construction, and capacity of the cooling water intake structures at the H.B. Robinson Steam Electric Plant reflect the best technology available for minimizing adverse environmental impact.

IX. Co-Treatment

Where various wastes are combined for treatment and discharge, 40 CFR 423.13(h) requires that the quantity of each pollutant or pollutant property not exceed the specified limitation for that waste source. Applicable guideline concentrations were flow weighted in calculating final effluent concentrations.

X. Toxicity Testing

Since the chemical specific approach does not address all specific chemicals and their interactions with other components in the waste stream, a more comprehensive testing requirement is needed. To ensure that water quality is not deteriorated, whole effluent toxicity testing is being required at Outfalls 001 and 011 in accordance with procedures set out in The South Carolina Department of Health and Environmental Control Toxic Control Strategy for Wastewater Discharges, South Carolina Department of Health and Environmental Control, October 1990. These procedures require either acute or chronic toxicity testing based on whether a diffuser is used and the Instream Waste Concentration (IWC), which is calculated as follows:

IWC for the Discharge Canal to Lake Robinson:

IWC = (Effluent flow/(Dilution flow + Effluent flow)) X 100
= (1.2608)/(209)
= 0.6%

Based on State procedures, if a diffuser is not installed and the IWC is less than 1%, then acute toxicity testing is required. Therefore, acute toxicity screening at 100% effluent will be required to be conducted at a frequency of once per quarter.

APPENDIX C

SPECIAL-STATUS SPECIES CORRESPONDENCE

CP&L
A Progress Energy Company

Serial: RNP-RA/01-0074

MAY 31 2001

Mr. Roger Banks
Field Supervisor
U. S. Fish and Wildlife Service
176 Croghan Spur Road
Suite 200
Charleston, SC 29407

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
REQUEST FOR INFORMATION ON
LISTED SPECIES AND IMPORTANT HABITATS

Dear Mr. Banks:

Carolina Power & Light (CP&L) Company is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the H. B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2, which expires on July 31, 2010. CP&L intends to submit this application for license renewal before the fourth quarter of 2002. As part of the license renewal process, the NRC requires, in 10 CFR 51.53(c)(3)(ii)(E), that applicants "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act." The NRC will consult with your office in accordance with Section 7 of the Endangered Species Act to determine if any listed species or critical habitat occurs in the project area. By contacting you early in the application process, CP&L hopes to identify any issues that need to be addressed or any information that your office may need to expedite the NRC consultation.

CP&L has operated HBRSEP and associated transmission lines, shown on the enclosed Figure 1, since 1970. The plant is in Darlington County, South Carolina, approximately 4.5 miles west northwest of the city of Hartsville. The plant is situated on the southwest shore of Lake Robinson, which was created by CP&L in 1959 to serve as a source of cooling water for power production. The plant site encompasses approximately 4800 acres including the lake.

Robinson Nuclear Plant
3581 West Entrance Road
Hartsville, SC 29550

Mr. Roger Banks
U. S. Fish and Wildlife Service
Serial: RNP-RA/01-0074
Page 2 of 2

The plant is connected to the regional electric transmission grid by 230 kilovolt transmission lines with intrasystem tie points at Darlington, SC, at Rockingham, NC, at Sumter, SC, at Florence, SC, and two lines that connect to CP&L's Darlington County plant which is located near HBRSEP.

There are no plans to substantively alter current operations over the license renewal period. No substantive disturbance of land is anticipated. The operation of HBRSEP through the license renewal term of an additional 20 years is not expected to adversely affect any threatened or endangered species. Inactive nesting sites of the red cockaded woodpecker have been identified on the HBRSEP site. CP&L has entered into the Safe Harbors Program to protect this habitat.

Please provide any information that you may have about any state or federally listed species or ecologically significant habitats that may occur on the 4800 acre HBRSEP site or along the associated transmission corridors shown on the enclosed Figures by July 30, 2001. A copy of this letter and your response will be included in the license renewal application that is submitted to the NRC. This request was discussed with you in a telephone conference with Mr. Jan S. Kozyra, CP&L, on May 29, 2001.

If you have any questions concerning this matter, please contact Mr. Kozyra at 843-857-1872.

Sincerely,

B. L. Fletcher, III
Manager – Regulatory Affairs

Enclosures

c: Mr. Henry Porter, DHEC

United States Department of the Interior

FISH AND WILDLIFE SERVICE
176 Croghan Spur Road, Suite 200
Charleston, South Carolina 29407

June 7, 2001

Mr. B. L. Fletcher, III
Carolina Power and Light, Inc.
Robinson Nuclear Plant
3581 West Entrance Road
Hartsville, SC 29550

Re: H. B. Robinson Steam Electric Plant, Unit No. 2 license renewal

Dear Mr. Fletcher:

We have reviewed the information received May 31, 2001 concerning the above-referenced project. The project seeks to renew the operating license of the H. B. Robinson Steam Electric Plant and associated transmission lines that have been in production since 1970. The plant itself covers an area approximately 4800 acres, including Lake Robinson, and is connected to the regional electric transmission grid by 230 kilovolt transmission lines with intra-system tie points at Darlington, SC, at Rockingham, NC, at Sumter, SC, at Florence, SC, and two lines that connect to CP&L's Darlington County plant which is located near HBRSEP. The following comments are provided in accordance with the Fish and Wildlife Coordination Act, as amended (16 U.S.C. 661-667e), and section 7 of the Endangered Species Act, as amended (16 U.S.C. 1531-1543).

We believe there is potential habitat for federally protected species and/or the presence of designated or proposed critical habitat within the action area of your proposed project. Staffing limitations currently prevent us from conducting a field inspection of the action area. Therefore, we are unable to provide you with site-specific comments at this time.

Without further analysis of the "effects of the action," (as defined by 50 CFR 402.02) on federally protected species we are unable to concur that the proposed action is not likely to adversely impact such species and/or critical habitat.

Therefore, we are providing a list of the federally endangered (E) and threatened (T) and candidate (C) species which potentially occur in Sumter, Darlington, Florence, and Lee Counties in South Carolina to aid you in determining the impacts your project may have on protected species. The list also includes species of concern under review by the Service. Species of concern (SC) are not legally protected under the Endangered Species Act, and are not subject to any of its provisions, including Section 7, until they are formally proposed or listed as endangered/threatened. We are including these species in our response for the purpose of giving you advance notification. These species may be listed in the future, at which time they will be protected under the Endangered Species Act. Therefore, it would be prudent for you to consider these species early in project planning to avoid any adverse effects.

In-house surveys should be conducted by comparing the habitat requirements for the attached listed species with available habitat types at the project site. Field surveys for the species should be performed if habitat requirements overlap with that available at the project site. Surveys for protected plant species must be conducted by a qualified biologist during the flowering or fruiting period(s) of the species. Surveys for the red-cockaded woodpecker should be conducted in accordance with the "Guidelines for preparation of biological assessments and evaluations for the red-cockaded woodpecker" by Gary Henry. A copy of these guidelines is available from this office. Please notify this office with the results of any surveys for the below list of species and an analysis of the "effects of the action," as defined by 50 CFR 402.02 on any listed species including consideration of direct, indirect, and cumulative effects.

**South Carolina Distribution Records of
Endangered, Threatened, Candidate and Species of Concern**

E	Federally endangered
T	Federally threatened
P	Proposed in the Federal Register
CH	Critical Habitat
C	The U.S. Fish and Wildlife Service or the National Marine Fisheries Service has on file sufficient information on biological vulnerability and threat(s) to support proposals to list these species
S/A	Federally protected due to similarity of appearance to a listed species
SC	Federal Species of concern. These species are rare or limited in distribution but are not currently legally protected under the Endangered Species Act.
*	Contact the National Marine Fisheries Service for more information on this species

These lists should be used only as a guideline, not as the final authority. The lists include known occurrences and areas where the species has a high possibility of occurring. Records are updated continually and may be different from the following.

County	Common Name	Scientific Name	Status	Occurrences
Darlington				
	Red-cockaded woodpecker	*Picoides borealis*	E	Known
	Shortnose sturgeon	*Acipenser brevirostrum**	E	Possible
	Rough-leaved loosestrife	*Lysimachia asperulaefolia*	E	Known
	Awned meadowbeauty	*Rhexia aristosa*	SC	Known

	Carolina bogmint	*Macbridea caroliniana*	SC	Known
	Georgia lead-plant	*Amorpha georgiana var. georgiana*	SC	Known
	Rafinesque's big-eared bat	*Corynorhinus rafinesquii*	SC	Known
	Sandhills milkvetch	*Astragalus michauxii*	SC	Known
	Spring-flowering goldenrod	*Solidago verna*	SC	Known
	Well's pixie-moss	*Pyxidanthera brevifolia*	SC	Known
	White false-asphodel	*Tofieldia glabra*	SC	Known
Florence				
	Bald eagle	*Haliaeetus leucocephalus*	T	Known
	Red-cockaded woodpecker	*Picoides borealis*	E	Known
	Shortnose sturgeon	*Acipenser brevirostrum**	E	Known
	Chaffseed	*Schwalbea americana*	E	Known
	Carolina bogmint	*Macbridea caroliniana*	SC	Known
	Georgia lead-plant	*Amorpha georgiana var. georgiana*	SC	Known
	Ovate catchfly	*Silene ovata*	SC	Known
Lee				
	Red-cockaded woodpecker	*Picoides borealis*	E	Known
	Canby's dropwort	*Oxypolis canbyi*	E	Known
	Chaffseed	*Schwalbea americana*	E	Known
	Awned meadowbeauty	*Rhexia aristosa*	SC	Known
Sumter				
	Bald eagle	*Haliaeetus leucocephalus*	T	Known
	Red-cockaded woodpecker	*Picoides borealis*	E	Known
	Shortnose sturgeon	*Acipenser brevirostrum**	E	Known
	Canby's dropwort	*Oxypolis canbyi*	E	Known
	Chaff-seed	*Schwalbea americana*	E	Known
	Dwarf burhead	*Echinodorus parvulus*	SC	Known
	Awned meadowbeauty	*Rhexia aristosa*	SC	Known
	Boykin's lobelia	*Lobelia boykinii*	SC	Known

We also recommend you contact the S.C. Department of Natural Resources (SCDNR), Data Manager, Wildlife Diversity Section, Columbia, SC 29202, concerning known populations of federal and/or state endangered or threatened species, and other sensitive species in the project area. Additional habitat information may also be available from SCDNR. The National Marine Fisheries Service, 9721 Executive Center Drive North, St. Petersburg, FL 33702-2449 should be contacted for consultation on species under their jurisdiction.

Your interest in ensuring the protection of endangered and threatened species and our nation's valuable wetland resources is appreciated. If you have any questions please contact Ms. Lori Duncan or Ms. Olivia Westbrook of my staff at (843) 727-4707 ext. 21. In future correspondence concerning the project, please reference FWS Log No. 4-6-01-I-285.

Sincerely yours,

Steven S. Gilbert
Acting Field Supervisor

SSG/LWD/OW

CP&L
A Progress Energy Company

Serial: RNP-RA/01-0073

MAY 31 2001

Ms. Julie Holling
Data Manager
Wildlife Diversity Section
South Carolina Heritage Trust Program
South Carolina Department of Natural Resources
P. O. Box 167
Columbia, SC 29202

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
REQUEST FOR INFORMATION ON
LISTED SPECIES AND IMPORTANT HABITATS

Dear Ms. Holling:

Carolina Power & Light (CP&L) Company is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the H. B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2, which expires on July 31, 2010. CP&L intends to submit this application for license renewal before the fourth quarter of 2002. As part of the license renewal process the NRC requires, in 10 CFR 51.53(c)(3)(ii)(E), that applicants, "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act." The NRC will consult with the U. S. Fish and Wildlife Service in accordance with Section 7 of the Endangered Species Act, and may also seek your assistance in the identification of important species and habitats in the project area. By contacting you early in the application process, CP&L hopes to identify any issues that need to be addressed or any information that your office may need to expedite the NRC consultation.

CP&L has operated HBRSEP and associated transmission lines, shown on the enclosed Figure 1. since 1970. The plant is in Darlington County, South Carolina, approximately 4.5 miles west northwest of the city of Hartsville. The plant is situated on the southwest shore of Lake Robinson, which was created by CP&L in 1959 to serve as a source of cooling water for power production. The plant site encompasses approximately 4800 acres including the lake.

Robinson Nuclear Plant
3581 West Entrance Road
Hartsville, SC 29550

Ms. Julie Holling
South Carolina Heritage Trust Program
Serial: RNP-RA/01-0073
Page 2 of 2

The plant is connected to the regional electric transmission grid by 230 kilovolt transmission lines with intrasystem tie points at Darlington, SC, at Rockingham, NC, at Sumter, SC, at Florence, SC, and two lines that connect to CP&L's Darlington County plant which is located near HBRSEP.

There are no plans to substantially alter current operations over the license renewal period. No substantive additional disturbance of land is anticipated. The operation of HBRSEP through the license renewal term of an additional 20 years is not expected to adversely affect any threatened or endangered species. Inactive nesting sites of the red cockaded woodpecker have been identified on the HBRSEP site. CP&L has entered into the Safe Harbors Program to protect this habitat.

Please provide any information that you may have about any state or federally listed species or ecologically significant habitats that may occur on the 4800 acre HBRSEP site or along the associated transmission corridors, shown on the enclosed Figures, by July 31, 2001. The request was discussed with you in a telephone conference with Mr. Jan S. Kozyra, CP&L, on May 25, 2001. A copy of this letter and your response will be included in the license renewal application that will be submitted to the NRC.

If you have any questions concerning this matter, please contact Mr. Kozyra at 843-857-1872.

Sincerely,

B. L. Fletcher, III
Manager – Regulatory Affairs

Enclosures

c: Mr. H. Porter, DHEC

South Carolina Department of
Natural Resources

Paul A. Sandifer, Ph.D.
Director
William S. McTeer
Deputy Director for
Wildlife and
Freshwater Fisheries

June 4, 2001

B. L. Fletcher, III
Manager – Regulatory Affairs
CP&L, Robinson Nuclear Plant
3581 West Entrance Rd.
Hartsville, SC 29550

RE: H. B. Robinson Steam Electric Plant, Unit No. 2
Request for information on Listed Species and Important Habitat

Dear Mr. Fletcher,

The only information that I can provide is the known occurrences of rare, threatened and endangered species. Since a comprehensive biological inventory of the state has not been done, we rely on biologists to provide information for our database. We do not currently track habitat information.

I have checked our database, and there are two known occurrences within one mile of the HBRSEP. One, the federally endangered *Picoides borealis*, or Red-cockaded Woodpecker, is found west of the upper section of Lake Robinson (above SSR 346) on Sandhills State Forest property. The other occurrence is of *Condylura cristata* or Star-nosed Mole, a species of state concern. This occurrence is located North of Lake Robinson on Black Creek. Please understand that our database does not represent a comprehensive biological inventory of the state. Fieldwork remains the responsibility of the investigator.

If you need additional assistance, please contact me by phone at 803/734-3917 or by e-mail at JulieH@scdnr.state.sc.us.

Sincerely,

Julie Holling

Julie Holling
SC Department of Natural Resources
Heritage Trust Program

Rembert C. Dennis Building • 1000 Assembly St • P.O. Box 167 • Columbia, S.C. 29202 • Telephone: 803/734-3886
EQUAL OPPORTUNITY AGENCY www.dnr.state.sc.us PRINTED ON RECYCLED PAPER

APPENDIX D

MICROBIOLOGICAL ORGANISMS CORRESPONDENCE

CP&L
A Progress Energy Company

Serial: RNP-RA/01-0071

MAY 2 5 2001

Dr. John F. Brown
State Toxicologist
S. C. Department of Health and Environmental Control
Division of Health Hazard Evaluation
2600 Bull Street
Columbia, SC 29201

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
REQUEST FOR INFORMATION ON
THERMOPHILIC ORGANISMS

Dear Dr. Brown:

Carolina Power & Light (CP&L) Company is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the H. B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2, which expires on July 31, 2010. CP&L intends to submit this application for license renewal by the fourth quarter of 2002.

As part of the license renewal process, the NRC requires, in 10 CFR 51.53(c)(3)(ii)(G), that applicants provide, "... an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water." The NRC regulation states that, "these organisms are not expected to be a problem at most operating plants," but states further that, "without site-specific data, it is not possible to predict the effects generically."

CP&L has operated HBRSEP since 1970. The plant is in Darlington County, South Carolina, approximately 4.5 miles west-northwest of the city of Hartsville, South Carolina. The plant is situated on the southwest shore of Lake Robinson, which was created by CP&L in 1959 to serve as a source of cooling water for power production. The plant cooling system withdraws water from Lake Robinson and returns it to the lake via a discharge canal approximately 4.2 miles long. Discharge limits and monitoring requirements are set forth in NPDES Permit No. SC0002925 issued by the South Carolina Department of Health and Environmental Control (SCDHEC).

Robinson Nuclear Plant
3581 West Entrance Road
Hartsville, SC 29550

Dr. John F. Brown
South Carolina Department of Health and Environmental Control
Serial: RNP-RA/01-0071
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CP&L requests any information that SCDHEC may have compiled on the occurrence of thermophilic microorganisms in Lake Robinson, including the results of any monitoring or special studies that might have been conducted by SCDHEC or its contractors. CP&L is particularly interested in determining if there is a concern about the possible presence of *naegleria fowleri* in the lake. CP&L would appreciate a response by July 31, 2001. This request was discussed with you during a telephone conversation with Mr. Jan S. Kozyra, CP&L, on May 25, 2001.

If you have any questions concerning this matter, please contact Mr. Kozyra at 843-857-1872.

Very truly yours,

for B. L. Fletcher, III
Manager – Regulatory Affairs

JSK/jsk

c: Mr. H. Porter, DHEC

bc: Mr. H. K. Chernoff
Mr. T. B. Clements
Mr. J. Cudworth, Tetra Tech NUS

South Carolina
DHEC
Department of Health and Environmental Control

May 25, 2001

Mr. B.L. Fletcher, III
Robinson Nuclear Plant
3581 West Entrance Road
Hartsville, SC 29550

Dear Mr. Fletcher:

Thank you for your letter requesting DHEC public health concerns regarding thermophilic microorganisms associated with cooling water releases from nuclear power generation plants.

While some microorganisms associated with thermal water discharges, especially related to air conditioning cooling towers, have been demonstrated to have deleterious human health effects, these events have occurred rarely and none have been identified with heated water sources associated with nuclear power plants, to my knowledge. Pathogenic species of Legionella bacteria and Naegleria amoeba have been identified in heated cooling waters associated with nuclear plants. In most cases, the heated waters showed a very small increase (approximately 10-fold) over unheated source waters, but were substantially higher in source waters in a few cases.

The most likely exposure to Legionella aerosol would be to workers within the plant. This would not impact the general public beyond the plant boundaries. A similar exposure possibility exists for Naegleria, with a slightly greater exposure potential for swimmers. The potential public health hazard from pathogenic microorganisms whose abundance might be promoted by artificial warming of recreational waters is largely theoretical and not substantiated by available data. There is some justification for providing appropriate respiratory and dermal protection for workers regularly exposed to known contaminated water, but there seems no significant threat to off-site persons near such heated recreational waters. Routine monitoring for pathogenic microorganisms could be established if suspicious illnesses arose or if there were significant community concerns. Contact me at 803-896-9723, if you desire additional discussion of this matter.

Sincerely,

John F. Brown, DVM, PhD

John F. Brown, DVM, PhD
State Toxicologist

pc: H.J. Porter, Hazardous/Infectious Waste/Land & Waste Management/DHEC

printed on recycled paper

APPENDIX E

CULTURAL RESOURCES CORRESPONDENCE

CP&L
A Progress Energy Company

Serial: RNP-RA/01-0072

MAY 3 1 2001

Ms. Nancy Brock
State Historic Preservation Office - Review and Compliance
South Carolina Department of Archives and History
Archives & History Center
8301 Parklane Road
Columbia, SC 29223

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
REQUEST FOR INFORMATION ON
HISTORIC AND ARCHAEOLOGICAL RESOURCES

Dear Ms. Brock:

Carolina Power & Light (CP&L) Company is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the H. B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2, which expires on July 31, 2010. CP&L intends to submit this application for license renewal by the fourth quarter of 2002. As part of the license renewal process, the NRC requires, in 10 CFR 51.53(c)(3)(ii)(K), that applicants "assess whether any historic or archaeological properties will be affected by the proposed project." The NRC may also request an informal consultation with your office at a later date 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). By contacting you early in the application process, CP&L hopes to identify any issues that need to be addressed or any information that your office may need to expedite the NRC consultation.

CP&L has operated HBRSEP, Unit No. 2 and associated transmission lines, shown on the enclosed Figure 1, since 1970. The plant is in Darlington County, South Carolina, approximately 4.5 miles west northwest of the city of Hartsville, South Carolina. The plant is situated on the southwest shore of Lake Robinson, which was created by CP&L in 1959 to serve as a source of cooling water for power production. The plant site encompasses approximately 4800 acres including the lake.

Ms. Nancy Brock
State Historic Preservation Office
Serial: RNP-RA/01-0072
Page 2 of 2

The Robinson Plant is connected to the regional electric transmission grid by 230 kilovolt transmission lines with intrasystem tie points at Darlington, SC, at Rockingham, NC, at Sumter, SC, at Florence, SC, and two lines that connect to CP&L's Darlington County plant which is located near HBRSEP.

Using the National Register Information System (NRIS) on-line database, a list of sites on the National Register of Historic Places within a six-mile radius of the plant has been compiled. CP&L also has visited your office to review relevant materials. In addition, the project has been discussed with the South Carolina Institute of Archaeology and Anthropology, and files have been reviewed to identify archaeological sites in the vicinity of the plant.

CP&L believes that the operation of HBRSEP, Unit No. 2, through the license renewal term of an additional 20 years, will not have an adverse effect on historic or cultural resources in the region. There are no plans to substantially alter current operations over the license renewal period. No substantive additional disturbance of land is anticipated.

Please notify us of any concerns you may have about historic or archaeological properties in the site vicinity or confirming the conclusion that operation of HBRSEP over the license renewal term would have no effect on any historic or archaeological properties in South Carolina. Area maps are enclosed to aid you in locating HBRSEP. CP&L would appreciate a response by July 31, 2001. A copy of this letter and your response will be included in the license renewal application that will be submitted to the NRC. This request was discussed with you in a telephone conference with Mr. Jan S. Kozyra, CP&L, on May 29, 2001.

If you have any questions concerning this matter, please contact Mr. Kozyra at 843-857-1872.

Sincerely,

B. L. Fletcher, III
Manager – Regulatory Affairs

Enclosures

c: Mr. H. Porter, DHEC

bc: Mr. H. K. Chernoff
Mr. T. B. Clements
Mr. J. Cudworth, Tetra Tech NUS

South Carolina Archives History Center
History & Heritage For All Generations

August 8, 2001

Mr. B. L. Fletcher, III
Manger – Regulatory Affairs
Robinson Nuclear Plant
3581 W. Entrance Road
Hartsville, SC 29550

Re: Robinson Nuclear Plant
Darlington County

Dear Mr. Fletcher:

Thank you for your letter of May 31, which we received by fax transmittal on August 8, regarding the proposed renewal of the operating license for the Robinson Nuclear Plant in Darlington County.

It does not appear, based on the information provided, that any properties listed on or determined eligible for inclusion in the National Register of Historic Places will be affected. Since the license renewal does not involve new construction, archaeological sites should not be affected.

These comments are provided as evidence of your consultation with the State Historic Preservation Office. If you have questions, please don't hesitate to call me at 803/896-6169.

Sincerely,

Nancy Brock

Nancy Brock, Coordinator
Review and Compliance Programs
State Historic Preservation Office

S. C. Department of Archives & History • 8301 Parklane Road • Columbia • South Carolina • 29223-4905 • (803) 896-6100 • www.state.sc.us/scdah

APPENDIX F

SEVERE ACCIDENT MITIGATION ALTERNATIVES

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Appendix F

Severe Accident Mitigation Alternatives

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

F.1 METHODOLOGY

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

- RNP Probabilistic Safety Assessment (PSA) Model – Use the RNP PSA model as the basis for the analysis (Section F.2).
- Level 3 PSA Analysis – Use RNP Level 1 and 2 PSA output and site-specific meteorology, demographic, land use, and emergency response data as input in performing a Level 3 probablistic safety assessment (PSA) using the MELCOR Accident Consequences Code System Version 2 (MAACS2) (Section F.3).
- Baseline Risk Monetization – Use NRC regulatory analysis techniques, calculate the monetary value of the unmitigated RNP severe accident risk. This becomes the maximum averted cost-risk that is possible (Section F.4).
- Phase I SAMA Analysis – Identify potential SAMA candidates based on RNP, NRC, and industry documents. Screen out Phase 1 SAMA candidates that are not applicable to the RNP design or are of low benefit in pressurized water reactors (PWRs) such as RNP, candidates that have already been implemented at RNP or whose benefits have been achieve at RNP using other means, and candidates whose estimated cost exceeds the maximum possible averted cost-risk (Section F.5).
- Phase II SAMA Analysis – Calculate the risk reduction attributable to each remaining SAMA candidate and compare to a more detailed cost analysis to identify any net cost benefit. Probabilistic safety assessment (PSA) insights are also used to screen SAMA candidates in this phase (Section F.6).
- Uncertainty Analysis – Evaluate how a reduced discount value might affect the cost/benefit analyses and the effect of limiting the analyses to accident sequences that only contribute to the large early release frequency (LERF) (Section F.7).
- Conclusions – Summarize results and identify conclusions (Section F.8).

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

F.1.1 RNP SPECIFIC SAMA

The initial list of Severe Accident Mitigation Alternative candidates for RNP was developed from lists of SAMAs at other nuclear power plants (References 56, 9, 5, 7, 4, 12, 13, and 14), NRC documents (References 1, 2, 3, 6, 8, 15, 16, and 19), and documents related to advanced power reactor designs (ABWR SAMAs) (References 17, 10, and 11). In addition, plant specific analyses (References 20, 21) have been used to identify potential SAMAs which address RNP vulnerabilities. This process is considered to adequately address the requirement of identifying significant safety improvements that could be performed at RNP. The initial SAMA list, Table F-8, includes a column which documents the reference sources for each individual SAMA.

The RNP IPEEE (Reference 21) also identified potential opportunities for plant improvements. As a result of the Seismic and Fire Analysis, potential plant changes were considered and dispositioned according to their importance.

Given the existing assessments of external events and internal fires at RNP, the cost benefit analysis uses the internal events PSA as the basis for measuring the impact of SAMA implementation. No fire or external events models are used in this analysis as the fire and IPEEE programs are considered to have already addressed potential plant improvements related to those categories.

F.2 RNP PSA MODEL

The RNP IPE model (Reference 20) was submitted to the NRC in August of 1992.

MOR99 is the most recent RNP PSA model of record. After a minor correction (described below), it served as the base case for SAMA core damage frequency (CDF) and LERF calculations and as the model and database that were modified for all calculations shown in Section F.6. The MOR99 baseline CDF is 4.32×10^{-05} per year. The baseline LERF is 5.59×10^{-06} per year based on corrections performed on the MOR99 LERF model. These corrections include the re-labeling of plant damage states (PDS) and an alteration in the truncation process.

It was determined that plant damage states were being incorrectly assigned in the MOR 99 model. A temporary fix has been adopted to obtain the appropriate cutsets. This fix requires that X-PDSX14B be re-assigned to X-PDSX14C, and X-PDSX14E be re-assigned to X-PDSX14F.

An additional change was identified that has no quantitative impact. Plant damage state X-PDS12C has been changed to X-PDS12O.

The truncation process has also been updated. Previously, the LERF cutset file was re-truncated at is 4.0×10^{-09} after the application of the PDS fractions. This is judged to remove legitimate cutsets that fall below a cutoff limit chosen based on quantification time. The re-truncation was not performed for the LERF calculations in this analysis so that all LERF cutsets are retained after application of the PDS fractions.

F.2.1 POWER UPRATE

The proposed approximately 1.7% power uprate plan for Carolina Power and Light's (CP&L's) Robinson Plant was reviewed to determine the potential impact on the RNP probabilistic safety assessment (PSA).

The methodology consisted of an examination of the current RNP PSA documentation to assess the impact of the following changes on the PSA elements:

- Hardware changes
- Procedural changes
- Set point changes
- Power level change

These changes were interpreted in terms of their effects on the PSA model that can then be used to assess whether there are any potential resulting risk profile changes.

The PSA success criteria still provides a relatively large best estimate safety margin (generally on the order of 20 to 50%). Based on the inherent safety margins in the PSA success criteria, relatively small changes in power (~1.7%) should have minimal impact on the success criteria used in the PSA for mitigation systems.

This review determined that the only potential impact of the proposed power uprate on the PSA model would be the timing of the switchover from the injection mode to the recirculation mode of safety injection. Due to the very small magnitude of the proposed change, any such impact should be negligible. This impact would be seen in the Human Reliability Analysis (HRA) and in the results rather than in the construction of these sequences.

The only quantitative difference identified for the SAMA evaluation due to power uprate is in the calculation of replacement power costs. A scaling factor is required to fit the calculation to a given plant based on net electric output. The post power uprate output of 738 MWe [Reference 70] is used for the analysis.

F.3 <u>LEVEL 3 PSA ANALYSIS</u>

F.3.1 ANALYSIS

The MACCS2 code (Reference 59) was used to perform the level 3 probabilistic safety assessment (PSA) for the RNP. The input parameters given with the MACCS2 "Sample Problem A," which included the NUREG-1150 flood model (Reference 60), formed the basis for the present analysis. These generic values were supplemented with parameters specific to RNP and the surrounding area. Site-specific data included population distribution, economic parameters, and agricultural production. Plant-specific release data included the time-nuclide distribution of releases, release frequencies, and release locations. The behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points (i.e., declaration of a General Emergency) and emergency planning zone (EPZ) evacuation time estimates (Reference 61). These data were used in combination with site-specific meteorology to simulate the probability distribution of impact risks (exposure and economic) to the surrounding (within 50 miles) population from the large early release accident sequences at RNP.

F.3.2 POPULATION

The population surrounding the plant site was estimated for the year 2030. The distribution was given in terms of population at distances to 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles from the plant and in the direction of each of the 16 compass points (i.e., N, NNE, NE...NNW). The total population for the 160 sectors (10 distances × 16 directions) in the region was estimated as 1,160,726, the distribution of which is given in Tables F-1 and F-2.

Population projections within 50 miles of RNP were determined using a geographic information system (GIS), U.S Nuclear Regulatory Commission (NRC) sector population data for 1990, and population growth rates based on 1990 and 2000 county-level census data. Population sectors were created for 16 sectors at an interval of 1 mile from 0 to 5 miles, the interval from 5 to 10 miles and at 10-mile intervals from 10 miles to 50 miles. The counties were combined with the sectors to determine what counties fell within each sector. The area of each county within a given sector was calculated to determine the area fraction of a county or counties that comprise each sector. The decennial growth rate for each county was converted to an equivalent annual growth rate. The annual growth rate in each sector was then calculated by the sum of the products of the annual growth rate of each county within a sector and the fraction of the area in that sector occupied by that county. This weighted-average annual growth rate for each sector is given in Tables F-3 and F-4.

The NRC 1990 sector population data for RNP provided in NUREG/CR-6525 (Reference 57) was projected to the year 2030 using the county area-weighted-average annual growth rate in each sector. The county populations in 1990 and 2000 are provided in Reference 58. It was assumed that the annual population growth rate would remain constant to that reported between 1990 and year 2000. Using the sector specific population growth rates, projections were made for the year 2030 by multiplying the 1990 sector population data by the annual growth rate raised to the power of 40 (2030-1990 = 40).

F.3.3 SITE PARAMETERS

Economy

MACCS2 requires the spatial distribution of certain economic data (fraction of land devoted to farming, annual farm sales, fraction of farm sales resulting from dairy production, and property value of farm and non-farm land) in the same manner as the population. This was done by specifying the data for each of the 20 counties surrounding the plant, to a distance of 50 miles. The values used for each of the 160 sectors was then the data corresponding to that county which made up a vast majority of the land in that sector. For 24 sectors, no county encompassed more than two thirds of the area, so conglomerate data (weighted by the fraction of each county in that sector) was defined.

In addition, generic economic data that are applied to the region as a whole were revised from the MACCS2 sample problem input when better information was available. These revised parameters include per diem living expenses (applied to owners of interdicted properties and relocated populations), relocation costs (for owners of interdicted properties), value of farm and non-farm wealth, and fraction of farm wealth from improvements (e.g., buildings, equipment).

Agriculture

Agricultural production information was taken from the 1997 Agricultural Census (Reference 64). Production within 50 miles of the site was estimated based on those counties within this radius. Production in those counties, which lie partially outside of this area, was multiplied by the fraction of the county within the area of interest. Cotton and tobacco, non-foods, were harvested from 18 percent of the croplands within 50 miles of the site. Of the food crops, legumes (35 percent of total cropland, consisting mainly of soybeans) and grain (34 percent of the total cropland, made up of corn and wheat) were harvested from the largest areas.

The lengths of the growing seasons for grains, roots, and legumes were obtained from Reference 65. The duration of the growing season for the remaining crop categories (pasture, stored forage, green leafy vegetables, and other food crops) were taken to be the same as those used previously at a site in the neighboring state of Georgia (Reference 66).

Nuclide Release

The core inventory at the time of the accident was based on the input supplied in the MACCS User's Guide (Reference 59). The core inventory corresponds to the end-of-cycle values for a 3412-MWth PWR plant. A scaling factor of 0.686 was used to provide a representative core inventory of 2339-MWth at RNP. Table F-5 gives the estimated RNP core inventory. Release frequencies (3.74×10^{-8}, 1.81×10^{-7}, 0, 3.7×10^{-6}, 1.28×10^{-6}, and 3.94×10^{-7} for sequences RC-2, RC-2B, RC-4, RC-4C, RC-5, and RC-5C, respectively) and nuclide release fractions (of the core inventory) were analyzed to determine the sum of the exposure (50-mile dose) and economic (50-mile economic costs) risks from these large early release sequences. RNP nuclide release categories were related to the MACCS categories as shown in Table F-6.

Where appropriate, multiple release duration periods were defined which represented the duration of each category's releases. Each RNP category corresponded with a single release duration (either puff or continuous); MACCS category Te required multiple releases.

The reactor building has a diameter of 133.5 feet and a height of 128.5 feet. All releases were modeled as occurring at ground level. The thermal content of each of the releases was conservatively assumed as to be the same as ambient; i.e., buoyant plume rise was not modeled.

Evacuation

Reactor trip for each sequence was taken as time zero relative to the core containment response times. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. For example, sequence RC-2 involves a Large Break LOCA with failure of containment isolation. The core is estimated to uncover at about 9 minutes into the event with core damage and fission product release from the fuel estimated to occur at 15 minutes; a General Emergency is declared at 15 minutes (after reactor trip) for Sequence RC-2. The general emergency declaration for sequences RC-2B, RC-4, RC-4C, RC-5, and RC-5C would be at 3, 8.5, 8.5, 5, and 5 hours, respectively.

The MACCS2 User's Guide input parameters of 95 percent of the population within 10 miles of the plant (Emergency Planning Zone) evacuating and 5 percent not evacuating were employed. These values have been used in similar studies (e.g., Hatch, Calvert Cliffs, References 66 and 67) and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the emergency planning zone (Reference 60). The evacuees are assumed to begin evacuation 30 minutes (Reference 61) after a General Emergency has been declared and are evacuated at a radial speed of 0.28 m/sec. This speed is taken from the minimum speed from any evacuation zone under adverse weather conditions.

Meteorology

Annual meteorology data sets from 1995 through 1999 were investigated for use in MACCS2. The 1998 data set was found to result in the largest doses and was subsequently used to create the one-year sequential hourly data set used in MACCS2. Wind speed and direction from the 9.3-meter sensor were combined with precipitation (hourly cumulative) and atmospheric stability (specified according to the vertical temperature gradient as measured between the 60.8-meter and 9.3-meter levels). Hourly stability was classified according to the scheme used by the NRC (Reference 68).

Atmospheric mixing heights were specified for AM and PM hours. These values were taken as 400 and 1380 meters, respectively (Reference 74).

F.3.4 RESULTS

The resulting annual risk from RNP early release sequences RC-2, RC-2B, RC-4, RC-4C, RC-5, and RC-5C (and their sum) are provided in Table F-7. The largest risk is from RC-5 as it has a relatively high release frequency and large radionuclide release. The two next largest contributors to risk are release categories RC-4C and RC-5C. Together, they yield approximately the same economic cost-risk as RC-5, but only about 82% of the RC-5 population dose-risk.

In total, these 3 sequences account for greater than 90% of the risks from these large early releases.

Quantification of the base case shows a baseline Core Damage Frequency (CDF) of 4.32×10^{-5}/yr based on 1,274 cutsets (accident scenarios). The baseline Large Early Release Frequency (LERF) is 5.59×10^{-6}/yr based on 1374 cutsets. MACCS2 calculated the annual baseline population dose risk within 50 miles at 5.840 person-rem. The total annual economic risk was calculated at $9,530.

F.4 BASELINE RISK MONETIZATION

F.4.1 OFF-SITE EXPOSURE COST

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

F.4.2 OFF-SITE EXPOSURE COST

The baseline annual off-site exposure risk was converted to dollars using the NRC's conversion factor of $2,000 per person-rem (Reference 52), and discounting to present value using NRC standard formula (Reference 52):

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

Where:

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

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

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

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

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

The Level 3 analysis showed an annual off-site population dose risk of 5.84 person-rem. The calculated value for C using 20 years and a 7 percent discount rate is approximately 10.76. Therefore, calculating the discounted monetary equivalent of accident risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (10.76). The calculated off-site exposure cost is $125,711.

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

The Level 3 analysis showed an annual off-site economic risk of $9,530. 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 $102,570.

F.4.4 ON-SITE EXPOSURE COST RISK

Occupational health was evaluated using the NRC methodology in Reference 52, which involves separately evaluating "immediate" and long-term doses.

<u>Immediate Dose</u> - For the case where the plant is in operation, the equation that NRC recommends using (Reference 52) is:

Equation 1:

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

Where:

W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting
R = monetary equivalent of unit dose ($/person-rem)
F = accident frequency (events/yr)
D_{IO} = immediate occupational dose (person-rem/event)
$_S$ = subscript denoting status quo (current conditions)
$_A$ = subscript denoting after implementation of proposed action
r = real discount rate
t_f = years remaining until end of facility life.

The values used in the RNP analysis are:

R = $2,000/person-rem
r = 0.07
D_{IO} = 3,300 person-rem/accident (best estimate)
t_f = 20 years (license extension period)
F = 4.32×10^{-5} (total core damage frequency)

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

$$W_{IO} = R\,(FD_{IO})_S\{[1 - \exp(-rt_f)]/r\}$$
$$= 2{,}000*4.32\times10^{-5}*3{,}300*\{[1 - \exp(-0.07*20)]/0.07\}$$
$$= \$3{,}069$$

Long-Term Dose - For the case where the plant is in operation, the NRC equation (Reference 52) is:

Equation 2:

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

Where:

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

m = years over which long-term doses accrue

The values used in the RNP analysis are:

R = \$2,000/person-rem
r = 0.07
D_{LTO} = 20,000 person-rem/accident (best estimate)
m = "as long as 10 years"
t_f = 20 years (license extension period)
F = 4.32×10^{-5} (total core damage frequency)

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

$$W_{LTO} = R\,(FD_{LTO})_S\{[1 - \exp(-rt_f)]/r\}\{[1 - \exp(-rm)]/rm\}$$
$$= 2{,}000*4.32\times10^{-5}*20{,}000*\{[1 - \exp(-0.07*20)]/0.07\}\{[1 - \exp(-0.07*10)]/0.07*10\}$$
$$= \$13{,}375$$

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

$$W_O = W_{IO} + W_{LTO} = (\$3{,}069 + \$13{,}375) = \$16{,}444$$

F.4.5 ON-SITE CLEANUP AND DECONTAMINATION COST

The net present value that NRC provides for cleanup and decontamination for a single event is \$1.1 billion, discounted over a 10-year cleanup period (Reference 52). NRC uses the following equation to integrate the net present value over the average number of remaining service years:

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

Where:

PV_{CD} = net present value of a single event
r = real discount rate
t_f = years remaining until end of facility life.

The values used in the RNP analysis are:

PV_{CD} = $\$1.1\times10^9$
r = 0.07
t_f = 20

The resulting net present value of cleanup integrated over the license renewal term, $\$1.18\times10^{10}$, must be multiplied by the total core damage frequency of 4.32×10^{-5} to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is \$511,453.

F.4.6 REPLACEMENT POWER COST

Long-term replacement power costs was determined following the NRC methodology in Reference 52. The net present value of replacement power for a single event, PV_{RP}, was determined using the following equation:

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

Where:

PV_{RP} = net present value of replacement power for a single event, (\$)
r = 0.07
t_f = 20 years (license renewal period)

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

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

Where:

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

After applying a correction factor to account for RNP's size relative to the "generic" reactor described in NUREG/BR-0184 (Reference 52) (i.e., 738 MWe/910 MWe), the replacement power costs are determined to be 6.40×10^9 (\$-year). Multiplying this value by the CDF (4.32×10^{-5}) results in a replacement power cost of \$276,435.

F.4.7 TOTAL

The sum of the baseline costs is as follows:

Off-site exposure cost =	$125,711
Off-site economic cost =	$102,570
On-site exposure cost =	$16,444
On-site cleanup cost =	$511,453
Replacement Power cost =	$276,435
Total cost =	$1,032,613

CP&L rounded this value up to $1,033,000 to use in screening out SAMAs as economically infeasible. The averted cost-risk calculations account for this rounding such that it does not impact the result. This cost estimate was used in screening out SAMAs that are not economically feasible; if the estimated cost of implementing a SAMA exceeded $1,033,000 it was discarded from further analysis. Exceeding this threshold would mean that a SAMA would not have a positive net value even if it could eliminate all severe accident costs. On the other hand, if the cost of implementation is less than this value, then a more detailed examination of the potential fractional risk benefit that can be attributed to the SAMA is performed.

F.5 PHASE I SAMA ANALYSIS

F.5.1 SAMA IDENTIFICATION

The initial list of Severe Accident Mitigation Alternative candidates for RNP was developed from lists of SAMAs at other nuclear power plants (References 56, 9, 5, 7, 4, 12, 13, and 14), NRC documents (References 1, 2, 3, 6, 8, 15, 16, and 19), and documents related to advanced power reactor designs (ABWR SAMAs) (References 17, 10, and 11). In addition, plant specific analyses (References 20, 26) have been used to identify potential SAMAs which address RNP vulnerabilities. This process is considered to adequately address the requirement of identifying significant safety improvements that could be performed at RNP. The initial SAMA list, Table F-8, includes a column which documents the reference sources for each individual SAMA.

The RNP IPEEE (Reference 21) also identified potential opportunities for plant improvements. As a result of the Seismic and Fire Analysis, potential plant changes were considered and dispositioned according to their importance.

Given the existing assessments of external events and internal fires at RNP, the cost benefit analysis uses the internal events PSA as the basis for measuring the impact of SAMA implementation. No fire or external events models are used in this analysis as the fire and IPEEE programs are considered to have already addressed potential plant improvements related to those categories.

F.5.2 SCREENING

An initial list of SAMA candidates is presented in Table F-8. This initial list was then screened to remove those candidates that were not applicable to RNP due to design differences or high implementation cost. In addition, SAMAs were eliminated if they were related to changes that would be made during the design phase of a plant rather than to an existing plant. These would typically screen on high cost, but they are categorized separately for reference purposes. The SAMA screening process is summarized in Figure F-1.

A majority of the SAMAs were removed from further consideration as they did not apply to the Westinghouse 3 Loop PWR design used at RNP. The SAMA candidates that were found to be implemented at RNP were screened from further consideration.

The SAMAs related to design changes prior to construction (primarily consisting of those candidates taken from the ABWR SAMAs) were removed as they were not applicable to an existing site. Any candidate known to have an implementation cost that far exceeds any possible risk benefit is screened from further analysis. Any SAMA candidates that were sufficiently similar to other SAMA candidates were treated in the same manner to those that they were related to either combined or screened from further consideration.

A preliminary cost estimate was prepared for each of the remaining candidates to focus on those that had the possibility of having a positive benefit and to eliminate those whose costs were beyond the possibility of any corresponding benefit (as determined by the RNP baseline screening cost). When the screening cutoff of $1,033,000 was applied, a majority of the remaining SAMA candidates were eliminated, as their implementation costs were more expensive than the maximum postulated benefit associated with the elimination of all risk associated with full power internal events. This left 9 candidates for further analysis. Those SAMAs that required a more detailed cost benefit analysis are evaluated in Section F.6. A list of these SAMAs is provided in Table F-9.

F.6 <u>PHASE II SAMA ANALYSIS</u>

It was possible to screen some of the remaining SAMA candidates from further analysis based on plant specific insights regarding the risk significance of the systems that would be affected by the proposed SAMAs. The SAMAs related to non-risk significant systems were screened from a detailed cost benefit analysis as any change in the reliability of these systems is known to have a negligible impact on the PSA evaluation. Table F-9 comments explain the bases for these screenings.

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

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

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

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

Subsections F.6.1 – F.6.9 describe the detailed cost benefit analysis that was used to determine how the remaining candidates were ultimately treated.

F.6.1 PHASE II SAMA NUMBER 1: PREVENT CHARGING PUMP FLOW DIVERSION FROM THE RELIEF VALVES

Description: This SAMA modification would reduce the frequency of the loss of RCP seal cooling if relief valve opening causes a flow diversion large enough to prevent RCP seal injection.

While the flow diversion through a relief valve failure mode is not directly modeled in the RNP PSA, it is considered to be subsumed by the event for common cause failure of charging pump seal injection (JCCFICVABC). The maximum possible risk reduction for this SAMA was obtained by setting JCCFICVABC to zero.

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

Phase II SAMA Number 1 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
Basic event JCCFICVABC (RCP A,B,&C INJ. CV COMMON CAUSE FAILURE TO OPEN)	Set to zero

PSA Model Results for Phase II SAMA Number 1

The results from this case indicate no reduction in CDF (CDF_{new}=4.32×10^{-05} per year) and no reduction in LERF ($LERF_{new}$= 5.59×10^{-06} per year). The results of the cost benefit analysis are shown below:

Phase II SAMA Number 1 Net Value

Base Case: Cost-Risk for RNP	SAMA 1 Cost-Risk for RNP	Averted Cost-Risk	Cost of Implementation	Net Value
$1,033,000	$1,033,000	$0	Not Required	**Not Cost Beneficial**

This SAMA has no impact on the calculated CDF or on the LERF cutsets. Implementation of this SAMA, therefore, would not be cost beneficial for RNP.

F.6.2 PHASE II SAMA NUMBER 2: IMPROVED ABILITY TO COOL THE RESIDUAL HEAT REMOVAL HEAT EXCHANGERS

Description: This SAMA would reduce the probability of a loss of decay heat removal by implementing procedure and hardware modifications to allow manual alignment of the Fire Water System to the RHR heat exchangers.

A new basic event, FP-RHR (Operators Fail To Align The Fire Water System To The RHR Heat Exchangers), was created. Four new gates, SAMA02A (Failure of Cooling To RHR Heat Exchanger A), SAMA02B#RB (Failure of Cooling To RHR Heat Exchanger A), SAMA02B (Failure of Cooling To RHR Heat Exchanger B) and SAMA02B#RB (Failure of Cooling To RHR Heat Exchanger B) were created. Gate SAMA02A is an AND gate with inputs of FP-RHR and existing gate K2401 (CCW TO HX A FAILS). Gate SAMA02A#RB is an AND gate with inputs of FP-RHR and existing gate K2401#RB (CCW TO HX A FAILS). Gate SAMA02B is an AND gate with inputs of FP-RHR and existing gate K2501 (CCW TO HX B FAILS). Gate SAMA02B#RB is an AND gate with inputs of FP-RHR and existing gate K2501#RB (CCW TO HX B FAILS). Gate SAMA02A was substituted in the logic for gate K2401, gate SAMA02A#RB was substituted in the logic for gate K2401#RB, gate SAMA02B was substituted in the logic for gate K2501 and gate SAMA02B#RB was substituted in the logic for gate K2501#RB.

The maximum possible risk reduction for this SAMA was obtained by setting FP-RHR to zero.

The model changes that were made to the PSA to represent the implementation of this SAMA at RNP are shown below:

Phase II SAMA Number 2 Model Changes

Gate and / or Basic Event ID and Description	Description Of Change
New basic event FP-RHR (Operators Fail To Align The Fire Water System To The RHR Heat Exchangers)	Set to zero
New gate SAMA02A (Failure of Cooling To RHR Heat Exchanger A)	AND FP-RHR K2401
New gate SAMA02A#RB (Failure of Cooling To RHR Heat Exchanger A)	AND FP-RHR K2401#RB
New gate SAMA02B (Failure of Cooling To RHR Heat Exchanger B)	AND FP-RHR K2501
New gate SAMA02B#RB (Failure of Cooling To RHR Heat Exchanger B)	AND FP-RHR K2501#RB
Gate L14D#HR (NO FLOW FROM RHR TRAIN A LOW HEAD RECIRC)	Deleted K2401 and added SAMA02A
L14DSD (NO FLOW FROM RHR TRAIN A)	Deleted K2401 and added SAMA02A
LRHXA#R (NO FLOW FROM RHR HX OR PUMP A)	Deleted K2401 and added SAMA02A
L14E#R (NO FLOW FROM RHR TRAIN B)	Deleted K2501 and added SAMA02B
L14ESD (NO FLOW FROM RHR TRAIN B)	Deleted K2501 and added SAMA02B
LRHXB#R (NO FLOW FROM RHR HX OR PUMP B)	Deleted K2501 and added SAMA02B
LRHXA#RB (NO FLOW FROM RHR HX OR PUMP A)	Deleted K2401#RB and added SAMA02A#RB
LRHXB#RB (NO FLOW FROM RHR HX OR PUMP B)	Deleted K2501#RB and added SAMA02B#RB

PSA Model Results for Phase II SAMA Number 2

The results from this case indicate about a 3.0 percent reduction in CDF (CDF_{new} = 4.19×10^{-05} / year) and a 15.2 percent reduction in LERF ($LERF_{new}$ = 4.74×10^{-06} / year). The results of the cost benefit analysis are shown below:

Phase II SAMA Number 2 Net Value

Base Case: Cost-Risk for RNP	Cost-Risk for RNP	Averted Cost-Risk	Cost of Implementation	Net Value
$1,033,000	$993,437	$39,563	Not Required	**Not Cost Beneficial**

Implementation of this SAMA would consist of modifying the fire water system to provide for a supply point where temporary hoses could be attached quickly somewhere near the RHR heat exchangers, modifying existing piping to the RHR heat exchanger with similar fittings for hoses, testing of the new connections, writing procedures, and, operator training. It is estimated that these actions would be substantially in excess of the $39,563 averted cost-risk. This SAMA would not be cost beneficial for RNP.

F.6.3 PHASE II SAMA NUMBER 3: INCREASE FREQUENCY FOR VALVE LEAK TESTING

Description: This SAMA could reduce the interfacing systems loss of coolant accident (ISLOCA) initiating event frequency.

To calculate the maximum possible impact of this SAMA, initiating event percent ISLOCA (INTERFACING SYSTEMS LOCA OCCURS OUTSIDE CONTAINMENT) was set to zero. This is the equivalent of assuming that every potential ISLOCA could be prevented by increasing the frequency of valve leak testing.

The model changes that were made to the PSA to represent the implementation of this SAMA at RNP are shown below:

Phase II SAMA Number 3 Model Changes	
Gate and / or Basic Event ID and Description	**Description of Change**
Initiating Event %ISLOCA (INTERFACING SYSTEMS LOCA OCCURS OUTSIDE CONTAINMENT)	Set to zero

PSA Model Results for Phase II SAMA Number 3

The results from this case indicate about a 2.8 percent reduction in CDF (CDF_{new} = $4.20x10^{-05}$ / year) and a 24.2 percent reduction in LERF ($LERF_{new}$ = $4.24x10^{-06}$ / year). The results of the cost benefit analysis are shown in below:

Phase II SAMA Number 3 Net Value

Base Case: Cost-Risk for RNP	Cost-Risk for RNP	Averted Cost-Risk	Cost of Implementation	Net Value
$1,033,000	$892,545	$140,455	>$280,000	**-$139,545**

Implementation of this SAMA would involve numerous procedure changes and potential increases to shop manpower to meet increased surveillance testing requirements. In addition, further testing would require another scheduled plant shutdown as the valve testing requires access to areas within the biological shield. A shutdown for this purpose would require multiple days off-line. For this analysis, a single day of lost power is conservatively used as the cost of implementation. Based on the insured value of a day of replacement power ($280,000) from Reference 72, the net value for this SAMA is about-$140,000. This SAMA is clearly not cost beneficial based on these parameters.

The impact of this SAMA is also judged to be greatly over estimated in this evaluation. The increased test frequency was assumed to eliminate ALL risk from ISLOCAs, which is not realistic. The typical process for developing the ISLOCA initiating event frequency also suggests that valve testing increases the likelihood of an ISLOCA event. Once the contribution of valve misalignment outweighs the benefit gained by identifying potential valve failures, the valve test become detrimental. Increasing the valve test frequency at RNP may actually increase the risk of an ISLOCA event.

F.6.4 PHASE II SAMA NUMBER 4: IMPROVED MSIV DESIGN

Description: This SAMA would install new, improved MSIVs of higher reliability.

There are six basic events associated with the RNP MSIVs. Each of the three MSIVs has one basic event for its failure to close on demand and one basic event for transferring closed during operation. To calculate the maximum possible impact of this SAMA, all six of these basic events were set to zero. This is the equivalent of assuming that the new MSIVs would be perfectly reliable.

The model changes that were made to the PSA to represent the implementation of this SAMA at RNP are shown below:

Phase II SAMA Number 4 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
Basic Event QAVV1-3AFF (MSIV MS-V1-3A FAILS TO CLOSE ON DEMAND)	Set to zero
Basic Event QAVV1-3BFF (MSIV MS-V1-3B FAILS TO CLOSE ON DEMAND)	Set to zero
Basic Event QAVV1-3CFF (MSIV MS-V1-3C FAILS TO CLOSE ON DEMAND)	Set to zero
Basic Event QAVV1-3AFN (PNEUMATIC VALVE MS-V1-3A TRANSFERS CLOSED)	Set to zero
Basic Event QAVV1-3BFN (PNEUMATIC VALVE MS-V1-3B TRANSFERS CLOSED)	Set to zero
Basic Event QAVV1-3BFN (PNEUMATIC VALVE MS-V1-3B TRANSFERS CLOSED)	Set to zero

PSA Model Results for Phase II SAMA Number 4

The results from this case indicate no reduction in CDF (CDF_{new}=4.32x10^{-05} / year) and no reduction in LERF ($LERF_{new}$ = 5.59x10^{-06} / year). The results of the cost benefit analysis are shown below:

Phase II SAMA Number 4 Net Value

Base Case: Cost-Risk for RNP	Cost-Risk for RNP	Averted Cost-Risk	Cost of Implementation	Net Value
$1,033,000	$1,033,000	$0	Not Required	**Not Cost Beneficial**

This SAMA has no impact on the calculated CDF or on the LERF cutsets. Implementation of this SAMA, therefore, would not be cost beneficial for RNP.

F.6.5 PHASE II SAMA NUMBER 5: INSTALL A DIGITAL FEEDWATER UPGRADE

Description: This SAMA would reduce the chance of a loss of main feedwater following a plant trip by installing a digital feedwater control system.

To calculate the maximum possible impact of this SAMA, initiating events %T4 (LOSS OF MAIN FEEDWATER) and %T4A (PARTIAL LOSS OF MAIN FEEDWATER) were set to zero. This is the equivalent of assuming that the new digital control system perfectly controlled main feedwater at all times.

The changes made to the RNP PSA model to simulate the implementation of this SAMA are shown below:

Phase II SAMA Number 5 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
Initiating Event %T4 (LOSS OF MAIN FEEDWATER)	Set to zero
Initiating Event %T4A (PARTIAL LOSS OF MAIN FEEDWATER)	Set to zero

PSA Model Results for Phase II SAMA Number 5

The results from this case indicate about a 3.9 percent reduction in CDF (CDF_{new} = $4.15x10^{-05}$ / year) and no reduction in LERF ($LERF_{new}$ = $5.59x10^{-06}$ / year). The results of the cost benefit analysis are shown below:

Phase II SAMA Number 5 Net Value

Base Case: Cost-Risk for RNP	Cost-Risk for RNP	Averted Cost-Risk	Cost of Implementation	Net Value
$1,033,000	$1,001,294	$31,706	Not Required	**Not Cost Beneficial**

The cost of installing a digital feedwater control system would be far in excess of the averted cost-risk of $31,706. This SAMA would not be cost beneficial for RNP.

F.6.6 PHASE II SAMA NUMBER 6: REPLACE CURRENT PRESSURIZER PORVS WITH LARGER ONES SUCH THAT ONLY ONE IS REQUIRED FOR SUCCESSFUL FEED AND BLEED

Description: This SAMA would reduce the dependencies required for successful feed and bleed. There are two PORVs and three SRVs for RCS pressure control. RNP PSA model currently requires two PORVs for successful feed and bleed.

This SAMA would require replacing the two existing PORVs with higher capacity valves. To simulate the implementation of this SAMA, gate R3000 (1 OF 2 PORV S FAIL TO OPEN MANUALLY) was replaced with existing gate R2000 (2 OF 2 PORVs FAIL TO OPEN MANUALLY) at gate #TH (EVENT H - FAILURE OF PRIMARY BLEED).

The changes made to the RNP PSA model to simulate the implementation of this SAMA are shown below:

Phase II SAMA Number 6 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
#TH (EVENT H - FAILURE OF PRIMARY BLEED)	Replaced input R3000 (1 OF 2 PORV S FAIL TO OPEN MANUALLY) with input R2000 (2 OF 2 PORVs FAIL TO OPEN MANUALLY)

PSA Model Results for Phase II SAMA Number 6

The results from this case indicate about a 1.8 percent reduction in CDF (CDF_{new} = $4.24x10^{-05}$ / year) and no reduction in LERF. The results of the cost benefit analysis are shown below:

Phase II SAMA Number 6 Net Value

Base Case: Cost-Risk for RNP	Cost-Risk for RNP	Averted Cost-Risk	Cost of Implementation	Net Value
$1,033,000	$1,018,073	$14,927	Not Required	**Not Cost Beneficial**

The averted cost-risk is relatively small for this SAMA with respect to the resources required for a significant plant hardware modification (i.e., replacement of the PORVs with higher capacity valves). No detailed cost of implementation was derived, as the cost of the hardware changes would clearly be larger than the averted cost-risk.

F.6.7 PHASE II SAMA NUMBER 7: IMPLEMENT AN RWST MAKE-UP PROCEDURE

Description: This SAMA would potentially decrease CDF from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTRs by implementing a procedure to refill the RWST.

The RWST is capable of being refilled at a rate of about 100 gpm. The RNP PSA contains logic for refilling the RWST during late (i.e., long-term) core damage sequences. This logic is in the form of gate #RYL (FAILURE TO PROVIDE LONG TERM RCS MAKEUP FOR LATE SEQUENCES). #RYL is an AND gate with HEP event OPER-80 (OPERATORS FAIL TO PROVIDE LONG-TERM MAKEUP) and recovery event R-RWST (RECOVERY OF FAILURE TO REFIL THE RWST FOR LATE SEQUENCES). To calculate the maximum possible impact of this SAMA, basic event R-RWST was set to zero. This is the equivalent of assuming that the operators are able to refill the RWST during all late core damage sequences.

The changes made to the RNP PSA model to simulate the implementation of this SAMA are shown below:

Phase II SAMA Number 7 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
R-RWST (RECOVERY OF FAILURE TO REFIL THE RWST FOR LATE SEQUENCES)	Set to zero

PSA Model Results for Phase II SAMA Number 7

The results from this case indicate about a 0.46 percent reduction in CDF (CDF_{new} = $4.30x10^{-05}$ / year) and a 5.9 percent reduction in LERF ($LERF_{new}$ = $5.26x10^{-06}$ / year). The results of the cost benefit analysis are shown below:

Phase II SAMA Number 7 Net Value

Base Case: Cost-Risk for RNP	Cost-Risk for RNP	Averted Cost-Risk	Cost of Implementation	Net Value
$1,033,000	$1,000,529	$32,471	$50,000	**-17,529**

At a minimum, the implementation of this SAMA would involve creating a new procedure for refilling the RWST during accident scenarios using the existing low capacity fill system. This implementation was estimated conservatively low at $50,000.

The averted cost-risk is relatively small for this SAMA with respect to the resources required for any significant plant hardware modifications (e.g., a higher capacity RSWT fill system). No detailed cost of implementation of a new fill system was derived, as the cost of the hardware changes would clearly be larger than the averted cost-risk.

The negative net value of this SAMA candidate indicates that its implementation would not be cost beneficial to RNP.

F.6.8 PHASE II SAMA NUMBER 8: CREATE AUTOMATIC SWAP OVER TO RECIRCULATION ON RWST DEPLETION

Description: The purpose of this SAMA is to improve the reliability of the transition to re-circulation mode after depletion of the RWST. RNP requires a manual swap to re-circulation mode that could be improved by automating RWST isolation (to prevent air entrainment in the RHR and charging pumps) and the opening of the sump suction valves (to provide a water source for the pumps).

The changes made to the RNP PSA model to simulate full automatic swap over to re-circulation mode are summarized below.

Phase II SAMA Number 8 Model Changes

System: Basic Events	Original Value	Revised Value
X-OR-0003: OPER-DE|OPER-1|	$7.5x10^{-05}$	$2.6x10^{-08}$
X-OA-0001: OPER-1|	$1.2x10^{-02}$	$5.0x10^{-05}$
X-OM-0001: OPER-1|	$6.6x10^{-03}$	$5.0x10^{-05}$
X-OS-0003: OPER-SD|OPER-1|	$3.1x10^{-05}$	$1.0x10^{-08}$
X-OS-0001: OPER-1|	$3.8x10^{-03}$	$5.0x10^{-05}$

Phase II SAMA Number 8 Model Changes

System: Basic Events	Original Value	Revised Value
X-OR-0001: OPER-1|	$3.8x10^{-03}$	$5.0x10^{-05}$
X-OQ-0102: OPER-SD|OPER-1|	$3.1x10^{-05}$	$1.0x10^{-08}$
X-OQ-0004: OPER-1|	$3.8x10^{-03}$	$5.0x10^{-05}$
X-OT-0012: OPER-18A|OPER-18B|OPER-1|	$1.9x10^{-07}$	$2.6 x10^{-09}$
X-OT-0004: OPER-1|	$3.8x10^{-03}$	$5.0 x10^{-05}$
X-OS-0017: OPER-SD|OPER-18A|OPER-18B|OPER-1|	$5.3x10^{-05}$	$5.2 x10^{-09}$
X-OA-0002: OPER-7|	$7.2x10^{-03}$	$5.0 x10^{-05}$

The plant changes are characterized by reducing the operator actions for aligning re-circulation to very low values. OPER-1 and OPER-7 represent the manual action to align recirculation mode. As the RNP PSA model addresses operator actions with a post processor recovery file, the operator actions have been altered by manipulating the Joint Human Error Probabilities (JHEPs) that are assigned to the operator action groups containing the OPER-1 and OPER-7 actions. Note that the only JHEPs requiring modification are those that appear in the final cutset files.

The revised JHEPs are provided above and have been calculated assuming that the OPER-1 and OPER-7 events are hardware failures with a failure probability of $5.0x10^{-05}$.

The cost of implementation for this SAMA has been estimated to be $264,750 (Engineering Judgement). This estimate does not include costs for operator re-training, procedure changes, document and database updating, simulator modification and certain installation costs, such as for temporary shielding and scaffolding.

PSA Model Results for Phase II SAMA Number 8

The results from this case indicate about a 4.9 percent reduction in CDF (CDF_{new}=4.11E-5/yr) and a 16.8 percent reduction in LERF ($LERF_{new}$=4.65E-6/yr). The results of the cost-benefit analysis are shown below.

Phase II SAMA Number 8 Net Value

Base Case: Cost-Risk for RNP	Cost-Risk for RNP	Averted Cost-Risk	Cost of Implementation	Net Value
$1,033,000	$975,115	$58,885	$264,750	-$205,865

The negative net value for this SAMA indicates that the proposed change would not be cost beneficial.

F.6.9 PHASE II SAMA NUMBER 9: TRAIN OPERATIONS CREW FOR RESPONSE TO INADVERTENT ACTUATION SIGNALS

Description: This SAMA would improve chances of a successful response to the loss of two 120 VAC buses, which may cause inadvertent signal generation.

The only scenarios in the RNP PSA that would cause a simultaneous failure of two instrument buses are the common cause failure events for Instrument Buses 1 and 4 (CCCF1&4BUS) and Instrument Buses 2 and 3 (CCCF2&3BUS). To simulate the implementation of this SAMA, these two common cause events were set to zero.

The changes made to the RNP PSA model to simulate the implementation of this SAMA are shown below:

Phase II SAMA Number 9 Model Changes

Gate Or Event Id and Description:	Description of Change:
Common Cause Event CCCF1&4BUS (COMMON CAUSE FAILURE OF 2 OF 2 INSTRUMENT BUSES 1 & 4)	Set to zero
Common Cause Event CCCF2&3BUS (COMMON CAUSE FAILURE OF 2 OF 2 INSTRUMENT BUSES 2 & 3)	Set to zero

PSA Model Results for Phase II SAMA Number 9

The results from this case indicate no reduction in CDF (CDF_{new}=$4.32x10^{-05}$ / year) and no reduction in LERF ($LERF_{new}$ = $5.59x10^{-06}$ / year). The results of the cost benefit analysis are shown below.

Phase II SAMA Number 9 Net Value

Base Case: Cost-Risk for RNP	Cost-Risk for RNP	Averted Cost-Risk	Cost of Implementation	Net Value
$1,033,000	$1,033,000	$0	Not Required	**Not Cost Beneficial**

This SAMA has no impact on the calculated CDF or on the LERF cutsets. Implementation of this SAMA, therefore, would not be cost beneficial.

F.6.10 PHASE II SAMA ANALYSIS SUMMARY

The SAMA candidates which could not be eliminated from consideration by the baseline screening process or other PSA insights required the performance of a detailed analysis of the averted cost-risk and SAMA implementation costs. SAMA candidates are potentially justified only if the averted cost-risk resulting from the modification is greater than the cost of implementing the SAMA. None of the SAMAs analyzed were found to be cost-beneficial as defined by the methodology used in this study. However, this evaluation should not necessarily be considered a definitive guide in determining the disposition of a plant modification that has been analyzed using other engineering methods. These results are intended to provide information about the relative estimated risk benefit associated with a plant change or modification compared with its cost of implementation and should be used as an aid in the decision making process. The results of the detailed analysis are shown below:

Summary of the Detailed SAMA Analyses

Phase II SAMA ID	Averted Cost- Risk	Cost of Implementation	Net Value	Cost Beneficial?
1	$0	Not Required	$0	No
2	$39,563	Not Required	N/A	No
3	$140,455	$280,000	-$139,545	No
4	$0	Not Required	$0	No
5	$31,706	Not Required	N/A	No
6	$14,927	Not Required	N/A	No
7	$32,472	$50,000	-$17,528	No
8	$58,885	$264,750	-$205,865	No
9	$0	Not Required	$0	No

F.7 UNCERTAINTY ANALYSIS

The following two uncertainties were further investigated as to their impact on the overall SAMA evaluation:

- Assume a discount rate of 3 percent, instead of 7 percent used in the original base case analysis.
- Investigate the impact for limiting the analysis to only those sequences that result in a Large Early Release.

The first item was investigated by re-calculating the total averted cost-risk associated with eliminating all severe accident risk with an assumed discount rate of 3 percent. The revised analysis results in a total averted cost of $1,254,000 compared to the base case value of $1,033,000. This represents a 21 percent increase in the total averted cost. The Phase 1 SAMA list was reviewed to see if any of the items screened would be impacted by this uncertainty in the assumed discount rate. Two SAMAs were potentially impacted, Phase I SAMAs 123 and 164. SAMA 123 requires installation of a unique, independent AC power system for the RHR system. The original estimate provided from Reference 17 was $1.2 million; however, this is considered to greatly underestimate the cost of implementating this SAMA. Given that use of the three percent real discount rate only indicates a net value of $54,000, this SAMA is still not considered to be cost beneficial. Given the diversity of the on-site AC system at RNP (three EDGs), a detailed cost benefit analysis would clearly show a minimal benefit from the implementaiton of this SAMA. SAMA 164 involves the addition of a larger CST tank to provide increased capacity for injection. Using Reference 17, an estimate for implementation of $1,000,000 was obtained and judged to be in excess of the total averted cost-risk for RNP. With a 21 percent increase in the total cost, it is still judged that the addition of a larger capacity CST (or RWST) tank would exceed the benefit obtained by the modification as the cost of implementation in Reference 17 is considered to be a low end estimate. In addition, increasing the cost benefit of those items analyzed in Phase II by 21 percent would not impact the overall conclusions summarized in Section F.6.

The second uncertainty involves an investigation into the accident sequences selected for the SAMA evaluation. LERF is used as one of the measures to estimate the cost benefit of implementing potential plant modifications. The Robinson SAMA evaluation has focused on those accident sequences that only contribute to the LERF. For Robinson, the Large Early Release Frequency represents approximately 13 percent of the total Core Damage Frequency. The remaining sequences involve accidents that do not contribute to LERF and would be made up of a significant fraction of sequences that do not result in containment failure. Some portion of these non-LERF cases would involve a potential late release of radionuclides from the containment. One major difference between these sequences and the LERF events is that natural removal of airborne fission products could occur over the period from vessel breach to containment failure. In fact, it has been calculated that for many PWR containments, late containment failure could occur on the order of 48 hours after accident initiation. This extended time would provide for removal and decay of radionuclides prior to release from containment.

To provide an assessment of the non-LERF events, the consequences of a late containment failure case were analyzed and combined with the LERF results. As a bounding estimate, a representative non-LERF source term (RC-1B) was chosen to represent non-LERF releases at the non-LERF release frequency (1.72E-5/yr). The maximum averted cost-risk was then re-calculated including these non-LERF accidents and found to result in an increase of 20 percent. The resulting maximum averted cost-risk was $1.2 million. This is a rather modest increase, and similar to the uncertainty on the discount rate, would not be expected to significantly impact the screening process. In addition, the conclusions summarized in Section F.6 would not be changed due to this uncertainty.

F.8 CONCLUSIONS

The benefits of revising the operational strategies in place at RNP and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. Use of the PSA in conjunction with cost benefit analysis methodologies has, however, provided an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on a much larger future population. The results of this study indicate that of the identified potential improvements that can be made at RNP, none are cost beneficial based on the methodology applied in this analysis.

F.9 TABLES AND FIGURES

TABLE F-1
ESTIMATED POPULATION DISTRIBUTION WITHIN A 10-MILE RADIUS OF RNP, YEAR 2030

Sector	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles	10-mile total
N	0	0	0	444	42	218	704
NNE	0	47	361	119	162	382	1,071
NE	0	113	125	4	114	916	1,272
ENE	8	151	389	861	54	1,792	3,255
E	25	0	426	548	1,248	4,322	6,569
ESE	35	134	80	895	2,112	9,778	13,034
SE	52	61	238	1,083	2,205	4,156	7,795
SSE	20	68	437	858	335	1,527	3,245
S	56	32	85	63	121	896	1,253
SSW	35	56	80	18	132	749	1,070
SW	166	80	110	127	135	461	1,079
WSW	172	248	317	7	37	251	1,032
W	63	217	67	68	45	580	1,040
WNW	0	28	12	0	18	1,020	1,078
NW	133	172	0	0	17	1,127	1,449
NNW	0	0	0	156	0	80	236
Total	765	1,407	2,727	5,251	6,777	28,255	45,182

TABLE F-2
ESTIMATED POPULATION DISTRIBUTION WITHIN A 50-MILE RADIUS OF RNP, YEAR 2030

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile total
N	704	1,437	7,422	13,131	10,338	33,032
NNE	1,071	2,899	8,656	7,222	28,646	48,494
NE	1,272	1,833	12,578	5,814	26,859	48,356
ENE	3,255	3,083	4,436	17,165	34,682	62,621
E	6,569	3,998	1,015	2,514	28,864	42,960
ESE	13,034	22,582	41,588	8,028	17,933	103,165
SE	7,795	4,563	59,971	16,342	11,945	100,616
SSE	3,245	5,929	7,279	11,656	16,954	45,063
S	1,253	2,210	5,502	4,897	16,772	30,634
SSW	1,070	9,346	5,509	82,645	10,627	109,197
SW	1,079	3,530	6,479	10,852	12,935	34,875
WSW	1,032	2,077	40,592	26,542	59,261	129,504
W	1,040	3,812	4,288	4,057	3,866	17,063
WNW	1,078	1,808	10,996	18,764	37,600	70,246
NW	1,449	1,746	4,570	18,823	54,475	81,063
NNW	236	912	11,406	19,729	171,554	203,837
Total	45,182	71,765	232,287	268,181	543,311	1,160,726

TABLE F-3
ESTIMATED ANNUAL POPULATION GROWTH RATE WITHIN A 10-MILE RADIUS OF RNP

Sector	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles
N	1.0086	1.0088	1.0103	1.0104	1.0104	1.0104
NNE	1.0086	1.0086	1.0090	1.0100	1.0104	1.0104
NE	1.0086	1.0086	1.0086	1.0086	1.0088	1.0096
ENE	1.0086	1.0086	1.0086	1.0086	1.0086	1.0086
E	1.0086	1.0086	1.0086	1.0086	1.0086	1.0086
ESE	1.0086	1.0086	1.0086	1.0086	1.0086	1.0086
SE	1.0086	1.0086	1.0086	1.0086	1.0086	1.0086
SSE	1.0086	1.0086	1.0086	1.0086	1.0086	1.0086
S	1.0086	1.0086	1.0086	1.0086	1.0086	1.0087
SSW	1.0086	1.0086	1.0086	1.0087	1.0087	1.0088
SW	1.0086	1.0086	1.0086	1.0086	1.0086	1.0087
WSW	1.0086	1.0086	1.0086	1.0086	1.0086	1.0118
W	1.0086	1.0086	1.0089	1.0098	1.0103	1.0139
WNW	1.0086	1.0087	1.0102	1.0104	1.0104	1.0104
NW	1.0086	1.0092	1.0104	1.0104	1.0104	1.0104
NNW	1.0086	1.0092	1.0104	1.0104	1.0104	1.0104

TABLE F-4
ESTIMATED ANNUAL POPULATION GROWTH RATE WITHIN A 10 TO 50-MILE RADIUS OF RNP

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles
N	See Table F-3	1.0104	1.0098	1.0074	1.0087
NNE	See Table F-3	1.0104	1.0092	1.0059	1.0056
NE	See Table F-3	1.0103	1.0049	0.9997	1.0056
ENE	See Table F-3	1.0092	1.0004	0.9984	1.0087
E	See Table F-3	1.0086	1.0039	1.0029	1.0056
ESE	See Table F-3	1.0086	1.0090	1.0082	1.0049
SE	See Table F-3	1.0086	1.0095	1.0096	1.0092
SSE	See Table F-3	1.0086	1.0081	1.0088	1.0047
S	See Table F-3	1.0087	1.0079	1.0046	1.0126
SSW	See Table F-3	1.0088	1.0055	1.0019	1.0036
SW	See Table F-3	1.0090	1.0106	1.0074	1.0104
WSW	See Table F-3	1.0168	1.0190	1.0188	1.0118
W	See Table F-3	1.0190	1.0190	1.0155	1.0056
WNW	See Table F-3	1.0187	1.0143	1.0121	1.0087
NW	See Table F-3	1.0126	1.0116	1.0164	1.0303
NNW	See Table F-3	1.0104	1.0103	1.0314	1.0390

TABLE F-5
ESTIMATED RNP CORE INVENTORY

Nuclide	Core Inventory (Becquerels)	Nuclide	Core Inventory (Becquerels)
Co-58	2.21×10^{16}	Te-131m	3.21×10^{17}
Co-60	1.69×10^{16}	Te-132	3.20×10^{18}
Kr-85	1.70×10^{16}	I-131	2.20×10^{18}
Kr-85m	7.95×10^{17}	I-132	3.24×10^{18}
Kr-87	1.45×10^{18}	I-133	4.65×10^{18}
Kr-88	1.96×10^{18}	I-134	5.10×10^{18}
Rb-86	1.30×10^{15}	I-135	4.38×10^{18}
Sr-89	2.46×10^{18}	Xe-133	4.65×10^{18}
Sr-90	1.33×10^{17}	Xe-135	8.73×10^{17}
Sr-91	3.17×10^{18}	Cs-134	2.97×10^{17}
Sr-92	3.29×10^{18}	Cs-136	9.03×10^{16}
Y-90	1.43×10^{17}	Cs-137	1.66×10^{17}
Y-91	3.00×10^{18}	Ba-139	4.31×10^{18}
Y-92	3.31×10^{18}	Ba-140	4.26×10^{18}
Y-93	3.74×10^{18}	La-140	4.36×10^{18}
Zr-95	3.79×10^{18}	La-141	4.00×10^{18}
Zr-97	3.95×10^{18}	La-142	3.85×10^{18}
Nb-95	3.58×10^{18}	Ce-141	3.88×10^{18}
Mo-99	4.18×10^{18}	Ce-143	3.77×10^{18}
Tc-99m	3.61×10^{18}	Ce-144	2.34×10^{18}
Ru-103	3.12×10^{18}	Pr-143	3.70×10^{18}
Ru-105	2.03×10^{18}	Nd-147	1.65×10^{18}
Ru-106	7.08×10^{17}	Np-239	4.43×10^{19}
Rh-105	1.40×10^{18}	Pu-238	2.51×10^{15}
Sb-127	1.91×10^{17}	Pu-239	5.67×10^{14}
Sb-129	6.77×10^{17}	Pu-240	7.15×10^{14}
Te-127	1.85×10^{17}	Pu-241	1.20×10^{17}
Te-127m	2.44×10^{16}	Am-241	7.95×10^{13}
Te-129	6.36×10^{17}	Cm-242	3.04×10^{16}
Te-129m	1.68×10^{17}	Cm-244	1.78×10^{15}

TABLE F-6
MACCS RELEASE CATEGORIES VS. RNP RELEASE CATEGORIES

MACCS Release Categories	RNP Release Categories
Xe/Kr	1 – noble gases
I	2 – CsI
Cs	2 & 6 – CsI and CsOH
Te	3 & 11- TeO_2 & Te_2
Sr	4 – SrO
Ru	5 – MoO_2 (not used)
La	8 – La_2O_3 (not used)
Ce	9 – CeO_2 (not used)
Ba	7 – BaO (not used)
Sb (supplemental category)	10 – Sb (not used)

TABLE F-7
RESULTS OF RNP LEVEL 3 PSA ANALYSIS

Sequence:	**RC-2**	**RC-2B**	**RC-4**	**RC-4C**	**RC-5**	**RC-5C**	**Sum of annual risk**
Population dose risk (person-rem)							
0-50 miles	2.39×10^{-2}	2.79×10^{-1}	0.000	1.56	3.04	9.38×10^{-1}	5.84
Total economic cost risk ($)							
0-50 miles	42	722	0	3,081	4,345	1,340	9,530

TABLE F-8
PHASE I SAMA

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
Improvements Related to RCP Seal LOCAs (Loss of CCW or SW)							
1	Cap downstream piping of normally closed component cooling water drain and vent valves.	1	SAMA would reduce the frequency of a loss of component cooling event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.	#3 - Already implemented at Robinson	Drawing 5379-376 indicates that most of the vents and drains are already capped.	Reference 41	N/A
2	Enhance loss of component cooling procedure to facilitate stopping reactor coolant pumps.	2	SAMA would reduce the potential for reactor coolant pump (RCP) seal damage due to pump bearing failure.	#3 - Already implemented at Robinson	For example, AOP - 014 (Rev. 17), Step 4 Section A, directs the operators to stop all RCPs.	Reference 22	N/A
3	Enhance loss of component cooling procedure to present desirability of cooling down reactor coolant system (RCS) prior to seal LOCA.	2	SAMA would reduce the potential for RCP seal failure.	#3 - Already implemented at Robinson	This SAMA may not be applicable to Robinson. Loss of CCW would not necessarily result in challenge to the RCP seals, since either seal injection or CCW is sufficient to protect our seals. And, since alternate cooling of charging pumps is possible, loss of CCW does not equal loss of seal injection. See item #5.	Reference 20	N/A
4	Provide additional training on the loss of component cooling.	2	SAMA would potentially improve the success rate of operator actions after a loss of component cooling (to restore RCP seal damage).	#3 - Already implemented at Robinson	Sufficient training is provided.	Reference 40	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
5	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	1 2	SAMA would reduce effect of loss of component cooling by providing a means to maintain the centrifugal charging pump seal injection after a loss of component cooling.	#3 - Already implemented at Robinson	Hose connections are available to allow Service Water, Fire Water, or Potable Water to supply cooling water to the charging pumps on loss of CCW. This SAMA is considered to be adequately addressed by these two independent, backup water supplies to CCW.	Reference 22	N/A
6	Procedure changes to allow cross connection of motor cooling for RHR/SW pumps.	12	SAMA would allow continued operation of both RHR/SW pumps on a failure of one train of SW.	#1 - N/A	The "equivalent" pumps for Robinson, the Component Cooling Water pumps, do not require cooling from any other system.	Reference 20	N/A
7	Proceduralize shedding component cooling water loads to extend component cooling heatup on loss of essential raw cooling water.	2	SAMA would increase time before the loss of component cooling (and reactor coolant pump seal failure) in the loss of essential raw cooling water sequences.	#3 - Already implemented at Robinson	For example, AOP - 014 (Rev. 17), Step 6 of Section D, directs the operators to shed excess loads.	Reference 22	N/A
8	Increase charging pump lube oil capacity.	2	SAMA would lengthen the time before centrifugal charging pump failure due to lube oil overheating in loss of CC sequences.	#1 - N/A	In the event of CCW failure, hose connections allow the use of fire water or SW as a backup cooling supply. In addition, for scenarios where CPs are transferring borated water from the RWST to the RCS, the CPs may be able to continue to cool the RCP seals.	Reference 23 (A.18)	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
9	Eliminate the RCP thermal barrier dependence on component cooling such that loss of component cooling does not result directly in core damage.	2	SAMA would prevent the loss of recirculation pump seal integrity after a loss of component cooling.	#3 - Already implemented at Robinson	Refer to #3	Reference 20	N/A
10	Add redundant DC control power for PSW pumps C & D.	3	SAMA would increase reliability of PSW and decrease core damage frequency due to a loss of SW.	#3 - Already implemented at Robinson	The "D" service water pump currently has dual power and control power supplies. Additionally, the SW system consists of two independent trains, with different power sources, that are/can be crosstied.	Reference 20	N/A
11	Create an independent RCP seal injection system, with a dedicated diesel.	1	SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of component cooling or service water or from a station blackout event.	#5 - Cost would be more than risk benefit	While seal injection is an important function, the cost estimate for installation of new seals alone exceeds $2.5 million. A new, independent seal injection system is judged to greatly exceed this cost and the maximum averted cost risk of $1,033,000.	Reference 19	N/A
12	Use existing hydro-test pump for RCP seal injection.	4	SAMA would provide an independent seal injection source, without the cost of a new system.	#1 - N/A	Plant currently has 3 positive displacement charging pumps. There is no existing installed hydro pump.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
13	Replace ECCS pump motor with air-cooled motors.	1 14	SAMA would eliminate ECCS dependency on component cooling system (but not on room cooling).	#5 - Cost would be more than risk benefit	Based on engineering judgement, the cost of this enhancement is expected to greatly exceed the maximum averted cost risk that could be gained by its implementation. Installation of an additional Service Water pump has been estimated at $5.9 million; this change is considered to be similar to installing new ECCS pumps. While new piping and power supplies would not have to be installed to support the new ECCS pumps, unneeded piping would have to be removed and capped and the number of new ECCS pumps is five compared with only one in the reference case.	Reference 17	N/A
14	Install improved RCS pumps seals.	1	SAMA would reduce probability of RCP seal LOCA by installing RCP seal O-ring constructed of improved materials	#3-Already implemented at Robinson	RCP pump "B" and "C" seals have already been replaced. The pump "A" seal is scheduled to be replaced in a future outage. The new seals are capable of withstanding temperatures of 550 degrees F.	Plant modifications	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
15	Install additional component cooling water pump.	1	SAMA would reduce probability of loss of component cooling leading to RCP seal LOCA.	#5 - Cost would be more than risk benefit	Based on engineering judgement, the cost of this enhancement is expected to greatly exceed the maximum averted cost risk ($1,033,000) that could be gained by its implementation. Installation of an additional Service Water pump has been estimated at $5.9 million; this change is considered to be similar to installing a new CCW pump.	Reference 17	N/A
16	Prevent centrifugal charging pump flow diversion from the relief valves.	1	SAMA modification would reduce the frequency of the loss of RCP seal cooling if relief valve opening causes a flow diversion large enough to prevent RCP seal injection.	#6 - Retain	Will likely be screened in Phase 2 due to low risk significance as CP (charging pump) and CCW both provide cooling to the RCPs while CP is dependent on CCW for pump cooling. CCW is the important system.	N/A	1
17	Change procedures to isolate RCP seal letdown flow on loss of component cooling, and guidance on loss of injection during seal LOCA.	1	SAMA would reduce CDF from loss of seal cooling.	#3 - Already implemented at Robinson	AOP-014 (Rev. 17) directs isolation of RCP seal letdown flow.	Reference 22	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
18	Implement procedures to stagger high-pressure safety injection (HPSI) pump use after a loss of service water.	1	SAMA would allow HPSI to be extended after a loss of service water.	#4-No significant safety benefit	This SAMA does not place the reactor in a stable condition. Credit would be in the form of a delay in core damage that would allow increased time to repair the SW system. This type of action is not credited in the PSA and the SAMA would yield no measurable safety benefit.	N/A	N/A
19	Use fire protection system pumps as a backup seal injection and high-pressure makeup.	1	SAMA would reduce the frequency of the RCP seal LOCA and the SBO CDF.	#5 - Cost would be more than risk benefit	Fire protection is a low head system at Robinson and cannot be used as a HP injection source. Modifications to convert it to a high pressure system would be a high cost improvement. The use of fire water for RCP seal injection would not be preferred since this is unborated lake water.	Refer to SAMA 179	N/A
20	Enhance procedural guidance for use of cross-tied component cooling or service water pumps.	1 14	SAMA would reduce the frequency of the loss of component cooling water and service water.	#3 - Already implemented at Robinson	The pump trains in each of these systems are normally cross-tied and run in parallel.	Reference 23, Appendix A.11	N/A
21	Procedure enhancements and operator training in support system failure sequences, with emphasis on anticipating problems and coping.	1 2 14 20	SAMA would potentially improve the success rate of operator actions subsequent to support system failures.	#2 - Similar item is addressed under other proposed SAMAs	See 20, 27, 30, 90, 95, 96, 97, 103	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
22	Improved ability to cool the residual heat removal heat exchangers.	1	SAMA would reduce the probability of a loss of decay heat removal by implementing procedure and hardware modifications to allow manual alignment of the fire protection system or by installing a component cooling water cross-tie.	#6 - Retain	CCW pump trains are already cross-tied. Modification of the fire protection system, another existing system or addition of a new system to provide redundant cooling is expected to exceed the estimated maximum averted cost-risk.	N/A	2
23	8.a. Additional Service Water Pump	17	SAMA would conceivably reduce common cause dependencies from SW system and thus reduce plant risk through system reliability improvement.	#5 - Cost would be more than risk benefit	The cost of implementing this SAMA has been estimated at approximately $5.9 million and is greater than the maximum averted cost-risk ($1,033,000).	Reference 17	N/A
24	Create an independent RCP seal injection system, without dedicated diesel	19	This SAMA would add redundancy to RCP seal cooling alternatives, reducing the CDF from loss of CC or SW, but not SBO.	#5 - Cost would be more than risk benefit	Calvert Cliffs Nuclear Power Plant estimated the cost of installing new seals that do not require cooling to be greater than $2.5 million. Based on this estimate and engineering judgement, the cost of installing a completely new and independent seal injection system would significantly exceed the maximum averted cost-risk ($1,033,000).	Reference 19	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
Improvements Related to Heating, Ventilation, and Air Conditioning							
25	Provide reliable power to control building fans.	2	SAMA would increase availability of control room ventilation on a loss of power.	#3 - Already implemented at Robinson	The important HVAC components for Robinson (EDG room cooling) are supplied by Class 1E power and are considered to be reliable power sources.	Reference 20	N/A
26	Provide a redundant train of ventilation.	1	SAMA would increase the availability of components dependent on room cooling.	#3 - Already implemented at Robinson	Redundancy currently exists in equipment rooms where it is needed for accident mitigation.	Reference 20	N/A
27	Procedures for actions on loss of HVAC.	12 14	SAMA would provide for improved credit to be taken for loss of HVAC sequences (improved affected electrical equipment reliability upon a loss of control building HVAC).	#3 - Already implemented at Robinson	Internal analyses for SBO indicates that only the control room requires cooling. Provisions exist for opening cabinet doors, providing aux ventilation, etc.	Reference 25	N/A
28	Add a diesel building switchgear room high temperature alarm.	1 14	SAMA would improve diagnosis of a loss of switchgear room HVAC. Option 1: Install high temp alarm. Option 2: Redundant louver and thermostat	#3 - Already implemented at Robinson	The EDG rooms are already equipped with high temperature alarms.	Reference 26	N/A
29	Create ability to switch fan power supply to DC in an SBO event.	1	SAMA would allow continued operation in an SBO event. This SAMA was created for reactor core isolation cooling system room at Fitzpatrick Nuclear Power Plant.	#1 - N/A	The control room is the only room that needs cooling for an SBO. It is already provided.	Reference 27	N/A
30	Enhance procedure to instruct operators to trip unneeded RHR/CS pumps on loss of room ventilation.	12	SAMA increases availability of required RHR/CS pumps. Reduction in room heat load allows continued operation of required RHR/CS pumps, when room cooling is lost.	#1 - N/A	Neither the CS nor RHR pumps are dependent on room cooling at Robinson.	Reference 18	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
31	Stage backup fans in switchgear (SWGR) rooms	19	This SAMA would provide alternate ventilation in the event of a loss of SWGR Room ventilation	#1 - N/A	Robinson system descriptions indicate that room cooling is not required in the 4 kV bus room due to its volume and construction characteristics.	Reference 27	N/A
Improvements Related to Ex-Vessel Accident Mitigation/Containment Phenomena							
32	Delay containment spray actuation after large LOCA.	2 14	SAMA would lengthen time of RWST availability.	#3 - Already implemented at Robinson	SAM-6 provides guidance to limit containment spray flow to preserve RWST.	Reference 24	N/A
33	Install containment spray pump header automatic throttle valves.	4 8	SAMA would extend the time over which water remains in the RWST, when full CS flow is not needed	#2 - Similar item is addressed under other proposed SAMAs	See 32	N/A	N/A
34	Install an independent method of suppression pool cooling.	5 6	SAMA would decrease the probability of loss of containment heat removal. For PWRs, a potential similar enhancement would be to install an independent cooling system for sump water.	#5 - Cost would be more than risk benefit	Installation of a new, independent, sump water cooling system is similar in scope to installing a new containment spray system, which has been estimated to cost approximately $5.8 million. This exceeds the maximum averted cost-risk ($1,033,000).	Reference 19	N/A
35	Develop an enhanced drywell spray system.	5 6 14	SAMA would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal.	#3 - Already implemented at Robinson	Addressed in SAM-6. Also, see SAMAs 32, 33	Reference 24	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
36	Provide dedicated existing drywell spray system.	5 6	SAMA would provide a source of water to the containment to control containment pressure, when used in conjunction with containment heat removal. This would use an existing spray loop instead of developing a new spray system.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 35	Reference 24	N/A
37	Install an unfiltered hardened containment vent.	5 6 14	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products not being scrubbed.	#5 - Cost would be more than risk benefit	The long time periods associated with the need to vent with this type of containment would rule out any contribution to LERF, which dominates the offsite consequences. In addition, the estimated cost of installing an un-filtered containment vent ($3.1 million) is greater than the maximum averted cost-risk ($1,033,000).	Reference 19	N/A
38	Install a filtered containment vent to remove decay heat.	5 6	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products being scrubbed. Option 1: Gravel Bed Filter Option 2: Multiple Venturi Scrubber	#1 - N/A	The long time periods associated with the need to vent with this type of containment would rule out any contribution to LERF, which dominates the offsite consequences. In addition, the estimated cost of installing a filtered containment vent ($5.7 million) is significantly greater than the maximum averted cost-risk.	Reference 19	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
39	Install a containment vent large enough to remove ATWS decay heat.	5 6	Assuming that injection is available, this SAMA would provide alternate decay heat removal in an ATWS event.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 37, 38	Reference 19	N/A
40	Create/enhance hydrogen recombiners with independent power supply.	5 11	SAMA would reduce hydrogen detonation at lower cost. Use either 1) a new independent power supply 2) a nonsafety-grade portable generator 3) existing station batteries 4) existing AC/DC independent power supplies.	#3 - Already implemented at Robinson	Hydrogen recombiners are addressed in SAM-7. Power requirements are discussed along with methods for returning system to service.	Reference 24	N/A
41	Install hydrogen recombiners.	11	SAMA would provide a means to reduce the chance of hydrogen detonation.	#3 - Already implemented at Robinson	Robinson currently has access to hydrogen recombiners.	Reference 24	N/A
42	Create a passive design hydrogen ignition system.	4	SAMA would reduce hydrogen denotation system without requiring electric power.	#2 - Similar item is addressed under other proposed SAMAs	Alternate methods of hydrogen control are addressed in SAM-7. Also see SAMA #40	Reference 19	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
43	Create a large concrete crucible with heat removal potential under the basemat to contain molten core debris.	5 6	SAMA would ensure that molten core debris escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through of the basemat.	#5 - Cost would be more than risk benefit	Core retention devices have been investigated in previous studies. IDCOR concluded that "core retention devices are not effective risk reduction devices for degraded core events". Other evaluations have shown the worth value for a core retention device to be on the order of $7000 (averted cost-risk) compared to an estimated implementation cost of over $1 million (per unit).	Supplement 2 to NUREG-1437, Generic Environmental Impact Statement for License Renewal of Nuclear Plants, December 1999 for Oconee Nuclear Station, and IDCOR Technical Summary Report, November 1984	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
44	Create a water-cooled rubble bed on the pedestal.	5 6	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.	#5 - Cost would be more than risk benefit	Core retention devices have been investigated in previous studies. IDCOR concluded that "core retention devices are not effective risk reduction devices for degraded core events". Other evaluations have shown the worth value for a core retention device to be on the order of $7000 (averted cost-risk) compared to an estimated implementation cost of over $1 million (per unit).	Supplement 2 to NUREG-1437, Generic Environmental Impact Statement for License Renewal of Nuclear Plants, December 1999 for Oconee Nuclear Station, and IDCOR Technical Summary Report, November 1984	N/A
45	Provide modification for flooding the drywell head.	5 6	SAMA would help mitigate accidents that result in the leakage through the drywell head seal.	#1 - N/A	This is a BWR issue. PWR containment does not include an equivalent structure/component that this modification could be applied to and is screened from further consideration.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
46	Enhance fire protection system and/or standby gas treatment system hardware and procedures.	6	SAMA would improve fission product scrubbing in severe accidents.	#1 - N/A	Current Fire Protection and Standby Gas Treatment Systems (for BWRs) do not have sufficient capacity to handle the loads from severe accidents that result in a bypass or breach of the containment. Loads produced as a result of RPV or containment blowdown would require large filtering capacities. These filtered vented systems have been previously investigated and found not to provide sufficient cost benefit.	IDCOR Technical Summary Report, November 1984	N/A
47	Create a reactor cavity flooding system.	1 3 7 8 14	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.	#5 - Cost would be more than risk benefit	The estimated cost of implementation for this SAMA is $8.75 million, which greatly exceeds the maximum averted cost-risk ($1,033,000).	Reference 19	N/A
48	Create other options for reactor cavity flooding.	1 14	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.	#3 - Already implemented at Robinson	SAM-4 addresses various alternative methods for injecting into containment.	Reference 24	N/A
49	Enhance air return fans (ice condenser plants).	1	SAMA would provide an independent power supply for the air return fans, reducing containment failure in SBO sequences.	#1 - N/A	Robinson is not an ice condenser plant.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
50	Create a core melt source reduction system.	9	SAMA would provide cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur.	#5 - Cost would be more than risk benefit	Core retention devices have been investigated in previous studies. IDCOR concluded that "core retention devices are not effective risk reduction devices for degraded core events". Other evaluations have shown the worth value for a core retention device to be on the order of $7000 compared to an estimated implementation cost of over $1 million.	Supplement 2 to NUREG-1437, Generic Environmental Impact Statement for License Renewal of Nuclear Plants, December 1999 for Oconee Nuclear Station, and IDCOR Technical Summary Report, November 1984	N/A
51	Provide a containment inerting capability.	7 8	SAMA would prevent combustion of hydrogen and carbon monoxide gases.	#1 - N/A	Not considered viable in a large volume containment where access may be required.	N/A	N/A
52	Use the fire protection system as a backup source for the containment spray system.	4	SAMA would provide redundant containment spray function without the cost of installing a new system.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 35	N/A	N/A
53	Install a secondary containment filtered vent.	10	SAMA would filter fission products released from primary containment.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 38	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
54	Install a passive containment spray system.	10	SAMA would provide redundant containment spray method without high cost.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 35	N/A	N/A
55	Strengthen primary/secondary containment.	10 11	SAMA would reduce the probability of containment overpressurization to failure.	#5 - Cost would be more than risk benefit	Reference 17 discusses the cost of increasing the containment pressure capacity, which is effectively strengthening the containment. This cost is estimated assuming the change is made during the design phase whereas for Robinson, the changes would have to be made as a retrofit. The cost estimated for the ABWR was $12 million and it is judged that to properly retrofit an existing containment that the cost would be greater. This cost of implementation for this SAMA exceeds the maximum averted cost-risk ($1,033,000).	Reference 17	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
56	Increase the depth of the concrete basemat or use an alternative concrete material to ensure melt-through does not occur.	11	SAMA would prevent basemat melt-through.	#5 - Cost would be more than risk benefit	Core retention devices have been investigated in previous studies. IDCOR concluded that "core retention devices are not effective risk reduction devices for degraded core events". Other evaluations have shown the worth value for a core retention device to be on the order of $7000 compared to an estimated implementation cost of over $1 million/site.	Supplement 2 to NUREG-1437, Generic Environmental Impact Statement for License renewal of Nuclear Plants, December 1999 for Oconee Nuclear Station, and IDCOR Technical Summary Report, November 1984	N/A
57	Provide a reactor vessel exterior cooling system.	11	SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head could be submerged in water.	#5 - Cost would be more than risk benefit	This has been estimated to cost $2.5 million and exceeds the maximum averted cost-risk ($1,033,000).	Reference 19	N/A
58	Construct a building to be connected to primary/secondary containment that is maintained at a vacuum.	11	SAMA would provide a method to depressurize containment and reduce fission product release.	#5 - Cost would be more than risk benefit	Based on engineering judgement, the cost of this enhancement is expected to greatly exceed the maximum averted cost risk ($1,033,000).	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
59	Refill CST	14 16	SAMA would reduce the risk of core damage during events such as extended station blackouts or LOCAs which render the suppression pool unavailable as an injection source due to heat up.	#3 - Already implemented at Robinson	This capability exists. Like most plants, Robinson has the capability to supply makeup from the SW system. However, SW is dependent on AC power. Plant procedures also provide for adding makeup using firewater supplied by the diesel fire pump.	Reference 25	N/A
60	Maintain ECCS suction on CST	14 16	SAMA would maintain suction on the CST as long as possible to avoid pump failure as a result of high suppression pool temperature	#3 - Already implemented at Robinson	Procedures call for utilizing the CST until AFW suction is no longer possible. SAM-4 addresses various alternative methods and limitations for injecting into containment.	Reference 28	N/A
61	Modify containment flooding procedure to restrict flooding to below top of active fuel	14	SAMA would avoid forcing containment venting	#1 - N/A	Not applicable to the Robinson design.	Reference 20	N/A
62	Enhance containment venting procedures with respect to timing, path selection and technique.	14	SAMA would improve likelihood of successful venting strategies.	#3 - Already implemented at Robinson	These steps are addressed in the SAMGs.	Reference 29	N/A
63	1.a. Severe Accident EPGs/AMGs	17	SAMA would lead to improved arrest of core melt progress and prevention of containment failure	#3 - Already Implemented at Robinson	The SAMGs have been implemented at Robinson.	Reference 24	N/A
64	1.h. Simulator Training for Severe Accident	17	SAMA would lead to improved arrest of core melt progress and prevention of containment failure	#3 - Already Implemented at Robinson	These steps are addressed in the SAMGs.	Reference 24	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
65	2.g. Dedicated Suppression Pool Cooling	17	SAMA would decrease the probability of loss of containment heat removal. While PWRs do not have suppression pools, a similar modification may be applied to the sump. Installation of a dedicated sump cooling system would provide an alternate method of cooling injection water.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 34	N/A	N/A
66	3.a. Larger Volume Containment	17	SAMA increases time before containment failure and increases time for recovery	#5 - Cost would be more than risk benefit	RNP is already a large, dry containment. Further enlargement of the containment would be similar in scope to the ABWR design change SAMA to implement a larger volume containment, but would likely exceed the $8 million estimate for that change as a retrofit would be required. This is greater than the maximum averted cost-risk ($1,033,000 million).	Reference 17	N/A
67	3.b. Increased Containment Pressure Capability (sufficient pressure to withstand severe accidents)	17	SAMA minimizes likelihood of large releases	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 55	N/A	N/A
68	3.c. Improved Vacuum Breakers (redundant valves in each line)	17	SAMA reduces the probability of a stuck open vacuum breaker.	#1 - N/A	This is a BWR issue. PWR containment does not include an equivalent structure/component that this modification could be applied to and is screened from further consideration.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
69	3.d. Increased Temperature Margin for Seals	17	This SAMA would reduce containment failure due to drywell head seal failure caused by elevated temperature and pressure.	#1 - N/A	High temperature containment seal failure is not an issue for a large, dry containment; computed containment temperatures are generally below the failure threshold.	Reference 20	N/A
70	3.e. Improved Leak Detection	17	This SAMA would help prevent LOCA events by identifying pipes which have begun to leak. These pipes can be replaced before they break.	#3 - Already implemented at Robinson	Leak rates from the primary system are already monitored as part of technical specifications requirements and instrumentation is available to identify leaks. Enhancing the procedures or equipment is possible, but the reduction in the LOCA frequency resulting from these changes is judged to be negligible.	Reference 30	N/A
71	3.f. Suppression Pool Scrubbing	17	Directing releases through the suppression pool will reduce the radionuclides allowed to escape to the environment.	#1 - N/A	This is a BWR issue. PWR containment does not include an equivalent structure/component that this modification could be applied to and is screened from further consideration.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
72	3.g. Improved Bottom Penetration Design	17	SAMA reduces failure likelihood of RPV bottom head penetrations	#8 - ABWR design issue; not practical	This is primarily a BWR issue. The mechanisms of vessel breach due to contact with core debris are more of a concern with the larger penetrations present in the BWR bottom head design. Also, this is considered to be an initial design issue rather than a mod due to the prohibitive cost. Screened from further consideration.	Reference 17	N/A
73	4.a. Larger Volume Suppression Pool (double effective liquid volume)	17	SAMA would increase the size of the suppression pool so that heatup rate is reduced, allowing more time for recovery of a heat removal system	#1 - N/A	This is a BWR issue. PWR containment does not include an equivalent structure/component that this modification could be applied to and is screened from further consideration.	Reference 20	N/A
74	5.a/d. Unfiltered Vent	17	SAMA would provide an alternate decay heat removal method with the released fission products not being scrubbed.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 37	N/A	N/A
75	5.b/c. Filtered Vent	17	SAMA would provide an alternate decay heat removal method with the released fission products being scrubbed.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 38 and 53	N/A	N/A
76	6.a. Post Accident Inerting System	17	SAMA would reduce likelihood of gas combustion inside containment	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 51	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
77	6.b. Hydrogen Control by Venting	17	Prevents hydrogen detonation by venting the containment before combustible levels are reached.	#3 - Already Implemented at Robinson	The SAMG developers have considered the possibility of venting for hydrogen control, but the actions considered most appropriate for Robinson do not include venting for control. Hydrogen ignition and hydrogen recombination are directed to maintain low hydrogen concentrations within containment during an accident.	Reference 24	N/A
78	6.c. Pre-inerting	17	SAMA would reduce likelihood of gas combustion inside containment	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 51 and 76	N/A	N/A
79	6.d. Ignition Systems	17	Burning combustible gases before they reach a level which could cause a harmful detonation is a method of preventing containment failure.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 42	N/A	N/A
80	6.e. Fire Suppression System Inerting	17	Use of the fire protection system as a back up containment inerting system would reduce the probability of combustible gas accumulation. This would reduce the containment failure probability for small containments (e.g. BWR MKI)	#1 - N/A	This is a BWR issue. PWR containments are large and that would require extremely costly modifications to impose and would inhibit access to the containment. Screened from further consideration.	See SAMAs 51, 76, and 78	N/A
81	7.a. Drywell Head Flooding	17	SAMA would provide intentional flooding of the upper drywell head such that if high drywell temperatures occurred, the drywell head seal would not fail.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 45	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
82	7.b. Containment Spray Augmentation	17	This SAMA would provide additional means of providing flow to the containment spray system.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 32, 33, 35, 36, 52, 54	N/A	N/A
83	12.b. Integral Basemat	17		#8 - ABWR design issue; not practical	This is a SAMA that was considered for ABWR design. It is not practical to backfit this modification into a plant which is already built and operating.	Reference 17, Engineering Judgement	N/A
84	13.a. Reactor Building Sprays	17	This SAMA provides the capability to use firewater sprays in the reactor building to mitigate release of fission products into the Rx Building following an accident.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 32, 33, 35, 36, 52, 54, 82	N/A	N/A
85	14.a. Flooded Rubble Bed	17	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 44	N/A	N/A
86	14.b. Reactor Cavity Flooder	17	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.	#2 - Similar item is addressed under other proposed SAMAs	Addressed in SAMAs 47 & 57	N/A	N/A
87	14.c. Basaltic Cements	17	SAMA minimizes carbon dioxide production during core concrete interaction.	#8 - ABWR design issue; not practical	This is a SAMA which was considered for ABWR design. It is not practical to backfit this modification into a plant which is already built and operating.	Reference 17, Engineering Judgement	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
88	Provide a core debris control system	19	(Intended for ice condenser plants): This SAMA would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and the containment shell.	#1 - N/A	Robinson is not an ice condenser plant.	Reference 20	N/A
89	Add ribbing to the containment shell	19	This SAMA would reduce the risk of buckling of containment under reverse pressure loading.	#2 - Similar item is addressed under other proposed SAMAs	This item is similar in nature to SAMA 55, but for protection against negative pressure. Using SAMA 55 as an upper bound and a relatively simple modification such as SAMA 37 as a lower bound, the cost of performing structural enhancements to the containment building which will significantly strengthen the containment is judged to exceed the maximum averted cost-risk ($1,033,000).	References 17 and 19	N/A
Improvements Related to Enhanced AC/DC Reliability/Availability							
90	Proceduralize alignment of spare diesel to shutdown board after loss of offsite power and failure of the diesel normally supplying it.	1 3 7	SAMA would reduce the SBO frequency.	#3 - Already implemented at Robinson	Robinson has 2 EDGs and one SBO diesel, and the use is proceduralized.	Reference 31	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
91	Provide an additional diesel generator.	1 3 7 11 14	SAMA would increase the reliability and availability of onsite emergency AC power sources.	#5 - Cost would be more than risk benefit	The cost of installing an additional diesel generator has been estimated at over $20 million in Reference 19. This cost of implementation for this SAMA greatly exceeds the maximum averted cost-risk ($1,033,000).	Reference 19	N/A
92	Provide additional DC battery capacity.	1 3 7 11 12	SAMA would ensure longer battery capability during an SBO, reducing the frequency of long-term SBO sequences.	#5 - Cost would be more than risk benefit	The cost of implementation for this SAMA has been estimated to be $1.88 million in Reference 19. This exceeds the maximum averted cost-risk ($1,033,000)	Reference 19	N/A
93	Use fuel cells instead of lead-acid batteries.	11	SAMA would extend DC power availability in an SBO.	#5 - Cost would be more than risk benefit	The cost of implementation for this SAMA has been estimated to be $2 million in Reference 19. This exceeds the maximum averted cost-risk for ($1,033,000)	Reference 19	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
94	Procedure to cross-tie high-pressure core spray diesel.	1	SAMA would improve core injection availability by providing a more reliable power supply for the high-pressure core spray pumps.	#3 - Already implemented at Robinson	Previous regulatory concerns with an automatic bus transfer for SI pump B make this undesirable. Note that one of the three SI pumps can be powered from either Emergency Bus E1 or E2, but this requires manual action. Only one pump is needed for accident mitigation	Reference 20	N/A
95	Improve 4.16-kV bus cross-tie ability.	1 14	SAMA would improve AC power reliability.	#1 - N/A	See #94. The ability to crosstie non-ESF 4kV buses would result in little benefit since Robinson has only one transformer supplying offsite power. It is possible to backfeed and power the 4.16 kV buses.	Reference 20	N/A
96	Incorporate an alternate battery charging capability.	1 8 9 14	SAMA would improve DC power reliability by either cross-tying the AC busses, or installing a portable diesel-driven battery charger.	#3 - Already implemented at Robinson	Plant modification M-940 removed tie cables between Station Battery A and B and installed a redundant battery charger for each train. The On-Site Emergency DC Power System consists of 2 redundant 100 percent capacity 125V DC safety trains, each with 2 charges.	Reference 47	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
97	Increase/improve DC bus load shedding.	1 8 14	SAMA would extend battery life in an SBO event.	#3 - Already implemented at Robinson	This has been investigated and current load shed procedures are adequate.	Reference 25	N/A
98	Replace existing batteries with more reliable ones.	11 14	SAMA would improve DC power reliability and thus increase available SBO recovery time.	#3 - Already implemented at Robinson	Reliable batteries are already installed.	Reference 23, Appendix A.12	N/A
99	Mod for DC Bus A reliability.	1	SAMA would increase the reliability of AC power and injection capability. Loss of DC Bus A causes a loss of main condenser, prevents transfer from the main transformer to offsite power, and defeats one half of the low vessel pressure permissive for LPCI/CS injection valves.	#1 - N/A	Loss of a single DC bus does not prevent alignment of off-site power to the start-up transformer (E2 is already aligned to the offsite source) and the Reactor Safeguards Actuation System (plant logic) consists of 2 independent, redundant divisions.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
100	Create AC power cross-tie capability with other unit.	1 8 9 14	SAMA would improve AC power reliability.	#5 - Cost would be more than risk benefit	Robinson is a 2 unit site, with an adjacent coal plant. In addition, combustion turbines exist at nearby Darlington. However, no equipment is installed that would allow a direct connection between the plants' emergency AC buses. Power can be provided through the switchyard, but these sources are not available by definition in a LOOP event. Installation of direct connections between the plants' AC buses is a major modification considered to be greater in scope than SAMA 123. Reference 17 estimates the cost of a dedicated RHR power supply to be $1.2 million. This is considered to be a lower bound estimate for an inter-plant AC crosstie. The cost of this SAMA is greater than the RNP maximum averted cost-risk.	Reference 73	N/A
101	Create a cross-tie for diesel fuel oil.	1	SAMA would increase diesel fuel oil supply and thus diesel generator, reliability.	#3 - Already implemented at Robinson		Reference 23, Appendix A.11	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
102	Develop procedures to repair or replace failed 4-kV breakers.	1	SAMA would offer a recovery path from a failure of the breakers that perform transfer of 4.16-kV non-emergency busses from unit station service transformers, leading to loss of emergency AC power.	#3 - Already implemented at Robinson	Plant has maintenance procedures for 4 kv breakers.	PM-466,468, and 469.	N/A
103	Emphasize steps in recovery of offsite power after an SBO.	1 14	SAMA would reduce human error probability during offsite power recovery.	#3 - Already implemented at Robinson	Refer to procedures EPP-25 and OP-603.	EPP-25, OP-603	N/A
104	Develop a severe weather conditions procedure.	1 13	For plants that do not already have one, this SAMA would reduce the CDF for external weather-related events.	#3 - Already implemented at Robinson	Refer to procedure OMM-021.	OMM-021	N/A
105	Develop procedures for replenishing diesel fuel oil.	1	SAMA would allow for long-term diesel operation.	#3 - Already implemented at Robinson		Reference 32	N/A
106	Install gas turbine generator.	1 14	SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system.	#5 - Cost would be more than risk benefit	The cost of installing a diverse, redundant, gas turbine generator is similar in scope to installing a new diesel generator. The cost of installing an additional diesel generator has been estimated at over $20 million in Reference 19. This cost of implementation for this SAMA greatly exceeds the maximum averted cost-risk ($1,033,000).	Reference 19	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
107	Create a backup source for diesel cooling. (Not from existing system)	1	This SAMA would provide a redundant and diverse source of cooling for the diesel generators, which would contribute to enhanced diesel reliability.	#5 - Cost would be more than risk benefit	A potential enhancement would be to make them air cooled such that the do not rely on any service water systems for cooling. The cost of implementation is estimated to be $1.7 million per diesel. This SAMA exceeds the maximum averted cost-risk ($1,033,000).	Reference 19	N/A
108	Use fire protection system as a backup source for diesel cooling.	1, 20	This SAMA would provide a redundant and diverse source of cooling for the diesel generators, which would contribute to enhanced diesel reliability.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 107	Reference 20	N/A
109	Provide a connection to an alternate source of offsite power.	1	SAMA would reduce the probability of a loss of offsite power event.	#3 - Already implemented at Robinson	Refer to #95. OP-602 allows backfeeding as alternate source of off-site power. See also EPP-25.	OP-602	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
110	Bury offsite power lines.	1	SAMA could improve offsite power reliability, particularly during severe weather.	#5 - Cost would be more than risk benefit	While the actual cost of this SAMA will vary depending on site characteristics, the cost of burying offsite power lines has been estimated at a cost significantly greater than $25 million for another US PWR. Implementing this SAMA at Robinson is considered to be within the same order of magnitude and exceeds the maximum averted cost-risk for the plant ($1,033,000).	Reference 19	N/A
111	Replace anchor bolts on diesel generator oil cooler.	1	Millstone Nuclear Power Station found a high seismic SBO risk due to failure of the diesel oil cooler anchor bolts. For plants with a similar problem, this would reduce seismic risk. Note that these were Fairbanks Morse EDGs.	#1 - N/A	The Robinson IPEEE included an assessment of the plant's ability to cope with seismic events. No changes were identified for the EDG oil coolers and are considered to be sufficient.	Reference 21	N/A
112	Change undervoltage (UV), auxiliary feedwater actuation signal (AFAS) block and high pressurizer pressure actuation signals to 3-out-of-4, instead of 2-out-of-4 logic.	1	SAMA would reduce risk of 2/4 inverter failure.	#1 - N/A	Robinson does not have 4 inverters, nor do they have 4 train logic for AFW or pressurizer pressure. RNP has 2/3 logic for UV, keylock for AFW block, and 2/3 logic for high pressurizer pressure.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
113	Provide DC power to the 120/240-V vital AC system from the Class 1E station service battery system instead of its own battery.	12	SAMA would increase the reliability of the 120V AC Bus.	#3 - Already implemented at Robinson	Inverter "A" is powered from 125V DC PP A and inverter "B" is powered from 125V DC MCC "B"	Reference 23, Appendix A.11 and A.12	N/A
114	Bypass Diesel Generator Trips	14 16	SAMA would allow D/Gs to operate for longer.	#3 - Already implemented at Robinson	Robinson utilizes a "Trip Defeat" function for trips except overspeed. See TS Bases 3.8.1	TS Bases 3.8.1	N/A
115	2.i. 16 hour Station Blackout Injection	17	SAMA includes improved capability to cope with longer station blackout scenarios.	#2 - Similar item is addressed under other proposed SAMAs	Part of 128	N/A	N/A
116	9.a. Steam Driven Turbine Generator	17	This SAMA would provide a steam driven turbine generator, which uses reactor steam and exhausts to the suppression pool. If large enough, it could provide power to additional equipment.	#5 - Cost would be more than risk benefit	The cost of installing a steam driven turbine generator is greater in scope than installing a new diesel generator due to the interface with the plant's steam system. The cost of installing an additional diesel generator has been estimated at over $20 million in Reference 19. This cost of implementation for this SAMA is expected to exceed even this estimate and is considerably greater than the maximum averted cost-risk ($1,033,000).	Reference 19	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
117	9.b. Alternate Pump Power Source	17	This SAMA would provide a small dedicated power source such as a dedicated diesel or gas turbine for the feedwater or condensate pumps, so that they do not rely on offsite power.	#2 - Similar item is addressed under other proposed SAMAs	Firewater pump provides low pressure injection without offsite power (#52). Additional or passive high pressure systems addressed in other SAMAs, as is motor driven FW pump.	Reference 20	N/A
118	9.d. Additional Diesel Generator	17	SAMA would reduce the SBO frequency.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 90, 91	N/A	N/A
119	9.e. Increased Electrical Divisions	17	SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies.	#8 - ABWR design issue; not practical	This is a SAMA which was considered for ABWR design. It is not practical to backfit this modification into a plant which is already built and operating.	N/A	N/A
120	9.f. Improved Uninterruptable Power Supplies	17	SAMA would provide increased reliability of power supplies supporting front-line equipment, thus reducing core damage and release frequencies.	#4 - No significant safety benefit	Uninterruptable power supplies are not modeled in the RNP PSA, so it is not possible to obtain a risk delta for this SAMA. The risk involved with these power supplies is judged to be small.	Reference 20	N/A
121	9.g. AC Bus Cross-Ties	17	SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 95	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
122	9.h. Gas Turbine	17	SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 106	N/A	N/A
123	9.i. Dedicated RHR (bunkered) Power Supply	17	SAMA would provide RHR with more reliable AC power.	#2 - Similar item is addressed under other proposed SAMAs	This is estimated to cost more than $1.2 million, which is greater than the maximum averted cost risk for Robinson ($1,033,000).	Reference 17	N/A
124	10.a. Dedicated DC Power Supply	17	This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).	#5 - Cost would be more than risk benefit	The cost of implementation for this mod is estimated at $3 million, which is greater than the maximum averted cost-risk for Robinson ($1,033,000).	Reference 17	N/A
125	10.b. Additional Batteries/Divisions	17	This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).	#2 - Similar item is addressed under other proposed SAMAs	Part of 124	N/A	N/A
126	10.c. Fuel Cells	17	SAMA would extend DC power availability in an SBO.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 93	N/A	N/A
127	10.d. DC Cross-ties	17	This SAMA would improve DC power reliability.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 96	N/A	N/A
128	10.e. Extended Station Blackout Provisions	17	SAMA would provide reduction in SBO sequence frequencies.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 29, 90, 92, 93, 97, 98, 103, 105	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
129	Add an automatic bus transfer feature to allow the automatic transfer of the 120V vital AC bus from the on-line unit to the standby unit	19	Plants are typically sensitive to the loss of one or more 120V vital AC buses. Manual transfers to alternate power supplies could be enhanced to transfer automatically.	#1 - N/A	Robinson is not a multi-unit site; screened from further analysis.	Reference 20	N/A
Improvements in Identifying and Mitigating Containment Bypass							
130	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture (SGTR).	1	SAMA would enhance depressurization during a SGTR.	#3 - Already implemented at Robinson	Robinson currently has three methods of pressure reduction already, normal spray, PORVs, and Auxiliary spray (from charging pumps). See also EPP-19 if there is no pressure control.	Reference 20, EPP-19	N/A
131	Improve SGTR coping abilities.	1 4 11	SAMA would improve instrumentation to detect SGTR, or additional system to scrub fission product releases.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 133, 134, 135, 136, 137	N/A	N/A
132	Add other SGTR coping abilities.	4 10 11	SAMA would decrease the consequences of an SGTR.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 130	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
133	Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	10 11	SAMA would eliminate direct release pathway for SGTR sequences.	#5 - Cost would be more than risk benefit	Based on engineering judgement, increasing the secondary side pressure capacity is not feasible as it would require extensive upgrades to the secondary system. The cost of this modification would greatly exceed the maximum averted cost-risk for Robinson ($1,033,000).	Engineering judgement.	N/A
134	Replace steam generators (SG) with a new design.	1	SAMA would lower the frequency of an SGTR.	#5 - Cost would be more than risk benefit	The cost of installing new steam generators is estimated to exceed $100 million. This is far greater than the maximum averted cost risk for ($1,033,000).	Reference 19	N/A
135	Revise emergency operating procedures to direct that a faulted SG be isolated.	1	SAMA would reduce the consequences of an SGTR.	#3 - Already implemented at Robinson	SAM-5 provides guidance for isolating the faulted steam generator.	Reference 24	N/A
136	Direct SG flooding after a SGTR, prior to core damage.	10	SAMA would provide for improved scrubbing of SGTR releases.	#3 - Already implemented at Robinson	SAM-5 provides guidance for mitigating the releases from the SG. Included in the strategy is restoring the SG water level.	Reference 24	N/A
137	Implement a maintenance practice that inspects 100 percent of the tubes in a SG.	11	SAMA would reduce the potential for an SGTR.	#3 - Already implemented at Robinson	RNP currently inspects 100 percent of the tubes over an interval of 3 outages.	Reference 78	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
138	Locate residual heat removal (RHR) inside of containment.	10	SAMA would prevent intersystem LOCA (ISLOCA) out the RHR pathway.	#5 - Cost would be more than risk benefit	For an existing plant, the cost of moving an entire system is judged to greatly exceed the maximum averted cost-risk ($1,033,000).	Engineering judgement.	N/A
139	Install additional instrumentation for ISLOCAs.	3 4 7 8	SAMA would decrease ISLOCA frequency by installing pressure of leak monitoring instruments in between the first two pressure isolation valves on low-pressure inject lines, RHR suction lines, and HPSI lines.	#5 - Cost would be more than risk benefit	The cost of implementation for this SAMA has been estimated at $2.3 million in Reference 19. This is greater than the maximum averted cost-risk ($1,033,000).	Reference 19	N/A
140	Increase frequency for valve leak testing.	1	SAMA could reduce ISLOCA frequency.	#6 - Retain	N/A	N/A	3
141	Improve operator training on ISLOCA coping.	1	SAMA would decrease ISLOCA effects.	#3 - Already implemented at Robinson	ISLOCA coping is covered in SACRM-1.	SACRM-1	N/A
142	Install relief valves in the CC System.	1	SAMA would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA.	#3 - Already implemented at Robinson	CCW system currently includes relief valves to limit pressure.	Reference 33	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
143	Provide leak testing of valves in ISLOCA paths.	1	SAMA would help reduce ISLOCA frequency. At Kewaunee Nuclear Power Plant, four MOVs isolating RHR from the RCS were not leak tested.	#2 - Similar item is addressed under other proposed SAMAs	A similar configuration exists at RNP. The NRC is aware of the issue and has accepted the RNP IST program due to the impracticality of testing. Addition of test taps for these valves is considered to be qualitatively addressed by SAMA 139 and quantitatively bounded by SAMA 140 (Phase 2 SAMA 3). The averted cost-risk based on implementing SAMA 143 would be a fraction of this number and is clearly less than the cost required to modify the RHR piping, upgrade procedures, and train personnel on the equipment. This SAMA is screened from further review	N/A	N/A
144	Revise EOPs to improve ISLOCA identification.	1	SAMA would ensure LOCA outside containment could be identified as such. Salem Nuclear Power Plant had a scenario where an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.	#2 - Similar item is addressed under other proposed SAMAs	Refer to #141	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
145	Ensure all ISLOCA releases are scrubbed.	1	SAMA would scrub all ISLOCA releases. One example is to plug drains in the break area so that the break point would be covered with water.	#1 - N/A	This SAMA is judged not to be practically applicable to an operating plant. • Systems installed to flood break areas would be cost prohibitive. • Constructing reservoirs around piping with ISLOCA pathways would be cost prohibitive. • Plugging room drains may not be cost prohibitive, but the plant was designed with drains to prevent flooding areas containing required equipment. This may be more detrimental than beneficial. In addition, the flood rate may not be great enough to submerge the break point prior to release. No practical means of reducing risk at an operating plant have been identified.	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
146	Add redundant and diverse limit switches to each containment isolation valve.	1	SAMA could reduce the frequency of containment isolation failure and ISLOCAs through enhanced isolation valve position indication.	#4 - No significant safety benefit.	The failures addressed by this SAMA are not contributors to the CDF or LERF. The benefit gained by redundant and diverse limits switches would be in an operator recovery action. Given the failure of the primary equipment used for isolation valve indication, the operator would identify a mispositioned valve using the redundant indicators. This level of detail is not included in the model and would be dominated by other failure modes	Reference 20	N/A
147	Early detection and mitigation of ISLOCA	14 16	SAMA would limit the effects of ISLOCA accidents by early detection and isolation	#2 - Similar item is addressed under other proposed SAMAs	Refer to #141	N/A	N/A
148	8.e. Improved MSIV Design	17		#6 - Retain	N/A	N/A	4
149	Proceduralize use of pressurizer vent valves during steam generator tube rupture (SGTR) sequences	19	Some plants may have procedures to direct the use of pressurizer sprays to reduce RCS pressure after an SGTR. Use of the vent valves would provide a back-up method.	#3 - Already implemented at Robinson	SAM-2 provides guidance for RCS depressurization and specifically addresses the SGTR case.	Reference 24	N/A
150	Implement a maintenance practice that inspects 100 percent of the tubes in an SG	19	This SAMA would reduce the potential for a tube rupture.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 137	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
151	Locate RHR inside of containment	19	This SAMA would prevent ISLOCA out the RHR pathway.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 138	N/A	N/A
152	Install self-actuating containment isolation valves	19	For plants that do not have this, it would reduce the frequency of isolation failure.	#3 - Already implemented at Robinson	Plant currently has automatic isolation of containment. See UFSAR 6.4 and 7.3	UFSAR 6.4 and 7.3	N/A
Improvements in Reducing Internal Flooding Frequency							
153	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	1	SAMA would prevent flood propagation, for a plant where internal flooding from turbine building to safeguards areas is a concern.	#3 - Already implemented at Robinson	The Robinson IPE, Reference 20, analyzed the importance of internal floods to core damage accidents. As a result of that evaluation, the cost effective means of reducing flooding risk were identified. Additional modifications were judged not to be necessary	Reference 20	N/A
154	Improve inspection of rubber expansion joints on main condenser.	1 14	SAMA would reduce the frequency of internal flooding, for a plant where internal flooding due to a failure of circulating water system expansion joints is a concern.	#3 - Already implemented at Robinson	The Robinson IPE, Reference 20, analyzed the importance of internal floods to core damage accidents. As a result of that evaluation, the cost effective means of reducing flooding risk were identified. Additional modifications were judged not to be necessary	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
155	Implement internal flood prevention and mitigation enhancements.	1	This SAMA would reduce the consequences of internal flooding.	#3 - Already implemented at Robinson	The Robinson IPE, Reference 20, analyzed the importance of internal floods to core damage accidents. As a result of that evaluation, procedures were developed for coping with flooding scenarios.	References 20, 79, 80, 81 and 82	N/A
156	Implement internal flooding improvements such as those implemented at Fort Calhoun.	1	This SAMA would reduce flooding risk by preventing or mitigating rupture in the RCP seal cooler of the component cooling system ISLOCA in a shutdown cooling line, an auxiliary feedwater (AFW) flood involving the need to remove a watertight door.	#3 - Already implemented at Robinson	The Robinson IPE, Reference 20, analyzed the importance of internal floods to core damage accidents. As a result of that evaluation, the cost effective means of reducing flooding risk were identified. Additional modifications were judged not to be necessary	Reference 20	N/A
157	Shield electrical equipment from potential water spray	14	SAMA would decrease risk associated with seismically induced internal flooding	#3 - Already implemented at Robinson	The Robinson IPE, Reference 20, analyzed the importance of internal floods to core damage accidents. As a result of that evaluation, the cost effective means of reducing flooding risk were identified. Additional modifications were judged not to be necessary	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
158	13.c. Reduction in Reactor Building Flooding	17	This SAMA reduces the Reactor Building Flood Scenarios contribution to core damage and release.	#3 - Already implemented at Robinson	The Robinson IPE, Reference 20, analyzed the importance of internal floods to core damage accidents. As a result of that evaluation, procedures were developed to mitigate internal floods.	Reference 20	N/A
Improvements Related to Feedwater/Feed and Bleed Reliability/Availability							
159	Install a digital feedwater upgrade.	1	This SAMA would reduce the chance of a loss of main feedwater.	#6 - Retain	After plant trip AFW would be used. Robinson has 1 turbine driven and two motor driven Auxiliary Feedwater Pumps.	N/A	5
160	Perform surveillances on manual valves used for backup AFW pump suction.	1	This SAMA would improve success probability for providing alternative water supply to the AFW pumps.	#3 - Already implemented at Robinson	Valves that provide suction from SW are tested per OST-701-6.	OST-701-6	N/A
161	Install manual isolation valves around AFW turbine-driven steam admission valves.	1	This SAMA would reduce the dual turbine-driven AFW pump maintenance unavailability.	#1 - N/A	Robinson has 1 turbine driven and two motor driven Auxiliary Feedwater Pumps.	Reference 23, Appendix A.5	N/A
162	Install accumulators for turbine-driven AFW pump flow control valves (CVs).	4 8	This SAMA would provide control air accumulators for the turbine-driven AFW flow CVs, the motor-driven AFW pressure CVs and SG power-operated relief valves (PORVs). This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOOP.	#3 - Already implemented at Robinson	CVs use hydraulic oil. AFW had flow limiting devices installed. Normal motive source for PORVs is Instrument Air. An accumulator is in series with alternate motive source provided by the instrument air system.	References 36 and 37	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
163	Install separate accumulators for the AFW cross-connect and block valves	19	This SAMA would enhance the operator's ability to operate the AFW cross-connect and block valves following loss of air support.	#3 - Already implemented at Robinson	The AFW system can be initiated and controlled automatically or manually. Loss of instrument air has no effect on the steam driven pump since it fails safe at a regulated pump speed of 9400 rpm.	Reference 36 and 37	N/A
164	Install a new condensate storage tank (CST)	19	Either replace the existing tank with a larger one, or install a back-up tank.	#5 - Cost would be more than risk benefit	Reference 17 indicates that the cost of installing a new CST is $1 million. This is considered to be a lower bound estimate and it is judged that the actual cost would exceed the maximum averted cost-risk for Robinson ($1,033,000).	Reference 17	N/A
165	Provide cooling of the steam-driven AFW pump in an SBO event	19	This SAMA would improve success probability in an SBO by: (1) using the FP system to cool the pump, or (2) making the pump self cooled.	#3 - Already implemented at Robinson	Pump is self cooled	Reference 20	N/A
166	Proceduralize local manual operation of AFW when control power is lost.	19	This SAMA would lengthen AFW availability in an SBO. Also provides a success path should AFW control power be lost in non-SBO sequences.	#3 - Already implemented at Robinson	This is already done for SDAFWP.	AP-402	N/A
167	Provide portable generators to be hooked into the turbine driven AFW, after battery depletion.	19	This SAMA would extend AFW availability in an SBO (assuming the turbine driven AFW requires DC power)	#1 - N/A	DC power is not needed for SDAFWP. Pump can be started manually; see FRP H.1.	FRP H.1	N/A
168	Add a motor train of AFW to the Steam trains	19	For PWRs that do not have any motor trains of AFW, this would increase reliability in non-SBO sequences.	#3 - Already implemented at Robinson	Robinson has 1 turbine driven and two motor driven Auxiliary Feedwater Pumps.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
169	Create ability for emergency connections of existing or alternate water sources to feedwater/condensate	19	This SAMA would be a back-up water supply for the feedwater/condensate systems.	#3 - Already implemented at Robinson	Service Water can be connected to Auxiliary Feedwater.	Reference 20	N/A
170	Use FP system as a back-up for SG inventory	19	This SAMA would create a back-up to main and AFW for SG water supply.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 169	N/A	N/A
171	Procure a portable diesel pump for isolation condenser make-up	19	This SAMA would provide a back-up to the city water supply and diesel FP system pump for isolation condenser make-up.	#1 - N/A	Robinson does not have an Isolation Condenser system.	Reference 20	N/A
172	Install an independent diesel generator for the CST make-up pumps	19	This SAMA would allow continued inventory make-up to the CST during an SBO.	#3 - Already implemented at Robinson	No auto-refill during SBO, but the diesel fire pump is available as a long-term supply to the AFW suction header in an SBO.	Reference 20	N/A
173	Change failure position of condenser make-up valve	19	This SAMA would allow greater inventory for the AFW pumps by preventing CST flow diversion to the condenser if the condenser make-up valve fails open on loss of air or power.	#3 - Already implemented at Robinson	CST is required to maintain sufficient inventory for 2 hours of AFW operation. Then, Service Water provides backup to AFW and is virtually an unlimited supply.	Reference 46	N/A
174	Create passive secondary side coolers.	19	This SAMA would reduce CDF from the loss of Feedwater by providing a passive heat removal loop with a condenser and heat sink.	#5 - Cost would be more than risk benefit	This SAMA would require major modifications to be made to the plant and the cost would far exceed the maximum averted cost-risk ($1,033,000).	Engineering judgement.	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
175	Replace current PORVs with larger ones such that only one is required for successful feed and bleed.	19	This SAMA would reduce the dependencies required for successful feed and bleed.	#6 - Retain	There are 2 PORVs and 3 SRVs for RCS pressure control. Section A.8.1.4 of the PSA system notebook requires 2 PORVs for successful feed and bleed per FRP-H.1.	Reference 23 (A.8)	6
176	Install motor-driven feedwater pump.	1 12	SAMA would increase the availability of injection subsequent to MSIV closure.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 168	N/A	N/A
177	Use Main FW pumps for a Loss of Heat Sink Event	20	This SAMA involves a procedural change that would allow for a faster response to loss of the secondary heat sink. Use of only the feedwater booster pumps for injection to the SGs requires depressurization to about 350 psig; before the time this pressure is reached, conditions would be met for initiating feed and bleed. Using the available turbine driven feedwater pumps to inject water into the SGs at a high pressure rather than using the feedwater booster alone allows injection without the time consuming depressurization.	#3 - Already implemented at Robinson	The "Response to Loss of Secondary Heat Sink" FRP #1 has been updated to direct use of the turbine driven feedwater pumps as the primary SG injection source.	Reference 69	N/A
Improvements in Core Cooling Systems							
178	Provide the capability for diesel driven, low pressure vessel make-up	19	This SAMA would provide an extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., FP system)	#5 - Cost would be more than risk benefit	Based on engineering judgement and similarities to SAMA 179, the installation of a new, diesel driven, low pressure injection system is judged to greatly exceed the maximum averted cost-risk ($1,033,000).	Engineering judgement, SAMA 179	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
179	Provide an additional HPSI pump with an independent diesel	19	This SAMA would reduce the frequency of core melt from small LOCA and SBO sequences	#5 - Cost would be more than risk benefit	The cost of implementation for this SAMA has been estimated to be between $5 and $10 million (Reference 19). This greatly exceeds the maximum averted cost-risk ($1,033,000).	Reference 19	N/A
180	Install an independent AC HPSI system	19	This SAMA would allow make-up and feed and bleed capabilities during an SBO.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 179	N/A	N/A
181	Create the ability to manually align ECCS recirculation	19	This SAMA would provide a back-up should automatic or remote operation fail.	#3 - Already implemented at Robinson	Actions for alignment to recirculation are currently manual controls.	Reference 28	N/A
182	Implement an RWT make-up procedure	19	This SAMA would decrease CDF from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR.	#6 - Retain	RNP has a RWST fill system at about 100 gpm.	N/A	7
183	Stop low pressure safety injection pumps earlier in medium or large LOCAs.	19	This SAMA would provide more time to perform recirculation swap over.	#3 - Already implemented at Robinson	Refer to EPP-9	EPP-9	N/A
184	Emphasize timely swap over in operator training.	19	This SAMA would reduce human error probability of recirculation failure.	#3 - Already implemented at Robinson	Currently addressed in training.	Reference 40	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
185	Upgrade Chemical and Volume Control System to mitigate small LOCAs.	19	For a plant like the AP600 where the Chemical and Volume Control System cannot mitigate a Small LOCA, an upgrade would decrease the Small LOCA CDF contribution.	#5 - Cost would be more than risk benefit.	Upgrading the CVCS to be capable of mitigating a small LOCA would require replacement of the CVCS pumps, piping, and power supply support. This is equivalent to installing a new HP injection system. Reference 17 estimates the cost of a new, passive HP system at $1.7 m. This is judged to be a lower bound for an active high-pressure system.	Reference 17.	N/A
186	Install an active HPSI system.	19	For a plant like the AP600 where an active HPSI system does not exist, this SAMA would add redundancy in HPSI.	#3 - Already implemented at Robinson	The charging pumps provide high pressure injection for Robinson.	Reference 22, Appendix A.18	N/A
187	Change "in-containment" RWT suction from 4 check valves to 2 check and 2 air operated valves.	19	This SAMA would remove common mode failure of all four injection paths.	#1 - N/A	Robinson does not have a pathway equivalent for which such a modification would provide a benefit.	Reference 20	N/A
188	Replace 2 of the 4 safety injection (SI) pumps with diesel-powered pumps.	19	This SAMA would reduce the SI system common cause failure probability. This SAMA was intended for the System 80+, which has four trains of SI.	#1 - N/A	This is a system 80+ specific issue. Robinson does not have 4 trains of SI.	Reference 20	N/A
189	Align low pressure core injection or core spray to the CST on loss of suppression pool cooling.	19	This SAMA would help to ensure low pressure ECCS can be maintained in loss of suppression pool cooling scenarios.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A
190	Raise high pressure core injection/reactor core isolation cooling backpressure trip setpoints	19	This SAMA would ensure high pressure core injection/reactor core isolation cooling availability when high suppression pool temperatures exist.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
191	Improve the reliability of the automatic depressurization system.	19	This SAMA would reduce the frequency of high pressure core damage sequences.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A
192	Disallow automatic vessel depressurization in non-ATWS scenarios	19	This SAMA would improve operator control of the plant.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A
193	Create automatic swap over to recirculation on RWT depletion	19	This SAMA would reduce the human error contribution from recirculation failure.	#6 - Retain	N/A	Reference 20	8
194	Proceduralize intermittent operation of HPCI.	1	SAMA would allow for extended duration of HPCI availability.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A
195	Increase available net positive suction head (NPSH) for injection pumps.	1	SAMA increases the probability that these pumps will be available to inject coolant into the vessel by increasing the available NPSH for the injection pumps.	#5 - Cost would be more than risk benefit	Requires major plant modifications such as new RHR pumps, moving the RHR pumps, a new sump design, or a larger RWST (only applicable for injection phase). The cost of these changes would exceed the maximum averted cost-risk ($1,033,000).	Engineering judgement.	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
196	Modify Reactor Water Cleanup (RWCU) for use as a decay heat removal system and proceduralize use.	1	SAMA would provide an additional source of decay heat removal.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. An "equivalent" system, the Chemical and Volume Control System, is already used in a heat removal process at Robinson. Any modifications to further enhance the DHR ability of the system would likely cost more than the maximum averted cost-risk for the plant. Screened from further analysis.	Reference 20	N/A
197	CRD Injection	14 16	SAMA would supply an additional method of level restoration by using a non-safety system.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A
198	Condensate Pumps for Injection	14 16	SAMA to provide an additional option for coolant injection when other systems are unavailable or inadequate	#3 - Already implemented at Robinson	Robinson allows injection to the SGs with the condensate pumps when depressurized to about 600 psi.	References 20 and 69	N/A
199	Align EDG to CRD for Injection	14 16	SAMA to provide power to an additional injection source during loss of power events	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
200	Re-open MSIVs	14 16	SAMA to regain the main condenser as a heat sink by re-opening the MSIVs.	#1 - N/A	This is a long-term issue and will have no impact on LERF. PSA model credits use of steam dumps for transients. SG PORVs or safeties provide a reliable method to reject heat from the secondary side.	Reference 20	N/A
201	Bypass RCIC Turbine Exhaust Pressure Trip	14 16	SAMA would allow RCIC to operate longer.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A
202	2.a. Passive High Pressure System	17	SAMA will improve prevention of core melt sequences by providing additional high pressure capability to remove decay heat through an isolation condenser type system	#5 - Cost would be more than risk benefit	The cost of this enhancement has been estimated to be $1.7 million in Reference 17. This is greater than the maximum averted cost-risk ($1,033,000).	Reference 17	N/A
203	2.c. Suppression Pool Jockey Pump	17	SAMA will improve prevention of core melt sequences by providing a small makeup pump to provide low pressure decay heat removal from the RPV using the suppression pool as a source of water.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A
204	2.d. Improved High Pressure Systems	17	SAMA will improve prevention of core melt sequences by improving reliability of high pressure capability to remove decay heat.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 179, 180, 186, 202, 205	N/A	N/A
205	2.e. Additional Active High Pressure System	17	SAMA will improve reliability of high pressure decay heat removal by adding an additional system.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 179, 180, 186, 202	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
206	2.f. Improved Low Pressure System (Firepump)	17	SAMA would provide fire protection system pump(s) for use in low pressure scenarios.	#4 - No significant safety benefit	This is directed at BWRs. Injection of non-borated lake water into the PWR primary system would inject positive reactivity.	N/A	N/A
207	4.b. CUW Decay Heat Removal	17	This SAMA provides a means for Alternate Decay Heat Removal.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 196. The CUW system in ABWR is equivalent to the RWCU system.	N/A	N/A
208	4.c. High Flow Suppression Pool Cooling	17	SAMA would improve suppression pool cooling.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A
209	8.c. Diverse Injection System	17	SAMA will improve prevention of core melt sequences by providing additional injection capabilities.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 178, 179, 180, 186, 202, 205, 206	N/A	N/A
210	Alternate Charging Pump Cooling	20	This SAMA will improve the high pressure core flooding capabilities by providing the SI pumps with alternate gear and oil cooling sources. Given a total loss of Chilled Water, abnormal operating procedures would direct alignment of preferred Demineralized Water or the Fire System to the Chilled Water System to provide cooling to the SI pumps' gear and oil box (and the other normal loads).	#3 - Already implemented at Robinson	An abnormal operating procedure (AOP-022) has been implemented at Robinson to direct alignment of alternate cooling to the SI pumps on loss of the normal supply.	References 20 and 80	N/A
211	Not Used.						

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
Instrument Air/Gas Improvements							
212	Modify EOPs for ability to align diesel power to more air compressors.	19	For plants that do not have diesel power to all normal and back-up air compressors, this change would increase the reliability of IA after a LOOP.	#3 - Already implemented at Robinson	Ability exists to feed A and B air compressors from ESF busses.	Reference 34	N/A
213	Replace old air compressors with more reliable ones	19	This SAMA would improve reliability and increase availability of the IA compressors.	#3 - Already implemented at Robinson	C air compressor has been replaced with D, and primary AC has been replaced.	Plant modifications	N/A
214	Install nitrogen bottles as a back-up gas supply for safety relief valves.	19	This SAMA would extend operation of safety relief valves during an SBO and loss of air events (BWRs).	#3 - Already implemented at Robinson	Pressurizer PORVs are on a hard-piped nitrogen system with gas bottle backup, capable of air backup. Secondary PORVs are air with nitrogen backup.	Reference 36 and Reference 37	N/A
215	Allow cross connection of uninterruptable compressed air supply to opposite unit.	12 13	SAMA would increase the ability to vent containment using the hardened vent.	#1 - N/A	Robinson is not a multi-unit site; screened from further analysis.	Reference 20	N/A
216	Not Used						
ATWS Mitigation							
217	Install MG set trip breakers in control room	19	This SAMA would provide trip breakers for the MG sets in the control room. In some plants, MG set breaker trip requires action to be taken outside of the control room. Adding control capability to the control room would reduce the trip failure probability in sequences where immediate action is required (e.g., ATWS).	#4 - No significant safety benefit	Providing a switch in the Main Control Room to allow timely operation of the MG Set breakers during an ATWS would improve the reliability of a successful manual reactor trip. However, the accident sequences requiring this action are below the truncation limit of the model and are not included in the cutsets. No measurable benefit would be gained from this change.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
218	Add capability to remove power from the bus powering the control rods	19	This SAMA would decrease the time to insert the control rods if the reactor trip breakers fail (during a loss of FW ATWS which has a rapid pressure excursion)	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 217	N/A	N/A
219	Create cross-connect ability for standby liquid control trains	19	This SAMA would improve reliability for boron injection during an ATWS event.	#1 - N/A	This is a BWR issue; PWRs have diverse means of injecting borated water into the RCS during an ATWS.	Reference 20	N/A
220	Create an alternate boron injection capability (back-up to standby liquid control)	19	This SAMA would improve reliability for boron injection during an ATWS event.	#1 - N/A	This is a BWR issue; PWRs have diverse means of injecting borated water into the RCS during an ATWS.	Reference 20	N/A
221	Remove or allow override of low pressure core injection during an ATWS	19	On failure on high pressure core injection and condensate, some plants direct reactor depressurization followed by 5 minutes of low pressure core injection. This SAMA would allow control of low pressure core injection immediately.	#1 - N/A	This is a BWR issue. PWRs do not implement the same logic for governing low pressure injection that is used in BWRs.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
222	Install a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	19	This SAMA would improve equipment availability after an ATWS.	#3 - Already implemented at Robinson	Robinson meets the requirements of 10CFR50.62 by use of AMSAC (ATWS Mitigation System Actuation Circuitry) as described in UFSAR Section 7.8. This is considered to address the potential for overpressurization by providing a diverse, automatic system to shut down the reactor and initiate Emergency Feedwater Flow to the SGs given ATWS conditions.	Reference 38	N/A
223	Create a boron injection system to back up the mechanical control rods.	19	This SAMA would provide a redundant means to shut down the reactor.	#3 - Already implemented at Robinson	Robinson already has the capability for injection from the RWST and the boric acid tanks.	Reference 20	N/A
224	Provide an additional instrument system for ATWS mitigation (e.g., ATWS mitigation scram actuation circuitry).	19	This SAMA would improve instrument and control redundancy and reduce the ATWS frequency.	#3 - Already implemented at Robinson	Refer to SAMA 222	N/A	N/A
225	Increase the safety relief valve (SRV) reseat reliability.	1	SAMA addresses the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A
226	Use control rod drive (CRD) for alternate boron injection.	1 14	SAMA provides an additional system to address ATWS with SLC failure or unavailability.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
227	Bypass MSIV isolation in Turbine Trip ATWS scenarios	14	SAMA will afford operators more time to perform actions. The discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower human error probabilities	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A
228	Enhance operator actions during ATWS	14	SAMA will reduce human error probabilities during ATWS	#3 - Already implemented at Robinson	Extensive training is already performed.	Reference 40	N/A
229	Guard against SLC dilution	14 16	SAMA to control vessel injection to prevent boron loss or dilution following SLC injection.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A
230	11.a. ATWS Sized Vent	17	This SAMA would be provide the ability to remove reactor heat from ATWS events.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 39	N/A	N/A
231	11.b. Improved ATWS Capability	17	This SAMA includes items which reduce the contribution of ATWS to core damage and release frequencies.	#2 - Similar item is addressed under other proposed SAMAs	Addressed by SAMAs 222, 223, 224	N/A	N/A
Other Improvements							
232	Provide capability for remote operation of secondary side relief valves in an SBO	19	Manual operation of these valves is required in an SBO scenario. High area temperatures may be encountered in this case (no ventilation to main steam areas), and remote operation could improve success probability.	#3 - Already implemented at Robinson	Valves are located outside with their controls located at a distance.	Reference 25	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
233	Create/enhance RCS depressurization ability	19	With either a new depressurization system, or with existing PORVs, head vents, and secondary side valve, RCS depressurization would allow earlier low pressure ECCS injection. Even if core damage occurs, low RCS pressure would alleviate some concerns about high pressure melt ejection.	#5 - Cost would be more than risk benefit	Reference 19 estimates the cost of this SAMA to range between $500,000 and $4.6 million. For Robinson, more effective depressurization capabilities would require significant hardware changes and/or additions on top of the analysis that would be required to implement the change. The cost estimate for the modification is considered to be on the high end of the range provided in Reference 19. The cost of implementation for this SAMA is judged to greatly exceed the maximum averted cost-risk ($1,033,000).	Reference 19, engineering judgement	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
234	Make procedural changes only for the RCS depressurization option	19	This SAMA would reduce RCS pressure without the cost of a new system	#3 - Already implemented at Robinson	RCS depressurization has been enhanced at Robinson through the implementation of procedural revisions (in the EOP for "Response to Loss of Secondary heat Sink") that move critical depressurization steps so that they will be performed earlier in the accident. These steps direct the operators to re-energize any pressurizer PORV block valves that were closed and racked-out to isolate a leaking PORV. This change will allow the operators more time to prepare for feed and bleed before total loss of the secondary heat sink.	Reference 39	N/A
235	Defeat 100 percent load rejection capability.	19	This SAMA would eliminate the possibility of a stuck open PORV after a LOOP, since PORV opening would not be needed.	#1 - N/A	The PORVs are included on the pressurizer, in part, to prevent overpressurization. It is judged that the defeating this function would be more detrimental than beneficial. RNP does not currently have 100 percent load rejection.	Reference 36 and Reference 38	N/A
236	Change control rod drive flow CV failure position	19	Change failure position to the "fail-safest" position.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	Reference 20	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
237	Install secondary side guard pipes up to the MSIVs	19	This SAMA would prevent secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. This SAMA would also guard against or prevent consequential multiple SGTR following a Main Steam Line Break event.	#5 - Cost would be more than risk benefit	The RNP PSA concluded that the frequency of steam line breaks upstream of the MSIVs was sufficiently small, when compared to other faults, to be excluded from consideration. Multiple SGTRs are not analyzed in the RNP PSA.	Reference 52	N/A
238	Install digital large break LOCA protection	19	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (leak before break).	#3 - Already implemented at Robinson	Existence of leakage from RCS to the containment is detected by several methods outlined in UFSAR.	Reference 43	N/A
239	Increase seismic capacity of the plant to a high confidence, low pressure failure of twice the Safe Shutdown Earthquake.	19	This SAMA would reduce seismically - induced CDF.	#9 - IPEEE	Seismic issues were examined in the Robinson IPEEE and the cost-effective means of reducing plant risk were implemented as part of the program. This SAMA was considered in the System 80+ original design submittal and is not applicable to an existing plant.	Reference 21	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
240	Enhance the reliability of the demineralized water (DW) make-up system through the addition of diesel-backed power to one or both of the DW make-up pumps.	19	Inventory loss due to normal leakage can result in the failure of the CC and the SRW systems. Loss of CC could challenge the RCP seals. Loss of SRW results in the loss of three EDGs and the containment air coolers (CACs).	#1 - N/A	Loss of CCW doesn't result in RCP seal challenge for RNP. Note: DW and SW are not connected. Normal leakage from CCW is low and makeup infrequently required. Also, makeup to CCW is from Primary Water system; DW is the alternate. Control is local manual. This SAMA would have limited benefit.	Reference 23 (A.10)	N/A
241	Increase the reliability of safety relief valves by adding signals to open them automatically.	12	SAMA reduces the probability of a certain type of medium break LOCA. Hatch evaluated medium LOCA initiated by an MSIV closure transient with a failure of SRVs to open. Reducing the likelihood of the failure for SRVs to open, subsequently reduces the occurrence of this medium LOCA.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	N/A	N/A
242	Reduce DC dependency between high-pressure injection system and ADS.	1	SAMA would ensure containment depressurization and high-pressure injection upon a DC failure.	#1 - N/A	This is a BWR issue not applicable to the Robinson design. Screened from further analysis.	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
243	Increase seismic ruggedness of plant components.	11 13 14	SAMA would increase the availability of necessary plant equipment during and after seismic events.	#9 - IPEEE	Seismic issues were examined in the Robinson IPEEE and the cost-effective means of reducing plant risk were implemented as part of the program. This SAMA was considered in the System 80+ original design submittal and is not applicable to an existing plant.	Reference 21	N/A
244	Enhance RPV depressurization capability	14 15	SAMA would decrease the likelihood of core damage in loss of high pressure coolant injection scenarios	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 233	N/A	N/A
245	Enhance RPV depressurization procedures	14 15	SAMA would decrease the likelihood of core damage in loss of high pressure coolant injection scenarios	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 234	N/A	N/A
246	Replace mercury switches on fire protection systems	14	SAMA would decrease the probability of spurious fire suppression system actuation given a seismic event.	#9 - IPEEE	Seismic issues were examined in the Robinson IPEEE and the cost-effective means of reducing plant risk were implemented as part of the program.	Reference 21	N/A
247	Provide additional restraints for CO_2 tanks	14	SAMA would increase availability of fire protection given a seismic event.	#9 - IPEEE	Seismic issues were examined in the Robinson IPEEE and the cost-effective means of reducing plant risk were implemented as part of the program.	Reference 21	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
248	Enhance control of transient combustibles	14	SAMA would minimize risk associated with important fire areas.	#9 - IPEEE	Fire issues were examined in the Robinson IPEEE and the cost-effective means of reducing plant risk were implemented as part of the program.	Reference 21	N/A
249	Enhance fire brigade awareness	14	SAMA would minimize risk associated with important fire areas.	#9 - IPEEE	Fire issues were examined in the Robinson IPEEE and the cost-effective means of reducing plant risk were implemented as part of the program.	Reference 21	N/A
250	Upgrade fire compartment barriers	14	SAMA would minimize risk associated with important fire areas.	#9 - IPEEE	Fire issues were examined in the Robinson IPEEE and the cost-effective means of reducing plant risk were implemented as part of the program.	Reference 21	N/A
251	Enhance procedures to allow specific operator actions	14	SAMA would minimize risk associated with important fire areas.	#9 - IPEEE	Fire issues were examined in the Robinson IPEEE and the cost-effective means of reducing plant risk were implemented as part of the program.	Reference 21	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
252	Develop procedures for transportation and nearby facility accidents	14	SAMA would minimize risk associated with transportation and nearby facility accidents.	#4 - No significant safety benefit	Special event procedures may be pursued, but the contribution from these events is considered to be low and not risk significant. The IPEEE addressed these types of accidents and generally concluded that they did not impact the CDF.	Reference 21	N/A
253	Enhance procedures to mitigate Large LOCA	14	SAMA would minimize risk associated with Large LOCA	#3 - Already implemented at Robinson	EPP-9 currently addresses this.	EPP-9	N/A
254	1.b. Computer Aided Instrumentation	17, 20	SAMA will improve prevention of core melt sequences by making operator actions more reliable.	#3 - Already implemented at Robinson	SPDS provides graphic control room indication of critical system operability based on a variety of digital and analog inputs. This system is integrated with the plant computer and is used to provide operators with plant data in an easy to use format.	Reference 71	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
255	1.c/d. Improved Maintenance Procedures/Manuals	17	SAMA will improve prevention of core melt sequences by increasing reliability of important equipment	#3 - Already implemented at Robinson	The maintenance rule has been implemented in the industry. Root cause analysis is required as part of this program and will result in procedure enhancements to improve equipment reliability where they are necessary and where they will be effective in reducing maintenance errors.	Engineering judgement, 10 CFR 50.65	N/A
256	1.e. Improved Accident Management Instrumentation	17	SAMA will improve prevention of core melt sequences by making operator actions more reliable.	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 254	N/A	N/A
257	1.f. Remote Shutdown Station	17		#3 - Already implemented at Robinson	Robinson has procedures for remote shutdown and remote shutdown stations.	Reference 44 and 45	N/A
258	1.g. Security System	17, 20	Improvements in the site's security system would decrease the potential for successful sabotage.	#1 - N/A to SAMA evaluation	Sabotage is not included in the PSA model.	N/A	N/A
259	2.b. Improved Depressurization	17	SAMA will improve depressurization system to allow more reliable access to low pressure systems.	#2 - Similar item is addressed under other proposed SAMAs	Addressed in SAMAs 237, 240 and 241	N/A	N/A
260	2.h. Safety Related Condensate Storage Tank	17	SAMA will improve availability of CST following a Seismic event	#2 - Similar item is addressed under other proposed SAMAs	See SAMA 164	N/A	N/A

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
261	4.d. Passive Overpressure Relief	17		#3 - Already implemented at Robinson	Safety valves are installed.	Reference 23	N/A
262	8.b. Improved Operating Response	17		#3 - Already implemented at Robinson	The development of enhanced procedures combined with simulator training at Robinson is judged to address this issue.	Engineering judgement.	N/A
263	8.d. Operation Experience Feedback	17		#3 - Already implemented at Robinson	The Maintenance Rule requires tracking component performance. This issue is judged to be addressed by the Maintenance Rule.	Engineering judgement, 10 CFR 50.65	N/A
264	8.e. Improved SRV Design	17	This SAMA would improve SRV reliability, thus increasing the likelihood that sequences could be mitigated using low pressure heat removal.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 221, 237	N/A	N/A
265	12.a. Increased Seismic Margins	17	This SAMA would reduce the risk of core damage and release during seismic events.	#2 - Similar item is addressed under other proposed SAMAs	See SAMAs 111, 239	N/A	N/A
266	13.b. System Simplification	17	This SAMA is intended to address system simplification by the elimination of unnecessary interlocks, automatic initiation of manual actions or redundancy as a means to reduce overall plant risk.	#2 - Similar item is addressed under other proposed SAMAs	Addressed by SAMAs 13, 107, 113, 146, 194, 237, 238	N/A	N/A
267	Train operations crew for response to inadvertent actuation signals	19	This SAMA would improve chances of a successful response to the loss of two 120V AC buses, which may cause inadvertent signal generation.	#6 - Retain	N/A	N/A	9

TABLE F-8
PHASE I SAMA (Cont'd)

Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Screening Criteria	Disposition	Disposition Reference	Phase II SAMA ID number
268	Install tornado protection on gas turbine generators	19	This SAMA would improve onsite AC power reliability.	#9 - IPEEE	The Robinson IPEEE addressed the potential impact caused by tornadoes and high winds. The conclusion was that the plant could withstand the effects of the design tornado without endangering the health and safety of the public.	Reference 21	N/A

TABLE F-9
PHASE II SAMA

Phase II SAMA ID number	Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Potential Cost	Comment	Phase 2 Disposition
1	16	Prevent centrifugal charging pump flow diversion from the relief valves.	1	SAMA modification would reduce the frequency of the loss of RCP seal cooling if relief valve opening causes a flow diversion large enough to prevent RCP seal injection.	Not Required	While the flow diversion through a relief valve failure mode is not directly modeled in the RNP PSA, it is considered to be subsumed by the event for common cause failure of charging pump seal injection (JCCFICVABC). The maximum possible risk reduction for this SAMA was obtained by setting JCCFICVABC to zero. This action had no impact on the calculated CDF or on the LERF cutsets. Therefore, this SAMA has no impact on calculated risk.	Not cost beneficial See Section F.6.1

TABLE F-9
PHASE II SAMA (Cont'd)

Phase II SAMA ID number	Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Potential Cost	Comment	Phase 2 Disposition
2	22	Improved ability to cool the residual heat removal heat exchangers.	1	SAMA would reduce the probability of a loss of decay heat removal by implementing procedure and hardware modifications to allow manual alignment of the fire protection system or by installing a component cooling water cross-tie.	Not Required	The failure to supply cooling to the RHR heat exchangers is dominated by the operator action for CCW alignment. Failure of the operator to align one cooling source greatly limits the probability of successfully performing what is essentially the same action using another source of water (i.e., the level of dependence between the actions is defined as "high" or "complete"). Thus, modifications that would allow a physically independent system, such as Fire Water, to be aligned for RHR heat exchanger cooling would provide minimal benefit. The averted cost-risk for this SAMA is negligible and this candidate is screened from further review.	Not Cost Beneficial See Section F.6.2

TABLE F-9
PHASE II SAMA (Cont'd)

Phase II SAMA ID number	Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Potential Cost	Comment	Phase 2 Disposition
3	140	Increase frequency for valve leak testing.	1	SAMA could reduce ISLOCA frequency.	$50,000	To calculate the maximum possible impact of this SAMA, initiating event percent ISLOCA (INTERFACING SYSTEMS LOCA OCCURS OUTSIDE CONTAINMENT) was set to zero. This is the equivalent of assuming that every potential ISLOCA could be prevented by increasing the frequency of valve leak testing. This resulted in a 3 percent reduction in CDF.	Cost Beneficial See Section F.6.3
4	148	Improved MSIV Design	17		Not Required	There are six basic events associated with the RNP MSIVs. Each of the three MSIVs has one basic event for its failure to close on demand and one basic event for transferring closed during operation. To calculate the maximum possible impact of this SAMA, all six of these basic events were set to zero. This is the equivalent of assuming that the new MSIVs would be perfectly reliable. This resulted in no impact to CDF or LERF.	Not Cost Beneficial See Section F.6.4

TABLE F-9
PHASE II SAMA (Cont'd)

Phase II SAMA ID number	Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Potential Cost	Comment	Phase 2 Disposition
5	159	Install a digital feedwater upgrade.	1	This SAMA would reduce the chance of a loss of main feedwater.	Not Required	One of the purposes of installing a digital feedwater control system would be to increase the reliability / availability of main feedwater. To calculate the maximum possible impact of this SAMA, initiating events percent T4 (LOSS OF MAIN FEEDWATER) and percent T4A (PARTIAL LOSS OF MAIN FEEDWATER) were set to zero. This is the equivalent of assuming that the new digital control system perfectly controlled main feedwater at all times. This resulted in a 4.2 percent reduction in CDF.	Not Cost Beneficial See Section F.6.5
6	175	Replace current PORVs with larger ones such that only one is required for successful feed and bleed.	19	This SAMA would reduce the dependencies required for successful feed and bleed.	Not Required	There are 2 PORVs and 3 SRVs for RCS pressure control. Two 2 PORVs are required for successful feed and bleed. Gate R3000 (1 OF 2 PORV S FAIL TO OPEN MANUALLY) was replaced with gate R2000 (2 OF 2 PORVs FAIL TO OPEN MANUALLY) at gate #TH (EVENT H - FAILURE OF PRIMARY BLEED) to simulate the implementation of this SAMA. The result was a 2.1 percent reduction in CDF.	Not Cost Beneficial See Section F.6.6

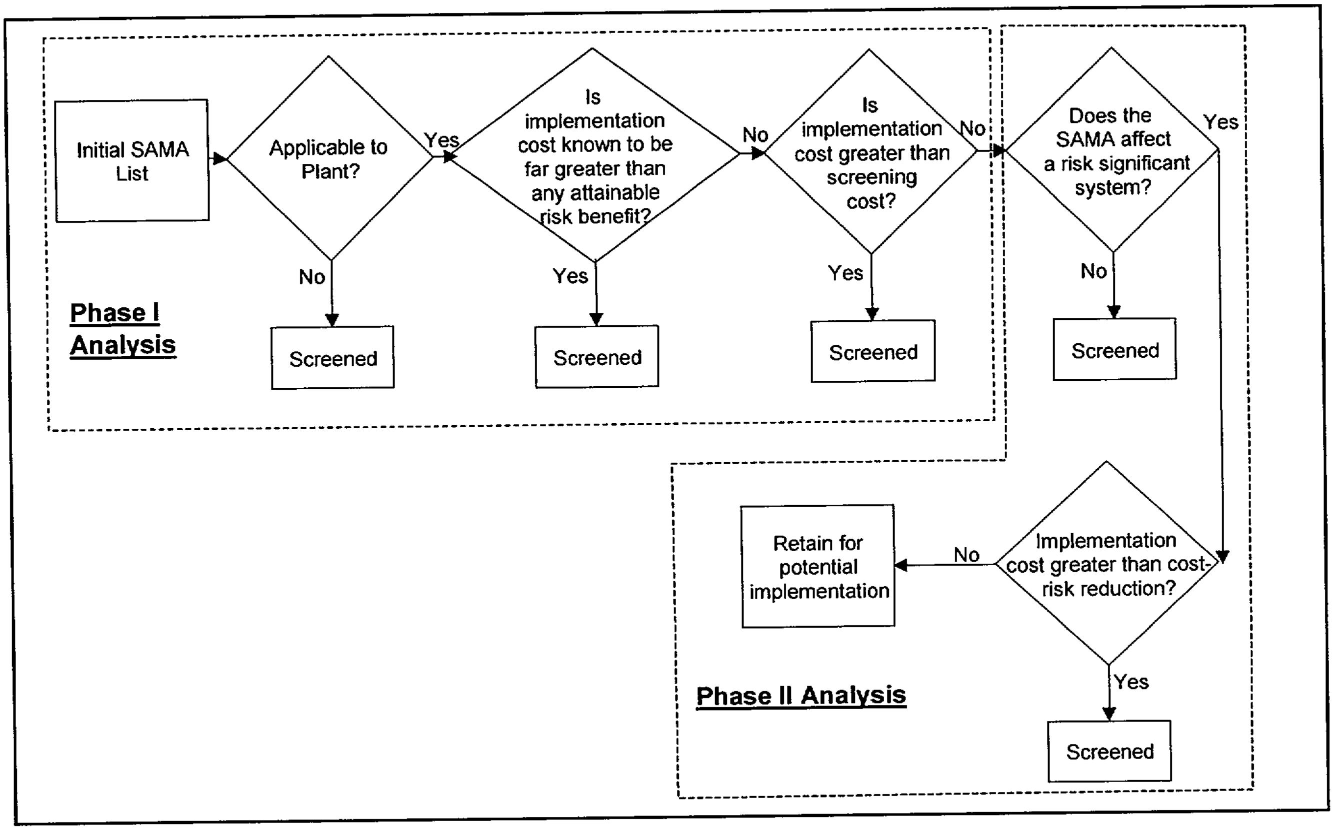
TABLE F-9
PHASE II SAMA (Cont'd)

Phase II SAMA ID number	Phase I SAMA ID number	SAMA title	Source Reference of SAMA	Result of potential enhancement	Potential Cost	Comment	Phase 2 Disposition
7	182	Implement an RWST make-up procedure	19	This SAMA would decrease CDF from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR.	$50,000	RNP has a RWST fill system at about 100 gpm. Use of this system is credited for appropriate late core damage sequences. R-RWST (RECOVERY OF FAILURE TO REFILL THE RWST FOR LATE SEQUENCES) was set to zero to simulate implementation of this SAMA. The result was a 0.7 percent reduction in CDF.	Not Cost Beneficial See Section F.6.7
8	193	Create automatic swap over to recirculation on RWT depletion.	19	This SAMA would reduce the human error contribution from recirculation failure.	$264,750	The implementation of this SAMA is estimated to yield an averted cost-risk of $58,885.	Not Cost Beneficial See Section F.6.8
9	267	Train operations crew for response to inadvertent actuation signals	19	This SAMA would improve chances of a successful response to the loss of two 120V AC buses, which may cause inadvertent signal generation.	Not Required	The only scenarios in the RNP PSA that would cause a simultaneous failure of two instrument buses are the common cause failure events for Instrument Buses 1 and 4 (CCCF1&4BUS) and Instrument Buses 2 and 3 (CCCF2&3BUS). To simulate the implementation of this SAMA, these two common cause events were set to zero. This resulted in no reduction of CDF or LERF.	Not Cost Beneficial See Section F.6.9

Notes to Table F-8

#1	Not applicable to the RNP Design
#2	Similar item is addressed under other proposed SAMAs
#3	Already implemented at Robinson
#4	No significant safety benefit associated with the systems / items associated with this SAMA
#5	The cost of implementation is greater than the cost-risk averted for the plant change or modification
#6	Retain
#7	Requested additional information from Robinson
#8	ABWR design issue; not practical
#9	IPEEE

FIGURE F-1
SAMA SCREENING PROCESS



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