Vogtle Electric Generating Plant
Units 1 and 2
License Renewal Application Environmental Report

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Applicant's Environmental Report
Operating License Renewal Stage

for

Vogtle Electric Generating Plant
Units 1 and 2

Southern Nuclear Operating Company

Docket No. 50-424
License No. NPF-068

and

Docket No. 50-425
License No. NPF-081

June 2007

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ACRONYMS AND ABBREVIATIONS

AADT	Annual Average Daily Traffic
ANS	Academy of Natural Sciences of Philadelphia
APPA	American Public Power Association
AQCR	Air Quality Control Region
Btu	British Thermal Unit
°C	degrees Celsius
CDF	Core damage frequency
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
cfs	cubic feet per second
CO	Carbon monoxide
CWA	Clean Water Act
DOE	Department of Energy
DSM	Demand-side management
DOT	Department of Transportation
EIS	Environmental Impact Statement
EO	Executive Order
EPA	U.S. Environmental Protection Agency
EPD	Environmental Protection Division
EPP	Environmental Protection Plan
ER	Environmental report
ESA	Endangered Species Act
ESP	Early Site Permit
°F	degrees Fahrenheit
FBC	fluidized bed combustion
FES	Final Environmental Statement
FR	Federal Register
FSAR	Final Safety Analysis Report
GDNR	Georgia Department of Natural Resources
GDOT	Georgia Department of Transportation
GE	General Electric
GEIS	Generic Environmental Impact Statement for License Renewal of Nuclear Plants
GIS	Geographic information systems
GPC	Georgia Power Company
gpm	gallons per minute

GPS	Global Positioning System
GPSC	Georgia Public Service Commission
IGCC	Integrated Gasification Combined Cycle
IPA	Integrated Plant Assessment
IPE	Individual plant examination
IPEEE	Individual plant external event examination
ISLOCA	Interfacing System Loss of Cooling Accident
ISO	International Standards Organization
kV	kilovolt
kWh	Kilowatt hours
LLC	Limited Liability Company
LOS	Level of Service
LOSP	loss of offsite power
MACCS	MELCOR Accident Consequences Code System
MGD	Million gallons per day
MM	million
MSA	Metropolitan Statistical Area
MSL	Mean sea level
MW	Megawatt
MWe	Megawatts-electric
MWt	Megawatts-thermal
NA	Not applicable
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NESC	National Electrical Safety Code
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxides
NO_2	nitrogen dioxide
NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
O_3	Ozone
RIMS II	Regional Input-Output Modeling System
Pb	lead
PM_{10}	particulates with diameters less than 10 microns
$PM_{2.5}$	particulates with diameters less than 2.5 microns

PRA	probabilistic risk assessment
PWR	Pressurized water reactors
SAMA	Severe Accident Mitigation Alternatives
SCDNR	South Carolina Department of Natural Resources
SCE&G	South Carolina Electric and Gas [Company]
SCR	Selective catalytic reduction
SHPO	State Historic Preservation Officer
SIP	State Implementation Plan
SMITTR	surveillance, monitoring, inspections, testing, trending, and recordkeeping
SNC	Southern Nuclear Operating Company
SO_2	sulfur dioxide
SO_x	sulfur oxides
SPLOST	Special Purpose Local Option Sales Tax
SRS	Savannah River Site
TCS	Traffic count sections
TSC	Technical Support Center
TSP	total suspended particulates
USACE	U.S. Army Corps of Engineers
USCB	U.S. Census Bureau
USFWS	U.S. Fish and Wildlife Service
VA	Veteran's Administration
VEGP	Vogtle Electric Generating Plant
WHC	Wildlife Habitat Council
WINGS	Wildlife Incentives for Non-game and Game Species
WMA	Wildlife Management Area
WSRC	Westinghouse Savannah River Company

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Chapter 1 Introduction

1.1 Purpose of and Need for Action

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants in accordance with the Atomic Energy Act of 1954, as amended, and NRC implementing regulations. Southern Nuclear Operating Company, (SNC) operates the Vogtle Electric Generating Plant (VEGP) Units 1 and 2, pursuant to NRC Operating Licenses NPF-068 and NPF-081, respectively. The license for Unit 1 will expire January 16, 2027 and the license for Unit 2 will expire February 9, 2029. The Unit 2 license will not expire within the 20-year period designated in the License Renewal Rule; therefore, SNC filed for and received exemption by letter from the NRC dated January 9, 2007 (Docket No. 50-425) that supports the early renewal of the Unit 2 license. SNC has prepared this environmental report in conjunction with its application to NRC to renew the VEGP operating licenses, as provided by the following NRC regulations:

> Title 10, "Energy", Code of Federal Regulations (CFR), Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants", Section 54.23, Contents of Application-Environmental Information (10 CFR 54.23) and
>
> Title 10, "Energy", CFR, Part 51, "Environmental Protection Requirements for Domestic Licensing and Related Regulatory Functions", Section 51.53, "Post construction Environmental Reports", Subsection 51.53(c), "Operating License Renewal Stage" [10 CFR 51.53(c)].

The NRC has defined the purpose and need for the proposed action, the renewal of the operating license for nuclear power plants such as VEGP, as follows:

> "...The purpose and need for the proposed action (renewal of an operating license) is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs, as such needs may be determined by State, utility, and, where authorized, Federal (other than NRC) decision makers." (NRC 1996a)

The renewed operating licenses would allow an additional 20 years of plant operation beyond the current VEGP licensed operating period of 40 years. SNC has applied to the NRC for an Early Site Permit (ESP) which would allow SNC to construct two additional nuclear units at VEGP. The impacts of renewing the licenses of the existing units on the new units and the cumulative impacts of four units are evaluated in the ESP application.

1.2 Environmental Report Scope and Methodology

NRC regulations for domestic licensing of nuclear power plants require environmental review of applications to renew operating licenses. The NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit with its application a separate document entitled "Applicant's Environmental Report - Operating License Renewal Stage". In determining what information to include in the VEGP Environmental Report, SNC has relied on NRC regulations and the following supporting documents which provide additional insight into the regulatory requirements:

- NRC supplemental information in the Federal Register (NRC 1996a, 1996b, 1996c, and 1999a)
- Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996d,1999b)
- Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses (NRC 1996e)
- Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response (NRC 1996f)
- Standard Review Plans for Environmental Reviews for Nuclear Power Plants (NRC 1999c)

SNC has prepared Table 1.2-1 to verify conformance with regulatory requirements. Table 1.2-1 indicates the sections of the ER that correspond to each requirement of 10 CFR 51.53(c).

Table 1.2-1. Environmental Report Responses to License Renewal Environmental Regulatory Requirements

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(1)		Entire Document
10 CFR 51.53(c)(2), Sentences 1 and 2	3.0	Proposed Action
10 CFR 51.53(c)(2), Sentence 3	7.2.2	Environmental Impacts of Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(1)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	7.0	Alternatives to the Proposed Action
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	6.5	Short-Term Use Versus Long-Term Productivity of the Environment
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	6.4	Irreversible and Irretrievable Resource Commitments
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
	6.2	Mitigation
	7.2.2	Environmental Impacts of Alternatives
	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	9.0	Status of Compliance
10 CFR 51.53(c)(2) and 10 CFR 51.45(e)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(3)(ii)(A)	4.1	Water Use Conflicts (Plants with Cooling Ponds or Cooling Towers Using Makeup Water from a Small River with Low Flow)
10 CFR 51.53(c)(3)(ii)(A)	4.6	Groundwater Use Conflicts (Plants Using Cooling Water Towers or Cooling Ponds and Withdrawing Makeup Water from a Small River)
10 CFR 51.53(c)(3)(ii)(B)	4.2	Entrainment of Fish and Shellfish in Early Life Stages
10 CFR 51.53(c)(3)(ii)(B)	4.3	Impingement of Fish and Shellfish

Table 1.2-1. (cont'd) Environmental Report Responses to License Renewal Environmental Regulatory Requirements

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(3)(ii)(B)	4.4	Heat Shock
10 CFR 51.53(c)(3)(ii)(C)	4.5	Groundwater Use Conflicts (Plants Using >100 gpm of Groundwater)
10 CFR 51.53(c)(3)(ii)(C)	4.7	Groundwater Use Conflicts (Plants Using Ranney Wells)
10 CFR 51.53(c)(3)(ii)(D)	4.8	Degradation of Groundwater Quality
10 CFR 51.53(c)(3)(ii)(E)	4.9	Impacts of Refurbishment on Terrestrial Resources
	4.10	Threatened or Endangered Species
10 CFR 51.53(c)(3)(ii)(F)	4.11	Air Quality During Refurbishment (Non-Attainment Areas)
10 CFR 51.53(c)(3)(ii)(G)	4.12	Microbiological Organisms
10 CFR 51.53(c)(3)(ii)(H)	4.13	Electric Shock from Transmission-Line-Induced Currents
10 CFR 51.53(c)(3)(ii)(I)	4.14	Housing Impacts
10 CFR 51.53(c)(3)(ii)(I)	4.15	Public Utilities: Public Water Supply Availability
10 CFR 51.53(c)(3)(ii)(I)	4.16	Education Impacts from Refurbishment
10 CFR 51.53(c)(3)(ii)(I)	4.17	Offsite Land Use
10 CFR 51.53(c)(3)(ii)(J)	4.18	Transportation
10 CFR 51.53(c)(3)(ii)(K)	4.19	Historic and Archeological Resources
10 CFR 51.53(c)(3)(ii)(L)	4.20	Severe Accident Mitigation Alternatives
10 CFR 51.53(c)(3)(iii)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(3)(iii)	6.2	Mitigation
10 CFR 51.53(c)(3)(iv)	5.0	Assessment of New and Significant Information
10 CFR 51, Appendix B, Table B-1, Footnote 6	2.6.2	Environmental Justice

1.3 Vogtle Electric Generating Plant Licensee and Ownership

Ownership of VEGP Units 1 and 2 is shared by Georgia Power Company (GPC) (45.7 percent), Oglethorpe Power Corporation (30 percent), Municipal Electric Authority of Georgia (22.7 percent), and the City of Dalton, a municipality in the state of Georgia, doing business by and through the Water, Light and Sinking Fund Board of Commissioners (Dalton Utilities, 1.6 percent). GPC is one of the electric utilities owned by the Southern Company, one of the largest producers of electricity in the United States. SNC is the subsidiary of Southern Company that operates Southern Company's three nuclear sites. SNC is the NRC licensee for VEGP and will submit the VEGP license renewal application to the NRC.

1.4 References

(NRC 1996a) U.S. Nuclear Regulatory Commission. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." Federal Register. Vol. 61, No. 109. June 5, 1996.

(NRC 1996b) U.S. Nuclear Regulatory Commission. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Correction." Federal Register. Vol. 61, No. 147. July 30, 1996.

(NRC 1996c) U.S. Nuclear Regulatory Commission. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." Federal Register. Vol. 61, No. 244. December 18, 1996.

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

(NRC 1996e) U.S. Nuclear Regulatory Commission. *Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses.* NUREG-1440. Washington, DC. May, 1996.

(NRC 1996f) U.S. Nuclear Regulatory Commission. *Public Comments on the Proposed 10 CFR Part 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, 1996.

(NRC 1999a) U.S. Nuclear Regulatory Commission. "Changes to Requirements for Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Final Rule." Federal Register. Vol. 64, No. 171. September 3, 1996.

(NRC 1999b) U.S. Nuclear Regulatory Commission. Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS). Section 6.3, "Transportation" and Table 9-1, "Summary of findings on NEPA issues for license renewal of nuclear power plants." NUREG-1437. Volume 1, Addendum 1. Washington, DC. August, 1996.

(NRC 1999c) U.S. Nuclear Regulatory Commission. *Standard Review Plans for Environmental Reviews for Nuclear Power Plants*. NUREG-1555. Office of Nuclear Reactor Regulations. Washington, D.C. October 1999.

Chapter 2 Site and Environmental Interfaces

2.1 Location and Features

VEGP is located on the Atlantic Coastal Plain, about 25 miles east of the Piedmont Province (GPC 1972). The topography of the area comprises low rolling hills with elevations ranging from 200 to 280 feet (ft) above mean sea level (msl). The land in the immediate vicinity of the site is rural with forestry and agriculture as the primary land use.

The 3,169-acre site is on a Coastal Plain bluff on the southwest side of the Savannah River in eastern Burke County. River Road, Hancock Landing Road, and approximately 1.7 miles of the Savannah River (River Miles 150.0 to 151.7) bound the site. The site is approximately 30 river miles above the U.S. Highway 301 bridge and directly across the river from the U. S. Department of Energy's (DOE's) Savannah River Site (SRS) (Barnwell County, South Carolina). The site is approximately 15 miles east-northeast of Waynesboro, Georgia and 26 miles southeast of Augusta, Georgia. It is about 136 miles from Savannah, Georgia and 150 river miles from the mouth of the Savannah River.

All or parts of 28 counties (12 in South Carolina and 16 in Georgia) are within 50 miles of the VEGP site. The nearest population center (i.e., having more than 25,000 residents) within 50 miles is Augusta, Georgia. A number of small towns occur within 50 miles of the site. Interstate highway (I)-20 traverses the northern portion of the 50-mile radius (Figure 2.1-1). Access to the site is via U.S. Route 25, Georgia routes 56, 80, 24 or 23, and River Road (Figure 2.1-2).

The Georgia side of the Savannah River within 6 miles of the VEGP site is mostly undeveloped land (Figure 2.1-2). The crossroads community of Telfair Woods is approximately 5 miles southwest of VEGP (Figure 2.1-2). Girard (population 230) is approximately 8 miles to the south. Much of the undeveloped land in the vicinity is sandhill-upland pine or oak-hickory hardwood communities. The 7,000 acre state Yuchi Wildlife Management Area (WMA) is adjacent to VEGP to the south.

The SRS, a DOE facility with restricted access, is directly across the Savannah River from VEGP (Figure 2.1-2). The SRS has two remediated industrial areas and one fossil-fueled power plant within the 6-mile radius. Three large recessed intake structures which supplied cooling water to SRS reactors, that are no longer operating, are located on the east side of the Savannah River within the 6-mile radius. The remainder of the SRS within the 6-mile radius is river swamp, bottomland hardwood or upland pine-hardwood communities. The U.S. Forest Service (USFS) maintains pine plantations, which are not affected by industrial activities, on upland areas of SRS.

Section 3.1 describes key features of VEGP, including the reactor and containment systems, the cooling water system, and the transmission system.

Figure 2.1-1 50-Mile Vicinity

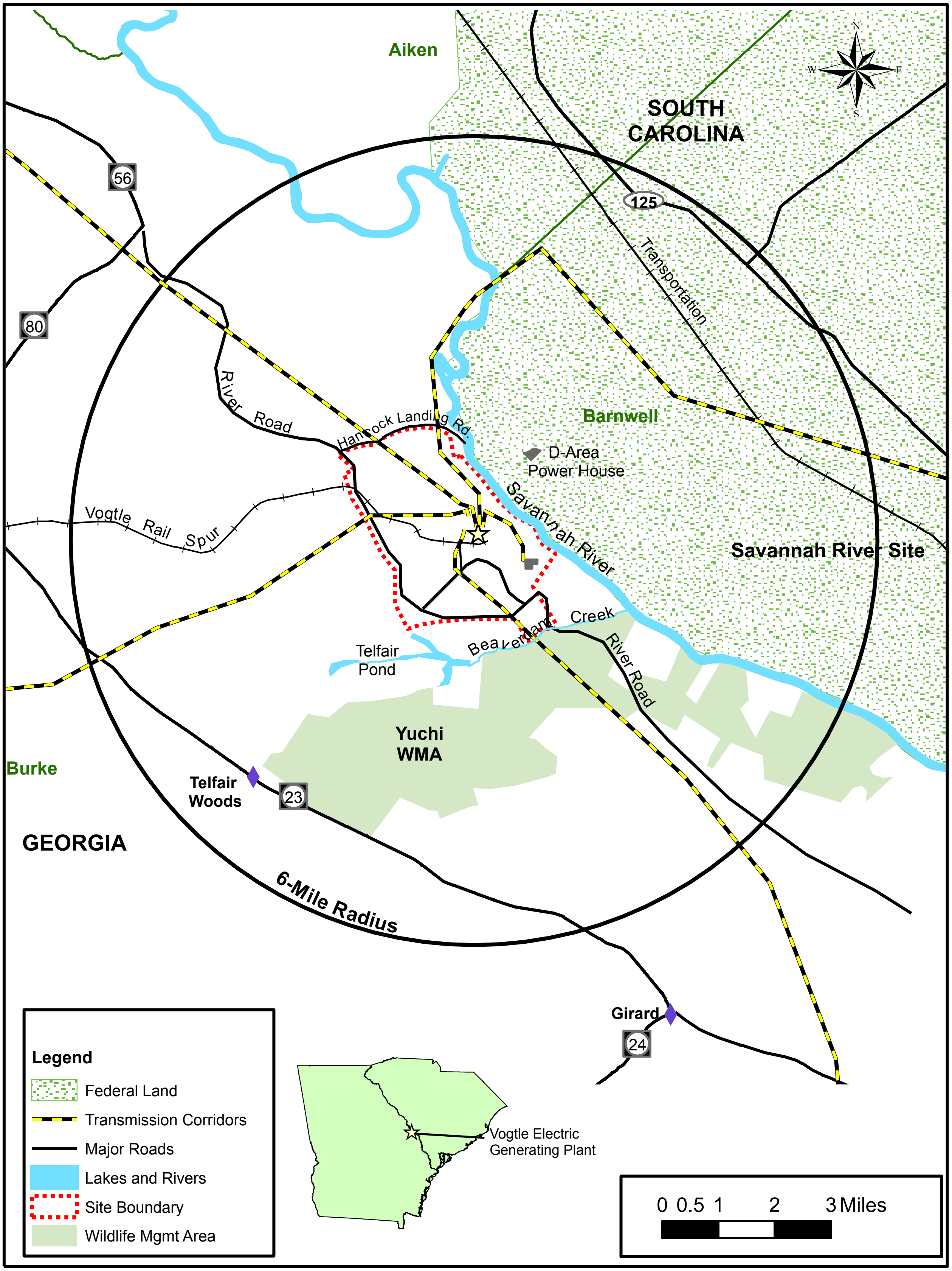

Figure 2.1-2 6-Mile Vicinity

2.2 Aquatic Communities

The Academy of Natural Sciences of Philadelphia (ANS) has monitored the aquatic communities of the middle Savannah River up- and downstream of VEGP since 1951 with focus on evaluating the impacts of operation of the Savannah River Site (SRS) on the Savannah River aquatic community (ANS 2005). These studies are used to establish the ecological baseline for the Savannah River aquatic community including macroinvertebrates, larval and adult fish, algae and diatoms, and insects; evaluate the impacts of cooling water withdrawals and discharges on those communities, and monitor radiological and nonradiological contaminants in the Savannah River. These ongoing studies include sampling stations located above the VEGP intake and below the VEGP discharge to ensure any impacts from operation of VEGP are considered. The ANS studies provide the most comprehensive source of information on the ecological health of the middle reaches of the Savannah River. The continual study of the aquatic ecology in the Savannah River compares past and present information to determine trends, changes, and impacts of the aquatic biota and the fishery used to predict future health of the system. The ongoing nature of this study and the 55 years of data including data from two sample stations representative of the VEGP site provide an outstanding resource for evaluating the effects of license renewal on the Savannah River aquatic communities.

The continuous monitoring conducted by ANS presents a comprehensive look at the aquatic community that could be affected by VEGP operations. The study includes monitoring of basic water chemistry and surveys of attached algae, aquatic macrophytes (aquatic vascular plants), aquatic macroinvertebrates, and fish (ANS 2005). The SRS has sponsored many other studies on the communities in the reach of the Savannah River adjacent to SRS and VEGP. In addition to providing snapshots of the condition of specific populations of aquatic organisms at specific times, the longevity of this monitoring results in the ability to see changes in the communities over time. SNC is also participating in a study of water quality in the Savannah River sponsored by the U. S. Environmental Protection Agency (EPA). An instream water quality monitor (Datasonde) is located near the Vogtle intake and has been collecting data continuously since late 2005. This data is being collected under an EPA grant developed to study water quality in the Savannah River. A report containing data from the first year of the study is required to be submitted to EPA by July 2007. Data for subsequent years will be reported in a similar manner. SNC reviewed the draft data from 2006 and confirmed that it is consistent with previous data collected from the sample stations at the Vogtle site.

Algae

Diatoms have generally been the most abundant algal group, with two pollution-tolerant species (*Melosira varians* and *Gomphonema parvulum*) dominating the collections (Wike et al. 2006).

The dominant algae collected were species characteristic of moderate to high nutrient levels and typical of southeastern coastal plain rivers. Algae downstream of SRS (and VEGP) and upstream of SRS (and VEGP) showed evidence of organic pollution, apparently from upstream (Augusta area) sources, most likely discharge from sewage treatment facilities (Wike et al. 2006).

Aquatic Insects

Aquatic insect density and diversity are two of the most important indicators of water quality. The ANS' monitoring of aquatic insects in the Savannah River up- and downstream of SRS (and VEGP) shows a generally increasing abundance of aquatic insects after the mid-1980s (Wike et al. 2006) as well as increased taxa richness (ANS 2005). Wike et al. (2006) indicate that the biological diversity (number of species) is greater downstream of VEGP and SRS than upstream. The number of pollution-tolerant species is greater upstream of SRS and VEGP. This analysis indicates that water quality downstream of SRS and VEGP is better than water quality upstream, in the vicinity of the cities of Augusta and North Augusta.

Mollusks

The 2000 ANS survey (Arnett 2001) summarizes changes in the mussel community of the middle Savannah River over the 1951-2000 period as follows: a generally decreasing abundance and diversity of native species, an increasing dominance of "hardier forms," and an increasing scarcity of juveniles of some species. These changes were attributed to increased competition over the last several decades with the non-native Asiatic clam and changes in the flow characteristics of the Savannah River associated with "the construction of dikes, upriver dams, and removal of meanders…" Mollusks have been collected at five locations: one upstream of VEGP, one immediately downstream of VEGP, and three further downstream of VEGP. ANS scientists collected 16 mussel species between 1951 and 2000, none of which were state or federally listed. Mollusks found in the vicinity of VEGP include fingernail clams, peaclams, the Asiatic clam (*Corbicula fluminea*), and native mussels (Arnett 2001).

Fishes of the Middle Savannah River

The fishes of the Middle Savannah River have been extensively studied. Four documents are particularly comprehensive and informative: The Fishes of the Savannah River Plant (Bennett and McFarlane 1983), the eight-volume Comprehensive Cooling Water Study prepared by Du Pont (1987), *Fishes of the Middle Savannah River Basin* (Marcy et al. 2005) and the Savannah River Biological Surveys for Westinghouse Savannah River Company (Arnett 2001).

The fishes of the Middle Savannah River include three groups: resident freshwater species, which are found in the area year-round, diadromous species, which are present during seasonal migrations, and marine/estuarine species, which are sometimes found in the middle Savannah

River well upstream of the saltwater-freshwater interface. Resident fishes include a variety of minnows (family Cyprinidae), suckers (family Catastomidae), catfish (family Ictaluridae), sunfish (family Centrarchidae), and perch (family Percidae). Diadromous species include eels (family Anguillidae), shad and river herring (family Clupeidae), striped bass (family Moronidae) and sturgeon (family Acipenseridae). Marine/estuarine species that are sometimes collected in the vicinity of VEGP include striped mullet (*Mugil cephalus*), needlefish (family Belonidae), and hogchoker (*Trinectes maculates*). Relatively small numbers of these marine "strays" are collected; consequently they are of little commercial or recreational importance and will not be discussed further in this environmental report.

Fish Found Year-round in the Vicinity of VEGP

The Savannah River and mouths of creeks flowing into the Savannah River were sampled intensively over the 1983-1985 period by SRS contractors as part of the Comprehensive Cooling Water Study (Du Pont 1987). In a 1983-1984 study, electrofishing collections were dominated by centrarchids, which made up approximately 60 percent of all fish collected (Du Pont 1987). Redbreast sunfish (*Lepomis auritus*), bluegill (*L. macrochirus*), and largemouth bass (*Micropterus salmoides*) appeared most frequently in electrofishing collections, representing 16.7, 14.1, and 8.9 percent, respectively of fish collected. They were followed by spotted sucker (*Minytrema melanops*; 8.5 percent), spotted sunfish (*L. punctatus*; 7.9 percent, chain pickerel (*Esox niger*; 5 percent), and bowfin (*Amia calva*; 5 percent). In the same study hoop net collections were numerically dominated by flat bullhead (*Ameiurus platycephalus*; 29.2 percent), channel catfish (*Ictalurus punctatus*; 21 percent), redbreast sunfish (9.7 percent), and white catfish (*A. catus*; 9 percent).

These species are all commonly found in large southeastern Coastal Plain river systems in habitats ranging from sloughs and backwaters to oxbow lakes to small tributary streams to small impoundments on these tributary streams (Lee et al. 1980; Manooch 1984). As such, they are considered habitat generalists.

The 1983-1984 study included separate surveys of "small fish." These surveys were intended to develop relative abundance estimates of small, schooling species that serve as forage for a variety of top-of-the-food-chain predators, including such recreationally important species as largemouth bass, black crappie (*Pomoxis nigromaculatus*), striped bass (*Morone saxatilis*), white bass (*M. chrysops*) and hybrid bass (*M. saxatilis* X *M. chrysops*). Shiners (genus *Notropis*) made up 89 percent of all fish collected in the small fish surveys (Du Pont 1987). Other species that appeared regularly in the small fish surveys were brook silversides (*Labidesthes sicculus*), lined topminnow (*Fundulus lineolatus*), golden shiner (*Noternigonus crysoleucas),* and mosquitofish *(Gambusia* spp.*). All of these species are common residents of swamps, bayous, and streams* in the southeastern U.S. The 1983-1984 study did not distinguish between the various species of *Notropis* collected. A follow-up Westinghouse Savannah River Company (WSRC) survey of small, minnow-like fish in the Savannah River and its tributaries found that three Notropids made up more than two-thirds of minnows collected: coastal shiner (*Notropis petersoni*; 39.6 percent), dusky shiner (*N. cummingsae*; 17.4 percent), and spottail shiner (*N. hudsonius*; 10.4 percent) (Du Pont 1987).

Between 1980 and 1995, ANS scientists collected 59 fish species upriver and downriver from SRS and VEGP (Halverson et al. 2006. These surveys showed the same species and species groups dominating the Savannah River fish community as those in the 1983-1985 study.

With regard to distribution and abundance of fishes in the vicinity of VEGP, the series of reports prepared by ANS is the best information source available. Initiated in 1951 and continuing through to present, these studies represent the "longest comprehensive study of a large river in the United States" (Arnett 2001). Covering the Savannah River from river mile 160 to river mile 123 (VEGP is at river mile 150.5) the ANS studies are designed to look for special patterns of biological disturbance and temporal patterns of change associated with the Savannah River within the boundary of the SRS and include measuring basic water chemistry, diatoms/periphyton, protazoa, aquatic insects, macro-invertebrates and fish. Two of the ANS study sample locations are located in close proximity to VEGP. Station 2A lies just upstream of VEGP at River Mile 151.2 while station 2B lies just downstream at River Mile 149.8. Results from boat electroshocking conducted during the 2000 study showed the same species and species groups dominating the Savannah River fish community as were seen in the 1983-1985 study and included the spottail shiner (*Notropis hudsonius;* 34.59 percent), bannerfin shiner (*Cyprinella leedsi*; 22.08 percent), bluegill (*Lepomis macrochirus*; 14.24 percent), whitefin shiner (*Cyprinella nivea*; 7.14 percent), brook silverside (*Labidesthes sicculus*; 4.92 percent), and redbreast sunfish (*Lepomis auritus*; 4.57 percent). Other commonly collected species included coastal shiner, largemouth bass, spotted sucker, redear sunfish and rosyface chub (Arnett 2001).

Diadromous Fish of the Middle Savannah River

Diadromous fish of the Middle Savannah River include sturgeons (*Acipenseridae*), shad and herring [Family Clupeidae], temperate basses of the genus *Morone*, and one eel species, the American eel (*Anguilla rostrata*).

Sturgeons (Acipenseridae)

The shortnose sturgeon (*Acipenser brevirostrum*) is an anadromous fish that spawns in large Atlantic coastal rivers from New Brunswick, Canada, to north Florida (Scott and Crossman 1973). A species of commercial importance around the turn of the century, the shortnose sturgeon is now listed by the National Marine Fisheries Service (NMFS) and the U.S. Fish and

Wildlife Service (USFWS) as an endangered species. The decline of the species has been attributed to the impoundment of rivers, water pollution, and overfishing; natural recruitment rates appear to be too low to replenish depleted populations.

Shortnose sturgeon grow slowly, reach sexual maturity late in life, and live as long as 30 years. Fish from southern populations can grow faster and mature earlier than those from northern populations. Spawning occurs in or adjacent to deep areas of rivers with significant currents during early spring when water temperatures warm to 9 to 12 degrees Celsius (°C) (48 to 54 degrees Fahrenheit [°F]) (Jenkins and Burkhead 1994). This can happen as early as February through March in Georgia and South Carolina. Adults apparently return to natal streams to spawn at 2- to 5-year intervals. Eggs are heavier than water and adhesive after fertilization, sinking quickly and adhering to sticks, stones, and gravel on the river bottom. The interaction of water temperature, current velocity, and substrate type determines suitability of spawning habitat and hatching success. Very few sturgeon larvae and juveniles have been collected in the Savannah River, so little is known of their distribution and movement.

Before 1982, shortnose sturgeon were not known to occur in the middle reaches of the Savannah River. From 1982 through 1985, SRS conducted intensive sampling of the ichthyoplankton in the mid-reaches (between river mile 79.9 and river mile 166.6) of the Savannah River and collected 12 shortnose sturgeon larvae (Paller et al. 1984, Paller et al. 1985 and Paller et al. 1986). WSRC also conducted a biological assessment to evaluate the potential impacts of SRS operations on shortnose sturgeon and concluded that "existing and proposed operations (specifically L-Reactor) of the Savannah River Plant will not affect the continued existence of the shortnose sturgeon in the Savannah River" (Muska and Matthews 1983). This conclusion was based on the fact that:

- shortnose sturgeon spawned in the Savannah River upriver and downriver of SRS;
- passage upstream and downstream was not blocked by thermal effluents;
- entrainment was unlikely because shortnose sturgeon eggs are demersal, adhesive, and negatively buoyant; and
- impingement of healthy juvenile and adult sturgeon on cooling water system screening devices is highly unlikely given their strong swimming ability.
- The NMFS concurred with the DOE determination that SRS operations did not threaten the Savannah River population of shortnose sturgeon (Du Pont 1987).

A South Carolina Wildlife and Marine Resources Division (now South Carolina Department of Natural Resources [SCDNR]) study of seasonal movement and spawning habitat preferences of Savannah River shortnose sturgeon found two probable spawning sites, one upstream of VEGP at river miles 171-173 (river kilometers 275-278) and the other downstream of VEGP at river miles 111-118 (river kilometers 179-190) (Hall, Smith, and Lamprecht 1991). A companion radiotelemetry study indicated that spawning habitat locations occurred between river mile 111 (river kilometer 179) and river mile 142 (river kilometer 228) at water temperatures of 9.8 to 16.5°C (50 to 62°F) (Collins and Smith 1993, pg. 490). VEGP borders the Savannah River from approximately river mile 150 to river mile 151.7.

From 1984-1992, more than 97,000 shortnose sturgeons were stocked in the Savannah River as part of a state and federal recovery program (Collins et al. 2000). Recaptures of marked fish after an average time of 7.2 years indicated that fish stocked as juveniles made up at least 38.7 percent of the adult population. Some of the stocked sturgeon did not imprint on the Savannah River and were later found in the Edisto River (South Carolina), the Ogeechee River (Georgia), the Cooper River (South Carolina), and Winyah Bay (South Carolina) (Collins et al. 2000).

Population estimates and catch-per-unit-effort data from 1997-2000 suggested that the adult shortnose sturgeon population was larger in 2000 than in 1990, but juveniles were still rare. This suggests that a recruitment bottleneck exists during early life stages. Water quality degradation in the nursery habitat is believed to be at least partially responsible for the poor recruitment in the Savannah River (Smith et al. 2001).

A related species, the Atlantic sturgeon (*A. oxyrinchus*), is also found from Canada (Labrador) to north Florida. Like the shortnose sturgeon, the Atlantic sturgeon is anadromous, ascending coastal rivers to spawn in the early spring. This takes place as early as February in Georgia and South Carolina and as late as May in Canada, when ambient water temperatures are from 13 to 21°C (55 to70°F) (Jenkins and Burkhead 1994).

Shad and River Herring (Clupeidae)

Three clupeids ascend the Savannah River to spawn in its middle reaches: the American shad (*Alosa sapidissima*), the hickory shad (*A. mediocris*), and the blueback herring (*A. aestivalis*). Two other clupeids, gizzard shad (*Dorosoma cepedianum*) and threadfin shad (*D. petenense*), are also found in the Savannah River, but do not move between the Savannah River and the open ocean, thus are not anadromous in the strictest sense. Gizzard shad are found in brackish water, and have been referred to as a "semi-anadromous" species.

The American shad is the most important clupeid in terms of the commercial and recreational fishing opportunities it provides. American shad once provided an important commercial fishery in the lower Savannah River, but a decline in the population in the 1980s and 1990s reduced the number of commercial fishermen pursuing shad.

Clemson University researchers, investigating movement of American shad through the New Savannah River Bluff Lock and Dam (river mile 187) in 2001 and 2002, developed estimates of the population size (Bailey et al. 2004). They estimated the population size of American shad that reached the New Savannah River Bluff Lock and Dam to be 158,000 fish in 2001 and 217,000 in 2002. This suggests that substantial numbers of spawning American shad pass VEGP during their annual spawning run: The New Savannah River Bluff Lock and Dam are located at river mile 187, approximately 36 miles upstream of VEGP. In both years, American shad were not uniformly distributed over the study area but were concentrated just below the dam and in a large pool approximately 3.6 miles below the dam.

Hickory shad are smaller and less numerous than American shad. They support a modest commercial and recreational fishery. Blueback herring are smaller still, but are netted by commercial operators who sell them for use as live bait.

Striped bass

The striped bass is an anadromous species, but in the Savannah River the degree of anadromy is greatly reduced (Dudley et al. 1977). Unlike striped bass in the northeast and middle Atlantic, which spend their adult lives in the Atlantic Ocean and ascend coastal rivers to spawn, Savannah River striped bass tend to spawn in the lower, tidally-influenced part of the river and move upstream to non-tidal portions of the river after spawning. Fish fitted with radio transmitters traveled as far upstream as the New Savannah Bluff Lock and Dam after spawning (Dudley et al. 1977). Dudley et al. (1977) theorized that "excessively warm coastal waters" in summer at the mouth of the Savannah River may have led to the development of this behavioral pattern in Savannah River striped bass; ambient water temperatures along the Georgia coast in the summer may reach 30ºC (86ºF), exceeding those tolerated by striped bass.

During the 1980s, Savannah River striped bass suffered a precipitous population decline. From 1980 to 1988, catch-per-unit-effort of large striped bass in the lower Savannah River declined by more than 90 percent (Reinert et al. 2005). Not surprisingly, the decline in large adult striped bass was accompanied by a steep decline in egg production. The population decline was attributed to operation of a tide gate, installed in the lower estuary by the U.S. Army Corps of Engineers (USACE) in 1977. The tide gate, which was intended to prevent sediment from accumulating in the harbor, had the unintended effect of increasing salinity upstream in important striped bass spawning areas and speeding the transport of eggs and larvae from upstream spawning sites to the harbor, where they encountered high salinities and industrial pollutants.

Because of the population decline, the states of Georgia and South Carolina declared moratoriums on the harvest of striped bass (from the mouth of the Savannah River to New Savannah Bluff Lock and Dam) in 1988 and 1990, respectively (Reinert et al. 2005). In response to concerns about the impact of the tide gate on anadromous fisheries, the Corps of Engineers discontinued operation of the tide gate in 1991. A long-standing program of stocking striped bass in the estuary was modified in the early 1990s. From 1990 to 2002, 1.6 million striped bass of various sizes and ages were stocked in the Savannah River.

Catch-per-unit effort of adult striped bass in the Savannah River increased sharply in the 1990s in response to the stocking programs (Reinert et al. 2005). More than 70 percent of striped bass collected were hatchery-bred fish. The success of the stocking program (and a preponderance of 2 and 3 year old fish) led the Georgia Department of Natural Resources (GDNR) to suspend Savannah River stocking in 2003 and 2004. In July 2005, the South Carolina (SCDNR) announced that Savannah River striped bass restoration efforts had been so successful that the harvest moratorium on Savannah River striped bass, in place since 1991, would end on October 1, 2005 (Creel 2005). Egg production has been slower to recover. Egg densities in 2000 were approximately 10 percent of densities recorded in the late 1970s (Reinert et al. 2005). However, with the return of suitable spawning conditions and the increased abundance of large spawning females in the estuary, egg production is expected to increase as well.

Although the population is currently dominated by hatchery-bred fish, the striped bass population of the Savannah River is expanding and, if current trends continue, should in time return to levels seen in the 1960s and 1970s, before the USACE' tide gate was installed and operated. Striped bass populations in river systems up and down the Atlantic coast have largely rebounded as a result of commercial and recreational harvest restrictions that followed enactment of the Atlantic Striped Bass Conservation Act (16 United States Code [U.S.C.] § 1851) in 1984.

American eel (Anguilla rostrata)

The American eel occurs in rivers and streams along the east coast of the United States from Maine to Florida. The American eel is catadromous, growing to sexual maturity in freshwater and migrating hundreds of miles into the Atlantic Ocean (the Sargasso Sea) to spawn. Eggs spawned in the Sargasso Sea drift westward and northward with ocean currents and develop into larvae, then nektonic glass eels, which swim west across the Continental Shelf and enter east coast estuaries, where they darken and become elvers (at about 65 millimeters (mm) long). At about 100 mm, elvers become fully-pigmented juvenile (yellow) eels. Males, which tend to remain in estuarine areas, grow rapidly and mature into adults at age 3 to10 (Jenkins and Burkhead 1994). Females tend to move inland, into tidal freshwater rivers and upriver tributaries, where they mature into adults at age 4 to 18. Adults leave estuaries and coastal rivers to migrate to the Sargasso Sea, and do not return to freshwater after spawning. They may live to be 20 to25 years old.

American eel numbers along the Atlantic coast were relatively stable through the 1970s. Fisheries managers and commercial fishermen noticed a decline in numbers of eels ascending coastal streams in the 1980s and 1990s, a decline described by Haro et al (2000). Responding to concerns of state and federal agency biologists, in April 2000, the Atlantic States Marine Fisheries Commission (ASMFC) issued an "Interstate Fishery Plan for American Eel" (ASMFC 2000) that proposed a range of measures that would ensure the species' recovery and continued viability.

In response to a petition received in November 2004, on July 6, 2005, the USFWS announced in a 90-day Finding that it was initiating a status review to determine if listing the American eel on the threatened or endangered species list was warranted (Federal Register [FR] Vol 70, No. 128, July 6, 2005). The FR notice lists an array of threats to the species (e.g., commercial harvest, habitat loss and degradation, changes in oceanic conditions) and concludes "…we find that the petition presents substantial scientific and commercial information indicating that listing the American eel may be warranted." In the discussion of population status, the authors of the FR notice point out that population declines have been most dramatic in Canada and New England and populations may be stable in the southeastern U.S. In 2007 the USFWS completed the status review and determined that listing the American eel as a threatened or endangered species is not warranted (FR Vol 72, No. 22, February 2, 2007).

Eels in the Middle Savannah River Basin are fully pigmented juveniles (yellow eels) and are mostly females (Marcy et al. 2005). McCord (2004) observed high densities of yellow eels in the Middle Savannah River in relatively shallow, non-navigable reaches offering pool-riffle habitats with rocks and submerged aquatic vegetation. In the vicinity of VEGP, eels are found in the Savannah River mainstem, in the Savannah River swamp, in tributary streams, and in small impoundments on these tributaries (Marcy et al. 2005). There is scant information on current population trends in South Carolina and Georgia, but commercial landings of eels in Georgia declined more than 80 percent from 1983 to 1995 (ASFMC 2000). Resource agency biologists in South Carolina and Georgia do not monitor eel population trends in the Savannah River, but anecdotal information suggests that eel numbers are lower now than in the 1970s and 1980s.

2.3 Groundwater Resources

The VEGP site lies within the Coastal Plain Physiographic Province. The site is located approximately 40 miles southeast of the Fall Line, the northwestern boundary of the Coastal Plain Province, and is adjacent to the Savannah River. Geologic conditions beneath the VEGP site generally consist of about 1000 ft of Coastal Plain sediments with underlying Triassic Basin rock and Paleozoic crystalline rock.

The Savannah River lies along the northeast border of the VEGP site and influences the local hydrogeologic conditions within the site area. Three aquifers underlie the VEGP site; the Cretaceous, Tertiary, and Water Table (or Upper Three Runs), all of which belong to the Southeastern Coastal Plain aquifer system. Although present regionally, the surficial aquifer system is not continuous under Burke County or the VEGP site (Miller 1990). The Floridan aquifer system, also present regionally, is absent from the VEGP site as well (Huddlestun and Summerour 1996).

The lower aquifer at the VEGP site overlies the bedrock and comprises Cretaceous-age sediments. Locally, this aquifer system is known as the Cretaceous aquifer and is approximately 700 feet thick. The Cretaceous aquifer yields large quantities of good groundwater (estimated 5 billion gallons per day [gpd] throughout its extent) (SNC 2005). The sediments include sands, gravels, and clays of the Cape Fear Formation, Pio-Nono Formation and associated unnamed sands, Galliard Formation, Black Creek Formation, and Steel Creek Formation. The middle aquifer is made up of Tertiary-age sediments occurring over the Cretaceous-age sediments described above. The middle aquifer system is locally known as the Tertiary aquifer and is approximately 100 feet thick. The Tertiary aquifer consists primarily of the permeable sands of the Still Branch and Congaree Formation. The relatively impermeable clays and silts of the Snapp and Black Mingo Formation overlie and confine the Cretaceous aquifer, while the clays and clayey sands of the Lisbon Formation overlie and confine the Tertiary aquifer. The upper aquifer is unconfined and comprises Tertiary-age sands, clays, and silts of the Barnwell Group, which overlie the relatively impermeable Lisbon Formation. This aquifer is known locally as the Water Table aquifer or Upper Three Runs aquifer. A hydrostratigraphic section showing geologic units, confining units, and aquifers for the VEGP site and surrounding areas is shown in Figure 2.3-1.

In the vicinity of VEGP, recharge to the Cretaceous aquifer is primarily from infiltration of rainfall at the point where the formation is exposed, northwest of the site. In the same outcrop area, the Tertiary aquifer is also exposed. The Cretaceous and Tertiary systems are in hydraulic contact and the groundwater is under water table conditions. After the water infiltrates the sediments, it migrates downdip in a south by southeast direction. (SNC 2005)

Within a few miles downgradient of the recharge/outcrop area, groundwater of the Cretaceous and Tertiary aquifers is confined beneath the Blue Bluff marl. At the VEGP site, both aquifers are confined beneath the marl, and are in apparent hydraulic contact with one another. At a point south of the VEGP site, the Cretaceous aquifer becomes hydraulically separated from the Tertiary aquifer by the intervening, relatively impermeable clays and silts of the Huber and Ellenton Formations. (SNC 2005)

The regional direction of groundwater flow in the Cretaceous and Tertiary systems is south-by-southeast toward the coast. However, from the Fall Line just upstream of Augusta to a point a few miles south of VEGP, the Savannah River has downcut through the Blue Bluff marl confining layer into the underlying strata. This allows both the Cretaceous and the Tertiary aquifers to discharge to the riverbed. This condition gives rise to a groundwater sink, and flow directions in this limited area do not follow regional trends. (SNC 2005)

Recharge to the water table aquifer is almost exclusively by infiltration of direct precipitation. Lateral recharge from adjacent areas is insignificant because the plant area is situated on high ground between streams. Permeability varies considerably in the aquifer because of highly variable quantities of clay. (SNC 2005)

Groundwater use in eastern Burke County is almost exclusively for domestic needs. Small amounts of groundwater are used for agriculture and there are a few commercial buildings in the communities served by municipal wells. The only incorporated community within 10 miles of the site is the town of Girard. City water is provided from two wells located within the Tertiary aquifer. (SNC 2005)

Sylvania, a community approximately 25 miles southwest of VEGP, uses groundwater as its source for drinking water. The community's wells are located within the Tertiary aquifer. Monitoring of the water levels in the aquifer indicate no change in storage or evidence of dewatering except for a slight decline in the late 1970s which was prior to commencing operations at VEGP. (SNC 2005)

Sardis, located within 12 miles of the VEGP site, uses water from three groundwater wells within the Tertiary aquifer with production capacities of 300 to 500 gallons per minute (gpm). The water service provides water for approximately 1000 domestic water users. (SNC 2005)

The many private wells in eastern Burke County have maximum capacities less than 10 gpm with the average estimated to be less than 0.5 gpm (SNC 2005). The closest private well is just west of the VEGP site, across River Road, and is located in the Tertiary aquifer.

The southern portion of Richmond County (south of U.S. Highway 1) is served by 18 groundwater wells. Water from these wells is from the Tuscaloosa Formation. The wells are capable of producing 750 gpm each. Richmond County uses approximately 9.4 million gpd. (SNC 2005)

The Pine Hill Water Authority, which derives its water from the Tuscaloosa Formation, serves the area around McBean. Five wells, three of which are operable, produce water for its 2,200 customers. (SNC 2005)

The SRS, across the Savannah River in South Carolina, is the principal user of groundwater near the VEGP site. SRS withdraws groundwater at a relatively constant rate of 5,000 gpm from the Tuscaloosa Formation of the Cretaceous system. These withdrawals have no effect on groundwater conditions at VEGP. (SNC 2005)

Except for VEPG, there are no other industrial, irrigation, or similar activities that require continuous withdrawals of large quantities of groundwater.

<table>
<tr><th colspan="2">GEOLOGIC TIME</th><th colspan="3">NOMENCLATURE</th></tr>
<tr><th>PERIOD</th><th>SERIES</th><th>GEOLOGIC UNIT</th><th>HYDROGEOLOGIC UNIT</th><th>REGIONAL HYDROGEOLOGIC UNIT</th></tr>
<tr><td rowspan="4">TERTIARY</td><td rowspan="3">Eocene</td><td>Barnwell Gr.</td><td>Water Table aquifer</td><td rowspan="8">Southeastern Coastal Plain Aquifer System</td></tr>
<tr><td>Lisbon Fm. / Blue Bluff Mbr.</td><td>Confining unit</td></tr>
<tr><td>Still Branch Fm.
Congaree Fm.</td><td>Tertiary sand aquifer</td></tr>
<tr><td>Paleocene</td><td>Snapp Fm.
Black Mingo Fm.</td><td>Semi-confining unit</td></tr>
<tr><td colspan="2" rowspan="4">Cretaceous</td><td>Steel Creek Fm.</td><td rowspan="4">Cretaceous aquifer</td></tr>
<tr><td>Gaillard Fm. /
Black Creek Fm.</td></tr>
<tr><td>Pio-Nono Fm. /
unnamed sands</td></tr>
<tr><td>Cape Fear Fm.</td></tr>
</table>

Notes: Geologic unit naming convention (Huddlestun and Summerour 1996; Falls and Prowell 2001)
Regional hydrogeologic unit naming convention (Miller 1990)

Figure 2.3-1 Schematic Hydrostratigraphic Classification for the VEGP Site

2.4 Critical and Important Terrestrial Habitats

The VEGP site is located in the Atlantic Coastal Plain about 30 miles below the Fall Line. Land use surrounding VEGP is an irregular patchwork of row crops and pasture, pine plantations, unused fields, and second-growth forests of hardwoods and mixed pine-hardwoods. The topography of the VEGP site consists of low, rolling hills with a maximum elevation of 280 feet above mean sea level (msl) and a minimum elevation of 80 feet above msl along the Savannah River (GPC 1985).

The VEGP site is 3,169 acres. Approximately 1,400 acres support the generating facilities and associated buildings, maintenance facilities, parking lots, and roads. The remainder of the site consists primarily of forests dominated by pines or hardwoods (Figure 2.4-1). Upland areas support longleaf pine forests and slash pine plantations, with some areas of mixed pine-hardwood stands. Low areas along streams and in the Savannah River floodplain support bottomland hardwood forests and jurisdictional wetlands. The most common tree species in the hardwood forests are oaks (family Fagaceae), black gum (*Nyssa sylvatica*), red maple (*Acer rubrum)*, yellow poplar (*Liriodendron tulipifera*), sweet gum (*Liquidambar styraciflua*), sweet bay (*Laurus nobilis*), and hickory (*Carya* spp) (SNC 2003).

Wildlife species found in the forested portions of the VEGP site are those typically found in forests of eastern Georgia. Mammals such as the white-tailed deer (*Odocoileus virginianus*), raccoon (*Procyon lotor*), opossum (*Didelphis virginiana*), gray squirrel (*Sciurus carolinensis*), Eastern cottontail (*Sylvilagus floridanus*), and gray fox (Urocyn carolinensis) occur at the site, as do smaller mammals such as moles (family Talpidae), shrews (family Soricidae), and a variety of mice (family Muridae) and voles (family Cricetidae). Various reptiles and amphibians (e.g., snakes, lizards, and toads) occur at the VEGP site. Common bird species at the VEGP site include the American crow (*Corvus rachyrhynchos*), blue jay (*Cyanocitta cristata*), Carolina chickadee (*Poecile carolinensis*), mourning dove (*Zenaida macroura*), black vulture (*Coragyps atratus*), turkey vulture (*Catharates aura*), song sparrow (*Melospiza melodia*), white-throated sparrow (*Zonotrichia albicollis*), dark-eyed junco (*Junco hyemalis*), northern cardinal (*Cardinalis cardinalis*), tufted titmouse (*Baeolophus bicolor*), red-bellied woodpecker (*Melanerpes carolinus*), and northern flicker (*Colaptes auratus*).

GPC developed a land management plan for VEGP to ensure effective management of timber and wildlife resources. The plan went into effect in January 1983, is periodically updated, and will remain in effect at least as long as the plant is in operation. The plan outlines forestry and wildlife management; with emphasis on the management of natural longleaf pine and existing hardwood communities (GPC 1985). Wildlife management strategies at VEGP include managing vegetation to promote diverse habitats, periodic thinning and burning of pine timber stands, maintaining wildlife food plots, and the installation and maintenance of nest boxes for bluebirds and wood ducks. The Wildlife Habitat Council (WHC), a nonprofit organization of corporations, conservation organizations and individuals dedicated to restoring and enhancing wildlife habitat, has recognized VEGP since 1993 for its wildlife and land management efforts (SNC 2003). The VEGP site is a Certified Wildlife Habitat with this designation maintained by a continuous wildlife habitat management program and recertification by the WHC every three years.

Section 3.1.3 describes the transmission lines that SNC built to connect VEGP to the transmission system. The principal land-use categories traversed by the transmission corridors are agriculture and forest. The transmission corridors are maintained to keep vegetation heights low enough to prevent interference with the transmission lines, and transmission line corridors are maintained in accordance with established procedures (GPC 1997). The current practice authorizes the use of approved herbicides on dry ground, low-lying wet areas, and stream crossings and hand clearing in some wetland areas. Some portions of the transmission corridors are cultivated by local farmers, and therefore require no additional vegetation maintenance. GPC also maintains portions of the transmission corridors for wildlife enhancement by participating in a wildlife management program with the GDNR. The "Wildlife Incentives for Non-Game and Game Species" (WINGS) program is designed to help land users convert GPC transmission corridors into productive habitat for wildlife. WINGS offers grant money and land management expertise to landowners, hunting clubs, and conservation organizations who commit to participating in the program for 3 years.

The West McIntosh (Thalmann) transmission corridor crosses the Yuchi Wildlife Management Area, which is adjacent to VEGP, and the Tuckahoe Wildlife Management Area, approximately 30 miles south of VEGP. The West McIntosh (Thalmann) transmission corridor also crosses the Ebenezer Creek Swamp near the West McIntosh plant. Although privately owned, Ebenezer Creek Swamp is designated as a National Natural Landmark. The Scherer transmission corridor crosses Oconee National Forest, northeast of Plant Scherer, and the Francis Plantation in Washington County. Otherwise, the transmission corridors do not cross any state or federal parks, wildlife refuges, or wildlife management areas. No areas designated by the USFWS as "critical habitat" for endangered species occur at VEGP or adjacent to associated transmission lines. Section 3.1.3 describes the routes of the transmission corridors.

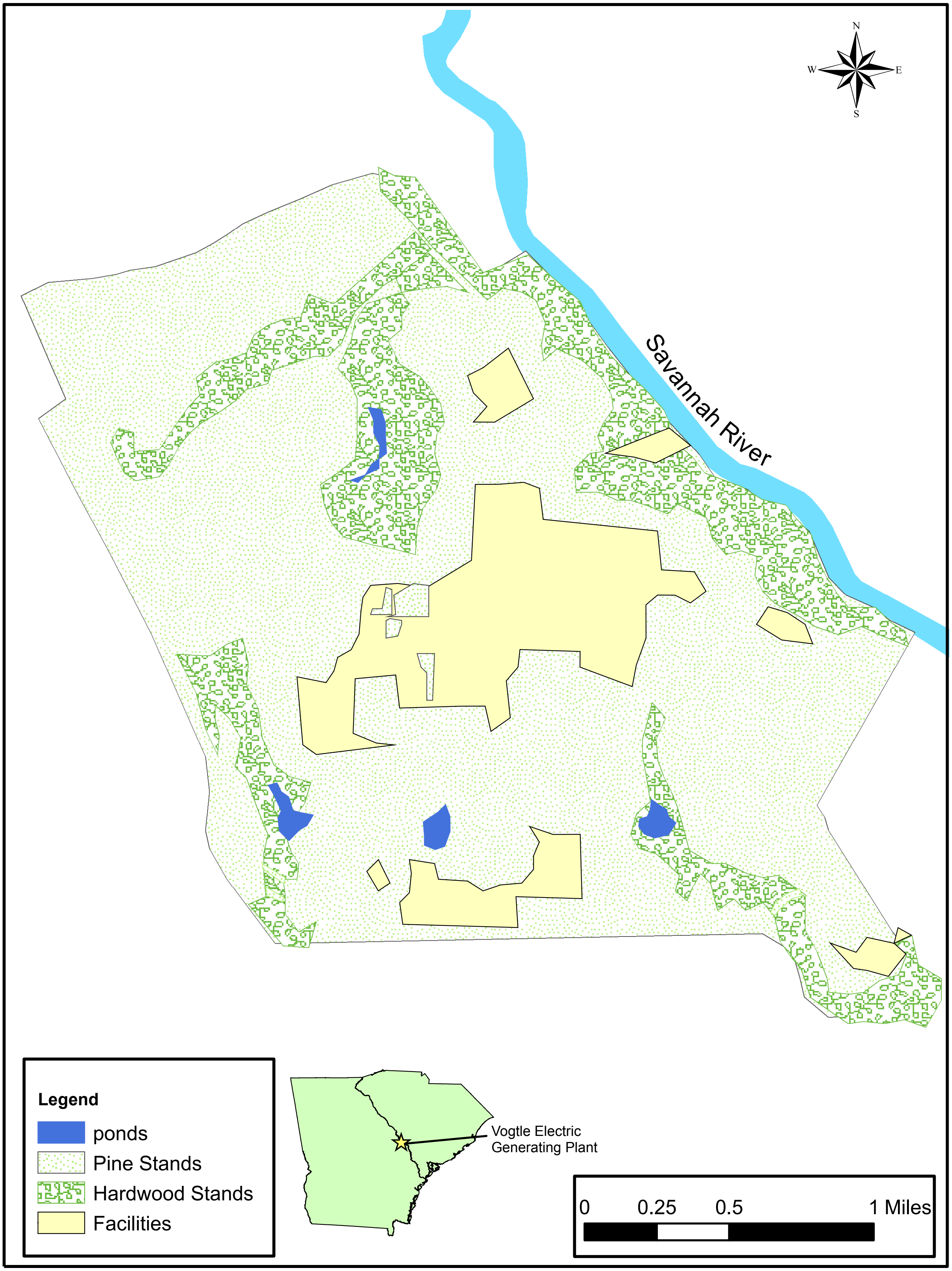

Figure 2.4-1 Vegetation communities on the VEGP site

2.5 Threatened or Endangered Species

Table 2.5-1 indicates animal and plant species that are state- or federally listed as endangered or threatened, or are proposed or candidates for listing, in counties within which VEGP and associated transmission lines are located. The transmission lines are located in Burke, Baldwin, Bryan, Chatham, Effingham, Hancock, Glynn, Jefferson, Jones, Liberty, Long, McIntosh, Monroe, Putnam, Richmond, Screven, and Washington counties in Georgia, and in Barnwell County, South Carolina. The species included in Table 2.5-1 are those that meet one of the following conditions:

- Records maintained by USFWS (USFWS 2004) indicate the species has been recorded in at least one of the counties crossed by the transmission lines.
- Records maintained by the Natural Heritage Program of the GDNR (GDNR 2005) indicate that the species is known to occur in at least one of the Georgia counties crossed by the transmission lines.
- Records maintained by the SCDNR (SCDNR 2003) indicate that the species is known to occur in Barnwell County.

SNC commissioned field surveys of state- and federally listed plant and animal species on the VEGP site and its transmission corridors as part of an Early Site Permit application for the VEGP site. These surveys, described in a report entitled *Threatened and Endangered Species Survey Final Report, Vogtle Electric Generating Plant and Associated Transmission Corridors* (Third Rock Consultants [TRC] 2006) were intended to identify listed species on the VEGP site and associated transmission corridors and provide a basis for the assessment of potential impacts of operations of additional units on these species. The surveys were conducted in spring (April), summer (August), and fall (October) of 2005. SNC has incorporated the findings from these surveys into this environmental report evaluating the continued operations of Units 1 and 2. No federally listed plants were found during the 2005 surveys of the VEGP site and associated transmission line corridors. Federally-listed animals observed during the 2005 surveys were the wood stork (*Mycteria americana*) and the American alligator (*Alligator mississippiensis*). Details regarding observations of these two species, and state listed species observed during the surveys, and the possibility of other special status species potentially at VEGP and along the associated transmission corridors, are discussed below.

Wood Stork

The wood stork is federally- and state-listed as endangered. Wood storks were seen during the 2005 surveys at three locations. TRC (2006) provides precise location (global positioning system [GPS] coordinates, transmission tower number) data. Wood storks were observed at two separate locations in Burke County along the Scherer transmission corridor during the spring 2005 survey. Both observations were of single birds that appeared to be foraging in shallow water. During the summer 2005 survey, 17 wood storks were observed in a wetland in Effingham County along the West McIntosh (Thalmann) transmission corridor; two wood storks were observed at this location during the spring survey. The Effingham County location is a large marsh beneath the transmission line, adjacent to a cypress-tupelo gum swamp. The storks were foraging in the marsh. No nests of storks or other wading birds were observed in the adjacent swamp during any of the three seasonal surveys. A large nesting colony (known as the Birdsville colony) of wood storks exists near Millen, Georgia. Researchers at the Savannah River Ecology Laboratory (SREL) (SREL 2001) have extensively monitored the colony. The colony is approximately 10 miles and 20 miles, respectively, from the two aforementioned Burke County sightings, and 45 miles from the Effingham County sighting (TRC 2006). The storks at all three locations were probably from the Birdsville colony.

Wood stork habitats include cypress/gum ponds, river swamps, marshes, and bays. The wood stork is highly gregarious in its nesting and feeding behavior. They are tactile feeders (vision is not used to locate or catch prey) and usually forage in shallow water (6 to 20 inches). Small fish are the primary food items, but storks also consume crustaceans, salamanders, tadpoles, and insects. Nesting storks generally forage within about 30 miles of their nests (USFWS 1996), but foraging as far as 50 or 60 miles is not uncommon (Ogden 1996; USFWS 1996). There are no known stork rookeries in the vicinity of the VEGP site or the transmission corridors. The Millen (Birdsville) rookery is approximately 10 miles from the Scherer corridor at its nearest point. It is unlikely that any rookeries exist on the VEGP site, because the gregarious behavior of this species would result in numerous sightings. Similarly, the existence of rookeries adjacent to the transmission corridors is unlikely, because they would have been discovered in the spring or summer 2005 surveys. Wood storks undoubtedly forage, at least occasionally, in suitable wetlands in or near the transmission corridors.

American Alligator

The American alligator is common in southern Georgia and South Carolina, and thus, is not State listed by either state as a special-status species. The alligator is federally listed as threatened due to its similarity in appearance to the endangered American crocodile (*Crocodylus acutus*). Alligator habitat consists of swamps, marshes, ponds, lakes, and slow-moving streams and rivers. Alligators are opportunistic feeders and food items include fish, turtles, birds, snakes, frogs, insects, and small mammals (Mount 1975). One adult alligator was observed in a pond on the VEGP site during the summer survey. Alligators are common throughout south-central Georgia and in South Carolina lowlands in suitable habitats and they undoubtedly can be found in wetlands along all the transmission corridors and in the swamps on the VEGP site.

Gopher Tortoise

The gopher tortoise (*Gopherus polyphemus*) is listed as threatened by GDNR and endangered by SCDNR. Georgia and South Carolina populations of this species are not federally listed. The gopher tortoise inhabits sandy, well-drained areas where adequate vegetation for foraging exists. Principal foods include grasses, legumes, sedges, and fruit. Numerous other species use the burrows excavated by gopher tortoises (Diemer 1992). Active gopher tortoise burrows were observed during the transmission line surveys at three locations along the West McIntosh (Thalmann) transmission corridor in Georgia (TRC 2006). Gopher tortoises are not known to occur at the VEGP site.

Southeastern Pocket Gopher

In October, 2006, the GDNR updated its list of protected species. One of the newly-added state-listed as threatened species is the Southeastern pocket gopher (*Geomys pinetis*). Surface mounds indicative of this species have been observed in the northern portion of VEGP. The Southeastern pocket gopher prefers deep, sandy soils and is absent from most hard clay or rocky soils, as well as from saturated or mucky soils. The species is characteristically found in pine-oak woodlands, open pine flatwoods, and in weedy or grassy fields. Southeastern pocket gophers are fossorial (living underground), and build extensive tunnel systems, with portions constantly being added and abandoned in search of food. Common food items include roots, tubers, bulbs, and other plant parts. The tunnels are deep enough to be undetectable at the surface, but loose soil is pushed up sloping tunnels to the surface and piled in mounds. Although rain and wind gradually erode the mounds, mound scars usually persist on the surface for a year or more. (Brown 1997). VEGP license renewal would not affect the pocket gopher habitat in the northern portion of the property.

Spotted Turtle

The spotted turtle (*Clemmys guttata*) is listed as unusual by GDNR and threatened by SCDNR. It inhabits swamps, marshes, ponds, and small streams. Plants and invertebrates are the primary foods (Berry 1992). A single spotted turtle was observed on the West McIntosh (Thalmann) corridor during the spring survey. Spotted turtles probably occur in at least a few other wetlands along some transmission corridors, but probably not along the Scherer corridor. Geographic range maps (Berry 1992) suggest that the Scherer corridor is outside the westward extent of the range of this species.

Pond Spice

Pond spice (*Litsea aestivalis*) is state-listed as threatened in Georgia. Habitat for this plant consists of swamps and the margins of cypress ponds and sandhill depression ponds. Several pond spice plants were observed at one location on the West McIntosh (Thalmann) corridor.

The existence of pond spice at this location was already known to GPC and the Georgia Natural Heritage Program (TRC 2006).

Bay Star-Vine

Bay star-vine (*Schisandra glabra*) is state-listed as threatened in Georgia. Habitat for this vine is rich forested areas, especially bottomlands and slopes. Bay star-vine was found at several locations on the VEGP site.

Hooded Pitcher Plant

The hooded pitcher plant (*Sarracenia minor*) is state-listed as unusual in Georgia. Habitat consists of acidic soil in open bogs, low areas of pine flatwoods, swamps, sphagnum seeps, and the margins of ponds, sloughs, and ditches. Hooded pitcher plants were observed at six locations along the West McIntosh (Thalmann) corridor.

Sensitive Aquatic Populations

As discussed previously in Section 2.2, the ANS has monitored the freshwater mussels of the middle Savannah River since 1951 as part of a larger monitoring program designed to assess potential impacts of the SRS on the general health of the river. Mussels are collected annually at five locations, one upstream of VEGP, one immediately downstream of VEGP, and three further downstream of VEGP. ANS scientists collected 16 mussel species between 1951 and 2000 (Arnett 2001), none of which was state- or federally listed.

The only federally listed fish species known to occur in the Savannah River in the vicinity of VEGP is the endangered shortnose sturgeon (*Acipenser brevirostrum*). This anadromous species, first documented in the middle Savannah River in the early 1980s by SRS researchers, is known to spawn upstream and downstream of VEGP (DOE 1997). A related species, the Atlantic sturgeon (*Acipenser oxyrinchus*), which has been designated a species of concern by the NMFS (NMFS 2004), also ascends the Savannah River to spawn in fresh water but little is known about its spawning habits in the Savannah River. The NMFS considered the Atlantic sturgeon for listing under the Endangered Species Act in 1998, but ultimately determined that listing was not warranted (FR, Volume 63, Number 182, page 50187, September 21, 1998).

The robust redhorse (*Moxostoma robustum*), a fish species believed to be extinct but "rediscovered" in 1991, was recorded in the Augusta Shoals area of the Savannah River in 1998, and has been found since then at several locations between Augusta and U.S. Highway 301, which is approximately 35 miles down-river from VEGP. The robust redhorse has no federal status, but has been designated an endangered species by the State of Georgia.

Georgia listed the blue-barred sunfish (*Elassoma okatie*) as endangered in October 2006. The primary habitat of this species is roadside ditches and the backwaters of blackwater creeks and rivers with abundant vegetation. It has been found on Fort Gordon, in Richmond County. Surveys done in the 1970s in Beaverdam Creek, which runs south of the Vogtle Training Center, and its tributary Daniels Branch, yielded no species of pygmy sunfish (*Elassoma* spp) or species which could be confused with pygmy sunfish (Wiltz 1982). This suggests that few, if any, representatives of the genus *Elassoma* were in the Beaverdam Creek drainage in the late 1970s. The blackwater streams of the SRS, across the river from VEGP, have been sampled since the early 1950s by Westinghouse and Savannah River Ecology Laboratory scientists, none of whom (based on Marcy et al. 2005) has ever captured a bluebarred pygmy sunfish. According to the distribution map in Marcy et al. (2005) a population of bluebarred pygmy sunfish has been found in a small stream in Allendale County, SC, south of the SRS.

The GDNR has found no pygmy sunfish on the Yuchi WMA, immediately southwest of VEGP.

Georgia Power has not conducted systematic surveys for the bluebarred pygmy sunfish on the Vogtle site. However, in April, 2007 Georgia Power fisheries biologists performed a habitat assessment of Mallard Pond drainage in order to determine the presence or absence of those habitats commonly associated with populations of bluebarred pygmy sunfish. Survey results indicate that neither Mallard Pond nor the pond drainage contains the vegetation types and flow characteristics regarded as the preferred habitat type for the bluebarred pygmy sunfish. Based on the April survey results, the fact Wiltz (1982) collected no bluebarred pygmy sunfish in the Beaverdam Creek drainage, and that GDNR has not collected any specimens from the Yuchi WMA, it appears unlikely that the species is present at the Vogtle site.

License renewal will not involve any modification of the plant or the existing transmission system and is not expected to have any impact on streams, ponds, and wetlands crossed by VEGP transmission lines. However, records of the USFWS, GDNR, and SDNR were reviewed for information on sensitive aquatic species in counties crossed by Vogtle transmission lines. The Altamaha spinymussel (*Elliptio spinosa*), a candidate for federal listing, occurs in the Altamaha River and its tributaries in the coastal plain of Georgia. It is found in two counties (Long and McIntosh) crossed by the Vogtle-Thalmann transmission line. This large mussel has experienced a substantial decline in number of sites occupied in recent years. The decline has been attributed to habitat degradation and competition with the non-native Asiatic clam, *Corbicula fluminea* (Georgia Museum undated; Wisniewski et al. 2005). Unauthorized collection of the Altamaha spinymussel is also thought to have contributed to the species' decline.

Other Special Status Species

As stated in earlier in this section, the species included in Table 2.5-1 are those that have been recorded in counties crossed by the transmission lines. Four of the 17 Georgia counties are adjacent to the Atlantic Ocean, and as a result, several species in Table 2.5-1 (e.g., whales, sea turtles) are strictly marine animals and would not occur on the transmission corridors. Some wide ranging special status animal species, even though not observed during the 2005 surveys, probably forage at least occasionally on or near the transmission corridors. Bald eagles (*Haliaeetus leucocephalus*), for example, are commonly observed along the Savannah River and at the SRS, within which the South Carolina Electric and Gas Company (SCE&G) corridor is located.

With the exception of the species included in Table 2.5-1, SNC is unaware of any endangered species, threatened species, candidate species (species that may warrant listing in the future but have no current statutory protection under the Endangered Species Act) or species proposed for listing by the USFWS that occur on the VEGP site or along associated transmission line corridors.

Table 2.5-1. Protected Species in Burke County or Counties Crossed by Existing Transmission Lines[1]

Common Name	Scientific Name	Federal Status[2]	State Status[2] Georgia	State Status[2] South Carolina
Mammals				
Rafinesque's big-eared bat	*Corynorhinus rafinesquii*	-	R	E
Northern right whale[3]	*Eubalaena glacialis*	E	E	-
Southeastern pocket gopher	*Geomys pinetis*	-	T	-
Humpback whale[3]	*Megaptera novaeangliae*	E	E	-
Manatee[3]	*Trichechus manatus*	E	E	E
Birds				
Bachman's sparrow	*Aimophila aestivalis*	-	R	-
Henslow's sparrow	*Ammodramus henslowii*	-	R	-
Bald eagle[4]	*Haliaeetus leucocephalus*	T	T	E
Piping plover	*Charadrius melodus*	T	T	-
Wilson's plover	*Charadrius wilsonia*	-	T	T
Kirtland's warbler	*Dendroica kirtlandii*	E	E	-
Southeastern American kestrel	*Falco sparverius paulus*	-	R	-
American oystercatcher	*Haematopus palliatus*	-	R	-
Wood stork[4,5]	*Mycteria americana*	E	E	E
Red-cockaded woodpecker[4]	*Picoides borealis*	E	E	E
Swallow-tailed kite	*Elanoides forficatus*	-	R	E
Black skimmer	*Rynchops niger*	-	R	-
Least tern	*Sterna antillarum*	-	R	T
Gull-billed tern	*Sterna nilotica*	-	T	-
Bachman's warbler	*Vermivora bachmanii*	E	-	-
Reptiles				
Loggerhead sea turtle	*Caretta caretta*	T	T	T
Green sea turtle	*Chelonia mydas*	T	T	-
Spotted turtle[4,5]	*Clemmys guttata*	-	U	T
Leatherback sea turtle	*Dermochelys coriacea*	E	E	-
Hawksbill sea turtle	*Eretmochelys imbricata*	E	E	-
American alligator[6,7]	*Alligator mississippiensis*	T(S/A)	-	-
Eastern indigo snake	*Drymarchon corais couperi*	T	T	-
Kemp's Ridley sea turtle	*Lepidochelys kempii*	E	E	-
Gopher tortoise[4,5]	*Gopherus polyphemus*	-	T	E
Southern hognose snake[4]	*Heterodon simus*	-	T	-
Mimic glass lizard	*Ophisaurus mimicus*	-	R	-
Amphibians				
Gopher frog[4]	*Rana capito*	-	R	E
Striped newt	*Notophthalmus perstriatus*	-	T	-
Flatwoods salamander[4]	*Ambystoma cingulatum*	T	T	E
Fish				
Shortnose sturgeon[4]	*Acipenser brevirostrum*	E	E	E
Altamaha shiner	*Cyprinella xaenura*	-	T	-

Table 2.5-1. (cont'd) Protected Species in Burke County or Counties Crossed by Existing Transmission Lines[1]

Common Name	Scientific Name	Federal Status[2]	State Status[2] Georgia	State Status[2] South Carolina
Bluebared pygmy sunfish	*Elassoma okatie*	-	E	-
Goldstripe darter	*Etheostoma parvipinne*	-	R	-
Bluefin killifish	*Lucania goodei*	-	R	-
Robust redhorse	*Moxostoma robustum*	-	E	-
Invertebrates				
Oconee burrowing crayfish	*Cambarus truncatus*	-	T	-
Say's spiketail	*Cordulegaster sayi*	-	T	-
Altamaha arcmussel	*Alasmidonta arcula*	-	T	-
Altamaha spinymussel	*Elliptio spinosa*	C	E	-
Atlantic pigtoe mussel[4]	*Fusconaia masoni*	-	E	-
Plants				
Pool sprite	*Amphianthus pusillus*	T	T	T
Georgia aster	*Aster georgianus (=Symphyotrichum georgianum)*	C	T	-
Sandhill vetch	*Astragulus michauxii*	-	T	-
Purple honeycomb head	*Balduina atropurpurea*	-	R	-
Velvet sedge	*Carex dasycarpa*	-	R	-
Sandhill rosemary[4]	*Ceratiola ericoides*	-	T	-
Atlantic white-cedar	*Chamaecyparis thyoides*	-	R	-
Floodplain tickseed	*Coreopsis integrifolia*	-	T	-
Harper's dodder	*Cuscuta harperi*	-	E	-
Pink ladyslipper	*Cypripedium acaule*	-	U	-
Radford's mint	*Dicerandra radfordiana*	-	E	-
Smooth coneflower	*Echinacea laevigata*	E	E	E
Georgia plume[4]	*Elliottia racemosa*	-	T	-
Green fly orchid	*Epidendrum conopseum*	-	U	-
Dwarf hatpins	*Eriocaulon koernickianum*	-	E	-
Florida wild privet	*Forestiera segregata*	-	R	-
Dwarf witch-alder	*Fothergilla gardenii*	-	T	-
Shoals spiderlily	*Hymenocallis coronaria*	-	T	-
Mat-forming quillwort	*Isoetes tegetiformans*	E	E	-
Corkwood	*Leitneria floridana*	-	T	-
Pondberry	*Lindera melissifolia*	E	E	E
Pondspice[5]	*Litsea aestivalis*	-	R	-
Pineland Barbara buttons	*Marshallia ramosa*	-	R	-
Trailing milkvine	*Matelea pubiflora*	-	R	-
Indian olive[4]	*Nestronia umbellula*	-	R	-
Canby's dropwort[4]	*Oxypolis canbyi*	E	E	E
Grit beardtongue	*Penstemon dissectus*	-	R	-

Table 2.5-1. (cont'd) Protected Species in Burke County or Counties Crossed by Existing Transmission Lines[1]

Common Name	Scientific Name	Federal Status[2]	State Status[2] Georgia	State Status[2] South Carolina
Crestless plume orchid	*Pteroglossaspis ecristata*	-	T	-
Harperella	*Ptilimnium nodosum*	E	E	E
Tiny-leaf (climbing) buckthorn	*Sageretia minutiflora*	-	T	-
Soapberry	*Sapindus marginatus*	-	R	-
Yellow flytrap	*Sarracenia flava*	-	U	-
Hooded pitcherplant[4,5]	*Sarracenia minor*	-	U	-
Parrot pitcherplant	*Sarracenia psittacina*	-	T	-
Sweet pitcherplant[4]	*Sarracenia rubra*	-	E	-
Bay star-vine[6]	*Schisandra glabra*	-	T	-
Chaffseed	*Schwalbea americana*	E	E	E
Ocmulgee skullcap[4]	*Scutellaria ocmulgee*	-	T	-
Swamp buckthorn	*Sideroxylon thornei*	-	R	-
Silky camellia[4]	*Stewartia malacodendron*	-	R	-
Pickering's morning-glory	*Stylisma pickeringii pickeringii*	-	T	-
Relict trillium	*Trillium reliquum*	E	E	E

1 Species has been recorded by USFWS 2004 or GDNR 2007 to occur in Georgia counties crossed by the transmission lines, or by SCDNR 2006 to occur in Barnwell County, South Carolina. Shaded species were observed during 2005 survey.
2 E = Endangered, T = Threatened, C = Candidate for federal listing, T(S/A) = Threatened due to similarity of appearance, R = Rare (Georgia only), U = Unusual (Georgia only), - = not listed.
3 Included for completeness. Some VEGP transmission lines cross Georgia coastal counties that list these marine mammals as protected species.
4 Species has been recorded by USFWS 2004 or GDNR 2007 in Burke County, Georgia.
5 Species was observed along VEGP-associated transmission corridors during field surveys conducted in 2005 (TRC 2006).
6 Species was observed at VEGP site during field surveys conducted in 2005 (TRC 2006).
7 County occurrences for the American alligator are not maintained by USFWS 2004, GDNR 2007, or SCDNR 2006; this species is included in this table because it is known to occur at the VEGP site.

2.6 Demography

2.6.1 Regional Demography

The Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) presents a population characterization method that is based on two factors: "sparseness" and "proximity" (NRC 1996). "Sparseness" measures population density and city size within 20 miles of a site and categorizes the demographic information as follows:

Demographic Categories Based on Sparseness

Category	Definition
Most sparse	1. Less than 40 persons per square mile and no community with 25,000 or more persons within 20 miles
	2. 40 to 60 persons per square mile and no community with 25,000 or more persons within 20 miles
	3. 60 to 120 persons per square mile or less than 60 persons per square mile with at least one community with 25,000 or more persons within 20 miles
Lease sparse	4. Greater than or equal to 120 persons per square mile within 20 miles
Source: NRC 1996	

"Proximity" measures population density and city size within 50 miles and categorizes the demographic information as follows:

Demographic Categories Based on Proximity

Category	Definition
Not in close proximity	1. No city with 100,000 or more persons and less than 50 persons per square mile within 50 miles
	2. No city with 100,000 or more persons and between 50 and 190 persons per square mile within 50 miles
	3. One or more cities with 100,000 or more persons and less than 190 persons per square mile within 50 miles
In close proximity	4. Greater than or equal to 190 persons per square mile within 50 miles
Source: NRC 1996	

The GEIS then uses the following matrix to rank the population category as low, medium, or high.

GEIS Sparseness and Proximity Matrix

Sparseness	Proximity	1	2	3	4
	1	1.1	1.2	1.3	1.4
	2	2.1	2.2	2.3	2.4
	3	3.1	3.2	3.3	3.4
	4	4.1	4.2	4.3	4.4

Low Population Area

Medium Population Area

High Population Area

Source: NRC 1996

SNC used 2000 census data from the U.S. Census Bureau (USCB) website (USCB 2000a and 2000b) and geographic information system (GIS) software (ArcView®) to determine demographic characteristics in the VEGP site vicinity.

As derived from 2000 Census Bureau information, 43,857 people lived within 20 miles of the VEGP site. Applying the GEIS sparseness measures, the VEGP site has a population density of 46 persons per square mile within 20 miles and falls into a sparser category, Category 2 (40 to 60 persons per square mile and no community with 25,000 or more persons within 20 miles).

Based on the 2000 USCB information, approximately 670,000 people lived within 50 miles of the VEGP site. This equates to a population density of 89 persons per square mile within 50 miles. Applying the GEIS proximity measures, the VEGP site is classified as Category 3 (one or more cities with 100,000 or more persons and less than 190 persons per square mile within 50 miles). According to the GEIS sparseness and proximity matrix, the VEGP site ranks of sparseness Category 2 and proximity Category 3 result in the conclusion that the VEGP site is in a medium population area.

The area defined by the 50-mile radius around VEGP Units 1 and 2 includes all or parts of 28 counties in Georgia and South Carolina and one major city in Georgia.

The nearest population center (i.e., more than 25,000 residents) is Augusta, Georgia, approximately 26 air miles northwest of the site. Augusta's 2000 population was 195,182 (USCB 2000c).

The 50-mile vicinity includes, in its entirety, the Augusta-Richmond County, Georgia-South Carolina (GA-SC) metropolitan statistical area (MSA). The Augusta-Richmond County, GA-SC MSA comprises urban, suburban, and rural areas, and a 2000 population of 499,684 (USCB 2003). The Augusta-Richmond County, GA-SC MSA is 89th largest in the U.S. From 1990 to 2000, the MSA grew 14.7 percent (USCB 2003). Burke, Richmond, and Columbia counties are all included in the Augusta-Richmond County, GA-SC MSA.

Approximately 79 percent of VEGP employees reside in Burke, Richmond, or Columbia counties, therefore, they are the counties with the greatest potential to be socioeconomically affected by license renewal at VEGP (see Section 3.4). These three counties will be the counties of interest for all of the socioeconomic analyses that follow (Table 2.6.1-1). Table 2.6.1-2 presents historic and projected population-growth-rate data for the three counties. Values for the state of Georgia are provided for comparison. Population data from 1970 to 2000 are from the USCB (USCB 1995, 2000c). From 1990 to 2000, Columbia County grew at an average annual growth rate of 3.1 percent. Burke and Richmond counties grew 0.8 and 0.5 percent, respectively. Over the same period, Georgia grew at an average annual rate of 2.4 percent.

Population projections are provided by the state of Georgia's Office of Planning and Budget (Georgia 2005). The 2010-2015 population projections for the three counties were developed using the Cohort-Survival Model (also known as the Cohort-Component Model). The method uses the following demographic equation:

$$\textit{Population}_1 = \textit{Population}_0 + \textit{Births} - \textit{Deaths} + \textit{Net Migration}$$

Existing population projections were updated with the most recent census data and the actual birth and death data for 1990 through 2003. Additionally, a comparison was made to the USCB 2003 population estimates, which include the most recent migration data. (Georgia 2005)

Between 2000 and 2015 Burke County's population growth rate is projected to remain approximately steady at 1.0 percent. Columbia County's rate is expected to slow to 2.6 percent annually by 2015. Richmond County is projected to decrease in population at the rate of -0.3 to -0.2 percent annually.

2.6.2 Environmental Justice

Methodology

Environmental justice has been defined as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies (EPA 2002). Concern that minority and/or low-income populations might be bearing a disproportionate share of adverse health and environmental impacts led President Clinton to issue an Executive Order (EO) in 1994 to address these issues. That Order, EO 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," directs federal agencies to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations. The Council on Environmental Quality (CEQ) has provided guidance for addressing environmental justice (CEQ 1997). To meet NRC requirements, SNC used guidance from the NRC Office of Nuclear Reactor Regulation. (NRC 2004)

NRC previously concluded that a 50-mile radius could reasonably be expected to contain potential environmental impact sites and that the state was appropriate as the geographic area for comparative analysis. SNC has adopted this approach for identifying the minority and low-income populations that could be affected by license renewal at the VEGP site.

SNC used ArcView® GIS software and USCB 2000 census data to determine the minority and low-income characteristics on a block group level within 50 miles of the VEGP site. SNC included a block group if any part of its area was within 50 miles of the VEGP site. The 50-mile radius includes 491 block groups. SNC defines the geographic area for the VEGP site as Georgia and South Carolina, independently, for analysis of block groups in each of the two states.

Minority Populations

The NRC "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues" defines a minority population as: American Indian or Alaskan Native; Asian; Native Hawaiian or other Pacific Islander; Black Races, and Hispanic Ethnicity (NRC 2001, Appendix D). Additionally, NRC's guidance requires that all other single minorities are to be treated as one population and analyzed, and that the aggregate of all minority populations are to be treated as one population and analyzed. The guidance indicates that a minority population exists if either of the following two conditions exists:

1. The minority population of the census block or environmental impact site exceeds 50 percent.

2. The minority population percentage of the environmental impact area is significantly greater (typically at least 20 percentage points) than the minority population percentage in the geographic area chosen for comparative analysis.

For each of the 491 block groups within the 50-mile radius, SNC calculated the percent of the block group's population represented by each minority. If any block group minority percentage exceeded 50 percent, then the block group was identified as containing a minority population. If any block group percentage exceeded its corresponding state percentage by more than 20 percent, then a minority population was determined to exist. SNC selected the entire states of Georgia and South Carolina as the geographic areas for comparative analysis and calculated the percentages of each minority category in each state.

Census data for Georgia (USCB 2000a) characterizes 28.7 percent of the population as Black races; 0.3 percent American Indian or Alaskan Native; 2.1 percent Asian; 0.1 percent Native Hawaiian or other Pacific Islander; 2.4 percent all other single minorities; 1.4 percent multi-racial; 34.9 percent aggregate of minority races; and 5.3 percent Hispanic ethnicity.

Census data for South Carolina (USCB 2000a) characterizes 29.5 percent of the population as Black races; 0.3 percent American Indian or Alaskan Native; 0.9 percent Asian; 0.04 percent Native Hawaiian or other Pacific Islander; 1.0 percent all other single minorities; 1.0 percent multi-racial; 32.8 percent aggregate of minority races; and 2.4 percent Hispanic ethnicity. Table 2.6.2-1 and Figures 2.6.2-1 through 2.6.2-3 present the results of the analysis.

One hundred and seventy-five census block groups within the 50-mile radius have Black races populations that exceed the state average by 20 percent or more. Of those 175 block groups, 171 have Black races populations of 50 percent or more. No block group met the 50 percent criterion without meeting the 20 percent criterion.

One hundred and sixty-eight census block groups within the 50-mile radius have aggregate minority population percentages that exceed the state averages by 20 percentage points or more. One hundred and eighty-three census block groups within the 50-mile radius have aggregate minority population percentages that exceed 50 percent. Because both Georgia and South Carolina have relatively large percentages of aggregate minority populations, 34.9 and 32.8 percent, respectively, adding 20 percentage points to these averages equates to 54.9 and 52.8 percent, respectively. Therefore, there are more census block groups that meet the "50 percent" threshold criterion than the "20 percentage points greater than the state average" thresholds.

One census block group within the 50-mile radius has Hispanic ethnicity populations that exceed the state average by 20 percent or more. No census block groups within the 50-mile radius have Hispanic ethnicity populations that exceed 50 percent.

Based on the "more than 20 percent" or the "exceeds 50 percent" criteria, no American Indian or Alaskan Native, Asian, Native Hawaiian or other Pacific Islander, or multi-racial minorities exist in the geographic area. In addition, no populations defined as "all other single minority races" exceed these criteria.

Low-Income Populations

NRC guidance defines low-income populations by assessing low-income households using statistical poverty thresholds in the block groups (NRC 2004, Appendix D) and determining if either of the following two conditions is met:

1. The low-income households in the census block group or the environmental impact site exceeds 50 percent.
2. The percentage of households below the poverty level in an environmental impact area is significantly greater (typically at least 20 percentage points) than the low-income households percentage in the geographic area chosen for comparative analysis.

SNC divided USCB low-income households in each census block group by the total households for that block group to obtain the percentage of low-income households per block group. Using the states of Georgia and South Carolina as the geographical areas chosen for comparative analysis, SNC determined that 12.6 percent of Georgia and 14.1 percent of South Carolina households are low-income (USCB 2000b). Table 2.6.2-1 identifies and Figure 2.6.2-4 locates the low-income block groups.

Seventy-two census block groups within the 50-mile radius have low-income households that exceed the state averages by 20 percent or more. Of those 72 block groups, 14 have 50 percent or more low-income households. No block groups met the 50 percent criteria without meeting the 20 percent criteria.

Migrant Populations

The 2002 Census of Agriculture collected information on migrant workers. Farm operators were asked whether any hired or contract workers were migrant workers, defined as a farm worker whose employment required travel that prevented the migrant worker from returning to his permanent place of residence the same day. In general, the migrant population in the 50-mile radius is expected to be low. Migrants tend to work such short-duration, labor-intensive jobs as harvesting fruits and vegetables. Table 2.6.2-2 provides information on farms in the region that employ migrant labor.

Subsistence-Living Populations

SNC investigated the possibility of subsistence-living populations in the vicinity of VEGP by contacting local government officials, the staff of social welfare agencies, and local businesses concerning any known unusual resource dependencies or practices that could result in potentially disproportionate impacts to minority and low-income populations. SNC asked about the presence of minority, low-income, or migrant populations of particular concern, and whether subsistence living conditions were evident. No agency reported such dependencies or practices, as subsistence agriculture, hunting, or fishing, through which the populations could be disproportionately adversely affected by the construction project.

Table 2.6.1-1. Residential Distribution of VEGP Operations Workforce (2005)

County	Employees per County	% of Total
Aiken	37	4.29%
Allendale	1	0.12%
Bamberg	2	0.23%
Barnwell	4	0.46%
Bryan	1	0.12%
Bulloch	10	1.16%
Burke	170	19.72%
Candler	2	0.23%
Columbia	289	33.53%
Edgefield	1	0.12%
Emanuel	12	1.39%
Fulton	1	0.12%
Glascock	2	0.23%
Jefferson	13	1.51%
Jenkins	16	1.86%
Johnson	2	0.23%
Lincoln	3	0.35%
Macon	1	0.12%
McCormick	4	0.46%
McDuffie	3	0.35%
Richland	2	0.23%
Richmond	224	25.99%
Screven	58	6.73%
Spalding	1	0.12%
Toombs	2	0.23%
Washington	1	0.12%
TOTAL	862	100.00%

Table 2.6.1-2. Population Growth in Richmond, Burke, and Columbia Counties and the State of Georgia, 1970 to 2015

	Burke		Richmond		Columbia		Georgia	
	Population	Annual Percent Growth	Population	Annual Percent Growth	Population	Annual Percent Growth	Population	Annual Percent Growth
1970[a]	18,255	N/A	162,437	N/A	22,327	N/A	4,589,575	N/A
1980[a]	19,349	0.6	181,629	1.1	40,118	6.0	5,463,105	1.8
1990[a]	20,579	0.6	189,719	0.4	66,031	5.1	6,478,216	1.7
2000[b]	22,243	0.8	199,775	0.5	89,288	3.1	8,186,453	2.4
2010[c]	24,561	1.0	193,914	-0.3	116,642	2.7	9,864,970	1.9
2015[c]	25,765	1.0	191,563	-0.2	132,303	2.6	10,813,573	1.9

a USCB 1995
b USCB 2000c
c State of Georgia 2005

Table 2.6.2-1. Minority and Low Income Population Census Blocks within 50-Mile Radius of the VEGP Site

State	County	Total Block Groups within 50 miles	Minority								Low-Income Households
			Black	Alaskan Indian or Native American	Asian	Native Hawaiian or Pacific Islander	Other	Multi-Racial	Aggregate[a]	Hispanic	
Georgia	Bulloch	30	7	0	0	0	0	0	7	0	10
Georgia	Burke*	18	11	0	0	0	0	0	11	0	7
Georgia	Candler	3	0	0	0	0	0	0	0	0	0
Georgia	Columbia	30	1	0	0	0	0	0	1	0	0
Georgia	Effingham	2	0	0	0	0	0	0	0	0	0
Georgia	Emanuel	12	2	0	0	0	0	0	2	0	2
Georgia	Glascock	3	0	0	0	0	0	0	0	0	0
Georgia	Jefferson	17	11	0	0	0	0	0	10	0	4
Georgia	Jenkins*	8	2	0	0	0	0	0	1	0	2
Georgia	Johnson	1	0	0	0	0	0	0	0	0	0
Georgia	Lincoln	2	0	0	0	0	0	0	0	0	0
Georgia	McDuffie	19	7	0	0	0	0	0	6	0	0
Georgia	Richmond*	125	63	0	0	0	0	0	61	0	30
Georgia	Screven*	14	5	0	0	0	0	0	4	0	0
Georgia	Warren	1	0	0	0	0	0	0	0	0	0
Georgia	Washington	2	2	0	0	0	0	0	2	0	0
South Carolina	Aiken	101	17	0	0	0	0	0	17	1	6
South Carolina	Allendale*	11	10	0	0	0	0	0	10	0	5
South Carolina	Bamberg	17	9	0	0	0	0	0	9	0	3
South Carolina	Barnwell*	19	8	0	0	0	0	0	8	0	1
South Carolina	Colleton	2	0	0	0	0	0	0	0	0	0
South Carolina	Edgefield	15	7	0	0	0	0	0	6	0	1
South Carolina	Hampton	13	6	0	0	0	0	0	6	0	1
South Carolina	Jasper	2	1	0	0	0	0	0	1	0	0
South Carolina	Lexington	6	0	0	0	0	0	0	0	0	0

Table 2.6.2-1. (Cont'd) Minority and Low Income Population Census Blocks within 50-Mile Radius of the VEGP Site

State	County	Total Block Groups within 50 miles	Minority								Low-Income Households
			Black	Alaskan Indian or Native American	Asian	Native Hawaiian or Pacific Islander	Other	Multi-Racial	Aggregate[a]	Hispanic	
South Carolina	McCormick	1	0	0	0	0	0	0	0	0	0
South Carolina	Orangeburg	13	4	0	0	0	0	0	4	0	0
South Carolina	Saluda	4	2	0	0	0	0	0	2	0	0
Totals:		**491**	**175**	**0**	**0**	**0**	**0**	**0**	**168**	**1**	**72**

Block Groups where minorities or low-income populations exceed 50 percent

State	County	Total Block Groups within 50 miles	Black	Alaskan Indian or Native American	Asian	Native Hawaiian or Pacific Islander	Other	Multi-Racial	Aggregate[a]	Hispanic	Low-Income Households
Georgia	Bulloch	30	7	0	0	0	0	0	7	0	3
Georgia	Burke*	18	11	0	0	0	0	0	11	0	1
Georgia	Candler	3	0	0	0	0	0	0	0	0	0
Georgia	Columbia	30	1	0	0	0	0	0	1	0	0
Georgia	Effingham	2	0	0	0	0	0	0	0	0	0
Georgia	Emanuel	12	2	0	0	0	0	0	2	0	0
Georgia	Glascock	3	0	0	0	0	0	0	0	0	0
Georgia	Jefferson	17	10	0	0	0	0	0	12	0	0
Georgia	Jenkins*	8	2	0	0	0	0	0	2	0	0
Georgia	Johnson	1	0	0	0	0	0	0	0	0	0
Georgia	Lincoln	2	0	0	0	0	0	0	0	0	0
Georgia	McDuffie	19	6	0	0	0	0	0	7	0	0
Georgia	Richmond*	125	62	0	0	0	0	0	68	0	9
Georgia	Screven*	14	4	0	0	0	0	0	4	0	0

Table 2.6.2-1. (Cont'd) Minority and Low Income Population Census Blocks within 50-Mile Radius of the VEGP Site

State	County	Total Block Groups within 50 miles	Minority								Low-Income Households
			Black	Alaskan Indian or Native American	Asian	Native Hawaiian or Pacific Islander	Other	Multi-Racial	Aggregate[a]	Hispanic	
Georgia	Warren	1	0	0	0	0	0	0	0	0	0
Georgia	Washington	2	2	0	0	0	0	0	2	0	0
South Carolina	Aiken	101	17	0	0	0	0	0	17	0	1
South Carolina	Allendale*	11	10	0	0	0	0	0	10	0	0
South Carolina	Bamberg	17	9	0	0	0	0	0	10	0	0
South Carolina	Barnwell*	19	8	0	0	0	0	0	9	0	0
South Carolina	Colleton	2	0	0	0	0	0	0	0	0	0
South Carolina	Edgefield	15	7	0	0	0	0	0	8	0	0
South Carolina	Hampton	13	6	0	0	0	0	0	6	0	0
South Carolina	Jasper	2	1	0	0	0	0	0	1	0	0
South Carolina	Lexington	6	0	0	0	0	0	0	0	0	0
South Carolina	McCormick	1	0	0	0	0	0	0	0	0	0
South Carolina	Orangeburg	13	4	0	0	0	0	0	4	0	0
South Carolina	Saluda	4	2	0	0	0	0	0	2	0	0
Totals:		**491**	**171**	**0**	**0**	**0**	**0**	**0**	**183**	**0**	**14**

State Percentages

State	Black	Alaskan Indian or Native American	Asian	Native Hawaiian or Pacific Islander	Other	Multi-Racial	Aggregate[a]	Hispanic	Low-Income (Households)
Georgia	28.70	0.27	2.12	0.05	2.40	1.39	34.93	5.32	12.64
South Carolina	29.54	0.34	0.90	0.04	1.00	1.00	32.81	2.37	14.11

* Counties completely within the 50-mile radius.
[a] All minorities, except Hispanic ethnicity

Table 2.6.2-2. Farms that Employ Migrant Labor in the Region of Interest[a]

County	Total Farms[b]	Farms with Migrant Labor[c]	Percent of Total Farms
Georgia			
Burke	494	9	2
Richmond	140	0	0
Columbia	196	0	0
Jenkins	240	2	<1
Screven	347	4	1
Emanuel	554	5	1
Jefferson	388	1	<1
McDuffie	296	48	16
South Carolina			
Aiken	929	21	2
Edgefield	325	9	3
Allendale	156	6	4
Barnwell	370	16	4
Bamberg	340	13	4
Hampton	248	0	0

a Includes counties with approximately more than half their area within the 50-mile radius.

b From Table 1 (USDA 2004a, 2004b)

c From Table 7 (USDA 2004a, 2004b)

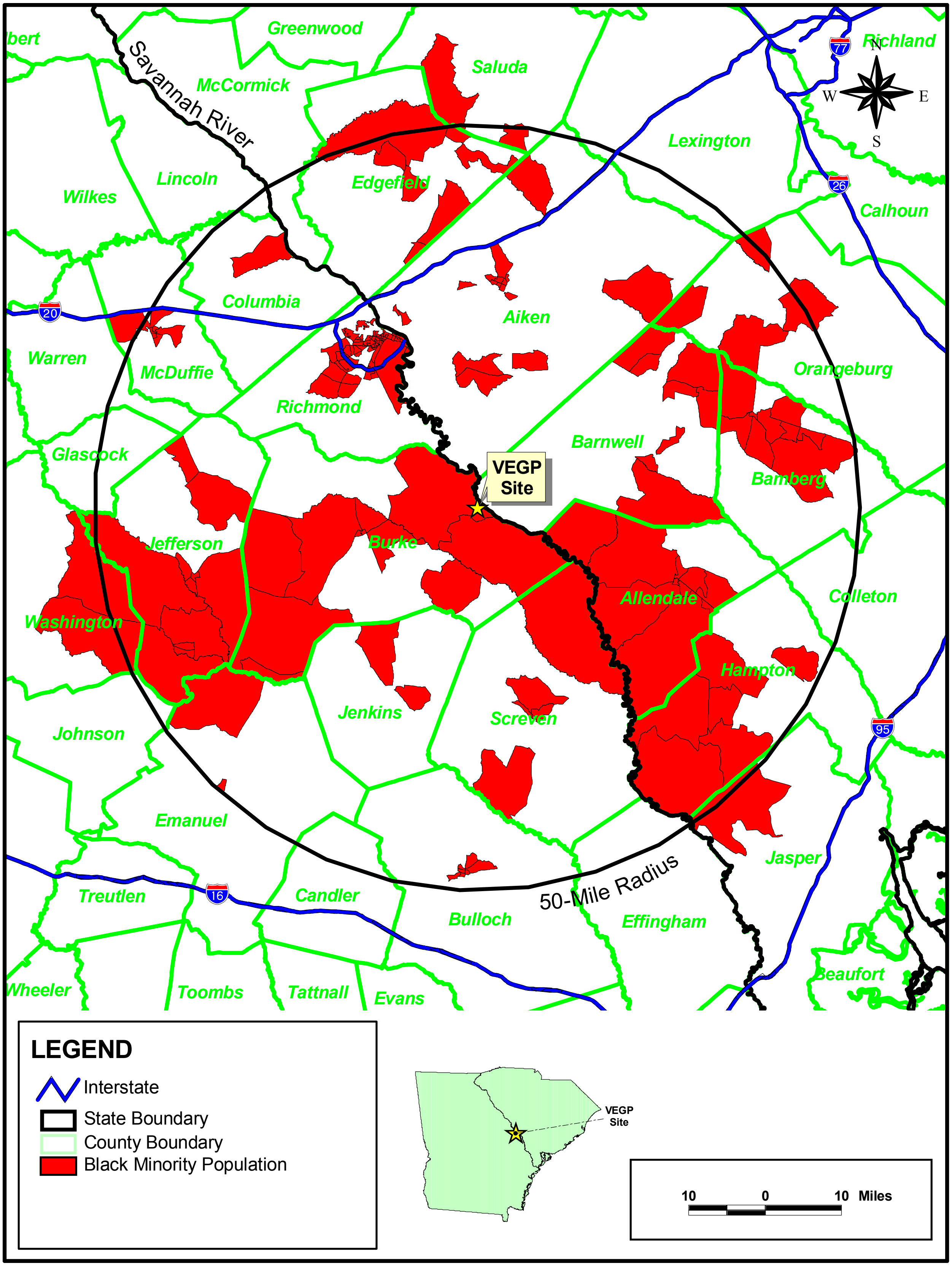

Figure 2.6.2-1 Black Minority Population Block Groups within the 50-Mile Radius of VEGP

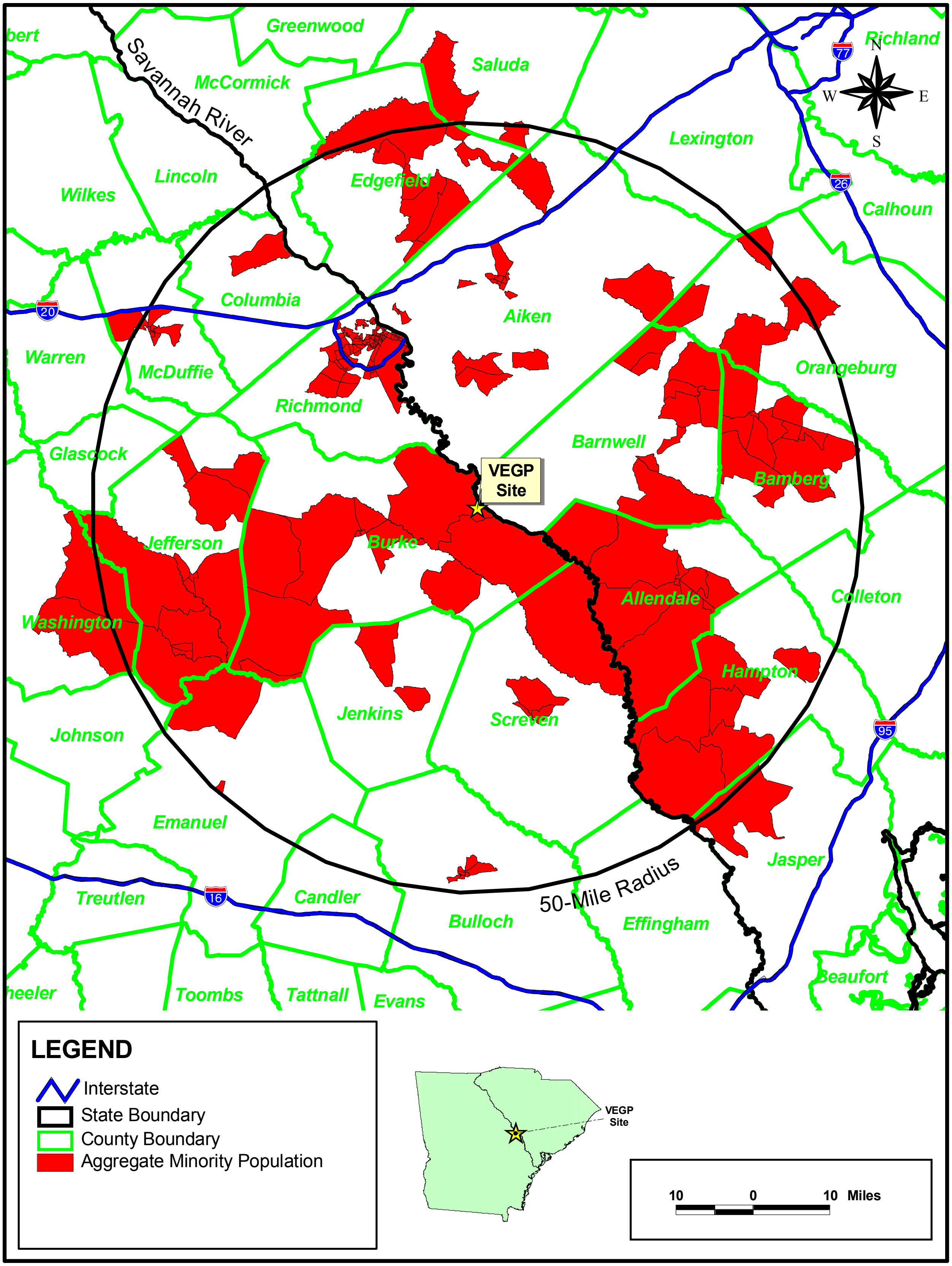

Figure 2.6.2-2 Aggregate of Minority Population Block Groups within the 50-Mile Radius of VEGP

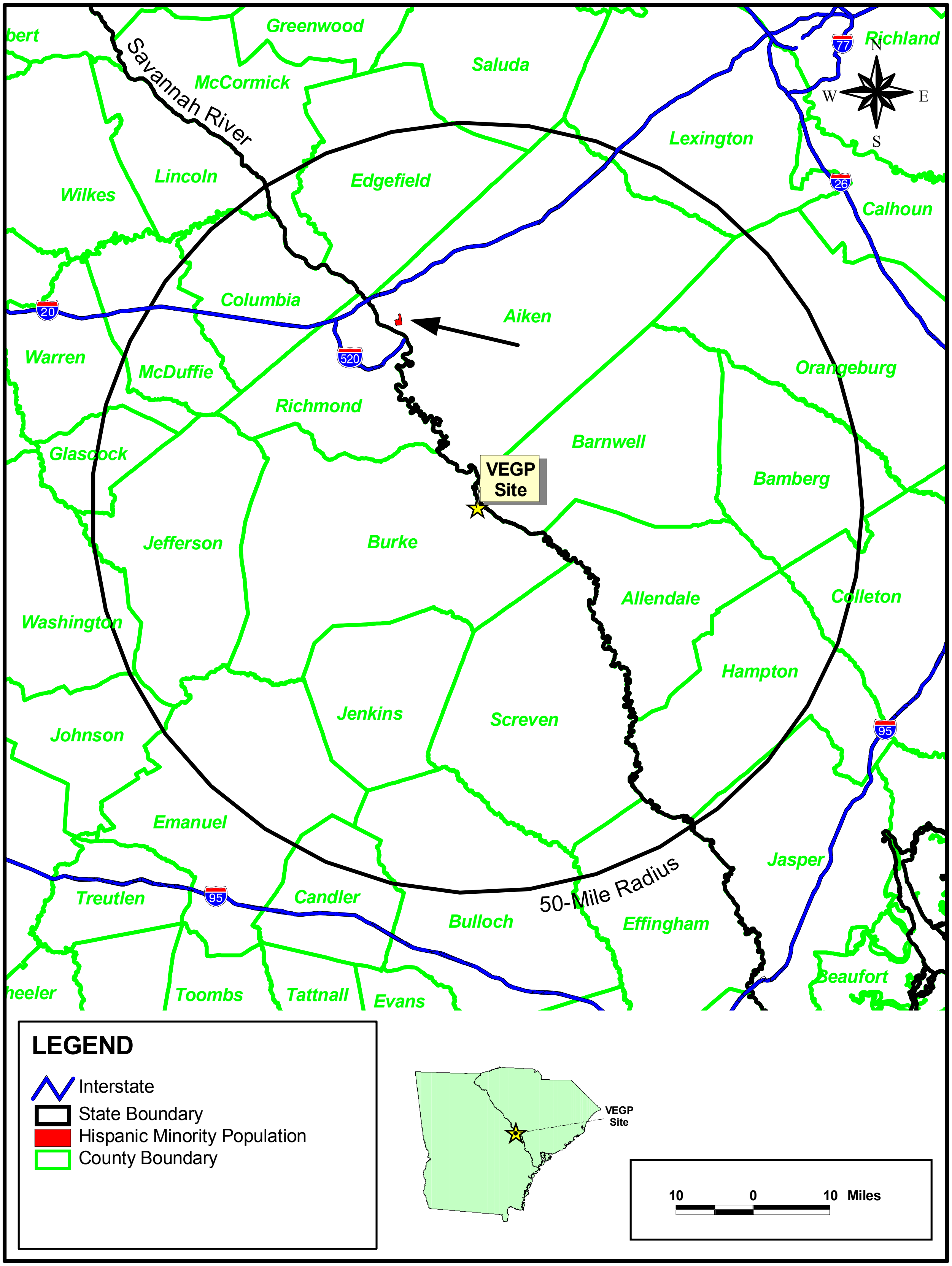

Figure 2.6.2-3 Hispanic Ethnicity Population Block Groups within the 50-Mile Radius of VEGP

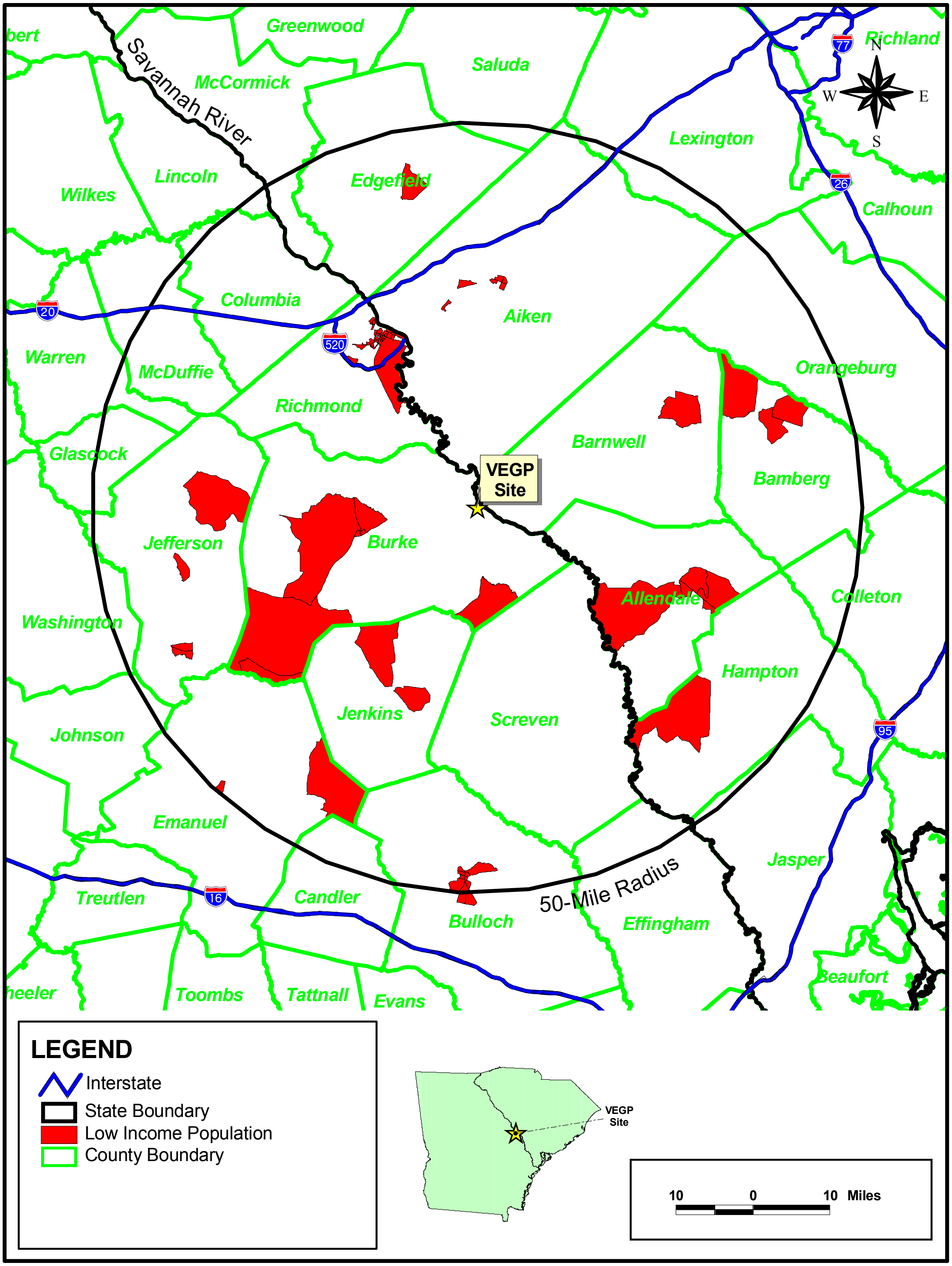

Figure 2.6.2-4 Low-Income Population Block Groups within the 50-Mile Radius of VEGP

2.7 Taxes

SNC pays annual property taxes for VEGP to Burke County, so the focus of this analysis will be on Burke County. Table 2.7-1 presents information on the total property taxes SNC pays to Burke County, the total property taxes collected, and the percent of the total property taxes that are paid by SNC.

From 2000 to 2004, Burke County collected between $29,713,972 and $30,758,563 annually in tax revenues. Each year, Burke County collects these taxes, retains a portion for county operations and disburses the remainder to the state, the school district, and fire/emergency management/public safety services to fund their respective operating budgets (Burke County Tax Commission 2006). For the years 2000 through 2004, VEGP's property taxes have represented 79.8 to 82.2 percent of Burke County's total tax revenues. Over the past five years, the County has disbursed the majority of the tax revenues to the Burke County School District (Burke County Tax Commission 2006).

VEGP's Unit 1 and Unit 2 annual property taxes are expected to remain relatively constant through the license renewal period. The State of Georgia has taken no action with respect to electric utility deregulation. Therefore, the potential effects of deregulation are unknown at this time. Should deregulation ever be enacted in Georgia, this could affect utilities' tax payments. However, any changes to VEGP property tax rates due to deregulation would be independent of license renewal.

Table 2.7-1. VEGP Property Tax Information

Year	Total Burke County Property Tax Revenues[a] ($)	Portion of Burke County Tax Revenues Disbursed to the Burke County School District ($)	Property Tax Paid by SNC ($)	Percent of Total Property Taxes Paid By SNC (%)
2000	30,329,024	19,116,331	24,930,927	82.2
2001	30,758,563	18,691,850	25,276,404	82.2
2002	29,713,972	18,022,492	23,699,476	79.8
2003	30,029,880	18,160,393	24,341,247	81.1
2004	29,805,738	17,838,847	24,358,042	81.7

Sources: SNC 2005; Burke County Tax Commission 2006

2.8 Land Use

The county with the greatest potential to be impacted by land-use changes as a result of VEGP operations is Burke County, which is the recipient of VEGP property tax payments. Although only 20 percent of the VEGP workforce lives in Burke County and 59 percent lives in either Richmond or Columbia counties, these latter two counties will not be analyzed because they have relatively large populations that sufficiently dilute any population impacts caused by residents employed at VEGP residents and they do not receive VEGP property tax payments. Richmond and Columbia Counties' 2000 populations were 199,775 and 89,288, respectively. Assuming a maximum license renewal workforce of 60 (Section 3.4), 59 percent equates to approximately 35 people or less than 0.0003 percent of the Columbia County population. Therefore, this discussion on land use focuses on the immediate VEGP vicinity and Burke County only.

Burke County and its municipalities use various planning tools such as comprehensive land use plans, land development codes, zoning, and subdivision regulations to guide development. The County encourages growth in areas where public facilities, such as water and sewer systems, exist or are scheduled to be built in the future. Burke County promotes the preservation of its communities' natural resources and has no growth control measures.

Burke County has the second largest land area of any county in Georgia. The predominant land uses are agriculture and forestry (97 percent of the unincorporated area in the county in 1990) (Burke County 1991). Fifteen percent of the county is classified as preferential agriculture, and is bound by covenant to remain agricultural for a given time. Less than one percent of the land was classified as industrial or commercial in 1990 (Burke County 1991). The only major park, recreation area or conservation area is the Yuchi WMA. Table 2.8-1 shows a breakdown of land-use type and area in Burke County. Figure 2.8-1 identifies land use within 6 miles of VEGP.

The Burke County Comprehensive Plan (Burke County 1991) identifies five land use issues:

- Burke County is the second largest Georgia county in land area.
- More than 97 percent of the usable land in the county is in agriculture or forestry.
- Nearly 15 percent of the total county acreage is classified as preferential agriculture, meaning it must remain agricultural for a specific number of years.
- Waynesboro has a comprehensive zoning ordinance.
- The county has a land development code which sets forth minimum development standards for various land uses.

The plan also identifies four goals:

- Provide for an efficient distribution of land use so that non-residential activities do not adversely impact residential activities,
- Identify and acquire a site for a landfill,
- Discourage development which would be detrimental to environmentally sensitive and historic areas of the county,
- Encourage development in areas which are already served by community services and roads.

Burke County is revising its comprehensive plan and developing a zoning plan but currently does not have zoning.

There are no Native American tribal land-use plans for any areas within the 50-mile region.

Table 2.8-1. Land Use Acreages in Unincorporated Burke County

Existing Land Uses	Burke County[1] Acreage(1990)
Residential	25,767
Commercial	731
Industrial	201
Transportation/communications/ utilities	No data
Public/Institutional	9,254
Parks/Open Space/ Conservation	No data
Agriculture/Forestry/Undeveloped	440,307 (includes open space)

1 Burke County 1991, Table 6-1

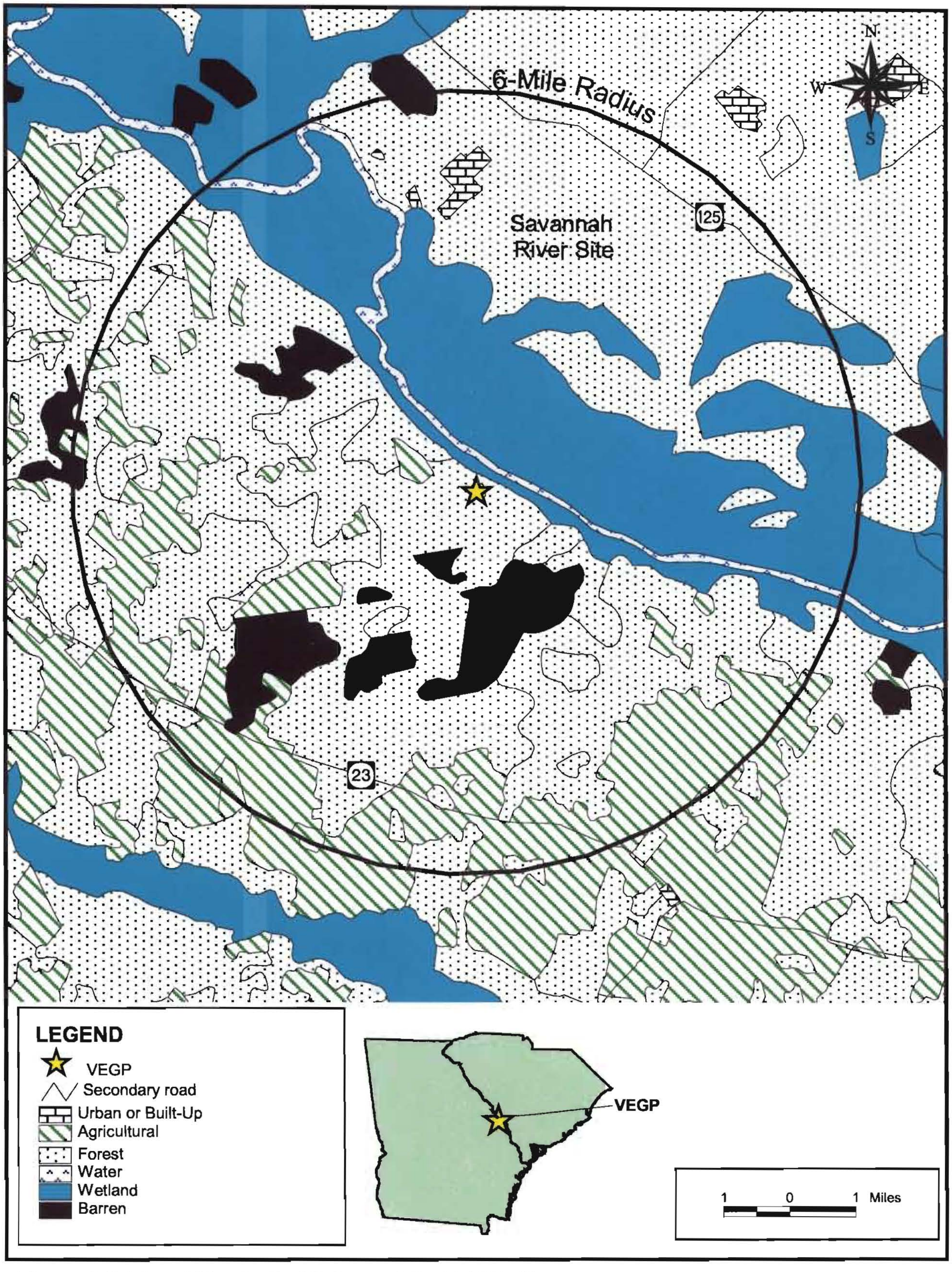

Figure 2.8-1 Land Use in the Vicinity of the VEGP site

2.9 Social Services and Public Facilities

2.9.1 Public Water Supply

Because VEGP is located in Burke County and most of the VEGP employees reside in Burke, Richmond, or Columbia Counties, the discussion of public water supply systems will be limited to those three counties.

VEGP uses 1.052 million gpd of groundwater from nine onsite groundwater wells. VEGP is permitted to withdraw an annual average of 5.5 million gpd.

In the Central Savannah River Area, water sources can be surface water, such as rivers, lakes, and streams, or groundwater. The land north of the Fall Line, which lies north of I-20, is characterized by a limited groundwater supply due to the dense, crystalline rock underlying the area. Most of the large municipal systems above the Fall Line obtain water from the Savannah River or one of its impoundments. However, some of the smaller municipalities above the Fall Line have wells that adequately meet water demands. Columbia County lies north of the Fall Line and most of its water is provided from surface water.

In the Coastal Plains of Georgia and South Carolina, south of the Fall Line, there are two major regional aquifer systems (see Section 2.3). The yields from these systems could support systems requiring nearly 3 million gpd. Consequently, most counties in the Coastal Plain obtain their water from groundwater. Richmond and Burke Counties water suppliers obtain the majority of their water from these aquifers. Some municipalities use the Savannah River to supplement deep wells. Table 2.9.1-1 details water suppliers in the three counties, their permitted capacities, and their average daily production. (CSRARDC 2005)

Many groundwater users in the lower Savannah River basin will be required to replace groundwater use with surface water due to concerns about saltwater intrusion into groundwater. Because of increased saltwater intrusion in the lower basin, Georgia and South Carolina capped current groundwater use in coastal counties at specified levels, directing that future coastal water supply be met with surface water from the Savannah River (USACE 1999).

According to local planning officials, water supply in the region is adequate. However, for Burke County the total increase in future water demand for combined surface water and groundwater usage is estimated to be over 50 percent by 2035 (Rutherford 2000). Local communities are adequately served by the existing water supply and planners estimate that the region will have adequate supply at least through the current planning periods.

Table 2.9.1-1. Largest State-Regulated Public Water Systems in the Three-County Area, 2005[a]

System Name	Permitted *Annual* Average Withdrawal (MGD)	Reported *Annual* Average Withdrawal (MGD)	Population Served – Groundwater and Surface Water
Groundwater			
Burke County			
Waynesboro	3.50	0.79	5,813
Sardis	0.40	0.07	1,152
Columbia County			
Columbia County	0.58	0.00	77,280
Grovetown	0.90	0.13	5,500
Harlem	0.25	0.02	4,290
Richmond County			
Augusta-Richmond County Water System	17.40	8.40	200,000
Hephzibah	1.20	0.34	3,011

System Name	Permitted *Monthly* Average Withdrawal Million Gallons Per Day (MGD)	Reported *Monthly* Average Withdrawal – 12 Month Range (MGD)	Population Served – Groundwater and Surface Water
Surface Water			
Burke County			
Waynesboro	1.00	0.10 – 0.19	5,813
Sardis	N/A	N/A	1,152
Columbia County			
Columbia County – Permit # 036-0109-04	8.0	0.82 – 2.69	77,280
Columbia County – Permit # 036-0110-01	31.00	7.53 – 15.09	
Grovetown	N/A	N/A	5,500
Harlem	N/A	N/A	4,290
Richmond County			
Augusta-Richmond County Water System – Permit # 121-0191-06	45.00	24.40 – 35.10	200,000
Augusta-Richmond County Water System – Permit # 121-0191-09	15.00	0.00 – 9.24	
Hephzibah	N/A	N/A	3,011

Source: EPA 2005
a Systems using 100,000 or more gallons of water per day.
N/A System does not use this type of water.

2.9.2 Transportation

Within the three counties of interest, there is one interstate highway; I-20, which runs east-west through Georgia and South Carolina connecting Atlanta to Columbia, and includes the I-520 connector being constructed around Augusta. A number of U.S. and State Routes intersect I-20 and connect to the towns within the counties, providing outlying areas access to the interstate system. For example, U.S. Route 221 runs north from I-20 to Appling, the Columbia County seat, and U.S. Route 25 runs south from I-20 to Waynesboro, the Burke County seat.

Workers commuting to VEGP take primarily one of three routes. Workers living in Columbia County take U.S. or State Routes to I-20 east. From I-20, workers follow I-520 south around Augusta to State Route 56 (also known as Old Savannah Road). After crossing into Burke County they take the east fork of State Route 56 (which becomes County Road 59, also known as River Road, in Burke County). River Road goes directly to VEGP. Figure 2.9.2-1 presents the transportation system in Burke County.

Workers living within the Augusta city limits use I-520 or State Route 56 to County Road 59 and VEGP. Workers living southeast of Fort Gordon either connect directly to State Route 56 from one of the county roads, or use U.S. Route 25, which runs parallel to State Route 56, until they reach a county road that connects U.S. Route 25 to State Route 56. From there, they follow the same route south and east to VEGP.

Workers commuting from within Burke County to VEGP can use a number of state routes, depending on their location with respect to Waynesboro. Those commuters living west of Waynesboro can use State Route 56 northeast, State Route 24 east, or State Route 80 east, all of which merge to become State Route 80 east. State Route 80 east runs through Waynesboro, connecting first to State Route 23 and then to River Road. Workers commuting from east of Waynesboro take either State Route 24, which intersects with State Route 80 (following the above route to the VEGP), or State Route 23 northeast to the local Ebenezer Church Road, which connects to River Road. They can also take State Route 23 directly to River Road (Figure 2.9.2-1).

In determining the significance levels of transportation impacts for license renewal, NRC uses the Transportation Research Board's level of service (LOS) definitions (NRC 1996). The Georgia Department of Transportation (GDOT) makes LOS determinations for roadways involved in specific projects. However, there are no current LOS determinations for the roadways analyzed in this document. As LOS data are unavailable, annual average daily traffic (AADT) volumes are substituted. Table 2.9.2-1 lists the roadways VEGP workers would use, the GDOT road classifications for each road, number of lanes, the 2004 AADT counts at the traffic count sections (TCS) of the road, and maximum road capacities. Data in the table indicate that current AADTs are well below maximum capacities for the roads leading to VEGP.

Table 2.9.2-1. Statistics for Most Likely Routes to the VEGP Site[a]

Location Number on Figure 2.9.2-1	Burke County	Number of Lanes	GDOT Road Classification[b]	Traffic Count Marker Number	Average Annual Daily Traffic (AADT) for 2004	Maximum Capacity (passenger cars per hour)[c]
22	State Route 23 (outside Girard heading southeast)	2	Major collector (R)	117	1,735	3,200
23	State Route 23 (outside Girard heading northwest)	2	Major collector (R)	121	2,473	3,200
24	State Route 23 (between Girard and SR 23/SR 80 interchange, near Rouse Stone Road)	2	Major collector (R)	123	2,240	3,200
25	State Route 23 (between SR 56/SR 23 interchange and SR 23/SR 80 interchange)	2	Major collector (R)	125	3,049	3,200
26	State Route 24 (intersection of SR 56, SR 24 and SR 80)	2	Major collector (R) Minor arterial (R)	149	4,654	3,200
27	State Route 56 (at McBean Club Road)	2	Minor arterial (R)	159	887	3,200
28	State Route 80 (approximately 2 miles west of State Route 23)	2	Major collector (R)	187	927	3,200
29	State Route 80 (approximately 3 miles east of State Route 23)	2	Major collector (R)	189	264	3,200
30	State Route 56 (northeast of Waynesboro, near Thompson Road)	2	Minor arterial (R)	171	8,303	3,200
31	US Route 25 (State Route 121) – from Augusta (near Hunnicutt Road)	2	Principal arterial (R)	211	8,332	3,200
32	County Road 455 (Story Mill Road) – from Hephzibah (near County Road 456)	2	Major collector (R)	267	804	3,200

Table 2.9.2-1 (cont'd). Statistics for Most Likely Routes to the VEGP Site[a]

Location Number on Figure 2.9.2-1	Burke County	Number of Lanes	GDOT Road Classification[b]	Traffic Count Marker Number	Average Annual Daily Traffic (AADT) for 2004	Maximum Capacity (passenger cars per hour)[c]
33	County Road 59 (River Road) (near CR 57 [Hatcher Road])	2	Major collector (R)	269	1,277	3,200
34	County Road 57 (Hatcher Road) (west of SR 23 intersection)	2	Major collector (R)	279	534	3,200
35	County Road 57 (Hatcher Road) (east of SR 23 intersection)	2	Local (R)	279	534	3,200

Sources: GDOT 1987a, 1987b, 1992, 1999, 2004, 2005.

[a] See also Figure 2.9.2-1. The traffic counts are identified on the figure with numbers that correspond to the numbers on this table.

[b] R= Rural; U = Urban. "R" or "U" designation is included if not apparent from definition of roadway.

[c] Traffic counts for both directions of route.

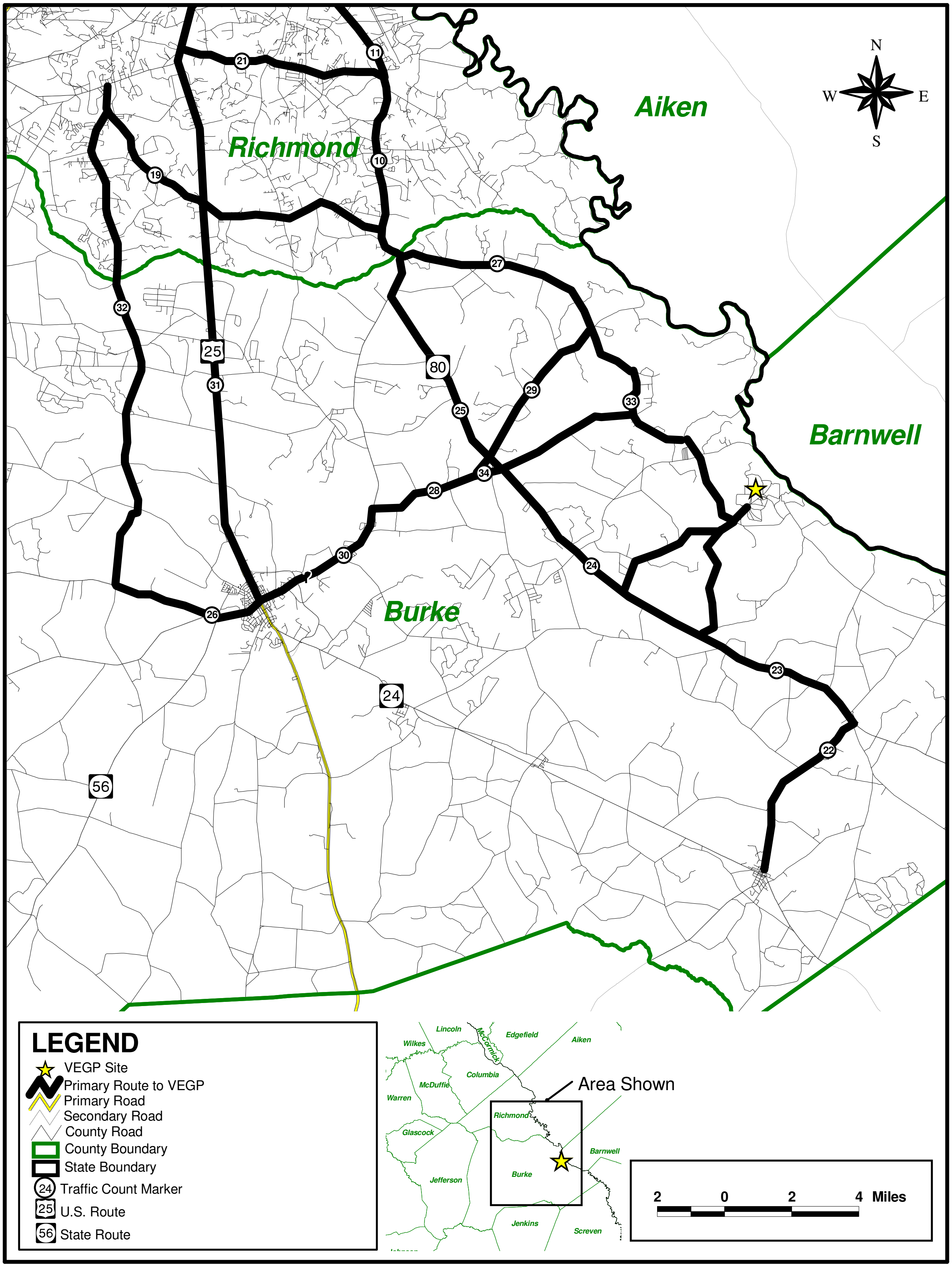

Figure 2.9.2-1Transportation System in Burke and Richmond Counties

2.10 Meteorology and Air Quality

VEGP is located in Burke County Georgia, which is part of the Augusta-Aiken Interstate Air Quality Control Region (AQCR) (40 CFR 81.114). This region has a humid subtropical climate characterized by long periods of mild sunny weather in the autumn, short mild winters, somewhat more windy but mild weather in the spring, and long hot humid summers. VEGP is located in a region of relatively low tornado activity and is far enough inland that the strong winds associated with tropical storms and hurricanes are greatly reduced, although these storms can cause heavy precipitation in late summer (SNC 2005).

All areas within the Augusta-Aiken AQCR are classified as achieving attainment with the National Ambient Air Quality Standards (NAAQS) (40 CFR 81.311 and 40 CFR 81.341). The NAAQS define ambient concentration criteria for sulfur dioxide (SO_2), particulate matter with aerodynamic diameters of 10 microns or less (PM_{10}), particulate matter with aerodynamic diameters of 2.5 microns or less ($PM_{2.5}$), carbon monoxide (CO), nitrogen dioxide (NO_2), ozone (O_3), and lead (Pb). These pollutants are generally referred to as "criteria pollutants." Areas of the United States having air quality as good as or better than the NAAQS are designated by the EPA as attainment areas. Areas having air quality that is worse than the NAAQS are designated by EPA as non-attainment areas. The nearest non-attainment area to VEGP is the Columbia, South Carolina metropolitan area, a non-attainment area under the 8-hour ozone standard, located approximately 80 miles northeast of the plant.

2.11 Cultural Resources

The Central Savannah River Area is one of the oldest and most historically rich areas of the state. Colonists led by James Oglethorpe settled Savannah in 1733 and Augusta in 1736. Native Americans and early settlers used the Savannah River as a major transportation route between the Coast and the Piedmont. Burke County is one of Georgia's original eight counties, and was named for Edmund Burke, an English spokesman for American liberty.

SNC has initiated informal discussions with the Georgia State Historic Preservation Office (SHPO) regarding the construction of proposed new units, and the license renewal process. Agreement has been reached on management of cultural resource issues and documentation of the terms of the agreement should be available by the end of the summer 2007. No new cultural resource issues are anticipated as a result of license renewal activities. Existing commitments and monitoring for cultural resources will continue through the renewed license period.

Historic or Archaeological Sites in the Vicinity of the VEGP Site

The Environmental Report (GPC 1972) and the Final Environmental Statement (FES) (AEC 1974) describe the known historic resources in the area in the early 1970s. Shell Bluff Landing is approximately 7 miles north-northwest of the VEGP site. It has both historic and archaeological significance. It was the site of the original grave of Dr. Lyman Hall, a signer of the Declaration of Independence. His body was later reinterred in Augusta. The original ER also reports that Shell Bluff Landing was important during the era of steamboat river traffic and was fortified during the War Between the States. Shell Bluff takes its name from a large bed of fossils of the giant oyster (*Crassostrea gigantissima*) found there. This bed likely was formed during the Eocene epoch when the coastal plain of Georgia was under the Atlantic Ocean. The site of an Indian village with artifacts dated from 4,000 years ago lies between Shell Bluff and Boggy Gut Creek, approximately 7.5 miles from VEGP. (GPC 1972)

Seven sites in Burke County are on the National Register of Historic Places (Table 2.11-1). One National Register listed building, the Sapp Plantation, is within 10 miles of VEGP. The SRS, located directly across the Savannah River from VEGP, is the only other historical site within 10 miles determined to be eligible for listing, is directly across the Savannah River from VEGP, in South Carolina. Twenty-two archaeological sites on the SRS and within 10 miles of VEGP have been determined to be eligible for listing.

Since the original ER was written, two important discoveries have been made near the Vogtle site and are discussed below.

The University of South Carolina Institute of Archaeology and Anthropology is excavating a prehistoric site on the Savannah River in Allendale County, approximately 15 miles downstream of the Vogtle property. Material from the site has been tentatively dated to 50,000 years ago (Powell 2004). If the dating techniques are accurate, the site, known as the Topper site, provides the earliest evidence of humans on the North American continent.

In 1983, during construction of the VEGP intake structure, the fossil of a 40-million-year-old whale species was uncovered in the Blue Bluff marl approximately 30 feet below ground surface. The skeleton of the whale, now known as *Georgiacetus vogtlensis*, is housed at the Georgia Southern University Museum in Statesboro, Georgia. (Reuters Limited 1998)

Historic or Archaeological Sites on the VEGP Site

In 1973 an archaeological survey of the VEGP site was performed under the direction of the Georgia State Archaeologist and the Georgia Historical Commission and submitted to the U.S. Atomic Energy Commission (the predecessor agency to the NRC). The survey identified seven archaeological sites (GPC 1972) (New South Associates [NSA] 2006). Four sites are along the river bluff, south of the barge canal. One was destroyed during construction of the barge slip. This site is the location of the Brown Cabin, which apparently also was destroyed during construction. The remaining two sites are shown to be on the plateau west of Mallard Pond on the maps in the 1973 report, however, the Universal Transverse Mercator (UTM) coordinates for these two sites do not place them in the location shown on the report map (NSA 2006). Based on the 1973 study the State Archaeologist considered that the archaeological resources at the VEGP site had been sufficiently characterized (GPC 1972; amendment 3, 2/27/1974).

In 2005 NSA surveyed VEGP property likely to be disturbed during construction of proposed new units. The survey identified 10 new archaeological sites (3 historic and 7 prehistoric) and 7 isolated finds (NSA 2006). None of the seven sites identified in the 1973 survey were examined during the 2005 survey. Two of the new sites are eligible and two are potentially eligible for inclusion on the National Register of Historic Places. The rest are recommended ineligible. Table 2.11-2 provides brief descriptions of the sites.

Native American Cultural Resources and Concerns

No federally-recognized tribes reside in the state of Georgia. Through OCGA 44-12-300, the state of Georgia officially recognized the following tribes of Georgia as legitimate American Indian tribes (500 Nations 2005):

- The Georgia Tribe of Eastern Cherokee, P.O. Box 1015, Cummings, Georgia 30028
- The Lower Muscogee Creek Tribe, Route. 2, Box 370, Whigham, Georgia 31797
- The Cherokee of Georgia, Saint George, Georgia 31646

Native Americans that settled in the Burke County area include a band of Chickasaw that "lived near Augusta from about 1723 to the opening of the American Revolution: (Georgia Indian

Tribes 2005) and a Shawnee band "which settled near Augusta" (Georgia Indian Tribes 2005). The Muskogee were the dominant tribe on either side of the Savannah River before the Europeans settled in North America (Sturtevant 1966).

The Catawba Indian Nation (P.O. Box 188, Catawba, SC 29704) is the only Federally-recognized tribe in South Carolina. The State of South Carolina (S.C. Code Chapter 139, Section 1-31-40(A)(10) officially recognizes the following tribes/groups as legitimate Native American Tribes and Groups (SCCMA No Date).

- The Waccamaw Indian People, P.O. Box 628, Conway, SC, 29528
- The Pee Dee Indian Nation of Upper South Carolina, 3814 Highway 57 N, Little Rock, SC 29576
- The Pee Dee Indian Tribe of South Carolina, P.O. Box 557, McColl, SC, 29507
- The Santee Indian Organization, 432 Bayview St., Holly Hill, SC 29059
- The Beaver Creek Indians, P.O. Box 699, Salley, SC, 29137
- The Eastern Cherokee, Southern Iroquois and United Tribes of South Carolina
- The Wassaamasaw Tribe of Varnertown Indians
- The Chaloklowa Chickasaw Indian People, 500 Tanner Lane, Hemingway, SC 29554
- The Piedmont American Indian Association, Lower Eastern Cherokee Nation of South Carolina
- The American Indian Chamber of Commerce of South Carolina, 9377 Koester Lane, Ladson, SC 29456

Table 2.11-1. National Register of Historic Sites Listings in Burke County, Georgia

Resource Name	Address	City	Distance from VEGP
Burke County Courthouse	Courthouse Square	Waynesboro	15 miles
Haven Memorial Methodist Episcopal Church	Barron St., South of Junction of Barron St. and 6th St.	Waynesboro	15 miles
Hopeful Baptist Church	Winter Rd., East of Junction with Blythe Road	Keysville	30 miles
John James Jones house	525 Jones Ave.	Waynesboro	15 miles
McCanaan Missionary Baptist Church and Cemetery	McCanaan Church Road	Sardis	12 miles
Sapp Plantation	NW of Sardis on GA 24	Sardis	12 miles
Waynesboro Commercial Historic District	E. 6th, E. 7th, E. 8th, S. Liberty, and Myrick Streets	Waynesboro	15 miles

Source: NPS 2005.

Table 2.11-2. Historic or Archaeological Sites Identified During a 2005 Survey of the VEGP Site

Site Number / Location	Description	Eligibility
9BK414; on plateau W of Mallard Pond	Homesite, likely the W. M. Buxton home	
9BK415; just W of railroad cut and approximately 2000 ft E of the nearest site boundary	Homesite identified from a 1989 topographic map that noted a home and outbuilding	
9BK416; on river bluff N of intake structure	Large multi-component prehistoric site	Eligible
9BK417; N of road to barge landing and intake	Liquor still	
9BK418; overlooking headwaters of Mallard Pond; composed of dirt road and landfill pit	Undiagnostic lithic scatter	
9BK419; under transmission line from switchyard to Plant Wilson	Woodland prehistoric site	Potentially eligible
9BK420; under transmission line to Plant Wilson on ridge overlooking Savannah River	Undiagnostic lithic site	Potentially eligible
9BK421; under SCE&G transmission line; bench of a ridge side overlooking Savannah River	Undiagnostic lithic scatter	
9BK422; near the training center overlooking Beaverdam Creek	Small scatter of historic and prehistoric artifacts; disturbed by logging and clearcutting	
9BK423; on a small bench above the floodplain N of the intake structure	Multi-component prehistoric campsite	Eligible

Source: NSA 2006.

2.12 Known or Reasonably Forseeable Projects in Site Vicinity

This section briefly describes federal and other activities in the area and the cumulative impacts that may occur as a result of the proposed action to continue operation of VEGP Units 1 and 2 for an additional 20 years. The cumulative impacts resulting from known and foreseeable projects with the operation of VEGP Units 1 and 2 are evaluated to determine if adverse impacts could occur that would result in required mitigation.

> **Council on Environmental Quality**
>
> "'Cumulative impact' is the impact on the environment which results from the incremental impact of the action when added to past, present, and reasonably foreseeable future actions, regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time." 40 CFR 1508.7

2.12.1 VEGP Power Uprate

A power uprate for Vogtle Units 1and 2 is in process and set for submittal to the NRC in 2007. The uprate is small, approximately 1.7%, and does not produce a significant impact to the environment. An environmental evaluation has been conducted in accordance with the Vogtle Environmental Protection Plan (EPP) as part of the power uprate evaluation and will be summarized in the submittal. Impacts from the power uprate will be SMALL and do not warrant mitigation.

2.12.2 Savannah River Water Quantity Issues

The USACE is responsible for the water quantity in the Savannah River. Three dams operated by the USACE upstream of VEGP have a significant influence on the available flow in the middle and lower reaches of the Savannah River.

- Hartwell Lake and Dam with 2,550,000 acre-feet of gross storage
- Russell lake and dam with 1,026,000 acre-feet of gross storage; and,
- Thurmond (a.k.a. Clarks Hill) Lake and Dam with 2, 510,000 acre-feet of gross storage

The authorized water management goals of this three-dam, multi-use project are specified for normal operation, flood operation, and drought operation in the Corps Water Control Plan:

- For normal conditions, the operation policy is designed to maximize the public benefits of hydropower, flood damage reduction, recreation, fish and wildlife, water supply, and water quality.
- Under flood conditions, the water management objective is to operate the reservoir system to minimize flooding downstream by timing turbine discharge, gate openings, and spillway discharge as required.
- For drought conditions, the water management objectives of the project are:
    - Prevent drawdown of lake levels below the bottom of conservation pool
    - Optimize use available storage during record drought
    - Maintain hydroelectric capability throughout the drought
    - Minimize impacts to recreation during the recreation season (May 1 – Labor day)

The Corps is conducting a basin-wide water resources management study focusing on water-quantity-related issues. They are investigating current operational plans for the three Federal reservoirs on the Savannah River to determine if changes or reallocations are warranted to meet current and future needs for, among other things, flood control, water supply, and water quality. Much of the impetus for the study is the realization that consumptive water use will continue to increase in the future and that the diverse set of water uses from drinking water supply, to hydropower, to recreation will compete for the available water resources. Comprehensive water use planning is essential to ensure that water resources are allocated fairly and equitably among all water uses.

The Corps maintains the New Savannah Bluff Lock and Dam located between VEGP and Augusta. The lock and dam was constructed in 1937 to serve commercial navigation. The lock and dam are necessary to maintain a constant pool elevation, which serves Augusta and North Augusta municipal and industrial water supply intakes and boat races and regattas, even during periods of low flow. (USACE 2004)

Cumulative Impacts to Savannah River Water Quantity

Approximately 80 percent of the water withdrawn from the Savannah River is returned (USACE no date), however there are several significant consumptive users on the river. Approximately 100 facilities withdraw water from the Savannah River. VEGP withdraws a monthly average of 85 MGD. Three of the largest withdrawers (monthly average withdrawal ranging from 130 to 267 MGD) are power plants downstream of VEGP. The Beaufort-Jasper (SC) Water Authority has two drinking water facilities that withdraw more than 24 MGD and the City of Savannah withdraws 50 MGD. The remainders include smaller industrial facilities or small communities that withdraw water directly from the river or its reservoirs and tributaries. Industrial facilities are clustered around Augusta GA, North Augusta, SC and Savannah, GA. As indicated above approximately 80 percent of all surface water removed from the basin is returned to the river system (SNC 2006). Cumulative impacts of all surface water withdrawals from the Savannah River are SMALL and do not warrant mitigation.

2.12.3 Early Site Permit for Additional Nuclear Reactors at VEGP

SNC applied to the NRC for an early site permit (ESP) in August 2006 consistent with the requirements of 10 CFR 52 to support construction and operation of two additional reactors at VEGP.

The site was originally planned for four reactors. SNC submitted comprehensive information on the site and surrounding area to NRC in its application for an early site permit (SNC 2006). NRC is reviewing the ESP application and will prepare an environmental impact statement (EIS) analyzing the impacts on the surrounding communities, including water and ecological resources to determine if the VEGP site is suitable to support additional nuclear power generation. NRC will also evaluate the cumulative impacts of four units on the surrounding environment and include this information in the EIS. The NRC expects to issue a draft EIS for review in September 2007 and issue the final EIS in early 2008.

Cumulative Impact from Additional Reactors at VEGP

Impacts of construction activities for the new units will be managed to ensure impacts to the operation of Units 1 and 2 will not occur and for this discussion only cumulative impacts from the operation of Units 1 and 2 with the operation of two additional reactors (Units 3 and 4) will be evaluated.

The addition of operating two new units will increase groundwater use. The groundwater use requirements of the new units, combined with the existing units will be less that the withdrawal rate currently permitted by the State. Therefore, cumulative impacts to groundwater during the operation of four units will be SMALL and not warrant mitigation.

Noise from the existing units is usually indistinguishable from background, and the new units will generate similar levels of noise. The only other source of industrial noise occurring in a 6-mile radius is a small power facility on the SRS. Cumulative noise pollution in the vicinity of VEGP is expected to be SMALL.

Operational activities that could impact surface water, such as NPDES-permitted discharges, will be SMALL. Based on computer modeling the maximum mixing zone for the existing units' thermal plume is estimated to be 4,300 cu ft with a downstream distance of about 20 feet and a depth of about 10 feet (AEC 1974). Results from the computer modeling done to support the ESP indicate the blowdown from the new units' cooling towers, adjusted by the centerline temperature of the existing thermal plume will result in a new thermal plume with a surface area of approximately 300 sq ft, a cross-sectional area of approximately 115 sq ft, and a volume of approximately 800 cu ft. Neither the existing plume, nor the new plume is large enough to significantly affect the water quality or biota of the river. The new discharge will be downstream of the existing discharge plume and the existing plume will mingle with the new plume. This commingling is reflected in the previously described model, which resulted in an additional 800 cu ft. plume associated with the new discharge. This plume impacts less than 11 percent of the bank-to-bank cross-section area. The cumulative impacts of the plumes from a new discharge with existing discharge on the Savannah River will be SMALL and will not warrant mitigation.

Through the operation of the cooling water intake structures, small numbers of adult and juvenile fish and fish eggs and larvae may become impinged or entrained at VEGP. Based on the results of impingement and entrainment studies performed immediately upstream at SRS and design features of the VEGP cooling water intake structures, cumulative impacts from the operation of the existing intake and the addition of a new intake on the Savannah River are essentially additive. That is, the cumulative impacts are equal to the total of the independent impacts from the existing and the new intake structures. At the average river flow, consumptive use represents approximately 1.4 percent of river flow. At the 7Q10 flow that occurs approximately once per decade, consumptive use represents approximately 3.4 percent of the 7Q10 flow. The impacts of the combined four units consumptive use of water are SMALL and will not warrant mitigation. Even during the extreme low flow event, the impacts remain SMALL. The impacts to both eggs and larval fish at the extreme low flow event are overstated since most of the spawning takes place in spring and early summer when flows are high. For the Savannah River near VEGP, 7Q10 flows occur in the fall, when the presence of eggs and larval fish is significantly lower.

The new cooling system will withdraw make up water from the Savannah River, as does the existing system. The existing units have a maximum actual consumptive water use of 30,000 gpm and the new units have a maximum estimated consumptive use of 28,904 gpm. This withdrawal is less than 2 percent (0.9 -1.8 percent) of the monthly average Savannah River flow at VEGP and less than 3.2 percent (2.7 – 3.2 percent) of the 7Q10 flow. Between VEGP and the nearest downstream users are several large tributary creeks that provide additional flow downstream. The cumulative impacts of VEGP water withdrawal on the Savannah River and downstream users will be SMALL and will not warrant mitigation.

The addition of two new reactors will include adding two natural draft cooling towers in addition to the two existing towers to the local viewscape. The four towers will be in close proximity so the visual impact will be only slightly different than the existing viewscape. Two additional towers will increase the size of the plume and its visibility from offsite areas, but will not change the nature of the visual experience. Cumulative impacts on the viewscape will be SMALL and will not warrant mitigation.

The distance between the additional pair of cooling towers and the existing pair of towers will be approximately 4,000 feet. A single cooling tower's plume is estimated to have a maximum salt deposition rate of 3.6 pounds per acre per month, and that maximum deposition will occur 1,600 feet from the tower. Salt deposition was not estimated for Units 1 and 2. Even assuming that all four towers deposited the maximum of 3.6 pounds per acre per month, SNC does not believe that salt deposition from all four units warrants mitigation for several reasons. The deposition rate is a calculated maximum rate, and so the actual rate will likely be less. The maximum salt deposition from all four towers will not overlap and combine since the distance between the two sets of towers (approximately 4,000 feet) is greater than twice the distance to the maximum deposition of 1,600 feet. The maximum estimated cumulative salt deposition rate is 7.2 pounds per acre per month at 1,600 feet north of the towers (3.6 pounds per acre per tower; well within the NUREG-1555 significant level of 8.9 pounds per acre per month) and will not constitute an adverse impact.

Radionuclide emissions were evaluated as part of the ESP and are summarized here. The new reactor units will release small quantities of radionuclides to the environment. Each new unit is predicted to have liquid emissions of approximately 1,000 curies annually and gaseous emissions of approximately 11,000 curies annually. The existing units' annual measured gaseous and liquid emissions are 115 curies and 1,400 curies respectively. All releases will be within regulatory limits. The cumulative impacts of radionuclide emission released will be SMALL and will not warrant mitigation.

The fuel cycle specific to new units at VEGP will contribute to the cumulative impacts of fuel production, storage and disposal of all nuclear units in the United States, but the cumulative impacts of the fuel cycle for the existing reactors are SMALL and the addition of the impacts of two new units will not change that conclusion. Fuel and waste transportation impacts from two new units also will be SMALL, and will not increase the cumulative impacts of transportation of all nuclear reactor fuel and wastes.

Non-radioactive solid wastes will be disposed in permitted landfills. The volume of additional wastes will be minimized through waste minimization programs, and therefore, cumulative impacts of waste disposal are expected to be SMALL and will not warrant mitigation.

Socioeconomic impacts, including increased tax revenues to Burke County, would be cumulative with socioeconomic changes brought about through the operation of the new units with existing units. Taxes from the four units will fund new infrastructure that could attract residents to Burke County. However, the construction and operation of the existing units did not result in large changes to tax-driven land use changes in Burke County, and it is not expected that the new units will either. The infrastructure of Burke, Richmond, and Columbia Counties is adequate to support new operations employees. No other projects that would involve immigration of a large workforce have been identified in the area. Cumulative socioeconomic impacts would be SMALL.

In conclusion, the impacts from the operation of one of more units at the VEGP site will not contribute significantly to existing or future cumulative impacts to the vicinity or the region.

2.12.4 U.S. Department of Energy's Savannah River Site (SRS)

The SRS is directly across the Savannah River from VEGP. The SRS was created in 1951 as part of the military-industrial complex that manufactured nuclear weapons components. SRS made plutonium, highly enriched uranium, and tritium for nuclear weapons in five nuclear production reactors, which required large amounts of cooling water from the Savannah River. Since the end of the Cold War, production of nuclear materials at SRS has ceased and the reactors are being decommissioned. The SRS has released radioactive and hazardous contaminants into groundwater and surface water, including the Savannah River. Currently SRS is remediating past releases, disposing of low-level radioactive waste in a designated on-site disposal facility and preparing high level radioactive waste and spent (non-commercial) nuclear fuel for ultimate disposal in a geologic repository. SRS has a tritium processing facility, and releases tritium into the atmosphere and on-site streams that drain into the Savannah River. A Mixed Oxide Fuel Fabrication Facility is being constructed to convert excess plutonium into commercial fuel assemblies. Additional information on the SRS is available at its web site, www.srs.gov.

Cumulative Impacts from SRS

The cumulative impacts on the environment from the operation of VEGP and SRS were evaluated, determined to be SMALL, and not warranting mitigation. The primary activities conducted at VEGP and SRS that result in the greatest impact to the environment were water withdrawal and radionuclide releases.

In recent years, SRS ceased all reactor operations, resulting in a significant reduction in the water withdrawal from the Savannah River. The decrease in SRS withdrawals should result in a positive impact to water quantity, water quality and to the aquatic community in the Savannah River.

Both VEGP and the SRS release radionuclides into the atmosphere and the Savannah River. Tritium accounts for nearly all the radioactivity released to the river. The SRS maintains an extensive monitoring program in the Savannah River. In 2004, the average tritium concentration at the Highway 301 Bridge, downstream of VEGP and SRS, from all sources, was

0.061 picocuries per milliliter (WSRC 2005). The EPA maximum contaminant level for maintaining safe drinking water is 20 picocuries of tritium per milliliter based on an annual composite sample. The cumulative impacts of tritium released to the Savannah River from the SRS and VEGP will be SMALL and will not warrant mitigation.

The combined radionuclide exposure to the population from releases at SRS and VEGP were evaluated. This evaluation considered a conservative approach by using the maximum dose in all pathways from SRS and VEGP. The potential maximally exposed individual dose (all pathways) from all SRS releases was 0.15 millirem in 2004 (WSRC 2005). The maximally exposed individual dose from the existing VEGP units in 2004 was 0.091 millirem. Therefore, if the same hypothetical individual was the maximally exposed individual to both SRS and VEGP releases, the total annual dose will be 0.241 millirem per year (SRS maximum release of 0.15 millirem plus VEGP maximum release of 0.091 millirem). The regulatory limit for exposure to an offsite member of the public is 25 millirem per year. Cumulative impacts to the maximally exposed individual will be SMALL and will not warrant mitigation.

2.12.5 Other Activities

Besides VEGP and the SRS, two other sources of radiation, hospitals and a state-owned commercial facility, are in the 50 mile radius of VEGP. The Medical College of Georgia and its teaching hospital, a Veterans Administration hospital, an Army hospital at Fort Gordon, and several large private hospitals are located in Augusta. All of these hospitals use medical isotopes that are discharged into the municipal water treatment system, and ultimately, the Savannah River. Energy Solutions` operates a commercial radioactive waste disposal facility in Barnwell County, SC, adjacent to the eastern side of the SRS. The Barnwell facility is the only state-owned facility currently available to most of the nation for disposal of commercially-generated low-level radioactive waste. After June 30, 2008, the site will accept waste only from organizations located in South Carolina, Connecticut or New Jersey. In accordance with federal guidelines (10 CFR 61.59) and state law (13-7-30 S.C.C.), the State of South Carolina accepts and assumes responsibility for ongoing monitoring, maintenance and custodial care of the site after it is closed (South Carolina Energy Office, no date).

Cumulative Impacts of Other Activities

Radiological dose limits for the protection of the public and workers have been developed by the EPA and NRC to address cumulative impacts of acute and long-term exposure to radiation and radioactive materials. These dose limits are codified in 40 CFR 190 and 10 CFR 20. In addition to VEGP several sources of radiation exist within a 50-mile radius of the plant. As discussed above, the most significant is the SRS, located directly across the Savannah River. It processes tritium for nuclear weapons, and processes radioactive and hazardous waste for permanent disposal on site or offsite. The Energy*Solutions* Low-level Nuclear Waste Disposal Facility is adjacent to the SRS in Barnwell County, South Carolina. Through 2007 it will continue to take low-level radioactive waste from throughout the country. In 2008, it will limit it wastes to that from Connecticut, New Jersey, and South Carolina. It is permitted by the South Carolina Department of Health and Environmental Control. Augusta is a regional medical center with five hospitals, all of which use radioisotopes for diagnostic tests.

SNC has an environmental radiological monitoring program for VEGP and the surrounding area. The findings are published annually in the Radiological Environmental Monitoring Report. The monitoring program measures radioactivity from all sources, and thus provides information on the cumulative radiological impacts. All measurements are well below the codified dose limits. Therefore, the cumulative radiological impacts are SMALL and do not warrant mitigation.

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Chapter 3 Proposed Action

NRC

"…The report must contain a description of the proposed action, including the applicant's plans to modify the facility or its administrative control procedures…. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

SNC proposes that the NRC renew the operating licenses for VEGP. Renewal would give the co-owners and the tate of Georgia the option of relying on VEGP to meet future electricity needs. Section 3.1 discusses the plant in general. Sections 3.2 through 3.4 address potential changes that could occur as a result of license renewal.

3.1 General Plant Information

General information about VEGP is available in several documents. In 1985, the NRC published the *Final Environmental Statement (FES) Related to the Operation of Vogtle Electric Generating Plant Units 1 and 2* (NRC 1985). The GEIS (NRC 1996) describes VEGP features and, in accordance with NRC requirements, SNC maintains the *Updated Final Safety Analysis Report for VEGP* (SNC 2005a). SNC has referred to each of these documents while preparing this environmental report for license renewal.

3.1.1 Reactor and Containment Systems

The VEGP Nuclear Steam Supply System consists of two pressurized water reactors (PWRs) with four-loop steam generator systems provided by Westinghouse. The turbine-generator system was supplied by General Electric (GE). Southern Company Services and Bechtel were the architect-engineers and GPC was the construction contractor. The rated core thermal power for each unit is 3,565 megawatts-thermal (MWt) with an approximate net electrical output of 1,232 megawatts-electrical (MWe) for each unit (SNC 2005a). A power uprate for Vogtle Units 1 and 2 is in process and set for submittal to the NRC in 2007. The uprate is small, approximately 1.7%, and does not produce a significant impact to the environment. An environmental evaluation has been conducted in accordance with the Vogtle EPP as part of the power uprate evaluation and will be summarized in the submittal. Impacts from the power uprate will be SMALL and do not warrant mitigation.

The nuclear steam supply system at VEGP is typical of a Westinghouse four-loop PWR. The primary system reactor core heats pressurized reactor coolant to a temperature of approximately 600^{o}F. In the PWR design, the radioactive reactor coolant in the primary system is isolated from the secondary water system that creates the steam to drive the turbine. The reactor coolant exits the reactor to the steam generator where it transfers heat to the lower-pressure secondary water system, producing steam. The radioactive primary water flows within tubing inside the steam generator and the secondary water flows outside of the tubing but within the shell of the steam generator. The reactor coolant is pumped back to the reactor, where it is reheated to start the heat transfer cycle over again. The (non-radioactive) secondary steam is transported from the steam generator to turbines connected to the electrical generator to produce electricity. After passing through the turbines the steam condenses back to water in the circulating-water-cooled main condenser. The secondary water is returned to the steam generator to repeat the cycle.

The primary containment for each unit consists of vertical, right-cylindrical, pre-stressed, post-tensioned concrete structure with a dome and flat base with a depressed center for a reactor cavity and instrumentation tunnel. The interior is lined with carbon steel plate for leak-tightness.

Vertical wall and dome thickness are 3 ft 9 inches. The concrete reactor containments serve as radiation shields and fulfill a secondary containment function.

The reactor fuel is slightly enriched uranium dioxide pellets sealed in Zircalloy-4/ZIRLO® tubes. Fuel is enriched to no more than 4.95 weight percent, with a burnup rate of approximately 60,000 megawatt days per metric ton uranium.

The containment systems and their engineered safeguards are designed to ensure that offsite doses resulting from postulated accidents are well below the guidelines in 10 CFR 100.

3.1.2 Cooling and Auxiliary Water Systems

At VEGP, the river water intake system draws makeup water from the Savannah River to replace circulating water lost to evaporation, drift and blowdown. A Nuclear Service Cooling Water (NSCW) system consisting of four forced-draft mechanical cooling towers with underground reservoirs is provided as the ultimate heat sink for VEGP. The nuclear service cooling water comes from groundwater wells. All blowdown from both the NSCW and circulating water systems is discharged to the Savannah River, downstream of the intake. Groundwater is also used to provide makeup for the water treatment plant, fire protection system potable and sanitary water systems, and for utility water. VEGP has nine groundwater wells; two large wells MU-1 and MU-2A provide makeup to pure water systems, fire protection, and NSCW makeup meeting most of the VEGP groundwater needs (Table 3.1-1). The following subsections describe water systems at VEGP.

3.1.2.1 Surface Water

VEGP employs a closed-cycle heat dissipation system designed to remove waste heat from the steam condensers. The river water intake system includes the intake canal, a four-bay intake structure, four intake pumps, condensers, two natural draft cooling towers, and an underground single port discharge pipe into the Savannah River.

The intake canal is a 365-ft long, 140-ft wide structure with an earthen bottom at approximately 67 ft above msl and vertical sheet pile sides extending to 98 ft msl. The intake canal has a skimmer weir (elevation 78 ft msl) with guide vanes at the river entrance. The skimmer weir consists of both fixed and removable sections with the fixed sections having elevations below 78 ft msl. A canal weir is located approximately 100 ft inside the canal.

A sedimentation basin between the skimmer weir and canal weir allows silt to settle outside of the intake canal. This arrangement has worked well and no dredging has been required to remove sediment from the intake canal. The depth of the intake canal is monitored regularly to evaluate siltation, and no significant deposition has occurred. The skimmer weir has also been very successful in preventing flotsam from entering the canal. The canal and weir design significantly reduce the amount of sediment entering the canal and the amount of floating material requiring removal by the intake traveling screens.

The intake structure consists of four bays. Each bay contains stop logs, a trash rack, traveling screens, and one pump. Intake velocity through the trash racks is less than 0.5 feet per second. The trash racks are made of vertical flat bars with a cross section of 3.5 inches by 0.5 inches and 3 inches on center. Traveling screens are annealed type 304 stainless steel with 3/8 inch mesh. Debris is rinsed from the traveling screen and sluiced into a debris basket located in a debris basin on the downstream side of the intake structure. The basket is emptied periodically (typically once or twice a year) and the contents disposed at an upland disposal site. Wash water is returned to the river from the debris basket. VEGP personnel responsible for operation and maintenance of the intake note that very little material enters the intake canal such that very little debris is removed from the traveling screens. They conduct daily inspections of the traveling screens and intake canal and note that fish and other aquatic organisms are rarely observed in the material removed from the traveling screens. No significant impingement occurs as a result of VEGP intake operation. The cooling water intake structure is located on the west bank of the Savannah River (Figure 3.1-1).

The FES for operation of VEGP observed that at the average river flow rate of 10,300 cubic feet per second (cfs) and water-level elevation of 84 feet msl, the velocities across the trash rack and traveling screens would be 0.3 and 0.7 foot per second, respectively (NRC 1985). The FES noted also that at a flow rate of 5,800 cfs and water-level elevation of 78.4 feet msl, the velocities across the trash rack and traveling screens would be 0.4 and 0.82 foot per second, respectively (NRC 1985). At these canal and screen velocities, fish that enter the intake canal can escape impingement by swimming away from the screens.

Liquid effluents (including cooling tower blowdown, and liquid radioactive waste treatment effluents) are discharged to the Savannah River through a common discharge structure, approximately 500 feet downstream of the intake structure (Figure 3.1-1). The discharge consists of a buried pipe leading to a submerged discharge structure in the river. The pipe is 2 ft in diameter, has a single discharge port, extends about 20 ft into the river from the low-flow mark, and is oriented at an angle 20 degrees downstream from a line perpendicular to the river bank.The pipe is elevated approximately 5 degrees off the bottom to minimize bottom scour.

Circulating Water System Description

Each unit's cooling tower is a hyperbolic natural draft structure with a design circulating water flow rate through the tower of 509,600 gpm. The cooling tower basin has a storage volume of 6.0×10^6 gal of water. The cooling towers use natural convection to remove heat added by cooling the condenser from the water as it falls through the fill material located in the tower. The water falls to the basin beneath the tower and, in the process, gives up some of its heat to the atmosphere. Provision is made during cold weather to direct all of the circulating water flow to the periphery of the cooling tower. This directs the total heat load to the peripheral region. Air flowing through the peripheral spray is thus preheated which allows deicing in the central cooling tower spray region.

Cooling tower make-up is drawn from the Savannah River through the weir arrangement described previously into the intake canal, then into one of four intake bays (two per cooling tower), each equipped with a vertical turbine pump with a pumping capacity of 22,000 gpm. The makeup water is supplied to the cooling tower basin. The river water makeup pumps supply water to the circulating water system to replace water losses due to evaporation, drift, and blowdown. Normally, only one or two of the makeup pumps are operating, depending upon the makeup demand.

Sodium hypochlorite and sodium bromide, are injected into the circulating water system to minimize fouling in the cooling towers and condensers. The residual oxidants are removed by addition of a reducing agent (typically ammonium bisulfite) into the blowdown mixing sump prior to discharge. Compliance with National Pollutant Discharge Elimination System (NPDES) permit requirements is determined by sampling and analysis (GDNR 2004).

3.1.2.2 Groundwater Resources

VEGP has nine groundwater wells that variously supply the nuclear service cooling water system, plant water treatment system, fire protection system, potable and sanitary water systems, and the landscape irrigation system. All the wells are permitted under a single groundwater withdrawal permit from the Environmental Protection Division of the GDNR (GDNR 2000). The permitted annual daily average withdrawal is 5.5 MGD. Between 2000 and 2004, the annual average daily withdrawal for all purposes was approximately 1.05 MGD (SNC 2000a, b, 2001a, b, 2002a, b, 2003a, b, 2004a, b, 2005b).

The site's main production wells are MU-1 and MU-2A. Well MU-1 has a 2,000 gpm pump capacity and is the primary well. MU-2A has a 1,000 gpm pump and is the backup well. These wells are approximately 2,100 ft apart. MU-1 is approximately 1,000 ft from the eastern site boundary and the Savannah River. MU-2A is approximately 5,700 ft from the western site boundary and River Road. Both wells are in the Cretaceous aquifer. Each well, its capacity and its primary purpose are provided in Table 3.1-1.

3.1.3 Transmission Facilities

The FES (NRC 1985) identifies two 500-kilovolt (kV) and three 230-kV transmission lines that would be built to connect VEGP to the electric grid. A pre-existing line from Plant Wilson to the Goshen substation crosses the VEGP property. One of the 500-kilovolt lines would run west to

Plant Scherer, routed near, but not connected to, the Wadley substation. The other 500-kilovolt line would run south to the Thalmann substation, routed near, but not connected to, the Effingham substation. Two of the 230-kV lines would run in the same corridor to the Goshen substation just south of Augusta. These lines would parallel the existing Wilson-Goshen line. The remaining 230-kV line would run north then east to a substation within the Savannah River Plant (now called the SRS, a DOE facility). The two 500-kV lines were to be connected to the Unit 2 switchyard; the 230-kV lines were to be connected to the Unit 1 switchyard.

Subsequent to the publication of the FES, two changes were made to the transmission system.

- The Wilson-Goshen line was rerouted to connect to VEGP instead of Wilson. The segment between Wilson and VEGP was used to connect the two plants together. Furthermore, a connection was made to this VEGP-Goshen line to connect to the Augusta Newsprint substation. This line is now known as the Augusta Newsprint line. The short segment to Wilson is known as the Wilson line.
- The Thalmann line was connected to the West McIntosh substation and is now known as the West McIntosh (Thalmann) line.

As a result of these system changes, the transmission lines of interest for this report are somewhat different than those described in the FES, as indicated below. Figure 3.1-2 is a map of the transmission system of interest.

- Scherer – This 500-kV line runs generally westward to Plant Scherer, north of Macon, Georgia. Built in 1986, it is 154 miles long and in a corridor that is mostly 150 ft wide, but up to 400 feet wide in some locations. The terrain is flat to rolling.
- West McIntosh (Thalmann) – Running 69 miles to the south, this 500-kV line, in a 150-ft wide corridor, connects VEGP to the West McIntosh substation near Plant McIntosh, just north of Savannah, Georgia. It then continues for 90 miles to its termination at the Thalmann substation near Brunswick.
- Goshen (Black) and Goshen (White) – The two 230-kV Goshen lines connect to the Goshen substation approximately 19 corridor miles from VEGP. The corridor is 275 ft wide and the lines were built in 1986. These two lines, plus 17 miles of the Augusta Newsprint line, share the corridor. The terrain is generally flat.
- Augusta Newsprint – The Augusta Newsprint substation is approximately 20 corridor miles from VEGP. The corridor is 275 ft wide until the 230-kV Augusta Newsprint line diverges from the Goshen lines at 17 miles and is 100 to 125 ft wide for the remaining distance. The Augusta Newsprint line was built in 1983. The terrain is generally flat.
- SCE&G – Built in 1986, this 230-kV line runs north and east for 4.5 miles to cross the Savannah River and then an additional 17 miles to a substation operated by SCE&G. The

corridor in South Carolina is 100 ft wide and the Georgia segment is 125 ft wide. The part of the corridor in South Carolina is wholly contained on the Savannah River Site and is maintained by South Carolina Electric and Gas. The terrain is mostly flat.

- Wilson – This 1.4-mile long transmission line is wholly contained on GPC property. It connects VEGP to Plant Wilson at 230-kV. The corridor is 150 ft wide. The Wilson line provides offsite power in the event of an emergency.

In total, the transmission lines considered in Section 4.13 are contained in approximately 360 miles of corridor that occupy approximately 7,200 acres. The corridors pass through land that is primarily agricultural and forest. The Scherer line crosses the Oconee National Forest, northeast of Plant Scherer. The West McIntosh (Thalmann) line crosses the Yuchi WMA, the Tuckahoe WMA, and Ebenezer Creek Swamp near the West McIntosh plant. The lines cross numerous county, state, and U.S. highways after leaving the switchyard. Corridors that pass through farmlands generally continue to be used as farmland. Southern Company plans to maintain these transmission lines, which are integral to the larger transmission system, indefinitely. These transmission lines will remain a permanent part of the transmission system after VEGP is decommissioned.

The transmission lines were designed and constructed in accordance with the National Electrical Safety Code (NESC) and other industry guidance that was current when the lines were built. Ongoing surveillance and maintenance of these transmission facilities ensure continued conformance to design standards. These maintenance practices are described in Section 4.13.

Table 3.1-1. Groundwater Wells at VEGP

Well Identifier	Depth (ft)	Capacity (gpm)	Primary Purpose
MU-1	851	2,000	Service water, potable and sanitary water, fire protection, plant water, and irrigation
MU-2A	884	1,000	Back-up for MU-1
TW-1	860	1,000	Back-up for production well make up system
SW-5	200	20	Water for old security tactical training area
REC	265	150	Potable water for recreation facility
CW-3	220	Not Available	Water supply for Nuclear Operations Garage
IW-4	370	120	Irrigation well for vegetation
SEC	320	10	Non-potable water for lavatory at plant entrance security building
SB	340	50	Potable water for Training Facility

ft = feet

gpm = gallons per minute

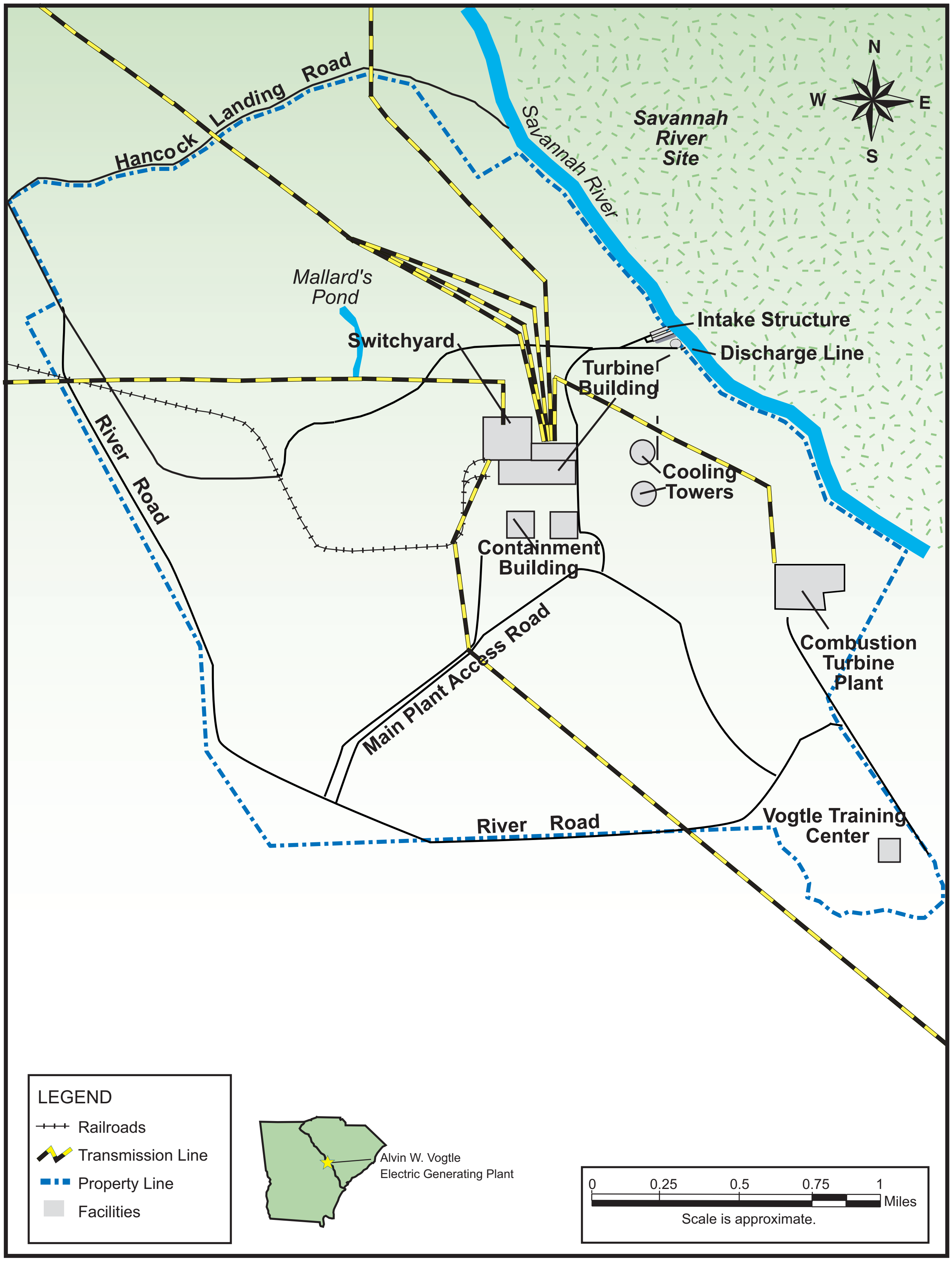

Figure 3.1-1 General Plant Layout

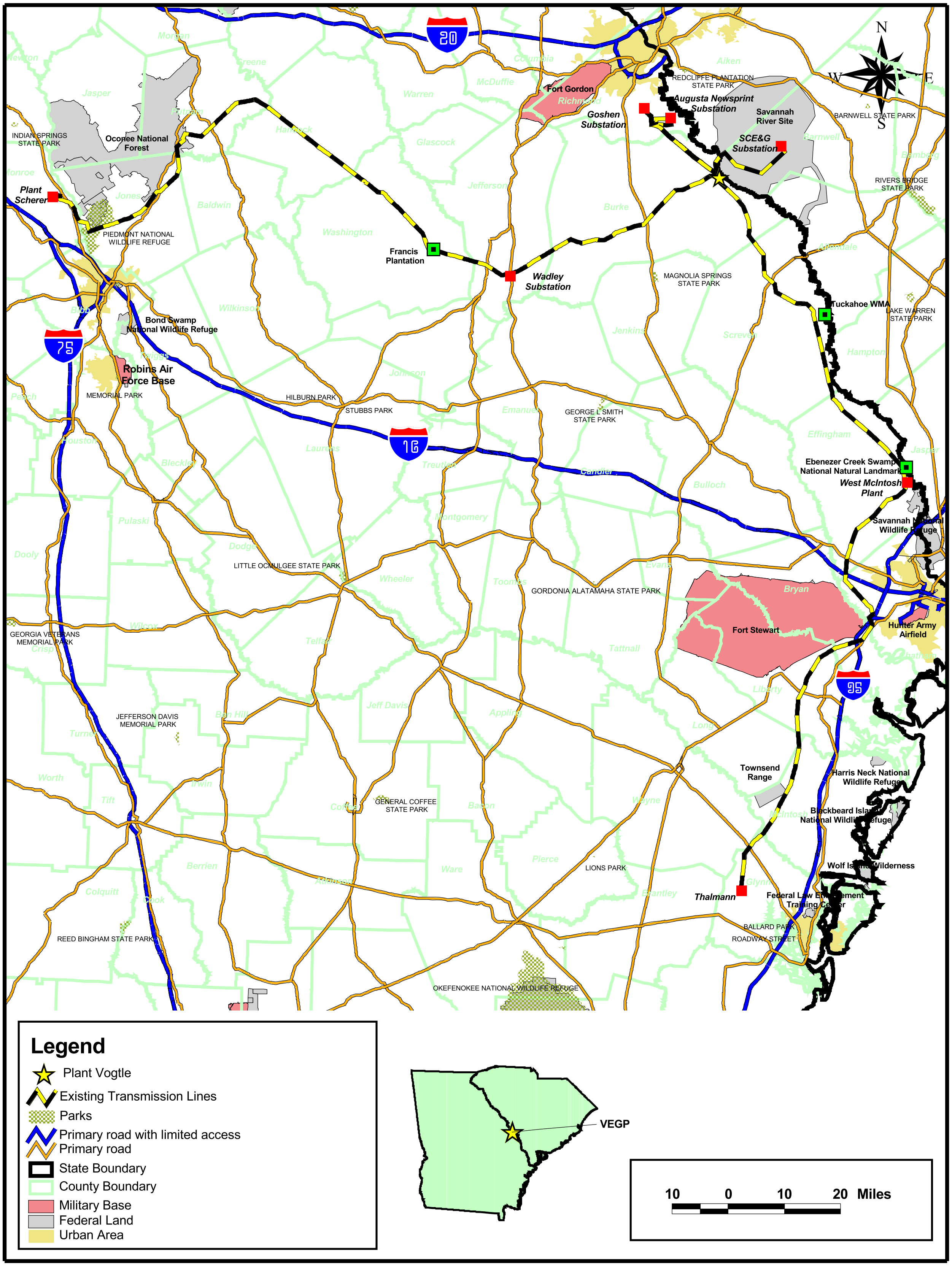

Figure 3.1-2 Transmission System

3.2 Refurbishment Activities

NRC

"… The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures…. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

"… The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40 year license term will be from one of two broad categories: ... and (2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item…." NRC 1996

SNC has addressed refurbishment activities in this ER in accordance with NRC regulations and complementary information in the NRC GEIS for license renewal (NRC 1996). NRC requirements for the renewal of operating licenses for nuclear power plants include the preparation of an integrated plant assessment (IPA) (10 CFR 54.21). The IPA must identify and list systems, structures, and components subject to an aging management review. Items that are subject to aging and might require refurbishment include, for example, steam generators, reactor coolant pump, and piping and component supports (see NRC 1996, Appendix B), as well as items that are not subject to periodic replacement.

During the VEGP IPA conducted under 10 CFR 54, SNC did not identify the need to undertake any major refurbishment or replacement actions to maintain the functionality of important systems, structures, and components to support license renewal at VEGP.

3.3 Programs and Activities for Managing the Effects of Aging

NRC

"…The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures…. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

"…The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40 year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals …." NRC 1996 (SMITTR is defined in NRC (1996) as surveillance, monitoring, inspections, testing, trending, and recordkeeping.)

The IPA required by 10 CFR 54.21 identifies the programs and inspections for managing aging effects at VEGP. These programs are described in the Vogtle Electric Generating Plant License Renewal Application, Appendix B, Aging Management Programs and Activities.

3.4 Employment

Current Workforce

SNC employs approximately 888 permanent and long-term contract employees at VEGP, a two-unit facility. Approximately 79 percent of current VEGP employees reside within three Georgia counties: Burke (20 percent), Richmond (26 percent), and Columbia (34 percent). The remaining 20 percent are distributed across 24 other counties, with numbers ranging from 1 to 58 employees per county.

VEGP is on an 18-month refueling cycle. During refueling outages, site employment increases above the permanent workforce by as many as 800 workers for approximately 30 days of temporary duty. This number of outage workers falls within the range (200 to 900 workers per reactor unit) reported in the GEIS for additional maintenance workers (NRC 1996).

License Renewal Increment

Performing the license renewal activities described in Sections 3.2 and 3.3 would necessitate increasing the VEGP staff workload by some increment. The size of this increment would be a function of the schedule within which SNC must accomplish the work and the amount of work involved. SNC has determined that no refurbishment is needed (Section 3.2), and the analysis of license renewal employment increment focuses on programs and activities for managing the effects of aging (Section 3.3).

The GEIS (NRC 1996) assumes that NRC would renew a nuclear power plant license for a 20-year period, plus the duration remaining on the current license, and that NRC would issue the renewal prior to license expiration. In other words, the renewed license would be in effect for the period of extended operation. The GEIS further assumes that the utility would initiate surveillance, monitoring, inspections, testing, trending, and recordkeeping (SMITTR) activities at the time of issuance of the new license and would conduct license renewal SMITTR activities throughout the remaining 30-year life of the plant, sometimes during full-power operation, but mostly during normal refueling and the 5- and 10-year in-service inspection and refueling outages (NRC 1996).

SNC has determined that the GEIS scheduling assumptions are reasonably representative of VEGP incremental license renewal workload scheduling. Many VEGP license renewal SMITTR activities would have to be performed during outages. Although some VEGP license renewal SMITTR activities would be one-time efforts, others would be recurring periodic activities that would continue for the life of the plant.

The GEIS estimates that the most additional personnel needed to perform license renewal SMITTR activities would typically be 60 persons during the 3-month duration of a 10-year in-service inspection and refueling outage. Having established this upper value for what would be a single event in 20 years, the GEIS uses this number as the expected number of additional permanent workers needed per unit attributable to license renewal. GEIS Section C.3.1.2 uses this approach to "...provide a realistic upper bound to potential population-driven impacts…."

SNC has identified no need for significant new aging management programs or major modifications to existing programs. SNC anticipates that existing "surge" capabilities for routine activities, such as outages, would enable SNC to perform the increased SMITTR workload without increasing VEGP staff. Nonetheless, for the purpose of analyses in this environmental report, SNC has adopted the NRC's GEIS approach as described, but assumes that 60 additional permanent personnel would accommodate the workload for both units. SNC license renewal plant modifications would be SMITTR activities that would be performed mostly during outages, and SNC would stagger VEGP outages so that both units would not be down at the same time. Therefore, as a reasonably conservative (high) estimate, SNC assumes that VEGP would require 60 additional permanent workers to perform license renewal SMITTR activities rather than the 60 additional workers per reactor assumed by the NRC in the GEIS.

Adding full-time employees to the plant workforce for operating during the license renewal period would have the indirect effect of creating additional jobs and related population growth in the community. Using the Regional Input-Output Modeling System (RIMS II), the U.S. Bureau of Economic Analysis calculated a regional employment multiplier appropriate for the power generation and supply industry for the Augusta, GA region, which includes Burke, Richmond, and Columbia Counties (BEA 2005).

SNC used this value (2.4128) to estimate the additional number of direct and indirect jobs during the license renewal period for the analysis assumption discussed above. Applying the multiplier, a total of 145 (60 × 2.4128) new jobs would be created in the area. Stated differently, SNC assumes that 60 additional permanent direct workers during the license renewal period would create an additional 85 indirect jobs in the community. Conservatively assuming that each direct and indirect job is filled by an in-migrating worker, these 145 new jobs (60 direct and 85 indirect) could result in a population increase of 384 in the area (145 jobs multiplied by 2.65 average number of persons per household in the state of Georgia in 2000 [USCB 2007]). This increase represents less than 1 percent of the population in year 2000 (311,306) for the combined area of Burke, Richmond, and Columbia Counties (Section 2.6).

3.5 References

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Chapter 4 Environmental Consequences of the Proposed Action and Mitigating Actions

NRC

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

"The environmental report shall include an analysis that considers…the environmental effects of the proposed action…and alternatives available for reducing or avoiding adverse environmental effects." 10 CFR 51.45(c) as adopted by 10 CFR 51.53(c)(2)

The environmental report shall discuss the "…impact of the proposed action on the environment. Impacts shall be discussed in proportion to their significance…." 10 CFR 51.45(b)(1) as adopted by 10 CFR 51.53(c)(2)

"The information submitted…should not be confined to information supporting the proposed action but should also include adverse information." 10 CFR 51.45(e) as adopted by 10 CFR 51.53(c)(2)

Chapter 4 presents an assessment of the environmental consequences associated with the renewal of the VEGP operating licenses. The NRC has identified and analyzed 92 environmental issues that it considers to be associated with nuclear power plant license renewal and has designated the issues as Category 1, Category 2, or not applicable (NA). NRC designated an issue as Category 1 if, based on the result of its analysis, the following criteria were met:

- the environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues, to plants having a specific type of cooling system or other specified plant or site characteristic;
- a single significance level (i.e., small, moderate, or large) has been assigned to the impacts that would occur at any plant, regardless of which plant is being evaluated (except for collective offsite radiological impacts from the fuel cycle and from high-level waste and spent-fuel disposal); and
- mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined additional plant-specific mitigation measures are likely to be not sufficiently beneficial to warrant implementation.

If the NRC analysis concluded that one or more of the Category 1 criteria could not be met, NRC designated the issue as Category 2. NRC requires plant-specific analyses for Category 2 issues.

Finally, NRC designated two issues as not applicable (NA), signifying that the categorization and impact definitions do not apply to these issues.

NRC rules do not require analyses of Category 1 issues that NRC resolved using generic findings (10 CFR 51) as described in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996a). An applicant may reference the generic findings or GEIS analyses for Category 1 issues. Attachment A of this report lists the 92 issues and identifies the environmental report section that addresses each issue.

Categories Designated as Category 1 or Not Applicable

NRC

> "The environmental report for the operating license renewal stage is not required to contain analyses of the environmental impacts of the license renewal issues identified as Category 1 issues in Appendix B to subpart A of this part." 10 CFR 51.53(c)(3)(i)
>
> "…[A]bsent new and significant information, the analyses for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant's environmental report for license renewal…." (NRC 1996b)

SNC has determined that 8 of the 69 Category 1 issues do not apply to VEGP because they are specific to design or operational features that are not found at the facility. Because SNC is not planning any refurbishment activities, seven additional Category 1 issues related to refurbishment do not apply. Attachment A, Table A-1 lists the 69 Category 1 issues, indicates whether or not each issue is applicable to VEGP, and if inapplicable provides the SNC basis for this determination. Attachment A, Table A-1 also includes references to supporting analyses in the GEIS where appropriate.

SNC has reviewed the NRC findings at 10 CFR 51 (Table A-1) and has not identified any new and significant information that would make the NRC findings, with respect to Category 1 issues, inapplicable to VEGP. Therefore, SNC adopts by reference the NRC findings for these Category 1 issues.

NA License Renewal Issues

NRC determined that its categorization and impact-finding definitions did not apply to Issues 60 and 92; however, SNC included these issues in Attachment A, Table A-1. NRC noted that applicants currently do not need to submit information on Issue 60, chronic effects from electromagnetic fields (10 CFR 51). For Issue 92, environmental justice, NRC does not require information from applicants, but noted that it will be addressed in individual license renewal reviews (10 CFR 51). SNC has included environmental justice demographic information in Section 2.6.2.

Category 2 License Renewal Issues

NRC

"The environmental report must contain analyses of the environmental impacts of the proposed action, including the impacts of refurbishment activities, if any, associated with license renewal and the impacts of operation during the renewal term, for those issues identified as Category 2 issues in Appendix B to subpart A of this part." 10 CFR 51.53(c)(3)(ii)

"The report must contain a consideration of alternatives for reducing adverse impacts, as required by § 51.45(c), for all Category 2 license renewal issues…." 10 CFR 51.53(c)(3)(iii)

NRC designated 21 issues as Category 2. Sections 4.1 through 4.20 (Section 4.17 addresses two issues) address the Category 2 issues, beginning with a statement of the issue. Five Category 2 issues apply to operational features that are not part of the VEGP. In addition, four Category 2 issues apply only to refurbishment activities. VEGP is not planning to conduct any refurbishment. If the issue does not apply to VEGP, the section explains the basis for inapplicability.

For the 12 Category 2 issues that SNC has determined to be applicable to VEGP, the appropriate sections contain the required analyses. These analyses include conclusions regarding the significance of the impacts relative to the renewal of the operating license for VEGP and, if applicable, discussions of potential mitigative alternatives to the extent required. SNC has identified the significance of the impacts associated with each issue as either SMALL, MODERATE, or LARGE, consistent with the criteria that NRC established in 10 CFR 51, Appendix B, Table B-1, Footnote 3 as follows:

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.

LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.

In accordance with National Environmental Policy Act (NEPA) practice, SNC considered ongoing and potential additional mitigation in proportion to the significance of the impact to be addressed (i.e., impacts that are small receive less mitigative consideration than impacts that are large).

4.1 Water Use Conflicts (Plants with Cooling Ponds or Cooling Towers Using Makeup Water from a Small River with Low Flow)

NRC

"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3 / year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on the flow of the river and related impacts on instream and riparian ecological communities must be provided. The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(c)(3)(ii)(A)

"…The issue has been a concern at nuclear power plants with cooling ponds and at plants with cooling towers. Impacts on instream and riparian communities near these plants could be of moderate significance in some situations…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 13

The NRC made surface-water-use conflicts a Category 2 issue because consultations with regulatory agencies indicate that water use conflicts are already a concern at two closed-cycle plants and may be a problem in the future at other plants. In the GEIS, NRC notes two factors that may cause water use and availability issues to become important for some nuclear power plants that use cooling towers. First, some plants equipped with cooling towers are located on small rivers that are susceptible to droughts or competing water uses. Second, consumptive water loss associated with closed-cycle cooling systems may represent a substantial proportion of the flows in small rivers (NRC 1996a).

As discussed in Section 3.1.2, VEGP has a cooling tower-based heat dissipation system. Cooling water lost to cooling tower evaporation, drift and blowdown is replaced by make-up water pumped from the Savannah River. Based on data from water years 1952 to 2004, the annual mean flow of the Savannah River at Augusta is 9,157 cfs (2.89×10^{11} cubic feet per year) (Gotvald et al. 2005), which means that the Savannah River meets the NRC definition of a small river. Therefore, this issue applies to VEGP.

Flow in the Savannah River is controlled by the USACE using three reservoirs: Hartwell, Richard B. Russell, and J. Strom Thurmond. The USACE created the federally authorized reservoirs as part of a flood control, hydropower, and navigation project. Authorized purposes now include recreation, water quality, water supply, and fish and wildlife management (COE 2007). Hartwell, Russell, and Thurmond power plants are referred to as "peaking" plants, meaning the power plants are designed to supply dependable power during hours of peak daily demand. J. Strom Thurmond Lake and Dam is located approximately 22 miles upstream of

Augusta and 72 miles upstream from the VEGP intake. Richard B. Russell and Hartwell dams are located 63 and 89 miles upstream from Augusta, respectively (COE 2006).

At VEGP, the river water intake system draws water from the Savannah River at a maximum rate of approximately 40,000 gpm (89 cfs) to provide makeup to the circulating water system. Consumptive use associated with evaporation and drift losses from the cooling towers represent 15,000 gpm (33.4 cfs) per unit for a total of 30,000 gpm (66.8 cfs) (NRC 1985). This represents approximately 0.7 percent of the average river flow at Augusta, GA (9,157 cfs), based on river flow data collected over a 5-year period of record.

In accordance with the current draft of the USACE Drought Contingency Plan for the Savannah River, a minimum flow of 3,800 cfs will be released from J. Strom Thurmond Dam based on the water needs of downstream water users unless the reservoir level drops below the bottom of the conservation pool (312 ft above msl) at which point outflow will be adjusted to equal inflow to the reservoir (COE 2006). J. Strom Thurmond Lake has not dropped below 312 ft msl since 1956 (COE 2007). VEGP consumptive use represents about 1.8 percent of the 3,800 cfs minimum release.

Since VEGP began operation in 1987, the lowest annual mean flow in the Savannah River at Augusta was 4,470 cfs in 2002 (Gotvald et al. 2005). VEGP consumptive water use from the Savannah River represents approximately 1.5 percent of this lowest annual mean flow rate.

VEGP river water withdrawals from the Savannah River during normal operating conditions represent less than 2 percent of the river flow during typical drought periods and less than 1 percent of average flow. Low flows in the Savannah River have never produced the need for constraints on VEGP operational output even during the severe drought of 1999 – 2002. Water conservation measures are integrated into the VEGP design and are considered in proposed changes to VEGP design or operation. As stated above, water withdrawal from VEGP represents a small percentage of the available river flow even during extreme low flow conditions. Therefore, impacts from VEGP makeup water withdrawal from the Savannah River are SMALL and do not warrant mitigation.

4.2 Entrainment of Fish and Shellfish in Early Life Stages

NRC

> "If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from…entrainment." 10 CFR 51.53(c)(3)(ii)(B)

> "...The impacts of entrainment are small in early life stages at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. Further, ongoing efforts in the vicinity of these plants to restore fish populations may increase the numbers of fish susceptible to intake effects during the license renewal period, such that entrainment studies conducted in support of the original license may no longer be valid..." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 25

NRC made impacts of entrainment of fish and shellfish in early life stages a Category 2 issue for certain plants because it could not assign a single significance level to the issue. The impacts of entrainment are small at many plants, but may be moderate or large at others (NRC 1996a). Information needed to ascertain the impacts includes: (1) type of cooling system (whether once-through or cooling pond), and (2) status of Clean Water Act (CWA) Section 316(b) determination or equivalent state documentation. A CWA Section 316(b) determination by the regulatory authority is needed only for once-through cooling systems.

The issue of entrainment of fish and shellfish in early life stages does not apply to VEGP because the plant does not use once-through cooling or cooling pond heat dissipation systems. As described in Section 3.1.2, VEGP uses a closed-cycle cooling system with cooling towers that withdraw make-up water from the Savannah River and discharge blowdown to the Savannah River.

4.3 Impingement of Fish and Shellfish

NRC

> "If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from…impingement…." 10 CFR 51.53(c)(3)(ii)(B)
>
> "…The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems…." 10 CFR 51, Subpart A, Appendix B, Table B 1, Issue 26

NRC made impacts of impingement of fish and shellfish a Category 2 issue for certain plants because it could not assign a single significance level to the issue. The impacts of impingement are small at many plants, but may be moderate or large at others (NRC 1996a). Information needed to ascertain the impacts includes: (1) type of cooling system (whether once-through or cooling pond), and (2) status of CWA Section 316(b) determination or equivalent state documentation. A CWA Section 316(b) determination by the regulatory authority is needed only for once-through cooling systems. The State of Georgia recognizes closed-cycle cooling systems as Best Technology Available (BTA) and exempts plants with installed BTA from further requirements of Section 316 of the CWA.

The issue of impingement of fish and shellfish in early life stages does not apply to VEGP because the plant does not utilize once-through cooling or cooling pond heat dissipation systems. As described in Section 3.1.2, VEGP uses a closed-cycle cooling system with cooling towers that withdraw make-up water from the Savannah River and discharge blowdown to the Savannah River.

4.4 Heat Shock

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act… 316(a) variance in accordance with 40 CFR Part 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock …." 10 CFR 51.53(c)(3)(ii)(B)

"…Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 27

NRC made impacts of heat shock on fish and shellfish a Category 2 issue for certain plants because of continuing concerns about thermal discharge effects and the possible need to modify thermal discharges in response to changing environmental conditions (NRC 1996a). Information needed to ascertain the impacts includes: (1) type of cooling system (whether once-through or cooling pond), and (2) evidence of CWA Section 316(a) variance or equivalent state documentation.

The issue of heat shock to fish and shellfish does not apply to VEGP because the plant does not use once-through cooling or cooling pond heat dissipation systems. As described in Section 3.1.2, VEGP uses a closed-cycle cooling system with cooling towers that withdraws make-up water from the Savannah River and discharge blowdown to the Savannah River.

4.5 Groundwater Use Conflicts (Plants Using >100 GPM of Groundwater)

NRC

"If the applicant's plant…pumps more than 100 gallons (total onsite) of groundwater per minute, an assessment of the impact of the proposed action on groundwater use must be provided." 10 CFR 51.53(c)(3)(ii)(C)

"Plants that use more than 100 gpm may cause groundwater use conflicts with nearby groundwater users." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 33

NRC made groundwater use conflicts a Category 2 issue because, at a withdrawal rate of more than 100 gpm, a cone of depression could extend offsite. This could deplete the groundwater supply available to offsite users, an impact that could warrant mitigation. Information to ascertain includes the VEGP groundwater withdrawal rate (whether greater than 100 gpm), drawdown in the Cretaceous aquifer at offsite location, and impacts on neighboring wells.

Based on information presented in Section 3.1.2.2, VEGP uses an annual average of approximately 1.05 MGD of groundwater. Therefore, the issue of groundwater use conflicts does apply.

In order to determine potential offsite impacts to wells, the 1.05 MGD (input as 730 gpm into the calculation) average cumulative well yield was used to calculate drawdown in the Cretaceous aquifer as though it had been pumped from a single onsite well. The well MU-2A location was used to calculate drawdown due to its proximity to the VEGP property boundary (5,700 feet), its proximity to the nearest offsite groundwater user (although that private well is in the Tertiary aquifer), and because the well is one of the site's primary production wells. Data used as input to an analytical distance-drawdown model were taken from VEGP's updated Final Safety Analysis Report (SNC 2005). Recent data (SNC 2006) indicate that the confining unit between the Cretaceous and Tertiary aquifers beneath the VEGP site may be semi-confining, and that current flow is upward from the Cretaceous to the Tertiary. Therefore, a leaky aquifer scenario was used to simulate site conditions. The equations used in the calculations assume that the aquifer is homogeneous, isotopic, with negligible recharge and gradient. It was also assumed that the current pumping rate was also the rate at which groundwater was pumped during the initial startup period. Based on the results of the modeling, pumping at a rate of 730 gpm in well MU-2A would result in stabilization of the drawdown at the closest section of the western property boundary at approximately 1.9 feet prior to the first 10 years of operation. Drawdown at the closest property line in the direction of the nearest offsite well, a distance of 5,700 feet, through the current license period (40 years) and through the end of the license renewal period is predicted to remain constant at 1.9 feet. Based on the predicted stabilized drawdown of the

Cretaceous aquifer through the license renewal term, VEGP concludes that impacts to the aquifer system in the area would be SMALL and mitigation would not be warranted.

4.6 Groundwater Use Conflicts (Plants using Cooling Towers Withdrawing Makeup Water from a Small River)

NRC

"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3 / year...[t]he applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(3)(ii)(A)

"…Water use conflicts may result from surface water withdrawals from small water bodies during low flow conditions which may affect aquifer recharge, especially if other groundwater or upstream surface water users come on line before the time of license renewal…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 34

NRC made this groundwater use conflict a Category 2 issue because consumptive use of withdrawals from small rivers could adversely impact groundwater-aquifer recharge. This is a particular concern during low-flow conditions on rivers that have multiple consumptive users.

The issue of groundwater use conflicts applies because VEGP withdraws makeup water from a small river, the Savannah River, which has an annual mean flow of 9,157 cfs (2.89×10^{11} cubic ft per year) at the VEGP intake (Gotvald et al. 2005). As discussed in Section 3.1.2, VEGP has a cooling tower-based heat dissipation system. Makeup water pumped from the Savannah River replaces cooling water lost to cooling tower evaporation and drift.

Alluvial deposits along the Savannah River consist of poorly sorted clay, sand, and gravel. Thickness rarely exceeds 30 ft. Areal extent is highly variable due to stream downcutting and erosional processes. In general, these deposits contain only small quantities of groundwater (SNC 2005).

Groundwater in the region is obtained primarily from the confined Cretaceous, and Tertiary aquifer systems, or in some cases the Water Table (unconfined) aquifer, not from the alluvium along the Savannah River. The largest user of groundwater from the Cretaceous aquifer is the SRS, located directly across the Savannah River from VEGP. Areas of Richmond County also use groundwater from the Cretaceous aquifer. Girard, Sardis, and Sylvania, located south of VEGP, obtain their water from the Tertiary aquifer. (SNC 2005)

Groundwater use in eastern Burke County is almost exclusively for domestic needs. The many private wells are small, with a maximum capacity of less than 10 gpm. The average of each well is estimated to be less than 0.5 gpm. Small amounts of groundwater are used for livestock, and there are a few small commercial buildings in the communities served by municipal wells. Except for VEGP there are no known industrial, irrigation, or similar activities requiring continuous withdrawals of large quantities of groundwater in eastern Burke County. (SNC 2005)

As discussed in Section 4.1, VEGP consumptive use (66.8 cfs) represents approximately 0.7 percent of the average flow in the Savannah River, and 1.8 percent of the required minimum release from J. Strom Thurmond Dam (3,800 cfs) (COE 2006). VEGP withdrawals drop the water level in the Savannah River near VEGP less than 1 inch, even during low flow conditions, and therefore have no measurable effect on recharge to the alluvial aquifer. No withdrawals of surface water from the alluvial aquifer currently occur and none are planned for the future. Because the alluvium is a poor source of groundwater, there is no anticipated increase in the use of this aquifer. SNC concludes that impacts of withdrawing water from the river on the alluvial aquifer would be SMALL and that mitigation measures would not be warranted.

4.7 Groundwater Use Conflicts (Plants using Ranney Wells)

NRC

"If the applicant's plant uses Ranney wells…an assessment of the impact of the proposed action on groundwater use must be provided." 10 CFR 51.53(c)(3)(ii)(C)

"…Ranney wells can result in potential ground-water depression beyond the site boundary. Impacts of large ground-water withdrawal for cooling tower makeup at nuclear power plants using Ranney wells must be evaluated at the time of application for license renewal…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 35

NRC made this groundwater use conflict a Category 2 issue because large quantities of groundwater withdrawn from Ranney wells could degrade groundwater quality at river sites by induced infiltration of poor-quality river water into an aquifer.

The issue of groundwater use conflicts does not apply to VEGP because the plant does not use Ranney wells. As Section 3.1.2 describes, VEGP uses a closed-cycle cooling system with cooling towers that use make-up water from the Savannah River and discharge blowdown to the Savannah River.

4.8 Degradation of Groundwater Quality

NRC

"If the applicant's plant is located at an inland site and utilizes cooling ponds, an assessment of the impact of the proposed action on groundwater quality must be provided." 10 CFR 51.53(c)(3)(ii)(D)

"…Sites with closed-cycle cooling ponds may degrade ground-water quality. For plants located inland, the quality of the ground water in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses…." 10 CFR 51, Subpart A, Appendix B, Table B 1, Issue 39

NRC made degradation of groundwater quality a Category 2 issue because evaporation from closed-cycle cooling ponds concentrates dissolved solids in the water and settles suspended solids. In turn, seepage into the water table aquifer could degrade groundwater quality.

The issue of groundwater degradation does not apply to VEGP because the plant does not use cooling ponds. As Section 3.1.2 describes, VEGP uses a closed-cycle cooling system with cooling towers that use make-up water from and discharge blowdown to the Savannah River.

4.9 Impacts of Refurbishment on Terrestrial Resources

NRC

The environmental report must contain an assessment of "…the impacts of refurbishment and other license renewal-related construction activities on important plant and animal habitats…." 10 CFR 51.53(c)(3)(ii)(E)

"…Refurbishment impacts are insignificant if no loss of important plant and animal habitat occurs. However, it cannot be known whether important plant and animal communities may be affected until the specific proposal is presented with the license renewal application…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 40

"…If no important resources would be affected, the impacts would be considered minor and of small significance. If important resources could be affected by refurbishment activities, the impacts would be potentially significant…." (NRC 1996a)

NRC made impacts to terrestrial resources from refurbishment a Category 2 issue, because the significance of ecological impacts cannot be determined without considering site- and project-specific details (NRC 1996a). Aspects of the site and project to be ascertained are: (1) the identification of important ecological resources, (2) the nature of refurbishment activities, and (3) the extent of impacts to plant and animal habitats.

The issue of impacts of refurbishment on terrestrial resources is not applicable to VEGP because, as discussed in Section 3.2, SNC has no plans for refurbishment.

4.10 Threatened and Endangered Species

NRC

"Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act." 10 CFR 51.53(c)(3)(ii)(E)

"Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 49

NRC made impacts to threatened and endangered species a Category 2 issue because the status of many species is being reviewed, and a site-specific assessment is required to determine whether any identified species could be affected by refurbishment activities or continued plant operations through the renewal period. In addition, compliance with the Endangered Species Act requires consultation with the appropriate federal agency (NRC 1996a).

Section 2.2 of this ER describes the aquatic communities of streams at the VEGP site and the adjacent Savannah River. Section 2.4 describes important terrestrial habitats at VEGP and along the associated transmission corridors. Section 2.5 discusses threatened or endangered species that occur or may occur at VEGP and along associated transmission corridors.

With the exception of the species identified in Section 2.5, SNC is not aware of any threatened or endangered species that could occur at VEGP or along the associated transmission corridors. VEGP current operations and GPC vegetation management practices along transmission line rights-of-way do not adversely affect any listed terrestrial or aquatic species or its habitat. Furthermore, plant operations and transmission line maintenance practices are not expected to change significantly during the license renewal term. Therefore, no adverse impacts to threatened or endangered species from current or future operations are anticipated.

SNC wrote to the GDNR, the SCDNR, the National Oceanic and Atmospheric Administration's NMFS, and the USFWS requesting information on any listed species or critical habitats that might occur on the VEGP site or along the associated transmission corridors, with particular emphasis on species that might be adversely affected by continued operation over the license renewal period. Agency correspondence is provided in Attachment C.

As discussed in Section 3.2, SNC has no plans to conduct refurbishment at VEGP during the license renewal term. Therefore, there would be no refurbishment-related impacts to special-status species and no further analysis of refurbishment-related impacts is applicable. Furthermore, because SNC has no plans to alter current operations and resource agencies contacted by SNC evidenced no serious concerns about license renewal impacts SNC concludes that impacts to threatened or endangered species from license renewal would be SMALL and do not warrant mitigation.

4.11 Air Quality During Refurbishment (Non-Attainment Areas)

NRC

"…If the applicant's plant is located in or near a nonattainment or maintenance area, an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce must be provided in accordance with the Clean Air Act as amended…." 10 CFR 51.53(c)(3)(ii)(F)

"…Air quality impacts from plant refurbishment associated with license renewal are expected to be small. However, vehicle exhaust emissions could be cause for concern at locations in or near nonattainment or maintenance areas. The significance of the potential impact cannot be determined without considering the compliance status of each site and the numbers of workers expected to be employed during the outage…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 50

NRC made impacts to air quality during refurbishment a Category 2 issue because vehicle exhaust emissions could be cause for some concern, and a general conclusion about the significance of the potential impact could not be drawn without considering the compliance status of each site and the number of workers expected to be employed during an outage (NRC 1996a). Information needed would include the attainment status of the plant-site area, and the number of additional vehicles because of refurbishment activities.

Air quality during refurbishment is not applicable to VEGP because, as discussed in Section 3.2, SNC has no plans for refurbishment at VEGP.

4.12 Microbiological Organisms

NRC

"If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flow rate of less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water must be provided." 10 CFR 51.53(c)(3)(ii)(G)

"These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals that discharge to small rivers. Without site-specific data, it is not possible to predict the effects generically." 10 CFR 51,Subpart A, Appendix B, Table B-1, Issue 57

Due to the lack of sufficient data from facilities using cooling ponds, lakes, or canals or discharging to small rivers, NRC designated impacts on public health from thermophilic organisms a Category 2 issue. Information to be determined is whether the plant discharges to a small river, and whether discharge characteristics (particularly temperature) are favorable to the survival of thermophilic organisms.

This issue is applicable to VEGP because the plant discharges to the Savannah River, which has an annual river flow at VEGP of 2.89×10^{11} cubic feet per year at VEGP (Gotvald et al. 2005). It is also relevant because the Savannah River in the vicinity of VEGP is used by the public for recreation, including boating and fishing.

Organisms of concern include the enteric pathogens *Salmonella* and *Shigella*, the *Pseudomonas aeruginosa* bacterium, thermophilic Actinomycetes ("fungi"), the many species of *Legionella* bacteria, and pathogenic strains of the free-living *Nageleria* amoeba.

Bacteria pathogenic to humans have evolved to survive in the digestive tracts of mammals and accordingly have optimum temperatures of around 99°F (Joklik and Smith 1972). Many of these pathogenic microorganisms (e.g., *Pseudomonas, Salmonella*, and *Shigella*) are ubiquitous in nature, occurring in the digestive tracts of wild mammals and birds (and thus in natural waters), but are usually only a problem when the host is immunologically compromised. Thermophilic bacteria generally occur at temperatures from 77°F to 176°F, with maximum growth at 122°F to 140°F (Joklik and Smith 1972).

VEGP uses two natural draft cooling towers to transfer the majority of the waste heat from the condensers to the atmosphere (see Section 3.1 for detailed description of condenser cooling system). The cooling tower blowdown routes the remaining heat load to the Savannah River. Thermal modeling associated with the cooling tower discharge to the river conducted for the operation of VEGP indicated that the winter plume is approximately 32 feet by 6 feet with a volume of 620 cubic feet, and that the summer plume is significantly smaller with a volume of only 50 cubic feet (NRC 1985). Maximum discharge temperature in summer is 92°F and river temperature in summer is approximately 79°F (NRC 1985). The VEGP NPDES permit does not require monitoring of discharge temperatures. In addition, the thermal discharge from VEGP rapidly mixes with river water flow such that the area with temperature above the CWA Water Quality Standard of 90° F is extremely small.

The maximum discharge water temperature of 92°F is well below the optimal temperature range for growth and reproduction of thermophilic microorganisms.

Another factor affecting survival and growth of thermophilic microorganisms in the thermal plume of VEGP is the biocides SNC adds to the cooling system to control the growth of biological organisms such as *Corbicula*. This reduces the possibility that a seed source or inoculant will be introduced into the Savannah River via the VEGP discharge.

Given the thermal characteristics of the Savannah River at the VEGP thermal discharge SNC does not expect station operations to stimulate growth or reproduction of thermophilic microorganisms or more than minimally support their survival.

SNC has written the Watershed Protection Branch of the Environmental Protection Division (EPD) of the GDNR, and the Surface Water Monitoring Program of South Carolina Department of Heath and Environmental Control requesting information on any studies that may have been conducted on thermophilic microorganisms in the Savannah River and any concerns they may have relative to these organisms. Copies of the correspondence are included in Attachment D of this environmental report. SNC concludes that the impact of thermophilic organisms is SMALL and does not warrant mitigation.

4.13 Electric Shock from Transmission-Line Induced Currents

NRC

The environmental report must contain an assessment of the impact of the proposed action on the potential shock hazard from transmission lines ". ...[i]f the applicant's transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced current…" 10 CFR 51.53(c)(3)(ii)(H)

"Electrical shock resulting from direct access to energized conductors or from induced charges in metallic structures have not been found to be a problem at most operating plants and generally are not expected to be a problem during the license renewal term. However, site-specific review is required to determine the significance of the electric shock potential at the site." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 59

NRC made impacts of electric shock from transmission lines a Category 2 issue because, without a review of each plant's transmission line conformance with the National Electrical Safety Code (NESC) (IEEE 1997) criteria, NRC could not determine the significance of the electrical shock potential. In the case of VEGP, there have been no previous NRC or NEPA analyses of transmission-line-induced current hazards. Therefore, this section provides an analysis of the plant's transmission lines' conformance with the NESC standard. The analysis is based on computer modeling of induced current produced under the lines.

Objects located near transmission lines can become electrically charged due to their immersion in the lines' electric field. This charge results in a current that flows through the object to the ground. The current is called "induced" because there is no direct connection between the line and the object. The induced current can also flow to the ground through the body of a person who touches the object. An object that is insulated from the ground can actually store an electrical charge, becoming what is called "capacitively charged." A person standing on the ground and touching a vehicle or a fence receives an electrical shock due to the sudden discharge of the capacitive charge through the person's body to the ground. After the initial discharge, a steady-state current can develop, the magnitude of which depends on several factors including the following:

- the strength of the electric field which, in turn, depends on the voltage of the transmission line as well as its height and geometry;
- the size of the object on the ground; and,
- the extent to which the object is grounded.

In 1977, a provision to the NESC was adopted that describes how to establish minimum vertical clearances to the ground for electric lines having voltages exceeding 98-kV alternating current to ground[1]. The clearance must limit the induced current[2] due to electrostatic effects to 5 milliamperes if the largest anticipated truck, vehicle, or equipment were short-circuited to ground. By way of comparison, the setting of ground fault circuit interrupters used in residential wiring (special breakers for outside circuits or those with outlets around water pipes) is 4 to 6 milliamperes.

As described in Section 3.1.3, there are two 500-kilovolt and five 230-kilovolt lines that were specifically constructed to distribute power from VEGP to the electric grid. SNC's analysis of these transmission lines began by identifying the limiting case for each line. The limiting case is the configuration along each line where the potential for induced-current shock would be greatest. Once SNC identified the limiting case, they calculated the electric field strength for each transmission line and then calculated the induced current.

SNC calculated electric field strength and induced current using a computer code called ACDCLINE, produced by the Electric Power Research Institute. The results of this computer program have been field-verified through actual electrostatic field measurements by several utilities. The input parameters included the design features of the limiting-case scenario, the NESC requirement that line sag be determined at 120ºF conductor temperature, and the maximum vehicle size under the lines (a tractor-trailer).

As Table 4.13-1 demonstrates, the analysis determined that none of the transmission lines has the capacity to induce greater than 5 milliamperes in a vehicle parked beneath the lines. Therefore, the VEGP transmission lines conform to the NESC provisions for preventing electric shock from induced current. SNC also analyzed a hypothetical span of a 230-kV and a 500-kV transmission line terminating at Plant Vogtle (GPC 2005). The hypothetical case is for a ruling span that represents a template for the design of all the spans. The analyzed case is the most extreme condition expected on the line. Table 4.13-1 presents the results of these generic analyses.

GPC and Georgia Transmission Corporation, the lines' owners, have surveillance and maintenance procedures that provide assurance that design ground clearances will not change. These procedures include routine aerial inspections, which include checking for encroachments, broken conductors, broken or leaning structures, and signs of trees burning, any of which would be evidence of clearance problems. Ground inspections include examination of clearance at questionable locations, integrity of structures, and surveillance for dead or diseased trees that

1. Part 2, Rules 232C1c and 232D3c.
2. The NESC and the GEIS use the phrase "steady-state current," whereas 10 CFR 51.53(c)(3)(ii)(H) uses the phrase "induced current." The phrases mean the same here.

might fall on the transmission lines. Problems noted during any inspection are brought to the attention of the appropriate organization(s) for corrective action.

SNC's assessment under 10 CFR 51 concludes that electric shock is of SMALL significance for the VEGP transmission lines and does not warrant mitigation.

Table 4.13-1. Results of Induced Current Analysis

Transmission Line	Voltage (kilovolts)	Induced Current[a] (milliamperes)
Scherer	500	4.7
West McIntosh (Thalmann)	500	4.3
Goshen (Black)	230	1.5[b]
Goshen (White)	230	1.5[b]
Augusta Newsprint	230	2.0
SCE&G	230	2.1
Wilson	230	(c)
Generic 500-kilovolt line[d]	500	4.7
Generic 230 kilovolt line[d]	230	1.4

a Conservatively calculated for 212 degree Fahrenheit sags for all cases except Thalmann and SCE&G for which the line was resagged to 120°F.

b Location has combined effects of Goshen (black), Goshen (white), and Augusta Newsprint, which run in parallel.

c There are no public road crossings for the Wilson transmission line. It is wholly contained on Georgia Power Company property.

d Calculation is for a 90-degree crossing. Lesser angles could produce higher results.

4.14 Housing Impacts

NRC

The environmental report must contain "...[a]n assessment of the impact of the proposed action on housing availability…" 10 CFR 51.53(c)(3)(ii)(I)

"…Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or areas with growth control measures that limit housing development…." 10 CFR 51, Subpart A, Table B-1, Issue 63

"...[S]mall impacts result when no discernible change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and no housing construction or conversion occurs…." (NRC 1996a)

NRC made housing impacts a Category 2 issue because impact magnitude depends on local conditions that NRC could not predict for all plants at the time of GEIS publication (NRC 1996a). Local conditions that need to be ascertained are population categorization as small, medium, or high and applicability of growth control measures.

Refurbishment activities and continued operations could potentially produce housing impacts due to increased staffing. As described in Section 3.2, VEGP does not plan to perform refurbishment. SNC concludes that there would be no refurbishment-related impacts to area housing and no analysis is therefore required. Accordingly, the following discussion focuses on impacts of continued VEGP operations on local housing availability.

As described in Section 2.6, the VEGP site is in a medium population area, according to NRC criteria. Burke, Richmond, and Columbia Counties have no county-imposed growth control measures that limit housing development (see Section 2.8). In 10 CFR Part 51, Subpart A, Appendix B, Table B-1 (Issue 63), the NRC concludes that impacts to housing are expected to be of small significance at plants in medium population areas where growth control measures are not in effect. Therefore, SNC expects related housing impacts to be SMALL.

A site-specific housing analysis supports this conclusion. The maximum impact to area housing was calculated using the following assumptions: (1) all direct and indirect jobs would be filled by immigrating residents, (2) the residential distribution of new residents would be similar to current worker distribution, and (3) each new job created (direct and indirect) represents one housing unit. As described in Section 3.4, approximately 79 percent of the VEGP site workforce resides in Burke, Richmond, and Columbia Counties. Therefore, the focus of the housing impact analysis is on these three counties. Also noted in Section 3.4, SNC's conservative estimate of 60 additional permanent employees during the license renewal period could generate the demand for 145 housing units (60 direct and 85 indirect jobs). If it is assumed that 79 percent of the 145 new workers would locate in the Burke, Richmond, and Columbia county area, consistent with current employee trends, 115 housing units (new construction or resale/rental of vacant single-family dwellings or multiple-family dwelling units) would be needed in the three-county area. In a three-county area with a population of more than 311,300, this would not create a discernible change in housing availability, change rental rates and housing values, or spur housing construction or conversion. Given the magnitude of the impact on housing from continued operation of the VEGP units in the license renewal period, which is SMALL, mitigative measures would not be necessary.

4.15 Public Utilities: Public Water Supply Availability

NRC

The environmental report must contain "…an assessment of the impact of population increases attributable to the proposed project on the public water supply." 10 CFR 51.53(c)(3)(ii)(I)

"…An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 65

"Impacts on public utility services are considered small if little or no change occurs in the ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services." (NRC 1996a)

NRC made public utility impacts a Category 2 issue because an increased problem with water availability, resulting from pre-existing water shortages, could occur in conjunction with plant demand and plant-related population growth (NRC 1996a). Local information needed would include a description of water shortages experienced in the area and an assessment of the public water supply system's available capacity.

NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on local water resources.

As discussed in Section 3.2, SNC does not plan to undertake major refurbishment for VEGP license renewal. SNC concludes there would be no refurbishment-related impacts on the water supply system, and no analysis is required. Accordingly, the following discussion addresses impacts of continued VEGP operation on public water supply availability during the license renewal term.

At this time, VEGP operations are responsible for the withdrawal of approximately 1.05 million gallons of potable water per day from onsite groundwater wells. VEGP is permitted to withdraw 5.5 MGD. The aquifer systems in the region have the capacity to produce 3 MGD per well. Therefore, operations at the VEGP site do not stress available capacity. SNC has identified no operational changes during the VEGP license renewal term that would increase plant water use. Therefore, because SNC has no plans to increase plant water usage, SNC concludes that impacts on public water supply from plant water usage would be SMALL and not require mitigation.

The impact to local water supply systems from plant-related population growth can be determined by calculating the amount of water that would be required by these individuals. As described in Section 3.4, SNC's conservative estimate of 60 additional permanent employees during the license renewal period could generate a total of 145 new jobs in the region. If it is assumed that 115 of the new workers would reside in the three-county area (145 multiplied by 79 percent), this could increase population in the three-county area by 305 (115 jobs multiplied by 2.65 average number of persons per household in the State of Georgia [USCB 2007]). The average American uses 90 gallons per day for personal use (EPA 2003). Using this consumption rate, the plant-related population increase would require approximately 10,350 additional gallons per day in the three-county area. As SNC describes in Section 2.9.1, the major water suppliers in Burke, Richmond, and Columbia Counties all have excess capacity. As noted in Section 2.6.1, population projections through 2015 indicate slow steady growth in Burke County, a declining population in Richmond County, and continued, but slowing, growth in Columbia County. Therefore, the impacts resulting from plant-related population growth to the public water supply from continued operation of the VEGP units in the license renewal period would be SMALL, and would not warrant mitigation.

4.16 Education Impacts from Refurbishment

NRC

The environmental report must contain "…an assessment of the impact of the proposed action on public schools (impacts from refurbishment activities only) within the vicinity of the plant…." 10 CFR 51.53(c)(3)(ii)(I)

"…Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 66

"…[S]mall impacts are associated with project-related enrollment increases of 3 percent or less. Impacts are considered small if there is no change in the school systems' abilities to provide educational services and if no additional teaching staff or classroom space is needed. Moderate impacts are associated with 4 to 8 percent increases in enrollment, and if a school system must increase its teaching staff or classroom space even slightly to preserve its pre-project level of service…. Large impacts are associated with enrollment increases greater than 8 percent…." (NRC 1996a).

NRC made refurbishment-related impacts to education a Category 2 issue because site- and project-specific factors determine the significance of impacts (NRC 1996a). Local factors to be ascertained include project-related enrollment increases and status of the student/teacher ratio.

The issue of impacts to the local education system due to refurbishment is not applicable to VEGP because, as Section 3.2 discusses, SNC has identified no refurbishment needs at VEGP.

4.17 Offsite Land Use

4.17.1 Offsite Land Use – Refurbishment

NRC

The environmental report must contain "…an assessment of the impact of the proposed action on... land-use... (impacts from refurbishment activities only) within the vicinity of the plant…" 10 CFR 51.53(c)(3)(ii)(I)

"…Impacts may be of moderate significance at plants in low population areas…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 68

"…[I]f plant-related population growth is less than 5 percent of the study area's total population, off-site land-use changes would be small, especially if the study area has established patterns of residential and commercial development, a population density of at least 60 persons per square mile, and at least one urban area with a population of 100,000 or more within 50 miles…." (NRC 1996a)

NRC made impacts to offsite land use as a result of refurbishment activities a Category 2 issue because land-use changes could be considered beneficial by some community members and adverse by others. Local conditions to be ascertained include plant-related population growth, patterns of residential and commercial development, and proximity to an urban area with a population of at least 100,000.

This issue is not applicable to VEGP because, as Section 3.2 discusses, SNC has no plans for refurbishment at VEGP.

4.17.2 Offsite Land Use – License Renewal Term

NRC

The environmental report must contain "…an assessment of the impact of the proposed action on …land-use…within the vicinity of the plant…" 10 CFR 51.53(c)(3)(ii)(I)

"Significant changes in land use may be associated with population and tax revenue changes resulting from license renewal." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 69

"…[I]f plant-related population growth is less than five percent of the study area's total population, off-site land-use changes would be small…" (NRC 1996a)

> "If the plant's tax payments are projected to be a dominant source of the community's total revenue, new tax-driven land-use changes would be large. This would be especially true where the community has no pre-established pattern of development or has not provided adequate public services to support and guide development in the past." (NRC 1996a)

NRC made impacts to offsite land use during the license renewal term a Category 2 issue, because land-use changes may be perceived as beneficial by some community members and detrimental by others. Therefore, NRC could not assess the potential significance of site-specific offsite land-use impacts (NRC 1996a). Site-specific factors to consider in an assessment of land-use impacts include

- the size of plant-related population growth compared to the area's total population,
- the size of the plant's tax payments relative to the community's total revenue,
- the nature of the community's existing land-use pattern, and
- the extent to which the community already has public services in place to support and guide development.

The GEIS presents an analysis of offsite land use for the renewal term that is characterized by two components: population-driven and tax-driven impacts (NRC 1996a).

Population-Related Impacts

Based on the GEIS case-study analysis, NRC concluded that all new population-driven land-use changes during the license renewal term at all nuclear plants would be small. Population growth caused by license renewal would represent a much smaller "percentage of the local area's" total population than the percent change represented by operations-related growth (NRC 1996a). SNC agrees with the NRC conclusion that population-driven land use impacts would be SMALL at VEGP. Mitigation would not be warranted.

Tax-Revenue-Related Land Use Impacts

Determining tax-revenue-related land use impacts is a two-step process. First, the significance of the plant's tax payments on taxing jurisdictions' tax revenues is evaluated. Then, the impact of the tax contribution on land use within the taxing jurisdiction's boundaries is assessed.

Tax Payment Significance

NRC has determined that the significance of tax payments as a source of local government revenue would be large if the payments are greater than 20 percent of revenue, moderate if the payments are between 10 and 20 percent of revenue, and small if the payments are less than 10 percent of revenue (NRC 1996a).

NRC further determined that, if the plant's tax payments are projected to be a dominant source of the community's total revenue, new tax-driven land-use changes would be large. This would be especially true where the community has no pre-established pattern of development or has not provided adequate public services to support and guide development in the past (NRC 1996a).

Land Use Significance

NRC defined the magnitude of land-use changes as follows (NRC 1996a):

- SMALL - very little new development and minimal changes to an area's land-use pattern.
- MODERATE - considerable new development and some changes to land-use pattern.
- LARGE - large-scale new development and major changes in land-use pattern.

VEGP Tax Impacts

Table 2.7-1 provides a comparison of total property tax payments made by VEGP to Burke County and Burke County's annual property tax revenues. For the years 2000 through 2004, VEGP's property taxes represented 80 to 82 percent of Burke County's total tax revenues. The majority of the Burke County property tax revenues have gone to the Burke County School District. Using NRC's criteria, VEGP's tax payments are of large significance to Burke County and the Burke County School District.

VEGP Land Use Impacts

From 1990 to 2000, the Burke County population grew at an average annual growth rate of 0.8 percent (Section 2.6). Burke County has the second largest land area of any county in Georgia and includes six small incorporated municipalities and a very large unincorporated area (Section 2.8). The predominant land uses are agriculture and forestry (76 percent of the unincorporated area in the county in 1990) (Section 2.6). In 1990, developed areas represented approximately 6 to 7 percent of the total land area in the county. County officials report that the rural character of Burke County has changed minimally over the last 30 years. Most industry is related to forestry and manufacturing and no new industries have been attracted to the area as a result of the VEGP's presence. The majority of the current VEGP workforce lives in Richmond or Columbia counties (Section 3.4).

Past and present VEGP-related land use impacts in Burke County are those induced by construction of the original units, the plant's property tax payments, and sales tax revenues generated by VEGP refueling outages. VEGP's construction had large indirect impacts on the economy in Burke County, as evidenced by an upswing in residential and commercial activity, but those were temporary and returned to pre-construction levels when construction was completed. The plant's property tax payments have allowed Burke County to upgrade and expand infrastructure, emergency management services, and social services. However, property tax revenues are not the only source of income for county infrastructure upgrades. The county also employs a Special Purpose Local Option Sales Tax (SPLOST), which is a tax added to the existing sales tax. Proceeds from SPLOST taxes are also used for service and infrastructure upgrades and expansions.

As stated in Section 2.8, Burke County and municipalities within the county use comprehensive land use planning, land development codes, zoning, and subdivision regulations to guide development. The County encourages growth in areas where public facilities, such as water and sewer systems, exist or are scheduled to be built in the future. Burke County promotes the preservation of its communities' natural resources and has no growth-control measures. The County is revising its comprehensive plan and developing a zoning plan.

Conclusion

VEGP's property taxes account for approximately 80 percent of Burke County's property tax revenues, well above the NRC significance level of high if the facility provides 20 percent of the tax revenues. As such, VEGP has been and will likely continue to be the dominant source of tax revenue for Burke County. However, despite having this income source, with concomitant improvements in public services, Burke County is still predominantly rural, and land in the county will likely continue to be used for agriculture and forestry into the license renewal term.

Although local officials expect some small-scale industrial and commercial growth in the county's incorporated towns, the nuclear plant's presence is not expected to directly attract support industries and commercial development or to encourage or deter residential development. License renewal would not generate additional tax revenues, but would continue the beneficial impact of the plant on the county. Therefore, the land-use impacts of VEGP's license renewal term are expected to be SMALL, with very little new development and minimal changes to the area's land-use pattern.

4.18 Transportation

NRC

The environmental report must "...assess the impact of highway traffic generated by the proposed project on the level of service of local highways during periods of license renewal refurbishment activities and during the term of the renewed license." 10 CFR 51.53(c)(3)(ii)(J)

"…Transportation impacts…are generally expected to be of small significance. However, the increase in traffic associated with additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 70

Small impacts would be associated with U.S. Transportation Research Board Level of Service A, having the following condition: "…Free flow of the traffic stream; users are unaffected by the presence of others." and Level of Service B, having the following condition: "…Stable flow in which the freedom to select speed is unaffected but the freedom to maneuver is slightly diminished…." (NRC 1996a)

NRC made impacts to transportation a Category 2 issue, because impact significance is determined primarily by road conditions existing at the time of license renewal, which NRC could not forecast for all facilities (NRC 1996a). Local road conditions to be ascertained are level of service conditions and incremental increases in traffic associated with refurbishment activities and license renewal staff.

As described in Section 3.2, no refurbishment is planned and no refurbishment impacts to local transportation are therefore anticipated. Accordingly, the following discussion addresses potential impacts to transportation from VEGP operation in the license renewal term.

As SNC notes in Section 2.9.2, access to the VEGP site is via River Road (also known as State Route 56 and County Road 59), and the major commuting routes used by VEGP site employees are in rural, uncongested areas. The current VEGP workforce is approximately 888 employees, including SNC employees and contractors (Section 3.4). Refueling outages, which are scheduled approximately every 18 months and last about 30 days, add as many as 800 temporary workers. SNC's conservative assumption of 60 additional employees associated with operating through the license renewal terms for both VEGP units represents a small (6.8 percent) increase in the current number of employees and an even smaller percentage of the employees on-site during outages (e.g., for periodic refueling), when VEGP traffic volume is heaviest. As described in Section 2.6, VEGP is located in an area with slow population growth;

therefore, traffic volumes are not expected to increase significantly from those presented in Table 2.9.2-1. On the basis of these considerations and the traffic counts and capacities for the commuting routes to the VEGP site as described in Section 2.9.2, SNC concludes that impacts to transportation from continued operation of the VEGP units in the license renewal period would be SMALL and mitigation would not be necessary.

4.19 Historic and Archaeological Resources

NRC

The environmental report must contain an assessment of "…whether any historic or archaeological properties will be affected by the proposed project." 10 CFR 51.53(c)(3)(ii)(K)

"Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 71

"Sites are considered to have small impacts to historic and archaeological resources if (1) the State Historic Preservation Officer (SHPO) identifies no significant resources on or near the site; or (2) the SHPO identifies (or has previously identified) significant historic resources but determines they would not be affected by plant refurbishment, transmission lines, and license-renewal term operations and there are no complaints from the affected public about altered historic character; and (3) if the conditions associated with moderate impacts do not occur." (NRC 1996a)

NRC made impacts to historic and archaeological resources a Category 2 issue, because determinations of impacts to historic and archaeological resources are site-specific in nature and the National Historic Preservation Act mandates that impacts must be determined through consultation with the State Historic Preservation Officer (SHPO) (NRC 1996a).

An archaeological survey of the VEGP site was done in 1973, prior to construction of Units 1 and 2, under the direction of the Georgia State Archaeologist and the Georgia Historical Commission and was submitted to the U.S. Atomic Energy Agency (the predecessor agency to the NRC) (Section 2.11). Based on this study the State Archaeologist considered that the archaeological resources at the VEGP site had been sufficiently characterized. (GPC 1972)

As discussed in Section 3.2, SNC has no refurbishment plans and no refurbishment-related impacts are anticipated. SNC is not aware of any historic or archaeological resources that have been negatively affected to date by VEGP operations, including operation and maintenance of transmission lines. SNC is aware that the site and the surrounding environs have cultural resources (NSA 2006). Therefore, SNC has included a cultural resources procedure to protect those resources during excavation or other land disturbing activities. Because SNC has no plans to construct additional facilities related to Units 1 and 2 at VEGP during the license renewal term and the procedure would protect any resources that may be discovered during any land disturbing activity, SNC concludes that operation of generation and transmission facilities over the license renewal term would have SMALL impacts to cultural resources; hence, no mitigation would be warranted.

4.20 Severe Accident Mitigation Alternatives (SAMA)

NRC

The environmental report must contain a consideration of alternatives to mitigate severe accidents "…if the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environment assessment..." 10 CFR 51.53(c)(3)(ii)(L)

"…The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 76

Section 4.20 summarizes SNC's analysis of ways to mitigate the impacts of severe accidents. Attachment F provides a detailed description of the severe accident mitigation alternatives (SAMA) analysis.

The term "accident" refers to any unintentional event (i.e., outside the normal or expected plant operation envelope) that results in the release or a potential for release of radioactive material to the environment. NRC categorizes accidents as "design basis" or "severe." Design basis accidents are those for which the risk is great enough that NRC requires plant design and construction to prevent unacceptable accident consequences. Severe accidents are those that NRC considers too unlikely to warrant design controls.

NRC concluded in its license renewal rulemaking that the environmental impacts from severe accidents met its Category 1 criteria. However, NRC made consideration of mitigation alternatives a Category 2 issue because not all plants had completed ongoing regulatory programs related to mitigation (e.g., individual plant examinations [IPE], individual plant examination of external events [IPEEE] and accident management). Site-specific information to be presented in the license renewal environmental report includes: (1) potential SAMAs; (2) benefits, costs, and net value of implementing potential SAMAs; and (3) sensitivity of analysis to changes in key underlying assumptions.

SNC maintains a probabilistic risk assessment (PRA) model to use in evaluating the most significant risks of core damage. For the SAMA analysis, SNC used the PRA model output as input to an NRC-approved methodology that calculates economic costs and dose to the public from hypothesized releases from the containment structure into the environment. Then, using NRC regulatory analysis techniques, SNC calculated the potential health effects and monetary value of the unmitigated severe accident risk. The result represents the monetary value of the base risk of dose to the public and worker, offsite and onsite economic costs, and replacement power. As a conservative approach, SNC reduced the risk to zero, calculated the Maximum Averted Cost (MACR) and used this value as the screening value. This value became a cost/benefit-screening tool for potential SAMAs; a SAMA whose cost of implementation exceeded the risk value could be rejected as being not cost-beneficial. The following list summarizes the steps of this process:

- VEGP PRA Model – Use the VEGP Internal Events PRA model as the basis for the analysis (Section F.2). Incorporate External Events contributions based on available quantitative information as described in Section F.5.1.8.
- Level 3 PRA Analysis – Use VEGP Level 1 and 2 Internal Events PRA output and site-specific meteorology, demographic, land use, and emergency response data as input in performing a Level 3 PRA using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section F.3). Incorporate External Events contributions as described in Section F.5.1.8.
- Baseline Risk Monetization – Use NRC regulatory analysis techniques, calculate the health effects and monetary value of the VEGP severe accident risk. This becomes the maximum averted cost-risk that is possible (Section F.4).
- Phase I SAMA Analysis – Identify potential SAMA candidates based on the VEGP PRA, IPE, IPEEE, and documentation from the industry and the NRC. Screen out Phase I SAMA candidates that meet any of the following criteria (Section F.5):
    - candidates not applicable to the VEGP design
    - candidates with low benefit in pressurized water reactors (PWRs) such as VEGP
    - candidates that have already been implemented at VEGP
    - candidates whose benefits have been achieved at VEGP using other means, and
    - candidates whose estimated cost exceeds the maximum averted cost-risk
- Phase II SAMA Analysis – Calculate the risk reduction attributable to each remaining SAMA candidate and compare it to a more detailed cost analysis to identify any net cost benefit (Section F.6).
- Uncertainty Analysis – Evaluate how changes in the SAMA analysis assumptions might affect the cost/benefit evaluation (Section F.7).

Using this process, SNC evaluated a compiled list of potential industry, NRC, and VEGP-specific candidate SAMAs. This list was screened using the criteria identified above and resulted in 12 candidate SAMAs requiring further consideration.

The PRA model was used to establish the change in core damage frequency (CDF) that would be attributable to each candidate SAMA (assuming SAMA implementation) and using MACCS2 calculated monetized value for the change in CDF. SNC used the detailed cost estimates for implementing each SAMA and the SAMA-specific calculated benefit to perform a cost benefit analysis. Two SAMAs were initially found to be cost beneficial for VEGP:

- SAMA 2: Maintain full-time black start capability of the Plant Wilson combustion turbines.
- SAMA 4: Prepare procedures and operator training for cross-tying an opposite unit diesel generator.

For SAMA 2, the Phase II analysis indicated that a reduction in CDF is achievable, and no physical modifications should be required. To maintain full-time black start capability, daily operator log items would need to be added to ensure the Wilson Black-start diesel generator and combustion turbines are ready to be started. In addition, two dedicated and trained operators would be required to operate Plant Wilson during a loss of offsite power (LOSP) event. If the existing Vogtle Operations crew cannot spare two qualified individuals during a LOSP event, the crew size will need to be expanded to meet the requirements. No new procedures would need to be developed as one already exists for performing a combustion turbines/diesel generators-black start.

For SAMA 4, currently, no procedures and training for cross-tying an opposite unit diesel generator exist except for the power option book in the Technical Support Center (TSC) room. Implementation of SAMA 4 would increase the success path of the operator in cross-tying the opposite unit diesel generator. Since the Phase II SAMA analysis indicates that better procedures for this action can lead to a reduction in CDF, this initiative will be considered for implementation at the site.

These two SAMAs could be considered to be cost beneficial alone, but given the similarities between these two SAMAs, implementation of either of them could make the averted cost risk of implementation of the remaining SAMA not cost beneficial as the relevant risk factors would be addressed.

SNC performed three additional analyses to evaluate how the SAMA analysis would change if certain key parameters were changed. The results of the uncertainty analysis indicate that use of the 95th percentile PRA results would suggest that two additional SAMAs are cost beneficial for VEGP:

- SAMA 6: Implementation of a bypass line for the cooling tower return isolation valves
- SAMA 16: Enhanced procedures for Interfacing System Loss of Cooling Accident (ISLOCA) response

For these two SAMAs, however, it is noted that the conservative (risk reduced to zero) PRA model assumptions or representations are likely leading to overestimating the reduction in CDF associated with their implementation. Additionally, even with these conservatisms, the net benefit is lower than the implementation cost, and is only slightly positive in the 95th percentile sensitivity case. Consequently, these SAMAs are unlikely candidates for realistic consideration at the site.

SAMAs 2 and 4 have the potential to reduce plant CDF for a relatively small cost and should be considered for implementation at VEGP. While these results are believed to reflect potential cost beneficial SAMAs, SNC notes that this analysis alone should not necessarily be considered a formal endorsement of these proposed changes as other engineering reviews are necessary to determine the ultimate benefit of implementation. SNC will implement or further consider the two SAMAs (2 and 4) identified in the analysis through the appropriate VEGP action process.

In conclusion, the benefits of revising the operational strategies in place at VEGP or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. However, review of the PRA in conjunction with cost-benefit analysis methodologies provides an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on the future population. The results of this study indicate that two SAMAs were identified that produce two potential improvements that can be made at VEGP. The resulting impacts of SAMAs at VEGP will be SMALL. The two SAMAs are cost-beneficial based on the methodology applied in this analysis and are not related to the aging analysis.

4.21 References

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(COE 2007) U.S. Army Corps of Engineers. "Welcome to J. Strom Thurmond Dam and Lake." Available at http://water.sas.usace.army.mil/cf/distribution/distribution.cfm. Accessed February 24, 2007.

(EPA 2003) U. S. Environmental Protection Agency. "Water on Tap. What You Need to Know." Available online at www.epa.gov/safewater. Accessed April 24, 2007.

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(IEEE 1997) Institute of Electrical and Electronic Engineers. *National Electrical Safety Code*, 1997 Edition. New York, New York. 1997.

(Joklik and Smith 1972) Joklik, W. K. and D. T. Smith. *Microbiology.* 15th Edition. Meredith Corporation. New York. 1972.

(NRC 1985) U.S. Nuclear Regulatory Commission. *Final Environmental Statement related to the Operation Vogtle Electric Generating Plant Units 1 and 2, Docket Nos. 50-424 and 50-425, Georgia Power Company et al.* NUREG-1087. Office of Nuclear Reactor Regulation. Washington, D.C. March, 1985.

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

(NRC 1996b) U.S. Nuclear Regulatory Commission. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." Federal Register, Volume 61, Number 109. June 5, 1996.

(NSA 2006) New South Associates. Intensive Archaeological Survey of the Proposed Expansion Areas at Vogtle Electric Generating Station, Burke County, Georgia. August 2006.

(SNC 2005) Southern Nuclear Operating Company. Vogtle Electric Generating Plant Updated Final Safety Analysis Report, Revision 13. January 31, 2005.

(USCB 2007) U. S. Census Bureau. *State and County Quickfacts, Georgia*, Available at http://www.census.gov/, accessed April 23, 2007.

Chapter 5 Assessment of New and Significant Information

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)

Description of Process

SNC performed systematic and deterministic evaluation of environmental issues applicable to license renewal for VEGP. This evaluation included the Category 1 issues identified in 10 CFR 51, subpart A, Appendix B, Table B-1. The purpose of the review of Category 1 issues was to verify that the conclusions of the GEIS remain valid with respect to VEGP.

The new and significant assessment process that SNC used during preparation of this license renewal application also included

- An extensive review of documents related to environmental issues at VEGP,
- Correspondence with state and federal agencies to determine if the agencies had concerns not addressed in the GEIS or were aware of new information that was not addressed in the ER,
- A review of evaluations conducted under the Vogtle EPP (non-radiological) and of reports submitted to NRC in accordance with the EPP documenting Unreviewed Environmental Questions or changes to the EPP,
- Discussion with plant and corporate personnel associated with environmental issues,
- A review of other license renewal applications for pertinent issues,
- Credit for the oversight provided by inspections of plant facilities by state and federal regulatory agencies, and
- Interfaces with other nuclear plants operated by SNC.

Review of Environmental Issues Prior to License Application Submittal

The VEGP EPP and SNC Environmental Services procedures govern review of environmental issues. SNC reviews changes in plant design, operation, or tests and experiments with potential for environmental impact in accordance with established procedures and responsibilities to ensure that such activities do not involve an unreviewed environmental question or require changes to the EPP. Established procedures and responsibilities will ensure that any new and significant information related to renewal of the VEGP licenses will be identified, reviewed, and addressed during the period of NRC review.

As a result of this review, SNC is not aware of any new and significant information regarding VEGP's environment or operations that would make a generic conclusion codified by NRC for Category 1 issues not applicable to VEGP, that would alter regulatory or GEIS statements regarding Category 2 issues, or that would suggest any other measure of license renewal environmental impact.

Chapter 6 Summary of License Renewal Impacts and Mitigating Actions

6.1 License Renewal Impacts

SNC has reviewed the environmental impacts of renewing the VEGP operating licenses and has concluded that impacts would be small and would not require mitigation. This ER documents the bases for SNC's conclusions. Chapter 4 incorporates by reference NRC findings for the 54 Category 1 issues that apply to VEGP, all of which have impacts that are small (Attachment A, Table A-1). The rest of Chapter 4 analyzes Category 2 issues, all of which are either not applicable or have impacts that are small. Table 6.1-1 identifies the impacts that VEGP license renewal would have on resources associated with Category 2 issues.

Table 6.1-1. Environmental Impacts Related to License Renewal at VEGP.

No.	Category 2 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**. VEGP withdrawals from the Savannah River represent less than 2 percent of the river flow during recent drought periods and less than 1 percent of the average annual flow.
Aquatic Ecology (for plants with once-through or cooling pond heat dissipation systems)		
25	Entrainment of fish and shellfish in early life stages	**None**. This issue does not apply because VEGP does not use a once-through or cooling pond heat dissipation system.
26	Impingement of fish and shellfish	**None**. This issue does not apply because VEGP does not use a once-through or cooling pond heat dissipation system.
27	Heat shock	**None**. This issue does not apply because VEGP does not use a once-through or cooling pond heat dissipation system.
Groundwater Use and Quality		
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use > 100 gpm)	**Small**. Based on modeling, drawdown of the Cretaceous aquifer at the VEGP property's western boundary stabilized at 1.9 feet in the first 10 years of operation and is not expected to increase through the license renewal term.
34	Groundwater use conflicts (plants using cooling towers or cooling ponds and withdrawing makeup water from a small river)	**Small**. VEGP consumes approximately 69 cfs, or approximately 0.7 percent of the average annual Savannah River flow. In addition, groundwater used in the vicinity of VEGP is from deep aquifers, not from the alluvium along the Savannah River. VEGP withdrawals from the Savannah River do not adversely affect the alluvial aquifer.

Table 6.1-1. (cont'd) Environmental Impacts Related to License Renewal at VEGP.

No.	Category 2 Issue	Environmental Impact
35	Groundwater use conflicts (Ranney wells)	**None**. This issue does not apply because VEGP does not use Ranney wells.
39	Groundwater quality degradation (cooling ponds at inland sites)	**None**. This issue does not apply because VEGP does not use cooling ponds.
Terrestrial Resources		
40	Refurbishment impacts	**None**. No impacts are expected because VEGP has no plans to undertake refurbishment.
Threatened or Endangered Species		
49	Threatened or endangered species	**Small**. VEGP operations and maintenance criteria along VEGP-associated transmission lines have no impact on threatened or endangered species or their habitats.
Air Quality		
50	Air quality during refurbishment (non-attainment and maintenance areas)	**None**. No impacts are expected because VEGP has no plans to 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**. The thermal characteristics of the Savannah River at the point of VEGP discharge are not conducive to stimulating the growth or reproduction of thermophilic organisms. In addition, biocides used in VEGP's cooling system decrease the likelihood that a seed source or inoculant would be introduced into the river via the VEGP discharge.
59	Electromagnetic fields, acute effects (electric shock)	**Small**. The largest modeled induced current under the VEGP lines is less than the 5-milliampere limit. Therefore, the VEGP transmission lines conform to the National Electrical Safety Code provisions for preventing electric shock from induced current.
Socioeconomics		
63	Housing impacts	**Small**. SNC anticipates no increase in staffing, however SNC performed an analysis assuming 60 additional permanent employees and found that impacts would be small.
65	Public services: public utilities	**Small**. SNC anticipates no increase in staffing, however SNC performed an analysis assuming 60 additional permanent employees and found that impacts would be small.
66	Public services: education (refurbishment)	**None**. No impacts are expected because VEGP has no plans to undertake refurbishment.
68	Offsite land use (refurbishment)	**None**. No impacts are expected because VEGP has no plans to undertake refurbishment.

Table 6.1-1. (cont'd) Environmental Impacts Related to License Renewal at VEGP.

No.	Category 2 Issue	Environmental Impact
69	Offsite land use (license renewal term)	**Small**. Although VEGP is the major contributor to property taxes in Burke County, the VEGP taxes have had little impact on land use in the county since the plant was constructed and the impact is not expected to change during license renewal term.
70	Public services: transportation	**Small**. SNC anticipates no increase in staffing and therefore, no impacts to transportation, however SNC performed an analysis assuming 60 additional permanent employees and found that impacts would be small.
71	Historic and archeological resources	**Small**. Continued operation of VEGP would not require construction at the site. Therefore, license renewal would have no effect on historic or archeological resources.
Postulated Accidents		
76	Severe accidents	**Small.** SNC did not identify any cost-beneficial SAMAs related to aging management.

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 monitoring activities that would continue during the license renewal term. SNC performs routine monitoring to ensure the safety of workers, the public, and the environment. These activities include the radiological environmental monitoring program, air quality emissions monitoring, and groundwater and effluent chemistry monitoring. These monitoring programs ensure that the plant's permitted emissions and discharges are within regulatory limits and that any unusual or off-normal emissions would be quickly detected, mitigating potential impacts.

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 ER adopts by reference NRC findings for applicable Category 1 issues, including discussions of any unavoidable adverse impacts (Attachment A, Table A-1). SNC identified the following unavoidable adverse impacts of license renewal:

- The cooling towers and their vapor plumes are visible from offsite. This visual impact will continue during the license renewal term. This impact has been evaluated and determined to be SMALL.
- Procedures for the disposal of sanitary, chemical, and radioactive wastes are intended to ensure impacts from these activities are maintained at acceptably low levels. However, small impacts will occur as long as the plant is in operation. Solid radioactive wastes are a product of plant operations and long-term disposal of these materials must be considered. Disposal of wastes associated with Vogtle has been evaluated and determined to be SMALL.
- Operation of VEGP results in a very small increase in radioactivity in the air and water. The incremental radiation dose to the local population resulting from Vogtle operations is typically less than the magnitude of the fluctuations that occur in natural background radiation. Operation of VEGP also creates a very low probability of accidental radiation exposure to inhabitants of the area.
- Operation of VEGP results in consumptive use of Savannah River water. The consumptive use of water is discussed in detail in Chapter 3 and has been determined to be SMALL.
- An extremely small number of adult and juvenile fish could be impinged on the traveling screens at the river water intake structure as a result of intake operations. VEGP uses closed-cycle recirculating cooling towers for cooling, therefore, this is a category 1 issue and impacts are SMALL.
- Small numbers of ichthyoplankton could be entrained at the river water intake structure as a result of intake operations. VEGP uses closed-cycle recirculating cooling towers for cooling, therefore, this is a category 1 issue and impacts are SMALL.

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 VEGP 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 fission products and spent nuclear fuel;
- Land required to dispose of spent nuclear fuel and low-level radioactive wastes generated as a result of plant operations and sanitary and solid wastes generated from normal industrial operations;
- Elemental materials that become radioactive as a result of activation; 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 VEGP site was established with the decision to convert approximately 1,400 acres of farmland and woodland to industrial use. The FESs related to construction (AEC 1974) and operation (NRC 1985) evaluated the impacts of constructing and operating VEGP. Natural resources that would be subjected to short-term use include land and water. The plant site and the area surrounding it are largely undeveloped. The 1,400 acres of the 3,169-acre site devoted to the production of electrical energy includes the areas occupied by VEGP facilities (buildings, parking lots, roadways, old construction facilities), transmission line rights-of-way, the Vogtle Training Center, the Plant Wilson facility, and landscaped areas around the facilities. Offsite transmission line construction required about 7,200 acres across natural lands and agricultural or silvicultural landscapes.

Although VEGP consumes water from the Savannah River, the impacts are minor and would cease once the reactors cease operation. The productivity of the aquatic community in the Savannah River in the vicinity of VEGP is not adversely affected by the water use.

After decommissioning, most environmental disturbances would cease and restoration of the natural habitat could occur. Thus, the "trade-off" between the production of electricity and changes in the local environment is reversible to some extent.

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. The degree of dismantlement 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 increase the short-term productivity impacts described here.

6.6 References

(AEC 1974) U.S. Atomic Energy Commission. *Final Environmental Statement Related to the Proposed Alvin W. Vogtle Nuclear Plant, Units 1, 2, 3, and 4, Georgia Power Company*. Docket Nos. 50-424, 50-425, 50-426, and 50-427. March 1974.

(NRC 1985) U.S. Nuclear Regulatory Commission*. Final Environmental Statement related to the operation of Vogtle Electric Generating Plant Units 1 and 2, Dockets Nos. 50-42024 and 50-425, Georgia Power Company et al.* Office of Nuclear Reactor Regulation. Washington, D.C. March 1985.

(SNC 2006) Southern Nuclear Operating Company. 2006. Vogtle Early Site Permit Application, Rev. 1. November 2006.

Chapter 7 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 VEGP license renewal. The chapter identifies actions that the owners of VEGP might take, and the associated environmental impacts of those actions, if NRC chooses not to renew the plant's operating license. The chapter also addresses alternatives to license renewal that VEGP owner's considered and their environmental impacts, and identifies bases for determining that such actions would be unreasonable.

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

"…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)].

SNC has determined that the analysis of alternatives should focus on comparative impacts, specifically whether an alternative's impacts would be greater, smaller or similar to 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). SNC considers Chapter 7 sufficient with regard to providing 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, SNC has used the same definitions of "small," "moderate," and "large" presented in the introduction to Chapter 4.

7.1 No-Action Alternative

SNC uses the "no-action alternative" to refer to a scenario in which NRC does not renew the VEGP operating licenses. Components of this alternative include replacing the generating capacity of VEGP and decommissioning the facility, as described below.

VEGP provides approximately 19.3 terawatt-hours of electricity annually to SNC's customers (Energy Information Administration [EIA] 2005). SNC believes that any alternative would be unreasonable if it did not include replacing the capacity of VEGP. Replacement could be accomplished by building new generating capacity, purchasing power from the wholesale market, or 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 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, and safe storage of the stabilized and defueled facility for a period of time, followed by additional decontamination and dismantlement. Regardless of the option chosen, decommissioning must be completed within a 60-year period. Under the no-action alternative, SNC would continue operating VEGP until the existing Unit 1 and Unit 2 licenses expire in 2027 and 2029, respectively, and 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- MWe Trojan Nuclear Plant). This description is applicable to decommissioning activities that SNC would conduct at VEGP.

As the GEIS notes, NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts include impacts of 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 of Nuclear Facilities; Supplement 1* (NRC 2002a) 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. SNC adopts by reference the NRC conclusions regarding environmental impacts of decommissioning.

SNC notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. SNC will have to decommission VEGP 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. SNC 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.

SNC 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 GEIS (NRC 2002a). The impacts of decommissioning would be temporary and would occur at the same time as the impacts from using an alternative technology to meet system generating needs.

7.2 Alternatives that Meet System Generating Needs

VEGP has a net capacity of 2,301 MWe (SNC 2005) and, in 2004, generated approximately 19.3 terawatt-hours of electricity (EIA 2005). This power, equivalent to the energy used by approximately 1.8 million residential customers, would be unavailable to SNC's customers in the event the VEGP operating licenses are not renewed. If the VEGP operating licenses are not renewed, the owners of VEGP would need to build new generating capacity, purchase power, or reduce power requirements through demand reduction to ensure they meet the electric power requirements of their customers.

The current mix of power generation options within Georgia is one indicator of what the owners of VEGP consider to be feasible alternatives. In 2004, electric generators in Georgia had a total generating capacity of 35,338 MWe. This capacity includes units fueled by coal (38.2 percent), gas (21.1 percent), dual-fired (i.e., gas and oil; 13.8 percent), nuclear (11.5 percent), hydroelectric (10.4 percent), oil (3.5 percent), and renewable (1.4 percent). In 2004, the electric industry in Georgia provided 126.8 terawatt-hours of electricity. Utilization of generating capacity in Georgia was dominated by coal (63.1 percent), followed by nuclear (26.6 percent), gas (4.9 percent), renewable (2.6 percent), hydroelectric (2.2 percent), and oil (0.7 percent) (EIA 2006a). Figures 7.2-1 and 7.2-2 illustrate the electric industry generating capacity and utilization, respectively, for Georgia.

Comparison of generating capacity with actual utilization of this capacity indicates that in Georgia coal and nuclear are used substantially more relative to their capacity than either oil-fired or gas-fired generation. This condition reflects the relatively low fuel cost and baseload suitability for nuclear power and coal-fired plants, and relatively higher use of gas- and oil-fired units to meet peak loads. Comparison of capability and utilization for petroleum and gas-fired facilities indicates a strong preference of gas firing over oil firing, indicative of higher cost and greater air emissions associated with oil firing. Energy production from hydroelectric and other renewable sources is also preferred from a cost standpoint, but capacity is limited and utilization can vary substantially depending on resource availability.

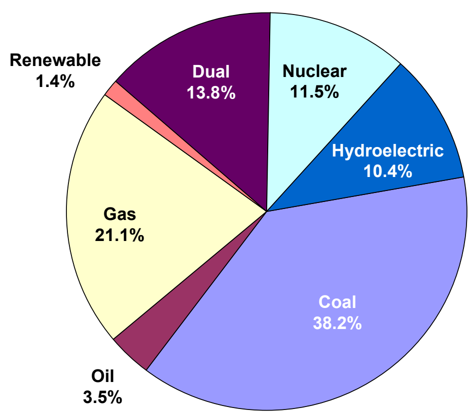

Figure 7.2-1. Georgia Generating Capacity by Fuel Type, 2004

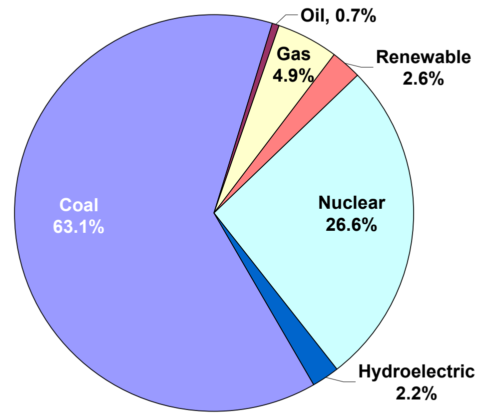

Figure 7.2-2. Georgia Utilization by Fuel Type, 2004

7.2.1 Alternatives Considered

Technology Choices

For this ER, SNC conducted evaluations of alternative generating technologies to identify candidate technologies that would be capable of replacing the net base-load capacity of the nuclear units at VEGP.

Based on these evaluations, it was determined that reasonably feasible generation alternatives to replace the capacity for base-load operation of the VEGP nuclear units are limited to pulverized-coal, gas-fired combined-cycle, or nuclear.

This conclusion is supported by the generation utilization information presented above that identifies coal and nuclear as the most heavily utilized generating technologies in the state. In addition, recent volatility in prices of oil and natural gas has made new coal and nuclear power plant construction more attractive from a cost standpoint. SNC would use natural gas as the primary fuel in its combined-cycle turbines because of the economic and environmental advantages of gas over oil. Manufacturers now have large standard sizes of combined-cycle gas turbines that are economically attractive and suitable for high-capacity base-load operation. For this license renewal ER, SNC has limited its analysis of new generating capacity alternatives to the technologies it considers feasible: pulverized coal-fired, gas-fired, and advanced light water nuclear units. SNC chose to evaluate combined-cycle turbines in lieu of simple-cycle turbines because the combined-cycle option is more economical. The benefits of lower operating costs for the combined-cycle option outweigh its higher capital costs.

Mixture

NRC indicated in the GEIS that, while many technologies and combinations of technologies are available for generating electricity and meeting system needs, it would be impractical to analyze all the combinations. Therefore, NRC determined that the alternatives evaluation 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, SNC has not evaluated mixes of generating sources. The impacts from the generation alternatives presented in this chapter would bound the impacts from any combination of the technologies.

Effects of Restructuring

Nationally, the electric power industry has been undergoing a transition from a regulated monopoly 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 (Nuclear Energy Institute [NEI] 2000).

Limited retail competition has been present in Georgia since the 1973 passage of the Georgia Territorial Electric Service Act. This Act provides customers with loads of at least 900 kW a choice in electric service suppliers. In 1998, the Georgia Public Service Commission (GPSC) published a report that identified issues that must be resolved to expand retail competition in Georgia's electric industry, and provided a set of guiding principles for continuing examination of electric industry restructuring. The GPSC report also concluded that Georgia's electric power industry would be restructured at some future time (GPSC 1998). However, no further action has been taken to expand retail competition in Georgia.

If the electric power industry is deregulated, full retail competition would replace the electric utilities' mandate to serve the public, and all electricity customers in an area would be able to choose among competing power suppliers, including those located outside their respective states. As such, electric generation would be based on customers' needs and preferences, the lowest price, or the best combination of prices, services, and incentives.

It is not clear which supplier would construct new generating units to replace those at VEGP, if its licenses were not renewed. However, 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 VEGP license renewal without regard to which supplier would implement them.

Alternatives

The following sections present fossil-fuel-fired generation (Section 7.2.1.1), advanced light water reactor (Section 7.2.1.2), and purchased power (Section 7.2.1.3) as reasonable alternatives to license renewal. Section 7.2.1.4 discusses reduced demand and presents the basis for concluding that it is not a reasonable alternative to license renewal. Section 7.2.1.5 discusses other alternatives that SNC has determined are not reasonable and the rationale for these determinations.

7.2.1.1 Construct and Operate Fossil-Fuel-Fired Generation

SNC analyzed locating hypothetical new coal- and gas-fired units at the existing VEGP site and at an undetermined green field site. VEGP is the preferred site for new construction because this approach would minimize environmental impacts by building on previously disturbed land and by taking advantage of existing infrastructure, such as transmission lines, roads and parking areas, office buildings, and components of the cooling system. Locating hypothetical units at the existing site has, therefore, been applied to the coal- and gas-fired units.

For comparability, SNC selected gas- and coal-fired units of equal generating capacity. In theory, one unit with a net capacity of 2,301 MWe could be used to replace the existing units. However, SNC's parent company, Southern Company's experience indicates that, although they can build custom-sized units, using standardized sizes is more economical. For example, standard-sized units include a gas-fired combined-cycle plant of 562.5 MWe net capacity (Chase and Kehoe 2000). Four of these standard-sized units would have 2,250 MWe net capacity. For comparability, SNC set the net power of the coal-fired units equal to the gas-fired plants (2,250 MWe). Although this provides less capacity than the existing units, it ensures against overestimating environmental impacts from the alternatives. The shortfall in capacity could be replaced by other technologies (see Mixture in Section 7.2.1).

It must be emphasized, however, that these are hypothetical scenarios. SNC does not have plans for such construction at VEGP.

Gas-Fired Generation

For purposes of this analysis, SNC assumed development of a natural gas-fired combined-cycle plant. SNC based its emission control technology and percent-control assumptions on alternatives that EPA has identified as being available for minimizing emissions (EPA 1998a). SNC assumes that the representative plant would be located at the VEGP site, which offers potential advantages of existing infrastructure (e.g., cooling water system, transmission, roads, and technical and administrative support facilities). Table 7.2-1 presents the basic gas-fired alternative characteristics.

Coal-Fired Generation

There are two primary technologies identified for generating electrical energy from pulverized coal: conventional pulverized coal boiler and fluidized bed combustion (FBC). In addition, Integrated Gasification Combined Cycle (IGCC) is an emerging, advanced technology for generating electricity with coal that combines modern coal gasification technology with both gas turbine and steam turbine power generation. As part of the coal-fired alternatives evaluation all three technologies (FBC, IGCC and conventional pulverized coal) were evaluated.

FBC is an advanced electric power generation process that minimizes the formation of gaseous pollutants by controlling coal combustion parameters and by injecting a sorbent (such as crushed limestone) into the combustion chamber along with the fuel. Crushed fuel mixed with the sorbent is fluidized on jets of air in the combustion chamber. Sulfur released from the fuel as sulfur dioxide is captured by the sorbent in the bed to form a solid compound that is removed with the ash. The resultant by-product is a dry, benign solid that is potentially a marketable byproduct for agricultural and construction applications. More than 90 percent of the sulfur in the fuel is captured in this process. Currently, FBC units are limited to a maximum size of approximately 265 MW (DOE 2003). Although a multi-unit facility could be built, this would not be benefit from the economies of scale associated with a 2,300 MW project such as is needed for replacement power for VEGP. Also, because of the lower operating temperature of the FBC system, it doesn't achieve the higher efficiency levels achieved by conventional pulverized coal boilers. Due to the limited size of available units, and lower thermal efficiency, FBC is not an effective alternative for the proposed project.

An IGCC system generates substantially less solid waste than a pulverized coal-fired plant. The largest solid waste stream produced by IGCC installations is slag, a black, glassy, sand-like material that is potentially a marketable byproduct. The other large-volume byproduct produced by IGCC plants is sulfur, which is extracted during the gasification process and can be marketed, rather than placed in a landfill. IGCC units are substantially cleaner than conventional pulverized coal plants because major pollutants can be removed from the gas stream prior to combustion. At present however, IGCC technology still has insufficient operating experience for widespread use in commercial-scale utility applications. System reliability is lower than conventional pulverized coal-fired power plants and there are problems with the integration of gasification and power production. For example, if there is a problem with gas cleaning, uncleaned gas can damage the gas turbine. (Rardin et al. 2005)

Because IGCC technology requires further research to achieve an acceptable level of reliability, an IGCC facility is not a reasonable alternative to the proposed project.

NRC has routinely evaluated pulverized coal-fired generation alternatives for nuclear plant license renewal. In the Supplemental GEIS for McGuire Nuclear Station (NRC 2002b), NRC analyzed 2,400 MWe of coal-fired generation capacity. SNC has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed more generating capacity than the 2,301 MWe discussed in this analysis. In defining the VEGP coal-fired alternative, SNC has used site- and Georgia -specific input and has scaled from the NRC analysis, where appropriate.

Table 7.2-2 presents the basic coal-fired alternative emission control characteristics. SNC based its emission control technology and percent control assumptions on alternatives that the EPA has identified as being available for minimizing emissions (EPA 1998a). SNC assumes that the representative plant would be located at the VEGP site, which offers potential advantages of existing infrastructure (e.g., cooling water system, transmission, roads, and technical and administrative support facilities). For the purposes of analysis, SNC has assumed that coal and lime (calcium oxide) would be delivered via an existing rail spur to VEGP.

7.2.1.2 Construct and Operate Advanced Light Water Reactor at an Existing Reactor Site

Since 1997, the NRC has certified new standard designs for nuclear power plants under 10 CFR Part 52, Subpart B. All of these NRC-certified plants are advanced light water reactors. In its application for an ESP for a new nuclear plant (SNC 2006), SNC evaluated an advanced light water reactor design. The reactors proposed in the ESP application would provide additional capacity for future electric power demand and are not intended to replace the existing units at VEGP.

A two-unit nuclear plant using an advanced light water reactor design as evaluated in the ESP application would have an output of approximately 2,234 MWe (SNC 2006). While this provides less capacity than the existing units at VEGP, the shortfall in capacity could be replaced by other technologies (see Mixture in Section 7.2.1). Therefore, SNC has evaluated a two-unit advanced light water reactor nuclear plant at an existing reactor site for this alternative.

7.2.1.3 Purchase Power

SNC has evaluated conventional and prospective power supply options that could be reasonably implemented before the current VEGP licenses expire. SNC parent company, Southern Company has entered into long-term purchase contracts with several entities to provide firm capacity and energy. These contracts are part of SNC's current and future capacity, therefore SNC does not consider these power purchases to be a feasible option for the purchased power alternative.

Georgia is a net importer of electricity. In 2003 Georgia imported approximately 46.8 gigawatt-hours of electricity (EIA 2006c). Some of the imported power may be the result of existing purchase contracts, which would prevent SNC from using this power to replace VEGP generation. However, SNC assumes that additional capacity might be available for purchase by the year 2027. Therefore, SNC has analyzed purchased power as a reasonable alternative.

The source of this purchased power is speculative, but may reasonably include new generating facilities developed within the State, or in neighboring states. The technologies that would be used to generate this purchased power are similarly speculative. SNC assumes that the generating technology used to produce purchased power would be one of those that NRC analyzed in the GEIS. For this reason, SNC is adopting by reference the GEIS description of the alternative generating technologies as representative of the purchased power alternative. Of these technologies, facilities fueled by coal, combined-cycle facilities fueled by natural gas, and advanced light water reactors are the most cost effective for providing base-load capacity.

SNC anticipates that additional transmission infrastructure would be needed in the event the owners of VEGP purchased power to replace its capacity. From a local perspective, loss of the VEGP could result in a load pocket that would require construction of new transmission lines to ensure local system stability.

7.2.1.4 Demand Side Management

SNC's parent company, Southern Company, has an extensive demand-side management (DSM) program that reduces generation needs through a combination of energy conservation, efficiency, and load management programs. Southern Company's DSM programs fall into the following categories (Southern Company 2005):

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; and
- Load-based pricing that encourages customers to use electricity more efficiently

Load Management Programs

- Standby generator program that encourages customers to let Southern Company switch loads to the customer's standby generators during periods of peak demand;
- Interruptible service program that encourages customers to allow blocks of their loads to be interrupted during periods of peak demand;
- Real-time pricing that encourages customers to reduce usage during specific times; and
- Time-of-use pricing that encourages customers to discontinue usage during periods of peak demand

By implementing the DSM program Southern Company has reduced its peak demand by more than 400 MWe (Southern Company 2005), which is substantially less than the 2,301 MWe net capacity of VEGP. Therefore, SNC determined that DSM programs are not an effective substitute for any of its large base-load units (such as VEGP) that operate at high-capacity factors.

7.2.1.5 Other Alternatives

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

Wind

Wind power systems produce power intermittently because they are only operational when the wind is blowing at sufficient velocity and duration. While recent advances in technology have improved wind turbine reliability, average annual capacity factors for wind power systems are relatively low (25 to 40 percent compared to 90 to 95 percent for a base-load plant such as a nuclear plant). (McGowan and Connors 2000)

The energy potential in the wind is expressed by wind generation classes ranging from 1 (least energetic) to 7 (most energetic). Wind regimes of Class 4 or higher are suitable for the advanced utility-scale wind turbine technology currently under development. Class 3 wind regimes may be suitable for future utility-scale technology. (American Public Power Association [APPA] 2004)

According to the *Wind Energy Resource Atlas of the United States* (National Renewable Energy Laboratory [NREL] 1986), the Southeast region is a Class 1 area, and the only places in the region with wind regimes of Class 3 or higher are exposed ridge crests and mountain summits in the southern Appalachian Mountains. This area is highly confined and represents an extremely small percentage of exposed land in the Southeast region (NREL 1986). The available land area within Georgia with wind regimes of Class 3 or higher is approximately 35 square miles (AWEA 2002).

Mountain ridge-top locations are remote, requiring incremental costs for developing access roads and power transmission infrastructure. Moreover, the hilly terrain increases the complexity of installation and the overall costs of wind energy due to the variable directional wind flows observed in mountainous regions compared to flatter landscapes. This variation tends to decrease the amount of usable energy that can be extracted from the wind, resulting in lower capacity factors. (Bowers 2005)

Estimates based on existing installations indicate that a utility-scale wind farm would require about 50 acres per MWe of installed capacity. The actual acreage occupied by the wind farm facilities would only occupy 3 to 5 percent of the wind farm's total acreage (McGowan and Connors 2000). The rest of the wind farm acreage could be used for other uses, primarily farming. Assuming ideal wind conditions (i.e., Class 3 wind or better) and a 35 percent capacity factor, a wind farm with a net output of 2,301 MWe would require about 328,720 acres (514 square miles) of which about 9,860 acres (15 square miles) would be occupied by turbines and support facilities. Based on the amount of land needed, the wind alternative would require a large green field site, which would result in a large environmental impact. Additionally, wind plants have aesthetic impacts, generate noise, and harm birds.

SNC has concluded that, due to the limited availability of area having suitable wind speeds, low capacity factors, the amount of land needed, and aesthetic impacts, wind generation is not a reasonable alternative to VEGP license renewal.

Solar

There are two basic types of solar technologies that produce electrical power: photovoltaic and solar thermal power. Photovoltaics convert sunlight directly into electricity using semiconducting materials. Solar thermal power systems use mirrors to concentrate sunlight on a receiver holding a fluid or gas, heating it, and causing it to turn a turbine or push a piston coupled to an electric generator. (Leitner and Owens 2003)

Solar technologies produce power intermittently because they only work when the sun is shining. More electricity is produced on a clear, sunny day with more intense sunlight and when the sunlight is at a more direct angle (i.e., when the sun is perpendicular to the collector). Cloudy days can significantly reduce output, and no power is produced at night. To work effectively, solar installations require consistent levels of sunlight (solar insolation). (Leitner and Owens 2003)

Solar thermal systems can be equipped with a thermal storage tank to store hot heat transfer fluid, providing thermal energy storage. By using thermal storage, a solar thermal plant can provide dispatchable electric power. (Black & Veatch 2005)

The lands having the best solar resources are usually arid or semi-arid. While photovoltaic systems use both diffuse and direct radiation, solar thermal power plants can only use the direct component of the sunlight. This makes solar thermal power unsuitable for areas like the Southeastern U.S with high humidity and frequent cloud cover, both of which diffuse solar energy and reduce its intensity. In addition, the average annual amount of solar energy reaching the ground needs to be 6.0 kW-hours per square meter per day or higher for solar thermal power systems (Leitner 2002). The Southeast, including Georgia, receives 3.5 to 5 kW-hours of solar radiation per square meter per day (NREL 2005).

Like wind, capacity factors also are too low to meet base-load requirements. Average annual capacity factors for solar power systems are relatively low (24 percent for photovoltaics and 30 to 32 percent for solar thermal power) compared to 90 to 95 percent for a base-load plant such as a nuclear plant. (Leitner 2002)

Land use requirements (and associated construction and ecological impacts) are also much higher for solar technologies compared to nuclear plants. The area of land required depends on the available solar insolation and type of plant, but is about 8 acres per megawatt for photovoltaic systems and 3.8 acres per megawatt for solar thermal power plants (Leitner 2002). Assuming capacity factors of 24 percent for photovoltaics and 32 percent for solar thermal power, replacement of VEGP generating capacity with solar power would require dedication of about 120 square miles for photovoltaic and 43 square miles for solar thermal systems. Neither type of solar electric system would fit at the VEGP site, and both would have large environmental impacts at a green field site.

SNC has concluded that, due to low capacity factors, lack of sufficient incident solar radiation, and the substantial amount of land needed to produce the desired output, solar power is not a reasonable alternative to VEGP license renewal.

Hydropower

Hydroelectric power is a fully commercialized technology. About 10.4 percent of Georgia's electric generating capacity is hydroelectric (EIA 2006a). According to the U.S. Hydropower Resource Assessment for Georgia the undeveloped hydropower potential in Georgia is approximately 613 MW. There are no remaining sites in Georgia that would be environmentally suitable for a large hydroelectric facility (Conner and Francfort 1998).

Land use for a large scale hydropower facility is estimated to be quite large. The GEIS (Section 8.3.4) estimates land use of 1,600 square miles per 1,000 MWe generated by hydropower. Based on this estimate, a 2,301 MWe project would require flooding more than 3,680 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 species. The NRC also notes that such facilities are difficult to site as a result of public concern over flooding, destruction of natural habitat, and alteration of natural river courses (NRC 1996a).

SNC has concluded that, due to the lack of suitable sites in Georgia and the amount of land needed, in addition to the adverse environmental impacts, hydropower is not a reasonable alternative to VEGP license renewal.

Geothermal

Geothermal energy is a proven resource for power generation. Geothermal power plants use naturally heated fluids as an energy source for electricity production. To produce electric power, underground high-temperature reservoirs of steam or hot water are tapped by wells and the steam rotates turbines that generate electricity. Typically, water is then returned to the ground to recharge the reservoir. (NREL 1997)

Geothermal energy can achieve average capacity factors of 95 percent and can be used for base-load power where this type of energy source is available (NREL 1997). Widespread application of geothermal energy is constrained by the geographic availability of the resource (NREL 1997). In the United States, high-temperature hydrothermal reservoirs are located in the western states, and Alaska and Hawaii. There are no known high-temperature geothermal sites in the Southeast region. (Southern Methodist University [SMU] 2004)

Geothermal power plants require relatively little land. An entire geothermal field uses 1 to 8 acres per MWe (Shibaki 2003). Assuming a 95 percent capacity factor, a geothermal power plant with a net output of 2,301 MWe would require at least 2,422 acres.

The major environmental concerns associated with geothermal development are the release of small quantities of carbon dioxide and hydrogen sulfide, noise, and disposal of sludge and spent geothermal fluids (Shibaki 2003 and NREL 1997). Subsidence and reservoir depletion may be a concern if withdrawal of geothermal fluids exceeds natural recharge or injection (Shibaki 2003).

SNC has concluded that, due to the lack of high-temperature geothermal reservoirs, geothermal power is not a reasonable alternative for base-load power in the Southeast.

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. 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. According to the DOE, Georgia has adequate wood resources (Walsh et al. 2000). However, the largest wood waste power plants are 40 to 50 MWe.

Further, as discussed in Section 8.3.6 of the GEIS (NRC 1996a), 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 (i.e., ash) disposal. 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 Georgia, SNC has concluded that, due to the lack of an environmental advantage, low heat content, handling difficulties, and high transportation costs, wood energy is not a reasonable alternative to VEGP license renewal.

Municipal Solid Waste

As discussed in Section 8.3.7 of the GEIS (NRC 1996a), 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 VEGP license renewal.

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

Other Biomass-Derived Fuels

In addition to wood and municipal solid waste fuels, energy crops such as switchgrass could be grown to ensure a reliable supply of biomass feedstocks for generation of electricity. The environmental impacts from converting large tracts of land to production of energy crops may include detrimental effects on wildlife habitat and biodiversity, reduced soil fertility, increased erosion, and reduced water quality. The net environmental impacts would depend on previous land use, the particular energy crop, and how the crop is managed. Displacing natural land cover, such as forests and wetlands, with energy crops would likely have negative impacts.

Nearly all of the biomass-energy-using electricity generation facilities in the United States use steam turbine conversion technology. However, at the scale appropriate for biomass (the largest biomass power plants are 40 to 50 MW), the technology is expensive and inefficient. Therefore, the technology is relegated to applications where there is a readily available supply of low-, zero-, or negative-cost delivered feedstocks. Other concepts for using biomass to fuel electric generators include 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, neither 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 VEGP.

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).

Another option for using biomass feedstocks to generate electricity is co-firing with coal. For more than 10 years, Southern Company has been evaluating co-firing biomass fuels in existing coal-fired generating plants. While Southern Company has proven that biomass can be successfully co-fired with coal, it is not without technical challenges. Biomass is much less dense than coal, requiring a large volume of fuel to be handled. Larger areas of biomass storage and additional handling are required to accommodate the lower-density materials. Moreover, the ash residue left from combusting biomass contains alkali and alkaline earth elements, such as sodium, potassium and calcium. These compounds bind irreversibly with the catalysts used in selective catalytic reduction (SCR) reactors that have been installed on coal-fired generating plants. These compounds can lead to increased catalyst plugging and cause deactivation of SCR catalysts, thus reducing or eliminating the ability of this technology to reduce nitrogen oxide emissions. (Bowers 2005)

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

Petroleum

Georgia has several petroleum (oil)-fired power plants; however, they produce only 1 percent of the total power generated in the state. From 1995 to 2004, the amount of power produced by oil-fired generating plants in Georgia has remained static (EIA 2006a). Oil-fired operation is more expensive than nuclear or coal-fired operation, and future increases in petroleum prices are expected to make oil-fired generation increasingly more expensive relative to coal-fired generation.

Also, construction and operation of an oil-fired plant would have environmental impacts. For example, Section 8.3.11 of the GEIS (NRC 1996a) estimates that construction of a 1,000-MWe oil-fired plant would require about 120 acres. Additionally, operation of oil-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.

SNC has concluded that, due to the high costs and lack of obvious environmental advantage, oil-fired generation is not a reasonable alternative to VEGP license renewal.

Fuel Cells

Fuel cell power plants are in the initial stages of commercialization. While more than 650 large stationary fuel cell systems have been built and operated worldwide, the global stationary fuel-cell electricity generating capacity in 2003 was only 125 MWe (Fuel Cell Today 2003). The production capability of the largest stationery fuel cell manufacturer is 50 MWe per year (California Stationary Fuel Cell Collaborative [CSFCC] 2002). The largest stationary fuel cell power plant yet built is only 11 MWe (Fuel Cell Today 2003).

Fuel cells are not cost effective when compared with other generation technologies, both renewable and fossil based. Capital costs for fuel cell installations range from $2,800 to $5,500 per kW. Recent estimates suggest that manufacturers would need to at least triple their production capacity to achieve a competitive price of $1,500 to $2,000 per kW. (Shipley and Elliott 2004)

SNC thinks that this technology has not matured sufficiently to support production for a facility the size of VEGP. SNC has concluded that, due to cost and production limitations, fuel-cell technology is not a reasonable alternative to VEGP license renewal.

Delayed Retirement

As the NRC noted in the GEIS (NRC 1996a, Section 8.3.13), extending the lives of existing non-nuclear generating plants beyond the time they were originally scheduled to be retired represents another potential alternative to license renewal. Fossil plants slated for retirement are old enough to have difficulty meeting today's restrictions on air contaminant emissions. In the face of increasingly stringent air quality restrictions, delaying retirement to compensate for a plant the size of VEGP would appear to be unreasonable without major construction to upgrade or replace plant components. SNC 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 SNC has determined to be reasonable alternatives to VEGP license renewal: gas-fired generation, coal-fired generation, advanced light water reactor, and purchased power.

7.2.2.1 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 SNC's reasons for defining the gas-fired generation alternative as a combined-cycle plant on the VEGP site. Land-use impacts from gas-fired units on VEGP would be less than those from the existing plant. Reduced land requirements, due to a smaller facility footprint, would reduce impacts to ecological, aesthetic, and cultural resources. 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.

In the Supplemental GEIS for McGuire Nuclear Station (NRC 2002b) NRC evaluated the environmental impacts of constructing and operating five 482 MWe combined-cycle gas-fired units as an alternative to a nuclear power plant license renewal. This analysis is for a generating capacity greater than the VEGP gas-fired alternatives analysis, because SNC would install 2,250 MWe of net power. SNC has scaled from the NRC analysis with necessary Georgia- and SNC-specific modifications noted.

Air Quality

Natural gas is a relatively clean-burning fuel that, during combustion, primarily emits carbon dioxide and nitrogen oxides, a greenhouse gas and regulated pollutant respectively. A natural-gas-fired plant would also emit small quantities of sulfur oxides, carbon monoxide, and particulate matter, all of which are regulated pollutants. Control technology for gas-fired turbines focuses on nitrogen oxide emissions. SNC estimates the gas-fired alternative emissions to be as follows:

Carbon dioxide = 5,700,000 tons per year

Nitrogen oxides = 565 tons per year

Sulfur oxides = 176 tons per year

Carbon monoxide = 117 tons per year

Filterable Particulates = 98 tons per year (all particulates are $PM_{2.5}$)

In 2004, Georgia was ranked 4th nationally in sulfur dioxide emissions and 12th nationally in nitrogen oxide emissions from electric power plants (EIA 2006a). The ranking was based on quantity emitted. That is, the electric power plants in only three states emitted more sulfur dioxide than those located in Georgia. The acid rain requirements of the Clean Air Act amendments capped the nation's sulfur dioxide emissions from power plants. Each company with fossil-fuel-fired units was allocated sulfur dioxide allowances. To be in compliance with the Act, the companies must hold enough allowances to cover their annual sulfur dioxide emissions. SNC would need to obtain sulfur dioxide credits to operate a fossil-fuel-burning plant at the VEGP site. In 1998, the EPA promulgated the nitrogen oxide State Implementation Plan (SIP) Call regulation that required 22 states, including Georgia, to reduce their nitrogen oxide emissions by over 30 percent to address regional transport of ground-level ozone across state lines (EPA 1998b). To operate a fossil-fuel-fired plant at the VEGP site, SNC would need to obtain enough nitrogen oxide credits to cover annual emissions either from the set-aside pool or by buying nitrogen oxide credits from other sources.

Nitrogen oxide effects on ozone levels, sulfur dioxide allowances, and nitrogen oxide credits could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, the emissions are still substantial. SNC concludes that emissions from the gas-fired alternative at VEGP would noticeably alter local air quality, but would not cause or contribute to violations of National Air Quality Standards. Air quality impacts would therefore be MODERATE.

Waste Management

The solid waste generated from this type of facility would be minimal. The only noteworthy waste would be from spent selective catalytic reduction (SCR) catalyst used for nitrogen oxide control. The SCR process for a 2,250 MWe plant would generate approximately 1400 ft^3 of spent catalyst per year. SNC concludes that gas-fired generation waste management impacts would be SMALL.

Other Impacts

The ability to construct the gas-fired alternative on the existing VEGP site would reduce construction-related impacts. A new gas pipeline would be required for the four gas turbine generators in this alternative. To the extent practicable, SNC would route the pipeline along existing, previously disturbed right-of-ways to minimize impacts. Approximately 20 miles of new pipeline construction would be required to connect VEGP to an existing 16 inch pipeline north of the plant. A 16-inch diameter pipeline would necessitate a 50-foot-wide corridor, resulting in the disturbance of as much as 8,240 acres. This new construction may also necessitate an upgrade of the state-wide pipeline network. SNC estimates that 160 acres would be needed for a plant site; this much previously disturbed acreage is available at VEGP, reducing loss of terrestrial habitat. Aesthetic impacts, erosion and sedimentation, fugitive dust, and construction debris impacts would be noticeable but small. SNC estimates a peak construction workforce of 1,040; therefore, so socioeconomic impacts of construction would be small. However, SNC estimates a workforce of 88 for gas operations. The reduction in work force would result in adverse socioeconomic impacts. SNC concludes that these impacts would be MODERATE and would be mitigated by the site's proximity to the Augusta, Georgia -- Aiken, South Carolina metropolitan area.

Impacts to aquatic resources and water quality would be similar to, but smaller than the impacts of VEGP, due to the plant's use of the existing cooling water system that withdraws from and discharges to the Savannah River, and would be offset by the concurrent shutdown of VEGP. The additional 200-foot flue stacks would increase the visual impact of the existing site. Impacts to cultural resources would be unlikely, due to the previously disturbed nature of the site.

SNC 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 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 SNC has defined in Section 7.2.1.1 would be located at VEGP.

Air Quality

A coal-fired plant would emit sulfur dioxide, nitrogen oxides, carbon monoxide, and particulate matter, all of which are regulated pollutants. In addition, carbon dioxide, a non-regulated greenhouse gas would be released in large amounts.

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

Sulfur dioxide = 5,940 tons per year

Nitrogen oxide = 1,930 tons per year

Carbon monoxide = 1,930 tons per year

Carbon dioxide = 21,260,000 tons per year

Particulates:

Total suspended particulates = 341 tons per year

PM_{10} (particulates having a diameter of less than 10 microns) = 78 tons per year

$PM_{2.5}$ (particulates having a diameter of less than 10 microns) = 0.34 tons per year

The Section 7.2.2.1 discussion of regional air quality is applicable to the coal-fired generation alternative. In addition, NRC noted in the GEIS 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. SNC 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, sulfur dioxide emission allowances, nitrogen oxide credits, low nitrogen oxide burners, overfire air, fabric filters or electrostatic precipitators, and scrubbers are regulatorily-imposed mitigation measures. As such, SNC concludes that the coal-fired alternative would have MODERATE impacts on air quality; the impacts would be noticeable and greater than those of the gas-fired alternative, but would not destabilize air quality in the area.

Waste Management

SNC concurs with the GEIS assessment that the coal-fired alternative would generate substantial solid waste. The coal-fired plant would annually consume approximately 7,720,000 tons of coal having an ash content of 8.83 percent. After combustion, 90 percent of this ash, approximately 613,000 tons per year, would be marketed for beneficial reuse. The remaining ash, approximately 68,000 tons per year, would be collected and disposed of onsite. In addition, approximately 324,000 tons of scrubber sludge would be disposed of onsite each year (based on annual lime usage of nearly 109,000 tons). SNC estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 236 acres (a square area with sides of approximately 3210 feet). While only half this waste volume and acreage would be attributable to the 20-year license renewal period alternative, the total numbers are pertinent as a cumulative impact.

SNC believes that, with proper siting coupled with current waste management and monitoring practices, waste disposal would not destabilize any resources. There would be enough previously disturbed land within the VEGP property for this disposal. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, SNC thinks that waste disposal for the coal-fired alternative would have SMALL impacts; the impacts of increased waste disposal would be detectable, but would not destabilize any important resource, and further mitigation would be unwarranted.

Other Impacts

SNC estimates that construction of the powerblock and coal storage area would affect 697 acres of land and associated terrestrial habitat. Most of this construction would be on previously disturbed land, therefore impacts at the VEGP site would be small to moderate but would be somewhat less than the impacts of using a green field site. Upgrades to an existing rail spur, approximately 20 miles in length, would be required for coal and lime deliveries under this alternative. Visual impacts, such as 500-foot flue stacks would be consistent with the industrial nature of the site. As with any large construction project, some erosion and sedimentation and fugitive dust emissions would be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of onsite.

SNC estimates a peak construction work force of 1,627. Socioeconomic impacts from the construction workforce would be minimal, because worker relocation would not be expected, due to the site's proximity to the Augusta, Georgia/Aiken, South Carolina metropolitan area. SNC estimates an operational workforce of 200 for the coal-fired alternative. The reduction in workforce would result in adverse socioeconomic impacts. SNC concludes that these impacts would be SMALL, due to VEGP's proximity to the Augusta, Georgia -- Aiken, South Carolina metropolitan area.

Impacts to aquatic resources and water quality would be similar to impacts of VEGP, due to the plant's use of the existing cooling water system that withdraws from and discharges to the Savannah River, and would be offset by the concurrent shutdown of VEGP. The additional stacks, boilers, and rail deliveries would increase the visual impact of the existing site. Impacts to cultural resources would be unlikely, due to the previously disturbed nature of the site.

SNC 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.

7.2.2.3 Advanced Light Water Reactor at an Existing Reactor Site

As discussed in Section 7.2.1.2, under the advanced light water reactor alternative SNC would construct and operate two advance light water reactors. For evaluation of this alternative SNC has scaled from the analysis in the ESP application submitted for additional units at VEGP (SNC 2006) although, for this analysis, the new reactors are assumed to be placed at any existing nuclear site.

Air Quality

Air quality impacts would be minimal. Air emissions are primarily from non-facility equipment and diesel generators and are comparable to those associated with the continued operation of VEGP. Overall, emissions and associated impacts would be considered SMALL.

Waste Management

High-level radioactive wastes would be similar to those associated with the continued operation of VEGP. Low-level radioactive waste impacts from an advanced light water reactor would be slightly greater but similar to those from the continued operation of VEGP. The overall impacts are characterized as SMALL.

Other Impacts

SNC estimates that construction of the reactors and auxiliary facilities would affect approximately 400 acres of land and associated terrestrial habitat. At an existing reactor site, it is likely that most of this construction would be on previously disturbed land, therefore impacts would be SMALL to MODERATE. 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 would be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of onsite.

SNC estimates a peak construction work force of 4,400. The surrounding communities would experience moderate to large demands on housing and public services. After construction, the communities would be impacted by the loss of jobs as construction workers moved on. SNC estimates an operational workforce of 660 for the advanced nuclear reactor alternative. Long-term job opportunities would be comparable to continued operation of VEGP; therefore SNC concludes that the socioeconomic impacts during operation would be SMALL to MODERATE.

Impacts to aquatic resources and water quality would be similar to impacts of VEGP, due to the proposed plant's use of a closed-cycle cooling water system. Impacts to cultural resources would be SMALL.

SNC thinks 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.

7.2.2.4 Purchased Power

As discussed in Section 7.2.1.2, SNC assumes that the generating technology used under the purchased-power alternative would be one of those that NRC analyzed in the GEIS. SNC 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 Southeast. SNC believes that imports from outside the Southeast region would not be required.

The purchased power alternative would include constructing up to 50 miles of high-voltage (i.e., 345- or 500-kV) transmission lines to get power from the remote locations to the GPC service area. SNC thinks most of the transmission lines could be routed along existing rights-of-way. SNC 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-fired, gas-fired, or nuclear generating capacity for purchased power at a previously undisturbed green field site would exceed those of a coal-fired, gas-fired, or nuclear alternative located on the VEGP site or another existing reactor site.

Table 7.2-1. Gas-Fired Alternative

Characteristic	Basis
Unit size = 562.5 MWe ISO rating net[a]	Manufacturer's standard size gas-fired combined-cycle plant that is < VEGP net capacity of 2,310 MWe
Unit size = 585 MWe ISO rating gross[a]	Calculated based on 4 percent onsite power
Number of units = 4	Assumed
Fuel type = natural gas	Assumed
Fuel heating value = 1,035Btu/ft^3	2005 value for gas used in Georgia (EIA 2006b, Table 14.A)
Fuel SO_x content = 0.0034 lb/MMBtu	EPA 2000, Table 3.1-2a
NO_X control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NO_X emissions (EPA 2000)
Fuel NOx content = 0.0109 lb/MMBtu	Typical for large SCR-controlled gas fired units with water injection (EPA 2000)
Fuel CO content = 0.00226 lb/MMBtu	Typical for large SCR-controlled gas fired units (EPA 2000)
Fuel PM_{10} content = 0.0019 lb/MMBtu	EPA 2000, Table 3.1-2a
Heat rate = 5,940 Btu/kWh	(Chase and Kehoe 2000)
Capacity factor = 0.85	Assumed based on performance of modern plants

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
MWe	=	megawatt
NO_x	=	nitrogen oxides
PM_{10}	=	particulates having diameter of 10 microns or less
<	=	less than

Table 7.2-2. Coal-Fired Alternative

Characteristic	Basis
Unit size = 750 MWe ISO rating net[a]	Calculated to be < VEGP net capacity of 2,301 MWe
Unit size = 795 MWe ISO rating gross[a]	Calculated based on 6 percent onsite power
Number of units = 3	Assumed
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions (EPA 1998a)
Fuel type = bituminous, pulverized coal	Typical for coal used in Georgia
Fuel heating value = 11,058 Btu/lb	2005 value for coal used in Georgia (EIA 2006b, Table 15.A)
Fuel ash content by weight = 8.83 percent	2005 value for coal used in Georgia (EIA 2006b, Table 15.A)
Fuel sulfur content by weight = 0.8percent	2005 value for coal used in Georgia (EIA 2006b, Table 15.A)
Uncontrolled NO_x emission = 10 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998a)
Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998a)
Heat rate = 9,578 Btu/kWh	Southern Company experience (Spring 2006)
Capacity factor = 0.85	Typical for large coal-fired units
NO_x control = low NO_x burners, overfire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NO_x emissions (EPA 1998a)
Particulate control = fabric filters (baghouse-99.9 percent removal efficiency)	Best available for minimizing particulate emissions (EPA 1998a)
SO_x control = Wet scrubber - lime (95 percent removal efficiency)	Best available for minimizing SO_x emissions (EPA 1998a)

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
MWe	=	megawatt
NO_x	=	nitrogen oxides
SO_x	=	oxides of sulfur
<	=	less than

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Chapter 8 Comparison of Environmental Impact 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 VEGP license renewal and Chapter 7 analyzes impacts of license renewal alternatives. Table 8.0-1 summarizes environmental impacts of the proposed action (license renewal) and the alternatives, for comparison purposes. The environmental impacts compared in Table 8.0-1 are those that are either Category 2 issues for the proposed action or are issues that the GEIS (NRC 1996) identified as major considerations in an alternatives analysis. For example, although the analysis 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. Therefore, Table 8.0-1 compares air impacts from the proposed action to the alternatives. Table 8.0-2 is a more detailed comparison of the alternatives.

Table 8.0-1. Impacts Comparison Summary.

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

LARGE – Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.

Table 8.0-2. Impacts Comparison Detail

		No-Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With Purchased Power**	**With 2,139 MW of New Nuclear**
		Alternative Descriptions			
VEGP license renewal for 20 years, followed by decommissioning	Decommissioning following expiration of current VEGP license; adopting by reference, as bounding VEGP decommissioning, GEIS description (NRC 1996, Section 7.1)	New construction at the VEGP site.	New construction at the VEGP site.	Would involve construction of new generation capacity in the southeast region; adopting by reference GEIS description of alternate technologies (Section 7.2.1.2)	New construction at existing nuclear site using existing closed-cycle cooling system
		Upgrade 20 miles of existing rail spur	Construct 20 miles of gas pipeline in a 50-foot-wide corridor, disturbing up to 8,240 acres; may require upgrades to existing 16-inch pipelines.		Upgrade 20 miles of existing rail spur
		Use existing switchyard and transmission lines	Use existing switchyard and transmission lines	Construct up to 50 miles of transmission lines	Use existing switchyard and transmission lines
		Three 750-MW (net) tangentially-fired, dry bottom units; capacity factor 0.85	Four 562.5-MW (net) combined-cycle units; capacity factor 0.85		Two 1,068-MWe advanced light water reactors

Table 8.0-2. (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**	**With 2,139 MW of New Nuclear**
		Existing VEGP intake/ discharge canal system	Existing VEGP intake/ discharge canal system		Use existing cooling water intake/ discharge system
		Pulverized bituminous coal, 11,058 Btu/lb; 9,578 Btu/kWh; 8.83% ash; 0.80% sulfur; 10 lb/ton nitrogen oxides; 7,718,732 tons coal/yr	Natural gas, 1,035 Btu/ft^3; 5,940 Btu/kWh; 0.0034 lb SOx/MMBtu; 0.0109 lb NOx/MMBtu; 100,156,793,478 ft^3 gas/yr		
		Low NOx burners, overfire air and selective catalytic reduction (95% NOx reduction efficiency).	Selective catalytic reduction with steam/water injection		
		Wet scrubber – lime/limestone desulfurization system (95% SOx removal efficiency); 108,362 tons lime/yr ;			
		fabric filters or electrostatic precipitators (99.9% particulate removal efficiency)			

Table 8.0-2. (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**	**With 2,139 MW of New Nuclear**
900 permanent and long-term contract workers		200 workers (Section 7.2.2.2)	88 workers (Section 7.2.2.1)		660 workers (SNC 2006, Section 5.8.2)
		Land Use Impacts			
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 52, 53)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	MODERATE – 697 acres required for the powerblock and associated facilities; 93 acres for ash disposal over the 20-year license renewal term (Section 7.2.2.2).	SMALL to MODERATE – 160 acres for facility at VEGP location; 8,240 acres for pipeline (Section 7.2.2.1); 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)	SMALL to MODERATE – 400 acres would be dedicated to power block and associated facilities (SNC 2006, Section 4.1.1)

Table 8.0-2. (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**	**With 2,139 MW of New Nuclear**
		Water Quality Impacts			
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 3 and 6-11); three Category 2 groundwater issues apply (Section 4.1, Issue 13; Section 4.5, Issue 33; and Section 4.6, Issue 34); two Category 2 groundwater issues don't apply (Section 4.7, Issue 35; and Section 4.8, Issue 39).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 89).	SMALL – Construction impacts minimized by use of best management practices; operational impacts minimized by use of the existing cooling towers that withdraw make-up water from the Savannah River. (Section 7.2.2.2)	SMALL – Reduced cooling water demands, inherent in combined-cycle design (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of water quality impacts from alternate technologies (NRC 1996)	SMALL – Construction impacts minimized by use of best management practices; operational impacts minimized by use of existing cooling water system
		Air Quality Impacts			
SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 51); Category 2 issue not applicable (Section 4.11, Issue 50).	SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issue 88)	MODERATE – 5,940 tons SOx/yr 1,930 tons NOx/yr 1,930 tons CO/yr 341 tons TSP/yr 78 tons PM_{10}/yr (Section 7.2.2.2)	MODERATE – 176 tons SOx/yr 565 tons NOx/yr 117 tons CO/yr 98 tons PM_{10}/yr[a] (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of air quality impacts from alternate technologies (NRC 1996)	SMALL – Only small emissions from diesel generators

Table 8.0-2. (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**	**With 2,139 MW of New Nuclear**
		Ecological Resource Impacts			
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 15-24,28-30, 41-43, and 45-48); four Category 2 issues not applicable (Section 4.2, Issue 25; Section 4.3, Issue 26; Section 4.4, Issue 27; and Section 4.9, Issue 40).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 90)	SMALL – 93 acres of previously disturbed land could be required for ash/sludge disposal over 20-year license renewal term. (Section 7.2.2.2)	SMALL to MODERATE – Construction of 20 miles of pipeline could alter the terrestrial habitat. (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of ecological resource impacts from alternate technologies (NRC 1996)	SMALL – Some habitat loss, impingement, entrainment, waste heat to receiving water body
		Threatened or Endangered Species Impacts			
SMALL – No threatened or endangered species are known residents 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	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats

Table 8.0-2. (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**	**With 2,139 MW of New Nuclear**
		Human Health Impacts			
SMALL – Adopting by reference Category 1 issues (Table A-1, Issues 56, 58, 61, 62); one Category 2 issue does apply because discharge water temperatures are too low (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 A-1, 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)	SMALL - <1% of dose a person gets from background radiation; small safety risks to workers at industrial facility

Table 8.0-2. (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**	**With 2,139 MW of New Nuclear**
		Socioeconomic Impacts			
SMALL – Adopting by reference Category 1 issue findings (Table A-1, 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 no growth controls minimizes potential for housing impacts. Section 4.14, Issue 63). Plant property tax payment represents 80 percent of county's total tax revenues (Section 4.17.2, Issue 69). Capacity of public water supply and transportation infrastructure minimizes potential for related impacts (Section 4.15, Issue 65 and Section 4.18, Issue 70)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 91)	SMALL – Reduction in permanent work force at VEGP could adversely affect surrounding counties, but would be mitigated by VEGP's proximity to the Augusta, Georgia -- Aiken, South Carolina metropolitan area (Section 7.2.2.2).	SMALL to MODERATE – Reduction in permanent work force at VEGP could adversely affect surrounding counties, but would be mitigated by VEGP's proximity to the Augusta, Georgia -- Aiken, South Carolina metropolitan area (Section 7.2.2.1).	SMALL to MODERATE – Adopting by reference GEIS description of socioeconomic impacts from alternate technologies (NRC 1996)	SMALL to LARGE – Moderate to large impacts from construction workforce of 4400. Small to moderate impacts from operations workforce of 660 workers, depending on location of site in low, moderate or population area.

Table 8.0-2. (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**	**With 2,139 MW of New Nuclear**
		Waste Management Impacts			
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 77-85)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 87)	SMALL – 840,000 tons of coal ash and 321,000 tons of scrubber sludge annually would require 93 acres over 20-year license renewal term; industrial waste generated annually (Section 7.2.2.2)	SMALL – Approximately 1,400 ft^3 spent SCR catalyst per year (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of waste management impacts from alternate technologies (NRC 1996)	SMALL – Spent fuel, slightly more mixed waste and low-level waste than license renewal
		Aesthetic Impacts			
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 73, 74)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL to MODERATE – The coal-fired power blocks and the exhaust stacks would be visible from a moderate offsite distance (Section 7.2.2.2)	SMALL– Steam turbines and stacks would create visual impacts comparable to those from existing VEGP facilities (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies (NRC 1996)	SMALL – Noise during construction; aesthetics similar to existing VEGP site; cooling towers likely visible from offsite

Table 8.0-2. (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**	**With 2,139 MW of New Nuclear**
		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 7.2.2.2)	SMALL – 8,240 acres of pipeline construction in previously disturbed soil would be unlikely to affect cultural resources (Section 7.2.2.1)	SMALL – Adopting by reference GEIS description of cultural resource impacts from alternate technologies (NRC 1996)	SMALL – Cultural resources are projected by state and federal laws.

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).

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

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

8.1 References

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

(SNC 2006) Southern Nuclear Operating Company. *Vogtle Early Site Permit Application*, Revision 1, November 2006.

Chapter 9 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 9.1-1 lists environmental authorizations that SNC has obtained for current VEGP operations. In this context, SNC uses "authorizations" to include any permits, licenses, approvals, or other entitlements. SNC expects to continue renewing these authorizations during the current license period and through the NRC license renewal period. Because the NRC regulatory focus is prospective, Table 9.1-1 does not include authorizations that SNC obtained for past activities that did not include continuing obligations.

Preparatory to applying for renewal of the VEGP license to operate, SNC conducted an assessment to identify any new and significant environmental information (Chapter 5). The assessment included interviews with SNC and GPC subject matter experts, review of VEGP environmental documentation, and communication with state and federal environmental protection agencies. Based on this assessment, SNC concludes that VEGP is in compliance with applicable environmental standards and requirements.

Table 9.1-2 lists additional environmental authorizations and consultations related to NRC renewal of the VEGP license to operate. As indicated, SNC 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, or proposed for listing as endangered, or threatened. Depending on the action involved, the Act requires consultation with the USFWS regarding effects on non-marine species, the NMFS for marine species, or both. The USFWS and the NMFS have issued joint procedural regulations at 50 CFR 402, Subpart B, that address consultation. The USFWS maintains the joint list of threatened and endangered species in 50 CFR 17.

Although not required of an applicant by federal law or NRC regulation, SNC has chosen to invite comment from federal and state agencies regarding any potential effects of VEGP license renewal. Attachment C includes copies of SNC correspondence with the USFWS, the NMFS, the GDNR Wildlife Resources Division, and the SCDNR (regarding the transmission line in South Carolina and fisheries in the Savannah River).

9.1.3 Historic Preservation

Section 106 of the National Historic Preservation Act (16 USC 470 et seq.) requires federal agencies having the authority to license an undertaking to 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, prior to issuing the license. Council regulations provide for the State Historic Preservation Officer (SHPO) to have a consulting role (35 CFR 800.2). Although not required of an applicant by federal law or NRC regulation, SNC has chosen to invite comment by the Georgia SHPO. Attachment E contains copies of the correspondence with the Georgia SHPO.

9.1.4 Water Quality (401) Certification

The federal Clean Water Act Section 401 requires that an applicant for a federal license to conduct an activity that might result in a discharge into navigable waters must provide the licensing agency with a certification from the state that the discharge will comply with applicable Clean Water Act requirements (33 USC 1341). The NRC has indicated in its GEIS (NRC 1996, Section 4.2.1.1) that issuance of an NPDES permit implies certification by the state. SNC is applying to the NRC for license renewal to continue VEGP operations. Consistent with the GEIS, SNC is providing VEGP's NPDES permit as evidence of state water quality (401) certification (Attachment B).

9.1.5 Coastal Zone Management Program

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 affects a state's costal zone. VEGP, located in Burke County, Georgia, is not located in a coastal county (NOAA and GDNR 2003). However a transmission line from VEGP crosses several coastal counties and thus that aspect of the activity is subject to Coastal Zone Management Act requirements. The Coastal Zone Management Act certification prepared by SNC will be provided to GDNR concurrent with NRC issuing the Draft EIS. SNC has reviewed the relevant Georgia regulations and determined that continued operation of VEGP will not adversely affect the Coastal Zone of Georgia.

Table 9.1-1. Environmental Authorizations for Current VEGP Operations.

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Federal and State Requirements					
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10	License to operate	NPF-68	Issued: 1/16/1987 Expires: 1/16/2027	Operation of VEGP Unit 1
			NPF-81	Issued: 2/9/1989 Expires: 2/9/2029	Operation of VEGP Unit 2
U.S. Department of Transportation	49 USC 5108	Registration	0614060030050	Issued: 6/15/2006 Expires: 6/30/2007	Hazardous materials shipments
U.S. Army Corps of Engineers	Section 10 of River and harbor Act of 1899 (33 USC 403)	Permit	200500606	Issued: 8/24/2005 Expires:8/31/2010	Maintenance dredging in front of the river intake structure
Georgia Department of Natural Resources	Clean Water Act (33 USC 1251 et seq.), Georgia Water Quality Control Act, NPDES	Permit	GA0026786	Issued: 6/30/1999 Expires:5/31/2004 (administratively extended)	Industrial wastewater discharges to Savannah River

Table 9.1-1. (Cont'd) Environmental Authorizations for Current VEGP Operations.

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Federal and State Requirements					
Georgia Department of Natural Resources	Clean Water Act (33 USC 1251 et seq.), Georgia Water Quality Control Act, NPDES	Permit	GAR000000	Issued: 8/1/2006 Expires: 7/31/2011	Industrial storm water discharges
Georgia Department of Natural Resources	Clean Water Act (33 USC 1251 et seq.), Georgia Water Quality Control Act, NPDES	Permit	GAR100001	Issued: 8/13/2003 Expires: 7/31/2008	Storm water discharges associated with construction activities for stand-alone construction projects
Georgia Department of Natural Resources	Clean Air Act (42 USC 7401 et seq), Georgia Air Quality Act (OCGA Section 12-9-1) and Georgia Rules for Air Quality Control (Chapter 391-3-1)	Operating Permit	4911-033-0030-V-02-0	Issued: 3/21/2006 Expires: 3/21/2011	Two turbine generators; six diesel generators
			4911-033-0030-V-02-1	Issued: 9/26/2006 Expires: 3/21/2011	Installation of temporary boiler package in chemical cleaning of steam generators

Table 9.1-1. (Cont'd) Environmental Authorizations for Current VEGP Operations.

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Federal and State Requirements					
Georgia Department of Natural Resources	Georgia Safe Drinking Water Act of 1977 (OCGA 12-5-170 et seq.) and Rules, Chapter 391-3-5	Permit	PG0330017	Issued: 3/17/2006 Expires:4/14/2016	Operate non-transient non-community makeup wells – Plant Vogtle Makeup Wells #1 and #2A
Georgia Department of Natural Resources	Georgia Safe Drinking Water Act of 1977 (OCGA 12-5-170 et seq.) and Rules, Chapter 391-3-5	Permit	NG03300367	Issued: 4/1/1998 Expires:3/31/2008	Operate public transient non-community water system – Plant Vogtle Employee Recreation Area
Georgia Department of Natural Resources	Georgia Safe Drinking Water Act of 1977 (OCGA.12-5-170 et seq.) and Rules, Chapter 391-3-5	Permit	PG0330035	Issued: 4/1/1998 Expires:3/31/2008	Operate public non-transient non-community water system – Plant Vogtle Simulator Building
Georgia Department of Natural Resources	Georgia Water Quality Control Act, Rules and Regulations for Water Quality Control, Chapter 391-3-6	Permit	017-0191-05	Issued: 4/17/2000 Expires: 9/1/2010	Withdraw surface water from the Savannah River for the purpose of cooling and in-plant use

Table 9.1-1. (Cont'd) Environmental Authorizations for Current VEGP Operations.

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Federal and State Requirements					
Georgia Department of Natural Resources	Provisions of the Groundwater Use Act (GA Laws 1972, p 976 et seq. as amended by GA Laws 1973, p 1273 et seq.) and Rules and Regulations	Permit	017-0003	Issued: 3/24/2000 Expires:8/6/2010	Withdraw 6 million gpd groundwater from 8 wells in the Cretaceous Sand Aquifer for sanitary facilities, central water supply, cooling water, process water and irrigation
Georgia Department of Natural Resources	Georgia Solid Waste Management Act, Act 1486, Georgia Laws of 1972, as amended and Rules and Regulations	Permit	017-006D(L)(I) No. 2	Issued: 7/10/1981 Expires: None	Dispose of 1500 cubic yards of asbestos transite board and cement asbestos pipe materials
Georgia Department of Natural Resources	Georgia Solid Waste Management Act, Act 1486, p. 1002 et seq. as amended	Permit	017-007D(L)(I) No. 3	Issued: 6/15/1987 Expires: None	Dispose of non-hazardous, non-putrescible waste

Georgia Department of Natural Resources	Rules for Solid Waste Management, Section 391-3-4-.06(3)(a)	Permit by Rule Operations	PBR-017-07COL	Issued: 11/13/2000 Expires: None	Collect and transport non-hazardous, non-industrial putrescible waste for disposal in permitted MSWLF.

Table 9.1-1. (Cont'd) Environmental Authorizations for Current VEGP Operations.

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Federal and State Requirements					
State of Georgia Public Service Commission	Transportation of Hazardous Materials Act, Act 394 at OCGA 46:11	Notification of shipment of hazardous materials – permit by rule	DOT Hazardous Materials Certification 051007 550 004P	Issued: 5/11/2007 Expires: 6/30/2008	Transportation of radioactive materials in the state of Georgia
South Carolina Department of Health and Environmental Control – Division of Waste Management	South Carolina Radioactive Waste Transportation and Disposal Act (Act No. 429)	South Carolina Radioactive Waste Transport Permit	0311-10-07-X	Issued: 12/14/2006 Expires: 12/31/2007	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-GA003-L07	Issued: 01/01/2007 Expires: 12/31/2007	Transportation of radioactive waste into the state of Tennessee

Table 9.1-2. Environmental Authorizations for VEGP 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 (FWS)	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires federal agency issuing a license to consult with the USFWS (Attachment C)
Georgia Department of Natural Resources, Environmental Protection Division	Clean Water Act Section 401 (33 USC 1341)	Certification	State issuance of NPDES permit (Attachment B) constitutes 401 certification (Section 9.1.4)
Georgia Department of Natural Resources, Historic Preservation Division	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Requires federal agency issuing a license to consider cultural impacts and consult with the SHPO. SHPO must concur that license renewal will not affect any sites listed or eligible for listing (Attachment E)
Georgia Department of Natural Resources, Coastal Resources Division	Coastal Zone Management Act (16 USC 1451 et seq.)	Certification	Requires applicants for a federal license to certify to the agency issuing the license that the action is consistent with enforceable polices of federally-approved Coastal Zone Management Act. (provided at issuance of Draft EIS)

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

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 could be constructed and operated to comply with applicable environmental quality standards and requirements. SNC notes that increasingly stringent air quality protection requirements could make the construction of a large fossil-fueled power plant infeasible in many locations. SNC also notes that the EPA has revised requirements for design and operation of cooling water intake structures at new and existing facilities (40 CFR 125 Subparts I and J). These requirements could necessitate construction of cooling towers for the coal- and gas-fired alternatives if surface water were used for once-through surface cooling.

9.3 References

(NOAA and GDNR 2003) National Oceanic and Atmospheric Administration and Georgia Department of Natural Resources. 2003. State of Georgia Coastal Management Program and Program Document. NOAA Office of Ocean and Coastal Resources Management and GDNR Coastal Resources Division. June 2003.

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

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ATTACHMENT A

NRC NATIONAL ENVIRONMENTAL POLICY ACT ISSUES FOR LICENSE RENEWAL OF NUCLEAR POWER PLANTS

SNC has prepared this environmental report in accordance with the requirements of NRC regulation 10 CFR 51.53. NRC included in the regulation a list of NEPA issues for license renewal of nuclear power plants. Table A-1 lists these 92 issues and identifies the section in which SNC addressed each applicable issue in this environmental report. For organization and clarity, SNC has assigned a number to each issue and uses the issue numbers throughout the environmental report.

TABLE A-1. VEGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUESa

Issue		Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Surface Water Quality, Hydrology, and Use (for all plants)				
1.	Impacts of refurbishment on surface water quality	1	NA	Issue applies to an activity, refurbishment, that VEGP has no plans to undertake.
2.	Impacts of refurbishment on surface water use	1	NA	Issue applies to an activity, refurbishment, that VEGP has no plans to undertake.
3.	Altered current patterns at intake and discharge structures	1	4.0	4.2.1.2.1/4-5
4.	Altered salinity gradients	1	NA	Issue applies to a plant feature, discharge to saltwater, that VEGP does not have.
5.	Altered thermal stratification of lakes	1	NA	Issue applies to a plant feature, discharge to a lake, that VEGP does not have.
6.	Temperature effects on sediment transport capacity	1	4.0	4.2.1.2.3/4-8
7.	Scouring caused by discharged cooling water	1	4.0	4.2.1.2.3/4-6
8.	Eutrophication	1	4.0	4.2.1.2.3/4-9
9.	Discharge of chlorine or other biocides	1	4.0	4.2.1.2.4/4-10
10.	Discharge of sanitary wastes and minor chemical spills	1	4.0	4.2.1.2.4/4-10
11.	Discharge of other metals in waste water	1	4.0	4.2.1.2.4/4-10
12.	Water use conflicts (plants with once-through cooling systems)	1	NA	Issue applies to a plant feature, once-through cooling, that VEGP does not have.
13.	Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	4.1	4.2.1.3/4-13

TABLE A-1. (cont'd) VEGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	NA	Issue applies to an activity, refurbishment, that VEGP has no plans to undertake.
15. Accumulation of contaminants in sediments or biota	1	4.0	4.2.1.2.4/4-10
16. Entrainment of phytoplankton and zooplankton	1	4.0	4.2.2.1.1/4-15
17. Cold shock	1	4.0	4.2.2.1.5/4-18
18. Thermal plume barrier to migrating fish	1	4.0	4.2.2.1.6/4-19
19. Distribution of aquatic organisms	1	4.0	4.2.2.1.6/4-19
20. Premature emergence of aquatic insects	1	4.0	4.2.2.1.7/4-20
21. Gas supersaturation (gas bubble disease)	1	4.0	4.2.2.1.8/4-21
22. Low dissolved oxygen in the discharge	1	4.0	4.2.2.1.9/4-23
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.0	4.2.2.1.10/4-24
24. Stimulation of nuisance organisms (e.g., shipworms)	1	4.0	4.2.2.1.11/4-25
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)			
25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	NA, and discussed in Section 4.2	Issue applies to a plant feature, once-through cooling or a cooling pond, that VEGP does not have.
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	NA, and discussed in Section 4.3	Issue applies to a plant feature, once-through cooling or a cooling pond, that VEGP does not have.
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	NA, and discussed in Section 4.4	Issue applies to a plant feature, once-through cooling or a cooling pond, that VEGP does not have.

TABLE A-1. (cont'd) VEGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)			
28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	4.0	4.3.3/4-33
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	4.0	4.3.3/4-33
30. Heat shock for plants with cooling-tower-based heat dissipation systems	1	4.0	4.3.3/4-33
Ground-water Use and Quality			
31. Impacts of refurbishment on groundwater use and quality	1	NA	Issue applies to an activity, refurbishment, that VEGP has no plans to undertake.
32. Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	NA	Issue applies to an activity, using less than 100 gpm of groundwater, that VEGP does not do.
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	4.5	4.8.1.1/4-116
34. Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	4.6	4.8.1.3/4-117
35. Groundwater use conflicts (Ranney wells)	2	NA, and discussed in Section 4.7	Issue applies to a feature, Ranney wells, that VEGP does not have.
36. Groundwater quality degradation (Ranney wells)	1	NA	Issue applies to a feature, Ranney wells, that VEGP does not have.
37. Groundwater quality degradation (saltwater intrusion)	1	NA	Issue applies to a feature, location in a coastal area, that VEGP does not have.

TABLE A-1. (cont'd) VEGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	NA	Issue applies to a feature, cooling ponds, that VEGP does not have.
39. Groundwater quality degradation (cooling ponds at inland sites)	2	NA, and discussed in Section 4.8	Issue applies to a feature, cooling ponds at inland sites, that VEGP does not have.
Terrestrial Resources			
40. Refurbishment impacts to terrestrial resources	2	NA, and discussed in Section 4.9	Issue applies to an activity, refurbishment, that VEGP has no plans to undertake.
41. Cooling tower impacts on crops and ornamental vegetation	1	4.0	4.3.4/4-34
42. Cooling tower impacts on native plants	1	4.0	4.3.5.1./4-42
43. Bird collisions with cooling towers	1	4.0	4.3.5.2/4-45
44. Cooling pond impacts on terrestrial resources	1	NA	Issue applies to a feature, cooling ponds, that VEGP does not have.
45. Power line right-of-way management (cutting and herbicide application)	1	4.0	4.5.6.1/4-71
46. Bird collisions with power lines	1	4.0	4.5.6.2/4-74
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.0	4.5.6.3/4-77
48. Floodplains and wetlands on power line right-of-way	1	4.0	4.5.7/4-81
Threatened or Endangered Species (for all plants)			
49. Threatened or endangered species	2	4.10	4.1/4-1

TABLE A-1. (cont'd) VEGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Air Quality			
50. Air quality during refurbishment (non-attainment and maintenance areas)	2	NA, and discussed in Section 4.11	Issue applies to an activity, refurbishment, that VEGP has no plans to undertake.
51. Air quality effects of transmission lines	1	4.0	4.5.2/4-62
Land Use			
52. Onsite land use	1	4.0	3.2/3-1
53. Power line right-of-way land use impacts	1	4.0	4.5.3/4-62
Human Health			
54. Radiation exposures to the public during refurbishment	1	NA	Issue applies to an activity, refurbishment, that VEGP has no plans to undertake.
55. Occupational radiation exposures during refurbishment	1	NA	Issue applies to an activity, refurbishment, that VEGP has no plans to undertake.
56. Microbiological organisms (occupational health)	1	4.0	4.3.6/4-48
57. Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	4.12	4.3.6/4-48
58. Noise	1	4.0	4.3.7/4-49
59. Electromagnetic fields, acute effects (electric shock)	2	4.13	4.5.4.1/4-66
60. Electromagnetic fields, chronic effects	NA	4.0	NA – Not applicable. The categorization and impact finding definitions do not apply to this issue.
61. Radiation exposures to public (license renewal term)	1	4.0	4.6.2/4-87
62. Occupational radiation exposures (license renewal term)	1	4.0	4.6.3/4-95

TABLE A-1. (cont'd) VEGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Socioeconomics			
63. Housing impacts	2	4.14	3.7.2/3-10 (refurbishment) 4.7.1/4-101 (renewal term)
64. Public services: public safety, social services, and tourism and recreation	1	4.0	Refurbishment 3.7.4/3-14 (public services) 3.7.4.3/3-18 (safety) 3.7.4.4/3-19 (social) 3.7.4.6/3-20 (tour, rec) Renewal Term 4.7.3/4-104 (public services) 4.7.3.3/4-106 (safety) 4.7.3.4/4-107 (social) 4.7.3.6/4-107 (tour, rec)
65. Public services: public utilities	2	4.15	3.7.4.5/3-19 (refurbishment) 4.7.3.5/4-107 (renewal term)
66. Public services: education (refurbishment)	2	NA , and discussed in Section 4.16	Issue applies to an activity, refurbishment, that VEGP has no plans to undertake.
67. Public services: education (license renewal term)	1	4.0	4.7.3.1/4-106
68. Offsite land use (refurbishment)	2	NA, and discussed in Section 4.17.1	Issue applies to an activity, refurbishment, that VEGP has no plans to undertake.
69. Offsite land use (license renewal term)	2	4.17.2	4.7.4/4-107
70. Public services: transportation	2	4.18	3.7.4.2/3-17 (refurbishment) 4.7.3.2/4-106 (renewal term)
71. Historic and archaeological resources	2	4.19	3.7.7/3-23 (refurbishment) 4.7.7/4-114 (renewal term)
72. Aesthetic impacts (refurbishment)	1	NA	Issue applies to an activity, refurbishment, that VEGP will not undertake.
73. Aesthetic impacts (license renewal term)	1	4.0	4.7.6/4-111
74. Aesthetic impacts of transmission lines (license renewal term)	1	4.0	4.5.8/4-83

TABLE A-1. (cont'd) VEGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Postulated Accidents			
75. Design basis accidents	1	4.0	5.3.2/5-11 (design basis) 5.5.1/5-114 (summary)
76. Severe accidents	2	4.20	5.3.3/5-12 (probabilistic analysis) 5.3.3.2/5-19 (air dose) 5.3.3.3/5-49 (water) 5.3.3.4/5-65 (groundwater) 5.3.3.5/5-96 (economic) 5.4/5-106 (mitigation) 5.5.2/5-114 (summary)
Uranium Fuel Cycle and Waste Management			
77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4.0	6.2/6-8
78. Offsite radiological impacts (collective effects)	1	4.0	Not in GEIS.
79. Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4.0	Not in GEIS.
80. Nonradiological impacts of the uranium fuel cycle	1	4.0	6.2.2.6/6-20 (land use) 6.2.2.7/6-20 (water use) 6.2.2.8/6-21 (fossil fuel) 6.2.2.9/6-21 (chemical)
81. Low-level waste storage and disposal	1	4.0	6.4.2/6-36 (low-level definition) 6.4.3/6-37 (low-level volume) 6.4.4/6-48 (renewal effects)
82. Mixed waste storage and disposal	1	4.0	6.4.5/6-63
83. Onsite spent fuel	1	4.0	6.4.6/6-70
84. Nonradiological waste	1	4.0	6.5/6-86
85. Transportation	1	4.0	6.3/6-31, as revised by Addendum 1, August 1999.

TABLE A-1. (cont'd) VEGP ENVIRONMENTAL REPORT DISCUSSION OF LICENSE RENEWAL NEPA ISSUES[a]

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Decommissioning			
86. Radiation doses (decommissioning)	1	4.0	7.3.1/7-15
87. Waste management (decommissioning)	1	4.0	7.3.2/7-19 (impacts) 7.4/7-25 (conclusions)
88. Air quality (decommissioning)	1	4.0	7.3.3/7-21 (air) 7.4/7-25 (conclusion)
89. Water quality (decommissioning)	1	4.0	7.3.4/7-21 (water) 7.4/7-25 (conclusion)
90. Ecological resources (decommissioning)	1	4.0	7.3.5/7-21 (ecological) 7.4/7-25 (conclusion)
91. Socioeconomic impacts (decommissioning)	1	4.0	7.3.7/7-24 (socioeconomic) 7.4/7-25 (conclusion)
Environmental Justice			
92. Environmental justice	NA	2.6.2	NA – Not applicable. The categorization and impact finding definitions do not apply to this issue.

a. Source: 10 CFR 51, Subpart A, Appendix A, Table B-1. (Issue numbers added to facilitate discussion.)
b. Source: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437).
NEPA = National Environmental Policy Act.

ATTACHMENT B

NPDES PERMIT

Georgia Department of Natural Resources

2 Martin Luther King, Jr. Drive, S.E., Suite 1152 East Tower, Atlanta, Georgia 30334-9000
Lonice C. Barrett, Commissioner
Carol A. Couch, Ph.D., Director
Environmental Protection Division
404/656-4713

May 21, 2004

Mr. Wayne C. Carr
Manager, Environmental Services
Southern Nuclear Operating Company
Post Office Box 1295
Birmingham, Alabama 35201

RE: NPDES Permit No. GA0026786
Plant Vogtle-Burke County

Dear Mr. Carr:

The Environmental Protection Division (EPD) has received your application for a permit to discharge treated wastewater to the waters of the State of Georgia.

As you may know, EPD has initiated a strategy to issue permits within the same river basin concurrently with a goal of establishing basin wide permitting. According to EPD's Basin Permitting Strategy, permits for facilities located in a certain basin groups will be issued within a scheduled calendar year. We are currently in the process of reissuing permits for facilities located in the Chattahoochee and Flint river basins. Facilities located in the Coosa, Tallapoosa, and Tennessee river basins will be reissued in 2004 and facilities located in the Savannah and Ogeechee river basins will be reissued in 2005.

Any permits that are expiring prior to being reissued in accordance with the scheduled basin issuance cycle may be extended until such time that the permit can be reissued.

Your facility fits the criteria for a permit extension. Therefore EPD is hereby extending the above referenced permit.

Sincerely,

Carol A. Couch

Carol A.Couch, Ph.D.
Director

CAC/shg

RECEIVED
MAY 2? 2004
Environmental Services

cc: Environmental Protection Agency

Angela Westin, EPD

Allison Cregger, EPD

PERMIT NO. GA0026786

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

AUTHORIZATION TO DISCHARGE UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provisions of the Georgia Water Quality Control Act (Georgia Laws 1964, p. 416, as amended), hereinafter called the "State Act;" the Federal Water Pollution Control Act, as amended (33 U.S. C. 1251 et seq.), hereinafter called the "Federal Act;" and the Rules and Regulations promulgated pursuant to each of these Acts,

Southern Nuclear Operating Company
Post Office Box 1295
Birmingham, Alabama 35201-1295

is authorized to discharge from a facility located at

Vogtle Electric Generating Plant
Waynesboro, Burke County, Georgia

to receiving waters

Savannah River and Beaver Dam Creek

in accordance with effluent limitations, monitoring requirements and other conditions set forth in Parts I, II and III hereof.

This permit shall become effective on June 30, 1999

This permit and the authorization to discharge shall expire at midnight, May 31, 2004.

Signed this 6th day of June, 1999.

Director,
Environmental Protection Division

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

1. During the period beginning effective date and lasting through May 31, 2004, the permittee is authorized to discharge from outfall(s) serial number(s) 001 - Final Plant Discharge (Combined Plant Waste Streams Units 1 & 2) to the Savannah River.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic (Specify Units)	Discharge Limitations Mass Based Daily Avg.	Mass Based Daily Max.	Concentration Based Daily Avg.	Concentration Based Daily Max.	Monitoring Requirements Measurement Frequency	Sample Type	Sample Location
Flow (MGD)	-	-	-	-	*1	*1	*1
Hydrazine*2	-	-	-	-	*3	Grab	Final Outfall

The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored twice per month by grab sample.

There shall be no discharge of floating solids or visible foam in other than trace amounts.

*1 See Part III, Special Requirements, Item 9.

*2 See Part III, Special Requirements, Item 16.

*3 This sample is to be collected when requested by the EPD.

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
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2. During the period beginning effective date and lasting through May 31, 2004, the permittee is authorized to discharge from outfall(s) serial number(s) 002 and 003 - Unit 1 Cooling Tower Blowdown and Unit 2 Cooling Tower Blowdown, respectively, to final outfall 001, and 002A and 003A - Unit 1 and Unit 2 Emergency Overflows to storm drains.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic (Specify Units)	Discharge Limitations				Monitoring Requirements		
	Mass Based		Concentration Based mg/l		Measurement Frequency	Sample Type	Sample Location
	Daily Avg.	Daily Max.	Daily Avg.	Daily Max.			
Flow (MGD)	-	-	-	-	*2	*2	*2
Free Available Chlorine	-	-	0.2 mg/l*6	0.5 mg/l	1/Week	Multiple*5 Grabs	*1
Total Residual Chlorine	-	-	-	-	1/Week	Multiple*5 Grabs	*1
Time of TRC Discharge*3	-	-	-	120 minutes/ day per unit	1/Week	Multiple*5 Grab	*1
Total Chromium*8	-	-	-	0.2 mg/l	1/Quarter	Grab	*4
Total Zinc	-	-	-	1.0 mg/l	1/Quarter	Grab	*4

*1 Monitored immediately following dechlorination system when dechlorination system is in use. At other times it will be monitored at the individual cooling towers.
*2 See Part III, Special Requirements, Item 9.
*3 See Part III, Special Requirements, Item 4.
*4 Monitored prior to mixing with other waste streams.
*5 Multiple grab samples are to be collected on 15 minute intervals during periods of FAC and TRC discharge attributable to cooling tower chlorination at these outfalls.
*6 During periods of dechlorination this limit is 0.02 mg/l at the blowdown sump mixing box.
*7 If bromine or a combination of bromine and chlorine is utilized for control of bifouling, limitations for TRC and FAC shall be applicable to TRO (Total Residual Oxidants) and FAO (Free Available Oxidants). There is no difference in test methods between TRC/FAC and TRO/FAO.
*8 Monitoring Frequency shall be 1/year if use of cooling tower maintenance chemicals containing this metal is not initiated by permittee.

The permittee shall certify yearly that no priority pollutant other than chromium or zinc is above detectable limits in this discharge. This certification may be based on manufacturer's certifications or engine 'ng calculations.

EPD ∠.21-3

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3. During the period beginning effective date and lasting through May 31, 2004, the permittee is authorized to discharge from outfall(s) serial number(s) 004 and 005 - Unit 1 Waste Water Retention Basin and Unit 2 Waste Water Retention Basin, respectively, to final outfall 001.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic (Specify Units)	Discharge Limitations				Monitoring Requirements		
	Mass Based		Concentration Based mg/l		Measurement Frequency	Sample Type	Sample Location
	Daily Avg.	Daily Max.	Daily Avg.	Daily Max.			
Flow (MGD)	-	-	-	-	*2	*2	*1
Total Suspended Solids (2)	-	-	30.0	100.0	2/Month	Grab	Discharge Line
Oil & Grease	-	-	15.0	20.0	2/Month	Grab	Discharge Line

*1 Prior to mixing with any other wast streams.

*2 See Part III, Special Requirements, Item 9.

*3 See Part III, Special Requirements, Item 10.

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EPD 2.21-4

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4. During the period beginning effective date and lasting through May 31, 2004, the permittee is authorized to discharge from outfall(s) serial number(s) 006 - Sewage Treatment Plant Emergency Overflow to Savannah River.*1

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic (Specify Units)	Discharge Limitations				Monitoring Requirements		
	Mass Based		Concentration Based mg/l		Measurement Frequency	Sample Type	Sample Location
	Daily Avg.	Daily Max.	Daily Avg.	Daily Max.			
Flow (MGD)	-	-	-	-	1/Discharge	Estimate	Outfall
BOD_5	-	-	30.0	45.0	1/Discharge	Grab	Outfall

The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored once per discharge event.

There shall be no discharge of floating solids or visible foam in other than trace amounts.

*1 This is an emergency outfall and is only to be used during upset or bypass conditions.

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EPD 2.21-5

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5. During the period beginning effective date and lasting through May 31, 2004, the permittee is authorized to discharge from outfall(s) serial number(s) 007 and 008 - Liquid Radwaste Systems Discharge Unit 1 and Liquid Radwaste System Unit 2, respectively, to final outfall 001.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic (Specify Units)	Discharge Limitations				Monitoring Requirements		
	Mass Based		Concentration Based mg/l		Measurement Frequency	Sample Type	Sample *1 Location
	Daily Avg.	Daily Max.	Daily Avg.	Daily Max.			
Flow (MGD)	-	-	-	-	*2	*2	Discharge Line
Total Suspended Solids	-	-	30.0	100.0	1/Quarter	Grab	Discharge Line
Oil and Grease	-	-	15.0	20.0	1/Quarter	Grab	Discharge Line

The pH shall be monitored at the combined Outfall 001.

*1 Prior to mixing with any other waste streams.

*2 See Part III, Special Requirements, Item 9.

Note: The radioactive component of this discharge is regulated by the U.S. Nuclear Regulatory Commission under the Atomic Energy Act.

EPD 2.21-6

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6. During the period beginning effective date and lasting through May 31, 2004, the permittee is authorized to discharge from outfall(s) serial number(s) 009 - Nuclear Service Cooling Tower Blowdown (Units 1 and 2), to outfall 001.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic (Specify Units)	Discharge Limitations				Monitoring Requirements		
	Mass Based		Concentration Based mg/l		Measurement Frequency	Sample Type	Sample Location
	Daily Avg.	Daily Max.	Daily Avg.	Daily Max.			
Flow (MGD)	-	-	-	-	*1	*1	*1
Free Available Chlorine*4	-	-	0.2*3	0.5	1/Discharge Event	Grab	*2

*1 See Part III, Special Requirements, Item 9.

*2 Monitored Immediately following dechlorination system, when dechlorination system is in use. At other times it will be monitored a the blowdown.

*3 During periods of dechlorination this limit is 0.02 mg/l at the blowdown sump mixing box.

*4 If bromine or a combination of bromine and chlorine is utilized for control of biofouling, limitations for TRC and FAC shall be applicable to TRO (Total Residual Oxidants) and FAO (Free Available Oxidants). There is no difference in test methods between TRC/FAC and TRO/FAO.

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EPD 2.21-7

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7. During the period beginning effective date and lasting through May 31, 2004,
The permittee is authorized to discharge from outfall(s) serial number(s) 010 - Radwaste Dilution Flow to outfall 001.

This is an internal waste stream consisting of river water with no additives.

The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored at the final outfall (001).

EPD 2.21-8

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8. During the period beginning effective date and lasting through May 31, 2004, the permittee is authorized to discharge from outfall(s) serial number(s) 011 - Intake Screen Backwash to the Savannah River.

The discharge shall consist only of intake screen backwash. If the Director determines that Water Quality Standards are not being protected as the result of this discharge and so notifies the permittee in writing, the permittee shall take all reasonable steps to minimize any adverse impact to waters of the State.

There shall be no discharge of floating oil or grease in other than trace amounts.

EPD 2.21-9

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PART I

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B. SCHEDULE OF COMPLIANCE

1. The permittee shall achieve compliance with the effluent limitations specified for discharges in accordance with the following schedule:

   N/A

2. No later than 14 calendar days following a date identified in the above schedule of compliance, the permittee shall submit either a report of progress or, in the case of specific actions being required by identified dates, a written notice of compliance or noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

EPD 2.21-10

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Note: EPD as used herein means the Environmental Protection Division of the Department of Natural Resources.

C. MONITORING AND REPORTING

1. Representative Sampling

Samples and measurements taken as required herein shall be representative of the volume and nature of the monitored discharge.

2. Reporting

Monitoring results obtained during the previous three months shall be summarized for each month and reported on an Operation Monitoring Report (Form WQ 1.45). Forms other than Form WQ 1.45 may be used upon approval by EPD. These forms and any other required reports and information shall be completed, signed and certified by a principal executive officer or ranking elected official, or by a duly authorized representative of that person, and submitted to the Division, postmarked no later than the 28th day of the month following the reporting period. Signed copies of these and all other reports required herein shall be submitted to the following address:

Environmental Protection Division
Industrial Wastewater Unit
4220 International Parkway, Suite 101
Atlanta, Georgia 30354

All instances of noncompliance not reported under Part I. B. and C. and Part II. A. shall be reported at the time the operation monitoring report is submitted.

3. Definitions

a. The "daily average" discharge means the total discharge by weight during a calendar month divided by the number of days in the month that the production or commercial facility was operating. Where less than daily sampling is required by this permit, the daily average discharge shall be determined by the summation of all the measured daily discharges by weight divided by the number of days sampled during the calendar month when the measurements were made.

b. The "daily maximum" discharge means the total discharge by weight during any calendar day.

EPD 2.21-11

c. The "daily average" concentration means the arithmetic average of all the daily determinations of concentrations made during a calendar month. Daily determinations of concentration made using a composite sample shall be the concentration of the composite sample.

d. The "daily maximum" concentration means the daily determination of concentration for any calendar day.

e. For the purpose of this permit, a calendar day is defined as any consecutive 24-hour period.

f. "Bypass" means the intentional diversion of waste streams from any portion of a treatment facility.

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

4. Test Procedures

Monitoring must be conducted according to test procedures approved pursuant to 40 CFR Part 136 unless other test procedures have been specified in this permit.

5. Recording of Results

For each measurement or sample taken pursuant to the requirements of this permit, the permittee shall record the following information:

a. The exact place, date, and time of sampling or measurements, and the person(s) performing the sampling or the measurements;

b. The dates the analyses were performed, and the person(s) who performed the analyses;

c. The analytical techniques or methods used; and

d. The results of all required analyses.

STATE OF GEORGIA
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PART I

6. Additional Monitoring by Permittee

If the permittee monitors any pollutant at the location(s) designated herein more frequently than required by this permit, using approved analytical methods as specified above, the results of such monitoring shall be included in the calculation and reporting of the values required in the Operation Monitoring Report Form (WQ 1.45). Such increased monitoring frequency shall also be indicated. The Division may require by written notification more frequent monitoring or the monitoring of other pollutants not required in this permit.

7. Records Retention

The permittee shall retain records of all monitoring information, including all records of analyses performed, calibration and maintenance of instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least three (3) years from the date of the sample, measurement, report or application. This period may be extended by request of the Division at any time.

8. Penalties

The Federal Clean Water Act and the Georgia Water Quality Control Act provide that any person who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit, makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance shall, upon conviction, be punished by a fine or by imprisonment, or by both. The Federal Clean Water Act and the Georgia Water Quality Control Act also provide procedures for imposing civil penalties which may be levied for violations of the Act, any permit condition or limitation established pursuant to the Act, or negligently or intentionally failing or refusing to comply with any final or emergency order of the Director of the Division.

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

PART II

Permit No. GA0026786

A. MANAGEMENT REQUIREMENTS

1. Change in Discharge

a. Advance notice to the Division shall be given of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. Any anticipated facility expansions, production increases, or process modifications must be reported by submission of a new NPDES permit application or, if such changes will not violate the effluent limitations specified in this permit, by notice to the Division of such changes. Following such notice, the permit may be modified to specify and limit any pollutants not previously limited.

b. All existing manufacturing, commercial, mining, and silviculture dischargers shall notify the Division as soon as it is known or there is reason to believe that any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant not limited in the permit, if that discharge will exceed (I) 100 µg/l, (ii) five times the maximum concentration reported for that pollutant in the permit application, or (iii) 200 µg/l for acrolein and acrylonitrile, 500 µg/l for 2,4 dinitrophenol and for 2-methyl-4-6-dinitrophenol, or 1 mg/l antimony.

c. All existing manufacturing, commercial, mining, and silvicultural dischargers shall notify the Division as soon as it is known or there is reason to believe that any activity has occurred or will occur which would result in any discharge on a nonroutine or infrequent basis, of any toxic pollutant not limited in the permit, if that discharge will exceed (I) 500 µg/l, (ii) ten times the maximum concentration reported for that pollutant in the permit application, or (iii) 1 mg/l antimony.

2. Noncompliance Notification

If, for any reason, the permittee does not comply with, or will be unable to comply with any effluent limitation specified in this permit, the permittee shall provide the Division with an oral report within 24 hours from the time the permittee becomes aware of the circumstances followed by a written report within five (5) days of becoming aware of such condition. The written submission shall contain the following information:

a. A description of the discharge and cause of noncompliance; and

EPD 2.21-14

b. The period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate and prevent recurrence of the noncomplying discharge.

3. Facilities Operation

The permittee shall at all times maintain in good working order and operate as efficiently as possible all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

4. Adverse Impact

The permittee shall take all reasonable steps to minimize or prevent any discharge in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment, including such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying discharge.

5. Bypassing

a. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Division at least 10 days (if possible) before the date of the bypass. The permittee shall submit notice of any unanticipated bypass with an oral report within 24 hours from the time the permittee becomes aware of the circumstances followed by a written report within five (5) days of becoming aware of such condition. The written submission shall contain the following information:

1. A description of the discharge and cause of noncompliance; and

2. The period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate and prevent recurrence of the noncomplying discharge.

b. Any diversion or bypass of facilities covered by this permit is prohibited, except (i) where unavoidable to prevent loss of life, personal injury, or severe property damage; (ii) there were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime (this condition is not satisfied if the permittee could have installed adequate back-up equipment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance); and (iii) the permittee submitted a notice as required above. The permittee shall operate the treatment works, including the treatment plant and total sewer system, to minimize discharge of the pollutants listed in Part I of this permit from combined sewer overflows or bypasses. Upon written notification by the Division, the permittee may be required to submit a plan and schedule for reducing bypasses, overflows, and infiltration in the system.

6. Sludge Disposal Requirements

Hazardous sludge shall be disposed of in accordance with the regulations and guidelines established by the Division pursuant to the Federal Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA). For land application of nonhazardous sludge, the permittee shall comply with any applicable criteria outlined in the Division's "Guidelines for Land Application of Municipal Sludges." Prior to disposal of sludge by land application, the permittee shall submit a proposal to the Division for approval in accordance with applicable criteria in the Division's "Guidelines for Land Application of Municipal Sludges." Upon evaluation of the permittee's proposal, the Division may require that more stringent control of this activity is required. Upon written notification, the permittee shall submit to the Division for approval, a detailed plan of operation for land application of sludge. Upon approval, the plan will become a part of the NPDES permit. Disposal of nonhazardous sludge by other means, such as landfilling, must be approved by the Division.

7. Sludge Monitoring Requirements

The permittee shall develop and implement procedures to insure adequate year-round sludge disposal. The permittee shall monitor the volume and concentration of solids removed from the plant. Records shall be maintained which document the quantity of solids removed from the plant. The ultimate disposal of solids shall be reported monthly (in the unit of lbs/day) to the Division with the Operation Monitoring Report Forms required under Part I (C)(2) of this permit.

8. Power Failures

Upon the reduction, loss, or failure of the primary source of power to said water pollution control facilities, the permittee shall use an alternative source of power if available to reduce or otherwise control production and/or all discharges in order to maintain compliance with the effluent limitations and prohibitions of this permit.

If such alternative power source is not in existence, and no date for its implementation appears in Part I, the permittee shall halt, reduce or otherwise control production and/or all discharges from wastewater control facilities upon the reduction, loss, or failure of the primary source of power to said wastewater control facilities.

B. RESPONSIBILITIES

1. Right of Entry

The permittee shall allow the Director of the Division, the Regional Administrator of EPA, and/or their authorized representatives, agents, or employees, upon the presentation of credentials:

a. To enter upon the permittee's premises where a regulated activity or facility is located or conducted or where any records are required to be kept under the terms and conditions of this permit; and

b. At reasonable times, to have access to and copy any records required to be kept under the terms and conditions of this permit; to inspect any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and to sample any substance or parameters in any location.

2. Transfer of Ownership or Control

A permit may be transferred to another person by a permittee if:

a. The permittee notifies the Director in writing of the proposed transfer at least thirty (30) days in advance of the proposed transfer;

b. A written agreement containing a specific date for transfer of permit responsibility and coverage between the current and new permittee (including acknowledgement that the existing permittee is liable for violations up to that date, and that the new permittee is liable for violations from that date on) is submitted to the Director at least thirty (30) days in advance of the proposed transfer; and

c. The Director, within thirty (30) days, does not notify the current permittee and the new permittee of the Division's intent to modify, revoke and reissue, or terminate the permit and to require that a new application be filed rather than agreeing to the transfer of the permit.

3. Availability of Reports

Except for data deemed to be confidential under O.C.G.A. § 12-5-26 or by the Regional Administrator of the EPA under the Code of Federal Regulations, Title 40, Part 2, all reports prepared in accordance with the terms of this permit shall be available for public inspection at an office of the Division. Effluent data, permit applications, permittee's names and addresses, and permits shall not be considered confidential.

4. Permit Modification

After written notice and opportunity for a hearing, this permit may be modified, suspended, revoked or reissued in whole or in part during its term for cause including, but not limited to, the following:

a. Violation of any conditions of this permit;

b. Obtaining this permit by misrepresentation or failure to disclose fully all relevant facts;

c. A change in any condition that requires either a temporary or permanent reduction or elimination of the permitted discharge; or

d. To comply with any applicable effluent limitation issued pursuant to the order the United States District Court for the District of Columbia issued on June 8, 1976, in Natural Resources Defense Council, Inc. et.al. v. Russell E. Train, 8 ERC 2120(D.D.C. 1976), if the effluent limitation so issued:

(1) is different in conditions or more stringent than any effluent limitation in the permit; or

(2) controls any pollutant not limited in the permit.

5. Toxic Pollutants

The permittee shall comply with effluent standards or prohibitions established pursuant to Section 307(a) of the Federal Clean Water Act for toxic pollutants, which are present in the discharge within the time provided in the regulations that establish these standards or prohibitions, even if the permit has not yet been modified to incorporate the requirement.

6. Civil and Criminal Liability

   Nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance.

7. State Laws

   Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or regulation under authority preserved by Section 510 of the Federal Clean Water Act.

8. Water Quality Standards

   Nothing in this permit shall be construed to preclude the modification of any condition of this permit when it is determined that the effluent limitations specified herein fail to achieve the applicable State water quality standards.

9. Property Rights

   The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations.

10. Expiration of Permit

   Permittee shall not discharge after the expiration date. In order to receive authorization to discharge beyond the expiration date, the permittee shall submit such information, forms, and fees as are required by the agency authorized to issue permits no later than 180 days prior to the expiration date.

11. Contested Hearings

   Any person who is aggrieved or adversely affected by an action of the Director of the Division shall petition the Director for a hearing within thirty (30) days of notice of such action.

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

PART II

Page 20 of 24
Permit No. GA0026786

12. Severability

The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

13. Best Management Practices

The permittee will implement best management practices to control the discharge of hazardous and/or toxic materials from ancillary manufacturing activities. Such activities include, but are not limited to, materials storage areas, in-plant transfer, process and material handling areas; loading and unloading operations; plant site runoff; and sludge and waste disposal areas.

14. Need to Halt or Reduce Activity Not a Defense

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

15. Duty to Provide Information

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

b. When the permittee becomes aware that it failed to submit any relevant facts in a permit application or submitted incorrect information in a permit application or any report to the Director, it shall promptly submit such facts and information.

16. Upset Provisions

Provisions of 40 CFR 122.41(n)(1)-(4), regarding "Upset" shall be applicable to any civil, criminal, or administrative proceeding brought to enforce this permit.

EPD 2.21-20

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

PART III

Page 21 of 24
Permit No. GA0026786

A. PREVIOUS PERMITS

1. All previous State water quality permits issued to this facility, whether for construction or operation, are hereby revoked by the issuance of this permit. This action is taken to assure compliance with the Georgia Water Quality Control Act, as amended, and the Federal Clean Water Act, as amended. Receipt of the permit constitutes notice of such action. The conditions, requirements, terms and provisions of this permit authorizing discharge under the National Pollutant Discharge Elimination System govern discharges from this facility.

B. SPECIAL REQUIREMENTS

1. There shall be no discharge of polyclorinated biphenyl compounds such as those commonly used for transformer fluid.

2. Any metal cleaning wastes generated will be contained for further treatment or disposal in a manner to permit compliance at time of discharge with requirements listed below. This applies to any preoperational chemical cleaning of metal process equipment also. The treatment and disposal procedures shall be discussed in the flow monitoring and characterization submittal.

3. The quantity of pollutants discharged in metal cleaning waste shall not exceed the quantity determined by multiplying the flow of metal cleaning wastes times the concentrations listed below. All effluent characteristics shall be monitored 1/week by grab sampling when a discharge is occurring.

Effluent Characteristic	Discharge Limitation (mg/l)	
	Daily Average	Daily Maximum
Total Suspended Solids	30.0	100.0
Oil and Grease	15.0	20.0
Copper	1.0	1.0
Iron	1.0	1.0

4. Neither free available chlorine (FAC) nor total residual chlorine (TRC) may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Director that the units in a particular location cannot operate at or below this level of chlorination.

EPD 2.21-21

5. The free available chlorine (FAC) average means the average over any individual chlorine release period which does not exceed 2 hours per day per unit. The FAC Maximum is the instantaneous maximum which may occur at any time. Further, the permittee will develop a system for monitoring and recording total time of FAC and TRC discharges. The results shall be reported in a suitably concise form beginning with the first scheduled Operation Monitoring Report (OMR) and continuing on each OMR thereafter.

6. The permittee shall certify annually that no priority pollutant other than chromium or zinc is above detectable limits in outfalls 002 and 003 (cooling tower bowdown or overflows). This certification may be based on manufacturers' certifications or engineering calculations.

7. In the event that waste streams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled by this permit shall not exceed the specified limitations for that source except that the limitations for free available chlorine and total residual chlorine discharges from cooling tower blowdown shall apply following the dechlorination system when that system is in use.

8 The Director may modify any effluent limitation upon request of the permittee if such limitation is covered by an approved variance or by an amendment to the Federal Clean Water Act.

9. Annually, the permittee shall submit to the Director flow monitoring and characterization information regarding the various waste streams.

10. The sewage Treatment plant must be properly operated and maintained. This applies to 004.

11. The permittee shall review the water treatment chemicals other than chlorine discharged to State waters. This includes, but is not limited to microbiocides, corrosion inhibitors, and dispersant. These chemicals shall be used and disposed of in accordance with the manufacturers' instructions unless other requirements are imposed by EPD. The permittee shall submit to EPD a current inventory of all water treatment chemicals discharged during the previous twelve months.

12. Summary of requirements from preceding items which are required every year:

    a. Metal cleaning waste treatment and disposal discussion.

    b. Flow monitoring and characterization information regarding various waste streams.

    c. Water treatment chemical inventory.

d. Cooling tower blowdown priority pollutant certification.

13. The effluent limits for all metals in this permit shall be defined and reported in terms of "total recoverable metal" in conformance with the appropriate language of the applicable Federal regulations.

14. Upon approval of the Director, the permittee shall, on a case-by-case basis, be able to utilize alternative analytical methods, conversion factors, methodology, procedures, or new technologies, to ensure that the biomonitoring and toxicity reduction requirements of Part III.C. and the testing/reporting requirements of the permit are adequately addressed.

15. The permittee shall report all visible discharges of floating materials, foam, and oil and grease.

16. No detectable level of Hydrazine is allowed at Outfall 001.

17. The Environmental Protection Division recognizes the inherent analytical variability in approved test methods and procedures and further agrees that such issues can be raised by the permittee as a defense in an enforcement action.

18. The provisions of 40 CFR 122.41(1)(6)(iii) regarding waiver of the five-day written report required by Part II.A.2 and Part II.A.5 of this permit shall be applicable and may be implemented on a case-by-case basis by EPD for non-compliances which are orally reported by the permittee within 24 hours of discovery of the non-compliance condition.

19. If the results for a given sample are such that a parameter is not detected at or above the method detection limit or reporting limit, a value of zero will be reported for that sample and the method detections limit or reporting limit will also be reported. Such sample shall be deemed to be in compliance with the permit.

20. The permittee is authorized to discharge stormwater from the out falls identified in Part I. Section A. of this permit provided that these discharges do not cause violations of State water quality standards in the receiving streams.

C. BIOMONITORING AND TOXICITY REDUCTION REQUIREMENTS

In order to determine whether the permittee is discharging wastes in concentrations or combinations which may have an adverse impact on the State's water quality, the Division can require the permittee to conduct a biomonitoring program.

If toxicity is believed to be present in the permittee's effluent, the Division may require the permittee to develop a biomonitoring screening program according to the following schedule:

1. Within 90 days of Division notification a screening program study plan detailing the test methodology and test organisms shall be submitted for conducting a forty-eight hour static acute test of the final effluent.

   Note: If residual chlorine is present in the final effluent from a treatment and/or disinfection process, a prechlorinated or dechlorinated sample will be tested.

2. Within 90 days of Division approval of the study plan, the permittee shall conduct and submit the results of the forty-eight hour static acute test.

The Division will then review the results of the forty-eight hour static acute test. If the test criteria specified in the study plan are exceeded, then the permittee shall within 90 days of written notification by the Division repeat steps 1. and 2. above replacing the forty-eight hour static acute test with the ninety-six hour test.

The Division will then review the results of the ninety-six hour test. If the criteria* detailed in the ninety-six hour test indicates toxicity, then the permittee shall within 90 days of written notification by the Division submit to the Division a plan to reduce the toxicity of the effluent. Within 270 days of Division approval of this plan, the permittee shall implement the plan and initiate follow-up biomonitoring of the effluent in accordance with the approved toxicity reduction plan. The toxicity reduction plan shall not be complete until the permittee meets the criteria detailed in the ninety-six hour test plan.

If there are substantial composition changes in the permittee's effluent, the permittee may be required to repeat the forty-eight hour static acute test upon notification by the Division. Unless otherwise advised, the permittee shall perform biomonitoring of the effluent as provided in C. 1. and 2. above, at a minimum of once every three years upon notification by the Division. On a case specific basis, chronic toxicity testing procedures may be required. Upon approval by the Division, all of the plans will become part of the requirements of this permit.

* The 96 hour criteria shall define toxicity as a greater than 10% mortality of the exposed test organisms in 96 hours or less when the test solution contains volumes of effluent and dilution water proportional to the plant daily average flow and the 7Q10 flow of the receiving stream, as determined using test procedures and methods, and statistical methods for evaluating test results, developed by the permittee and approved by the Division pursuant to this section or revised pursuant to Part III. B. 16. above.

EPD 2.21-24

ATTACHMENT C

SPECIAL STATUS SPECIES CORRESPONDENCE

Table of Contents

Southern Nuclear
Operating Company, Inc.
40 Inverness Center Parkway
Birmingham, Alabama 35242

SOUTHERN COMPANY
Energy to Serve Your World℠

APR - 3 2007

LR-07-0409

Mr. David Bernhart
Chief, Protected Species Branch
National Marine Fisheries Service
Southeast Regional Office
263 13th Avenue, South
St. Petersburg, Florida 33701

Re: Vogtle Electric Generating Plant – License Renewal
Request for Information on Threatened or Endangered Species

Dear Mr. Bernhart:

This letter replaces the letter dated March 23, 2007, as it was inadvertently sent without the enclosures. Southern Nuclear Operating Company (SNC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for Vogtle Electric Generating Plant (VEGP) Units 1 and 2. The current operating licenses for Units 1 and 2 expire in 2027 and 2029, respectively. As part of the license renewal process, the NRC requires the licensing applicant to "assess the impacts of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10CFR51.53). In preparation for the environmental impact statement, the NRC will be communicating with your organization during their review of the environmental report portion of VEGP's application. In an attempt to create a smooth transition we are contacting you early in the application process to identify any issues that need to be addressed or identify any information your office may need to expedite the NRC's review.

VEGP lies on a bluff along the middle reach of the Savannah River in Burke County, Georgia; approximately 26 miles south-southeast of Augusta, Georgia (see Figures 2.1-1 and 2.1-2). The Universal Transverse Mercator Grid Coordinates for the center of Unit 1 containment are Zone 17S, east 428,900 m, north 3,666,900 m. For the center of Unit 2 containment, the coordinates are Zone 17S, east 428,800 m, north 3,666,900 m. The VEGP site encompasses approximately 3,160 acres, where approximately 1,400 acres are developed.

VEGP currently utilizes six transmission lines that connect VEGP to the regional transmission system. Five of the six transmission lines originate from VEGP. These transmission corridors include the Vogtle-Goshen, Vogtle-Savannah River Site, Vogtle-Scherer, Vogtle-Thalmann, and Vogtle-Wilson. The Augusta Newsprint Loop diverges from the Vogtle-Goshen transmission line south of Augusta. All transmission lines service Georgia, with the exception of the Vogtle-Savannah River Site transmission line that delivers electricity to the Savannah River Site in South Carolina. The Vogtle-Wilson corridor is wholly contained on Georgia Power Company (GPC) property and connects VEGP with Plant Wilson. The transmission lines total approximately 360 miles of corridor that occupy approximately 7,200 acres.

Southern Nuclear Operating Company and associated owners are currently corresponding with the NRC regarding the Early Site Permit (ESP) application for two additional reactors (Units 3 & 4) within

VEGP's property boundary. The construction footprint for the new units will disturb approximately 500 total acres, with 310 acres consisting of the new units that will be lost to other uses. The ESP also includes an approximately 50 mile long new transmission corridor. Threatened and endangered species surveys have been conducted as part of the ESP for all areas located within the construction footprint, including the transmission corridor. This survey will be included in the license renewal application.

There are two sensitive aquatic species reported to inhabit the Savannah River: the federally endangered shortnose sturgeon and the robust redhorse, a Georgia Species of Interest. The operation of the existing two units at VEGP does not significantly impact these species. Additionally, Georgia Department of Natural Resources elevated the states listing of the bluebarred pygmy sunfish to an endangered species in October 2006. Georgia Power has not conducted systematic surveys for the bluebarred pygmy sunfish on the Vogtle site for obvious reasons: it is an obscure species that was first described in 1987 and was only granted legal protection by the state of Georgia in late 2006. However, previous studies indicate the stream habitat (brown stained, sluggish or still, waters with abundant vegetation, such as backwaters, bayous, oxbows, and swamps) on VEGP is not indicative to the bluebarred pygmy sunfish.

A response to this letter would be greatly appreciated, including any information you may have regarding threatened or endangered species and ecologically significant habitats that may occur on the VEGP site, within the transmission corridors, and/or in the reach of the Savannah River at VEGP. In addition, include any concerns associated with the current operation and maintenance activities at VEGP or along the transmission corridors related to threatened and endangered species. We will include a copy of this letter and your response with the license renewal application submitted to the NRC.

Please contact me at (205) 992-5807 or Mr. Dale Fulton (205) 992-7536 if you have any questions or require additional information.

Sincerely,

T. C. Moorer

Tom C. Moorer
Environmental Project Manager

Enclosures: Figures 2.1-1 and 2.1-2

cc: Southern Nuclear Operating Company (w/enclosures)
Mr. T. E. Tynan, Vice President - Vogtle
Ms. B. C. Terry, Vice President & General Counsel – External Affairs
Mr. B. J. George, Nuclear Licensing Manager
Mr. J. N. Stringfellow, Licensing Supervisor
Mr. M. A. Macfarlane, Project Manager – License Renewal
Mr. C. Myer, Project Manager – License Renewal
Mr. J. M. Godfrey, Environmental Affairs Manager
Document Services RTYPE: CVA02.003
File LR.00.02

Georgia Power Company (w/enclosures)
Mr. C. H. Huling, Vice President – Environmental Affairs
Mr. R. D. Just, Environmental Issues Manager

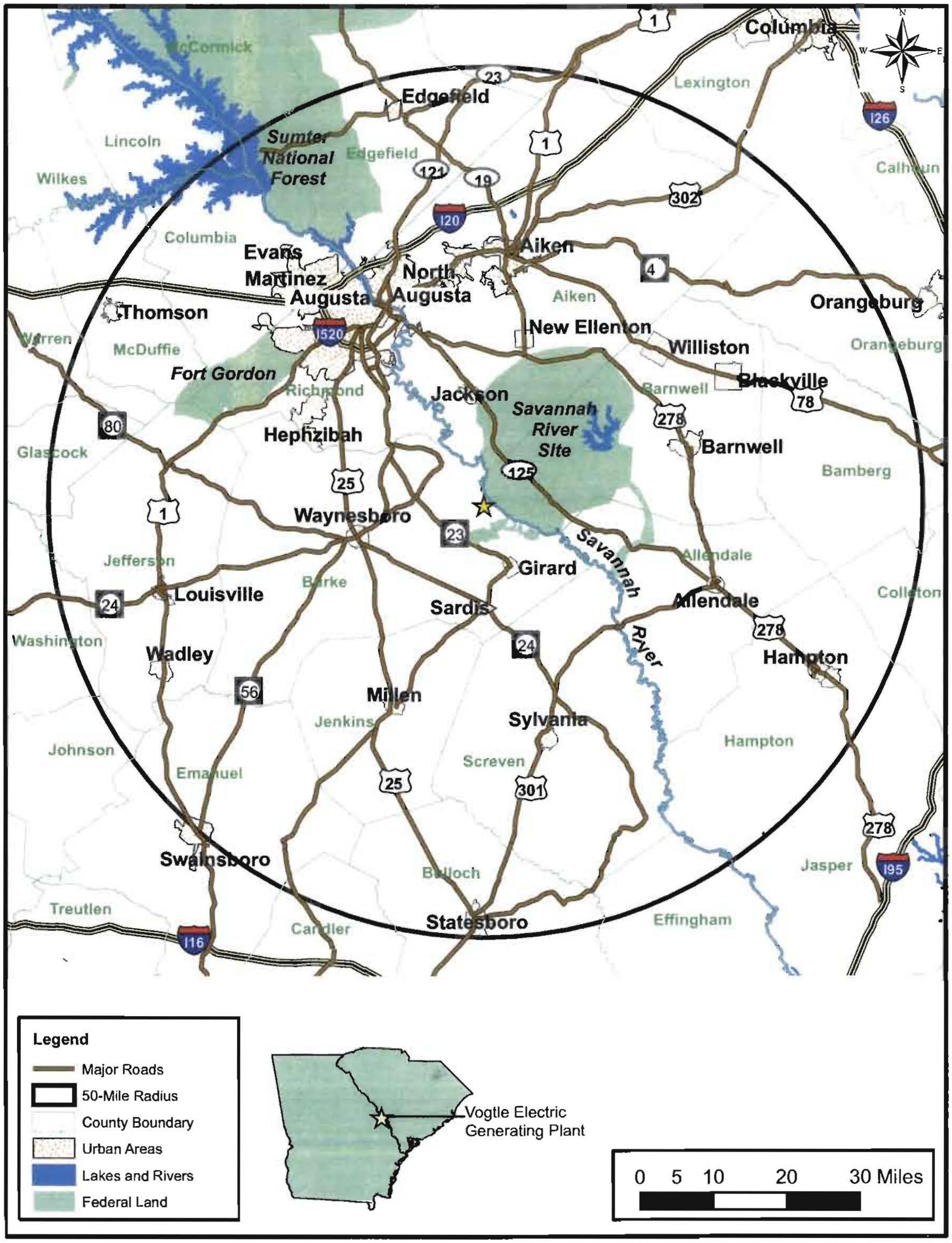

Figure 2.1-1 50-Mile Vicinity

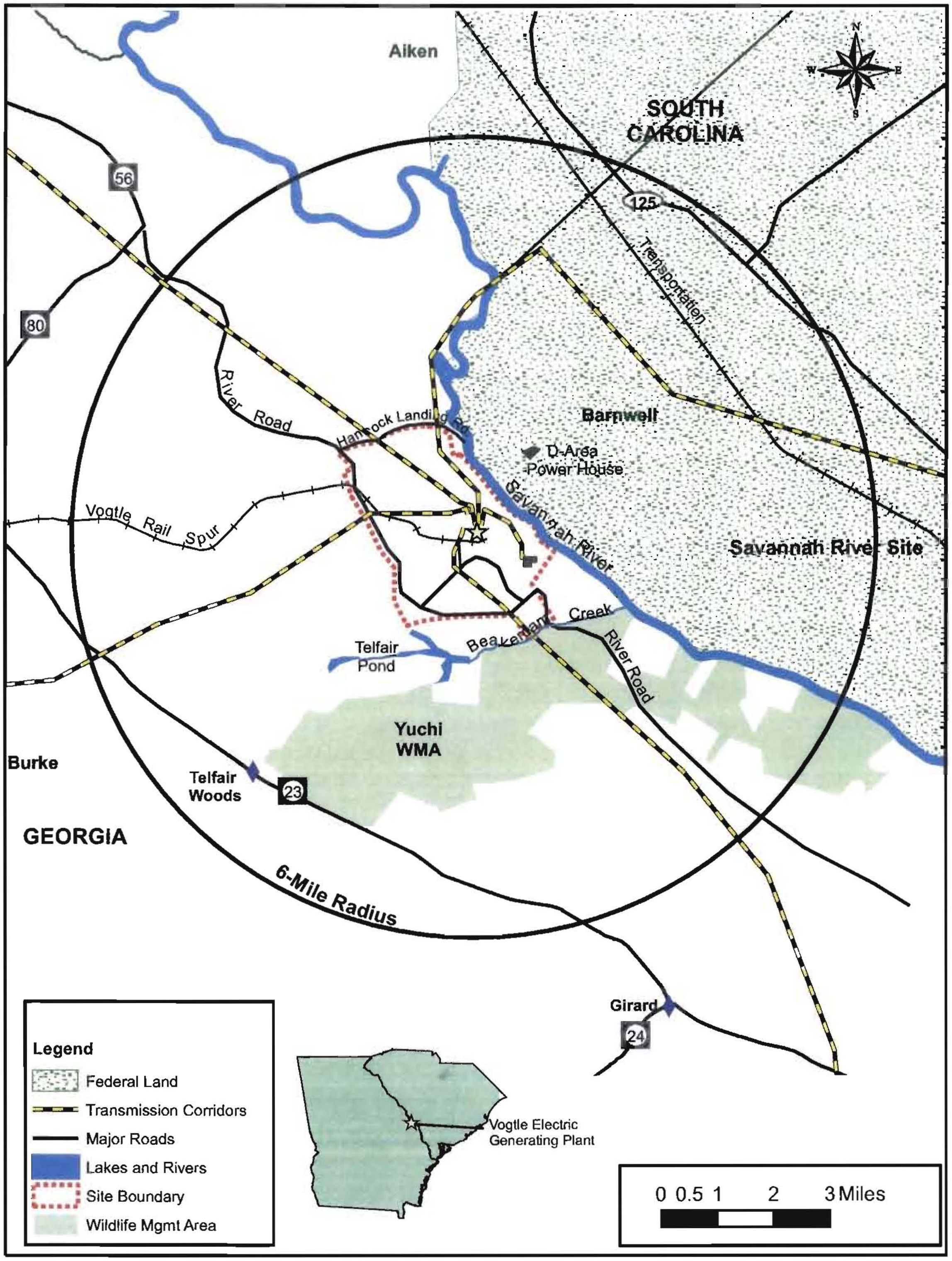

Figure 2.1-2 6-Mile Vicinity

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
Southeast Regional Office
263 13th Avenue South
St. Petersburg, FL 33701
(727) 824-5312, Fax 824-5309
http://sero.nmfs.noaa.gov

APR - 9 2007

Dear Colleague:

Pursuant to section 7(a)(2) of the Endangered Species Act (ESA), the Protected Resources Division of NOAA's National Marine Fisheries Service (NMFS) has reviewed your letter dated April 3, 2007, concerning Vogtle Electric Generating Plant – License Renewal (Request for Information on Threatened or Endangered Species).

___ **There are no ESA-listed species** or designated critical habitat under our purview in the action area.

___**We cannot determine** impacts to threatened or endangered species, or designated critical habitat, under NOAA Fisheries purview because the letter lacks sufficient information to evaluate the project.
Enclosed are guidelines to conduct a proper biological evaluation.

___**Please provide a letter** from the lead federal action agency designating you to conduct ESA section 7 consultation with this office.

_X_**Enclosed is a list** of federally-protected species under the jurisdiction of NMFS for the state of Georgia. Biological information on federally-protected species and candidate species can be found at the following website addresses: http://www.nmfs.noaa.gov/prot_res/prot_res.html; http://www.cccturtle.org;. http://noflorida.fws.gov/SeaTurtles/seaturtle-info.htm); http://endangered.fws.gov/wildlife.html#Species; http://www.cmc-ocean.org/main.php3; http://floridaconservation.org/psm/turtles/turtle.htm; http://obis.env.duke.edu/data/sp_profiles.php; www.mote.org/~colins/Sawfish/SawfishHomePage.html; www.floridasawfish.com; www.flmnh.ufl.edu/fish/sharks/InNews/sawprop.htm;.Gulf sturgeon critical habitat rule and maps (http://alabama.fws.gov/gs/).

___ **It is NMFS' opinion that the project will have no effect** on listed species or critical habitat protected by the ESA under NOAA Fisheries purview. No further consultation with NOAA Fisheries pursuant to section 7(a)(2) of the ESA is required unless the project description changes.

Consultation with NMFS' Habitat Conservation Division (HCD), pursuant to the Magnuson-Stevens Fishery Conservation and Management Acts requirements for essential fish habitat consultation, may be required. Please contact HCD at (727) 824-5317. If you have any ESA questions, please contact Eric Hawk at (727) 824-5312 or by e-mail at Eric.Hawk@noaa.gov.

Sincerely,

Teletha Mincey

Teletha Mincey
Administrative Support Ass't.
Protected Resources Division

Enclosure

File: 1514-22.M

Endangered and Threatened Species and Critical Habitats
under the Jurisdiction of the NOAA Fisheries Service

Georgia

Listed Species	Scientific Name	Status	Date Listed
Marine Mammals			
blue whale	*Balaenoptera musculus*	Endangered	12/02/70
finback whale	*Balaenoptera physalus*	Endangered	12/02/70
humpback whale	*Megaptera novaengliae*	Endangered	12/02/70
right whale	*Eubalaena glacialis*	Endangered	12/02/70
sei whale	*Balaenoptera borealis*	Endangered	12/02/70
sperm whale	*Physeter macrocephalus*	Endangered	12/02/70
Turtles			
green sea turtle	*Chelonia mydas*	Threatened[1]	07/28/78
hawksbill sea turtle	*Eretmochelys imbricata*	Endangered	06/02/70
Kemp's ridley sea turtle	*Lepidochelys kempii*	Endangered	12/02/70
leatherback sea turtle	*Dermochelys coriacea*	Endangered	06/02/70
loggerhead sea turtle	*Caretta caretta*	Threatened	07/28/78
Fish			
shortnose sturgeon	*Acipenser brevirostrum*	Endangered	03/11/67
smalltooth sawfish	*Pristis pectinata*	Endangered	04/01/03

Designated Critical Habitat
Right whale: Between 31°15'N (approximately the mouth of the Altamaha River, Georgia) and 30°15'N (approximately Jacksonville, Florida) from the coast out to 15 nautical miles offshore; the coastal waters between 30°15'N and 28°00'N (approximately Sebastian Inlet, Florida) from the coast out to 5 nautical miles.

Species Proposed for Listing
None

Proposed Critical Habitat
None

[1] Green turtles are listed as threatened, except for breeding populations of green turtles in Florida and on the Pacific Coast of Mexico, which are listed as endangered

Georgia

Candidate Species[2]	Scientific Name
None	

Species of Concern[3]	Scientific Name
Fish	
Atlantic sturgeon	*Acipenser oxyrhynchus oxyrhynchus*
dusky shark	*Carcharhinus obscurus*
night shark	*Carcharinus signatus*
sand tiger shark	*Carcharias taurus*
speckled hind	*Epinephelus drummondhayi*
Warsaw grouper	*Epinephelus nigritus*
white marlin	*Tetrapturus albidus*

[2] The Candidate Species List has been renamed the Species of Concern List. The term "candidate species" is limited to species that are the subject of a petition to list and for which NOAA Fisheries Service has determined that listing may be warranted (69 FR 19975).

[3] Species of Concern are not protected under the Endangered Species Act, but concerns about their status indicate that they may warrant listing in the future. Federal agencies and the public are encouraged to consider these species during project planning so that future listings may be avoided.

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World[SM]

LR-07-0412

MAR 23 2007

Ms. Sandy Tucker
Field Supervisor
Georgia Field Office
U.S. Fish and Wildlife Services
West Park Center, Suite D
105 West Park Drive
Athens, GA 30606

Re: Vogtle Electric Generating Plant - License Renewal
Request for Information on Threatened & Endangered Species and Important Habitats

Ms. Tucker:

Southern Nuclear Operating Company is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for Vogtle Electric Generating Plant (VEGP) Units 1 and 2. The current operating licenses for Units 1 and 2 expire in 2027 and 2029, respectively. As part of the license renewal process, the NRC requires the licensing applicant to "assess the impacts of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10CFR51.53). In preparation for the environmental impact statement, the NRC will be communicating with your organization during their review of the environmental report portion of VEGP's application. In an attempt to create a smooth transition we are contacting you early in the application process to identify any issues that need to be addressed or identify any information your office may need to expedite the NRC's review.

VEGP lies on a bluff along the middle reach of the Savannah River in Burke County, Georgia; approximately 26 miles south-southeast of Augusta, Georgia (see Figures 2.1-1 and 2.1-2). The Universal Transverse Mercator Grid Coordinates for the center of Unit 1 containment are Zone 17S, east 428,900 m, north 3,666,900 m. For the center of Unit 2 containment, the coordinates are Zone 17S, east 428,800 m, north 3,666,900 m. The VEGP site encompasses approximately 3,160 acres, where approximately 1,400 acres are developed.

VEGP currently utilizes six transmission lines that connect VEGP to the regional transmission system. Five of the six transmission lines originate from VEGP. These transmission corridors include the Vogtle-Goshen, Vogtle-Savannah River Site, Vogtle-Scherer, Vogtle-Thalmann, and Vogtle-Wilson. The Augusta Newsprint Loop diverges from the Vogtle-Goshen transmission line south of Augusta. All transmission lines service Georgia, with the exception of the Vogtle-Savannah River Site transmission line that delivers electricity to the Savannah River Site in South Carolina. The Vogtle-Wilson corridor is wholly contained on Georgia Power Company (GPC) property and connects VEGP with Plant Wilson. The transmission lines total approximately 360 miles of corridor that occupy approximately 7,200 acres.

Southern Nuclear Operating Company and associated owners are currently corresponding with the NRC regarding the Early Site Permit (ESP) application for two additional reactors (Units 3 & 4) within VEGP's property boundary. The construction footprint for the new units will disturb approximately 500 total acres, with 310 acres consisting of the new units that will be lost to other uses. The ESP also includes an approximately 50 mile long new transmission corridor. Threatened and endangered species surveys have been conducted as part of the ESP for all areas located within the construction footprint, including the transmission corridor. This survey will be included in the license renewal application.

A response to this letter would be greatly appreciated, including any information you may have regarding threatened or endangered species and ecologically significant habitats that may occur on the VEGP site, within the transmission corridors, and/or in the reach of the Savannah River at VEGP. In addition, include any concerns associated with the current operation and maintenance activities at VEGP or along the transmission corridors related to threatened and endangered species. We will include a copy of this letter and your response with the license renewal application submitted to the NRC.

Please contact me at (205) 992-5807 or Mr. Dale Fulton (205) 992-7536 if you have any questions or require additional information.

Sincerely,

T. C. Moorer

Tom C. Moorer
Environmental Project Manager

Enclosures: Figures 2.1-1 and 2.1-2

Cc: T. E. Tynan
B. C. Terry
B. J. George
J. N. Stringfellow
M. A. Macfarlane
C. Myer
C. H. Huling
R. D. Just
J. M. Godfrey

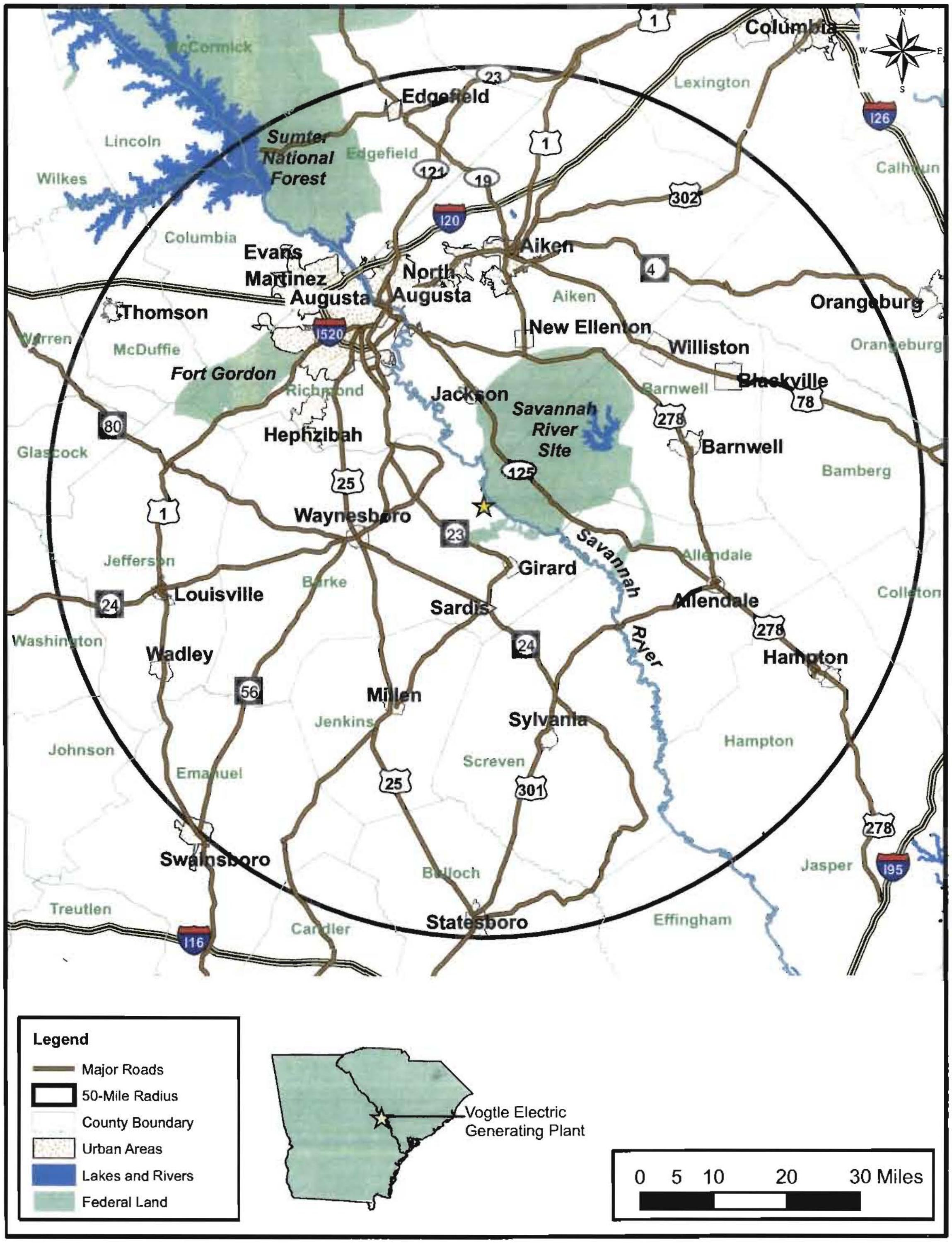

Figure 2.1-1 50-Mile Vicinity

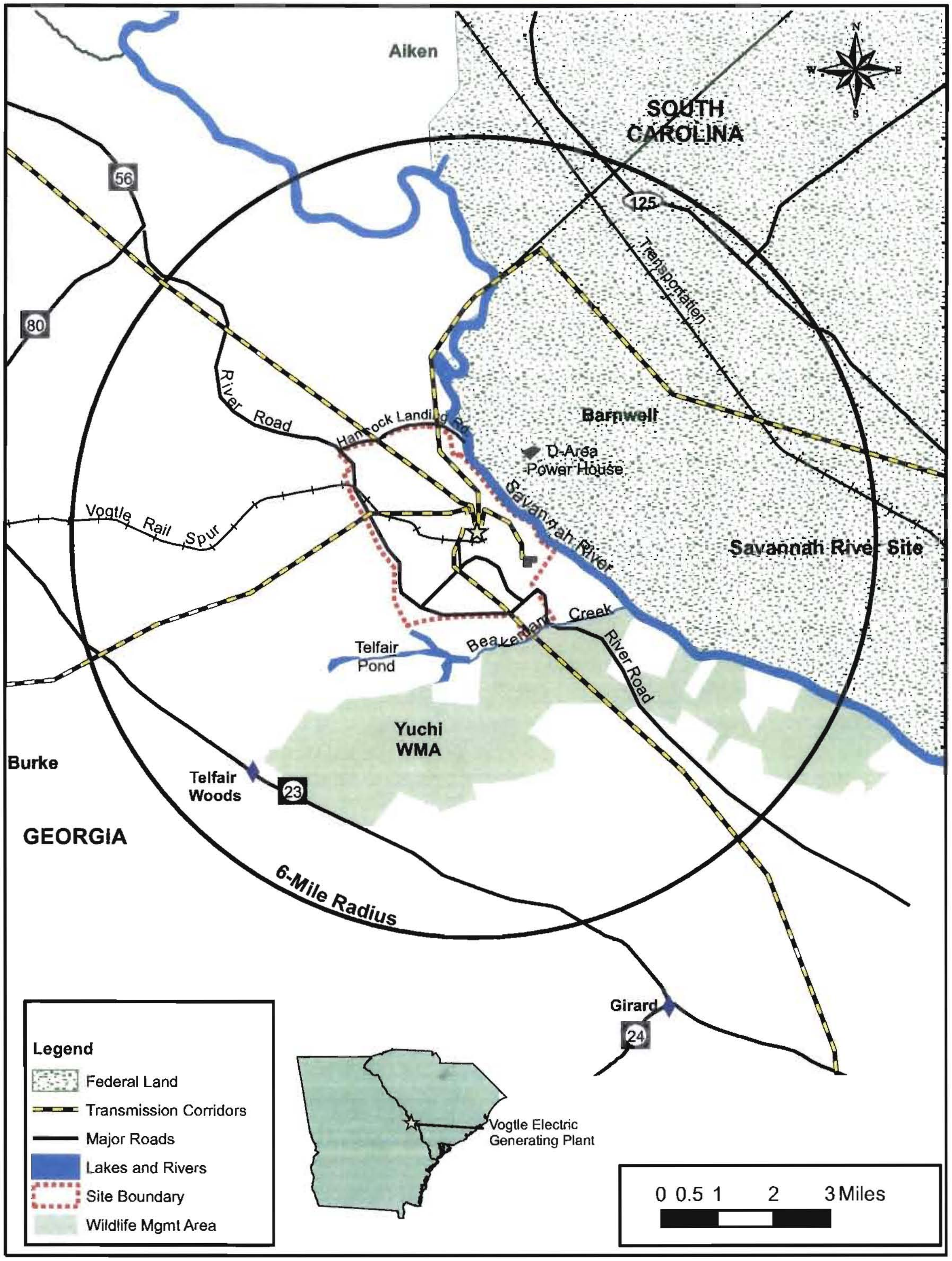

Figure 2.1-2 6-Mile Vicinity

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World℠

MAR 23 2007

LR-07-0406

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

Re: Vogtle Electric Generating Plant - License Renewal
Request for Information on Threatened & Endangered Species and Important Habitats

Dear Ms. Holling:

Southern Nuclear Operating Company is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for Vogtle Electric Generating Plant (VEGP) Units 1 and 2. The current operating licenses for Units 1 and 2 expire in 2027 and 2029, respectively. As part of the license renewal process, the NRC requires the licensing applicant to "assess the impacts of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10CFR51.53). In preparation for the environmental impact statement, the NRC will be communicating with your organization during their review of the environmental report portion of VEGP's application. In an attempt to create a smooth transition we are contacting you early in the application process to identify any issues that need to be addressed or identify any information your office may need to expedite the NRC's review.

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T. C. Moorer

Tom C. Moorer
Environmental Project Manager

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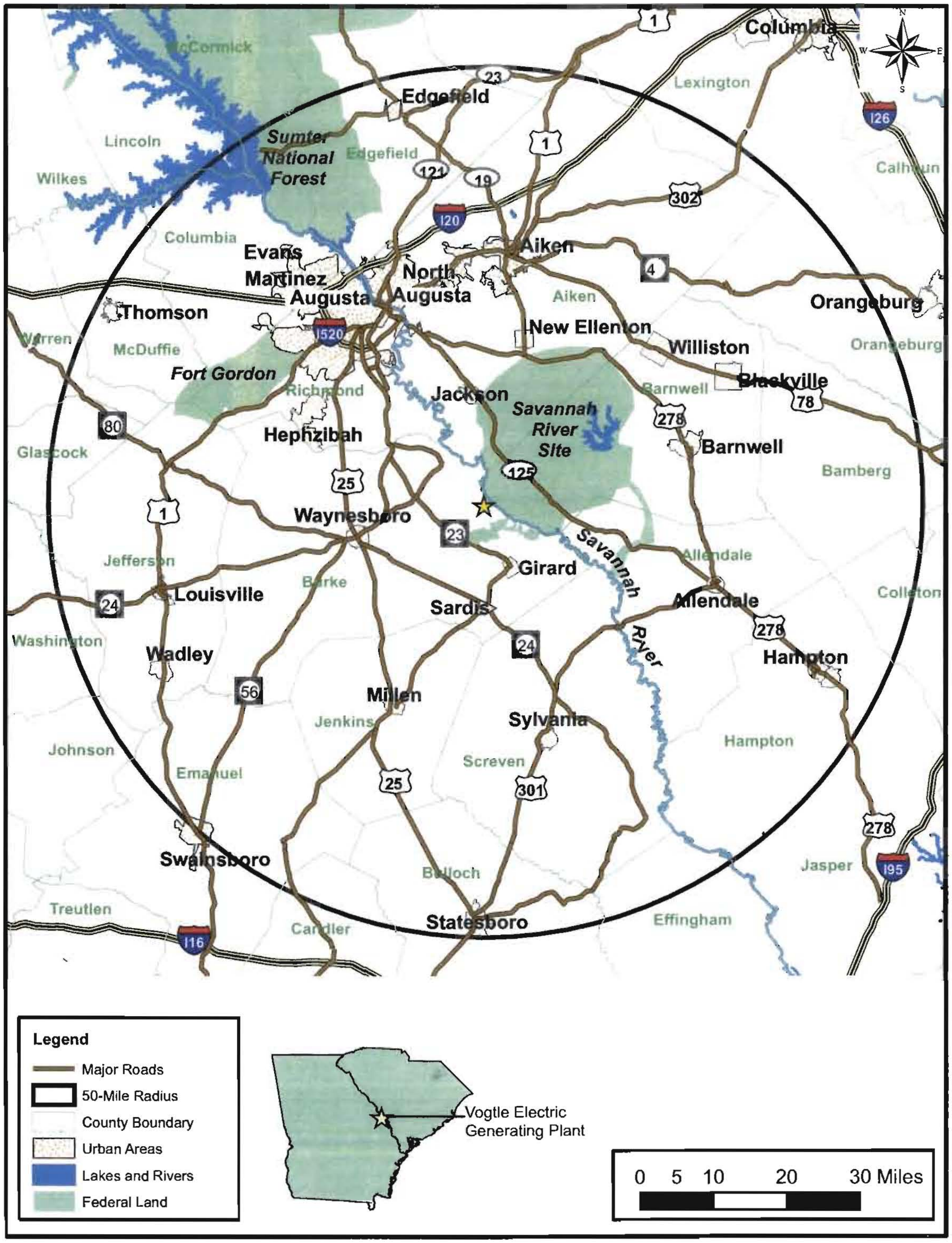

Figure 2.1-1 50-Mile Vicinity

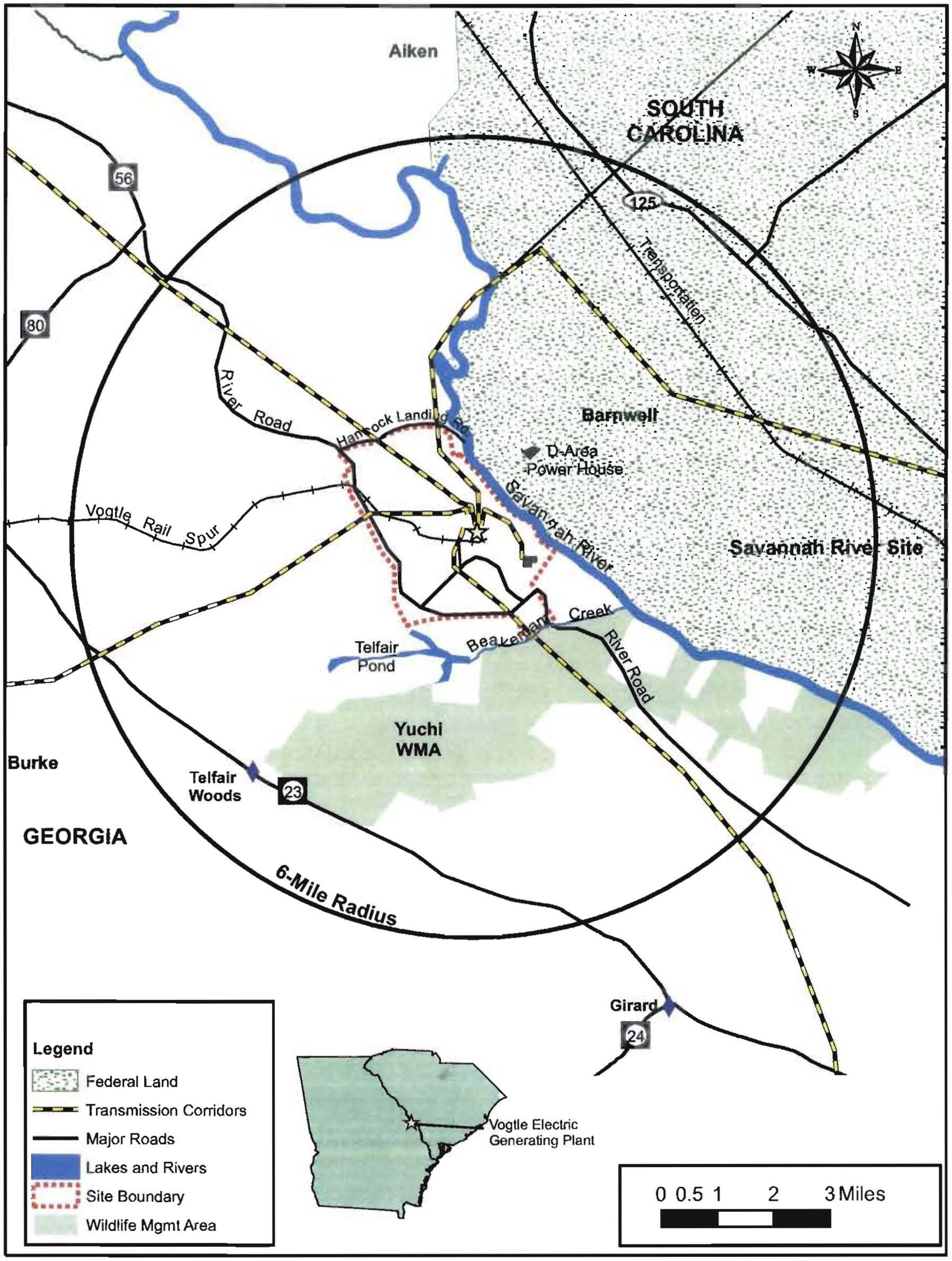

Figure 2.1-2 6-Mile Vicinity

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World[SM]

MAR 2 3 2007

LR-07-0411

Mr. Strant Colwell
Assistant Field Supervisor
U.S. Fish and Wildlife Service
4270 Norwich Street
Brunswick, GA 31520

Re: Vogtle Electric Generating Plant - License Renewal
Request for Information on Threatened & Endangered Species and Important Habitats

Dear Mr. Colwell:

Southern Nuclear Operating Company is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for Vogtle Electric Generating Plant (VEGP) Units 1 and 2. The current operating licenses for Units 1 and 2 expire in 2027 and 2029, respectively. As part of the license renewal process, the NRC requires the licensing applicant to "assess the impacts of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10CFR51.53). In preparation for the environmental impact statement, the NRC will be communicating with your organization during their review of the environmental report portion of VEGP's application. In an attempt to create a smooth transition we are contacting you early in the application process to identify any issues that need to be addressed or identify any information your office may need to expedite the NRC's review.

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T. C. Moorer

Tom C. Moorer
Environmental Project Manager

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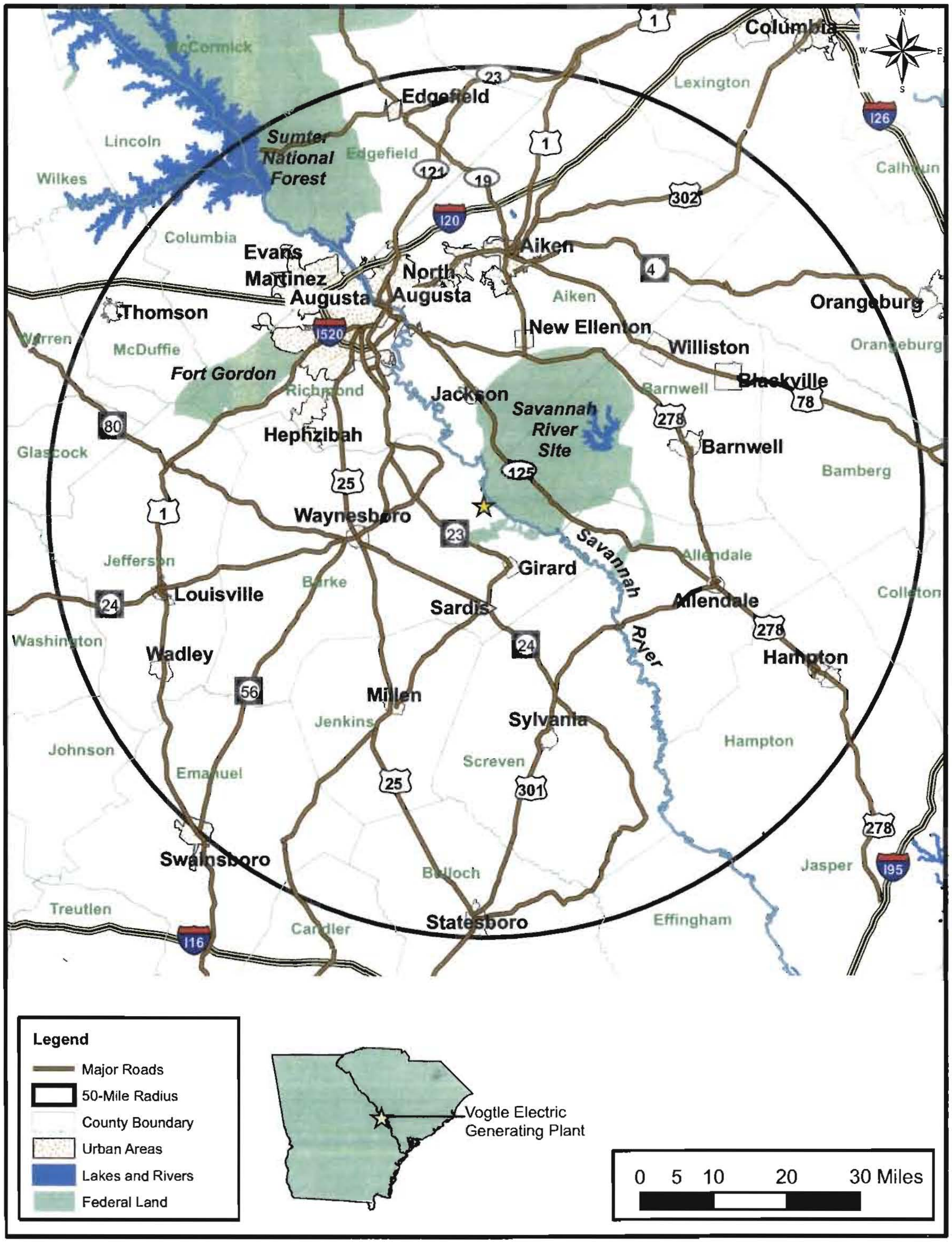

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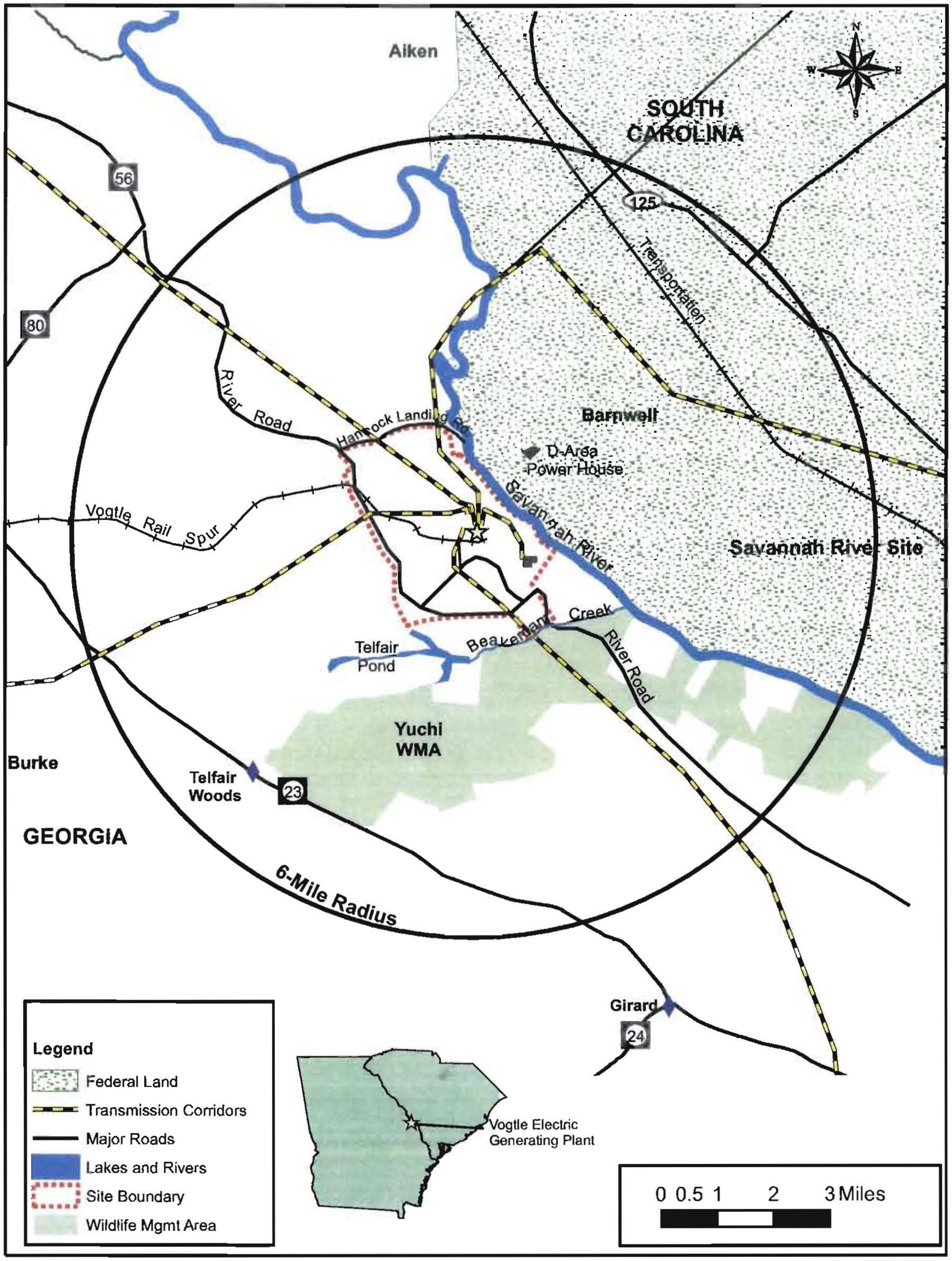

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Southern Nuclear
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P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
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MAR 23 2007

LR-07-0413

Mr. Mike Harris
Georgia Department of Natural Resources
Non-game Program
2117 U.S. Highway 278 SE
Social Circle, GA 30279

Re: Vogtle Electric Generating Plant – License Renewal
Review of Threatened and Endangered Species and Important Habitats

Dear Mr. Harris:

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Sincerely,

T. C. Moorer

T. C. Moorer
Project Manager- Environmental Support

Attachment

cc: T. E. Tynan
B. C. Terry
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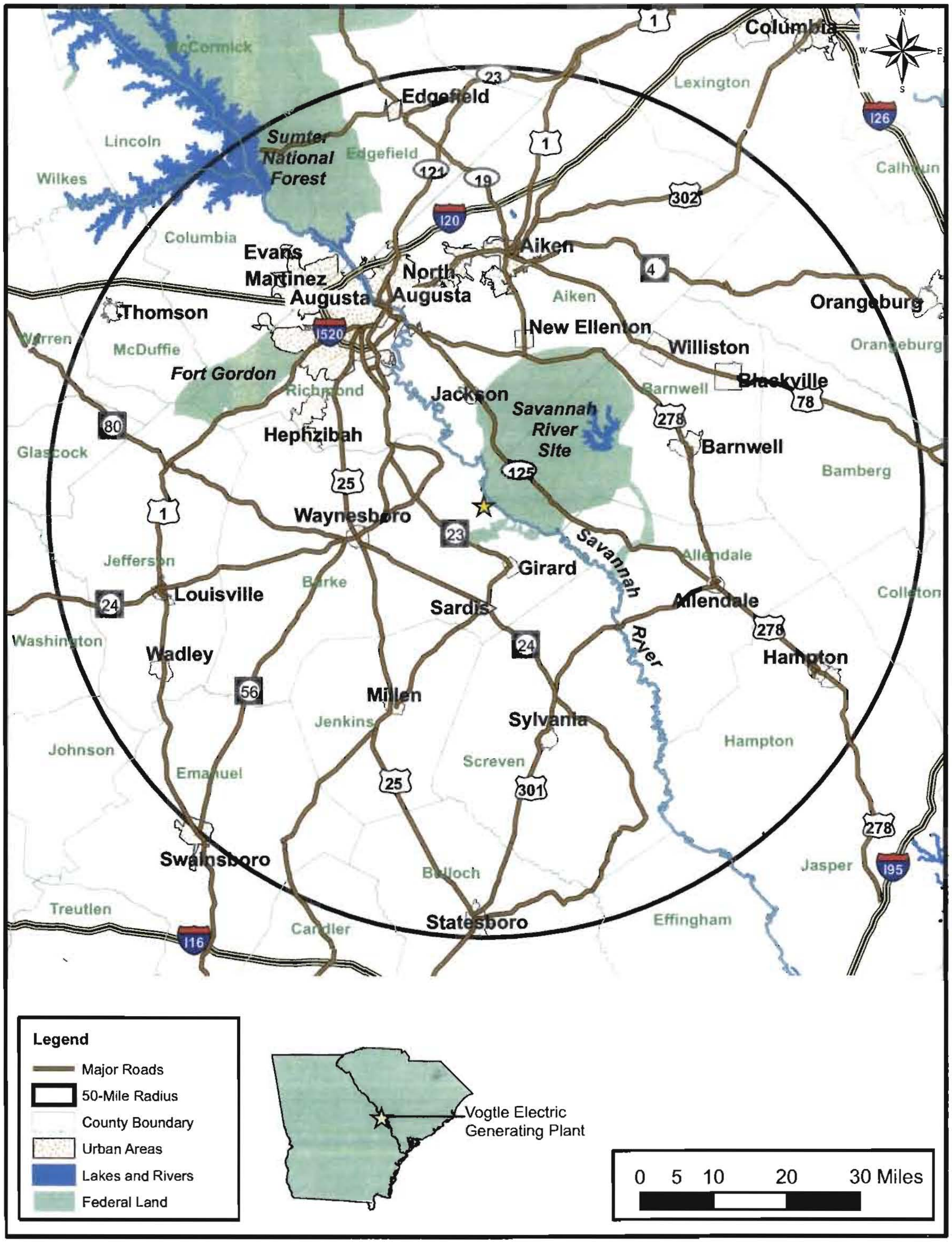

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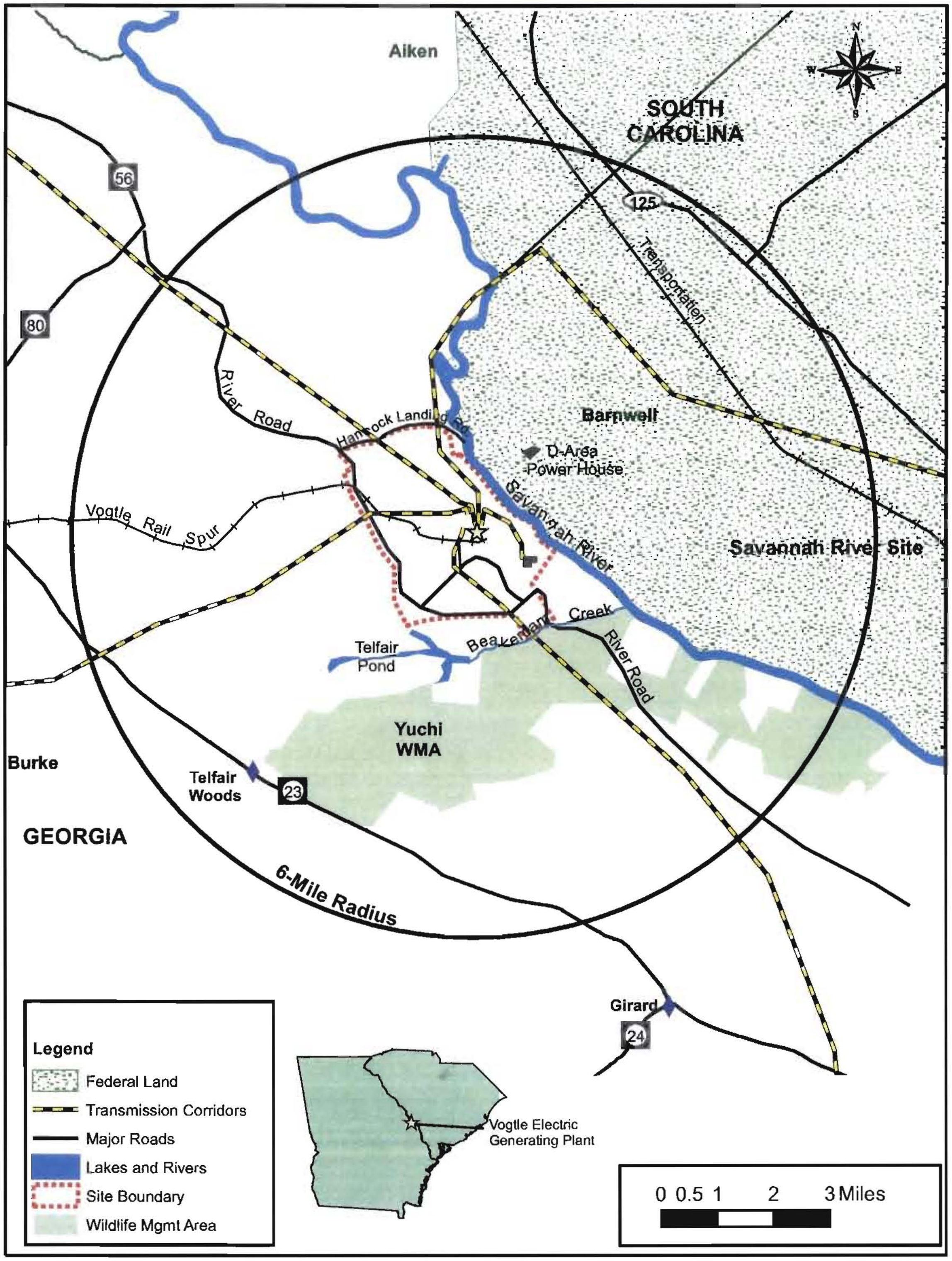

Figure 2.1-2 6-Mile Vicinity

South Carolina Department of
Natural Resources

John E. Frampton
Director
Alfred H. Vang
Deputy Director for
Land, Water & Conservation Division

June 23, 2005

Michael A. Abney, Fisheries Biologist
Georgia Power
5131 Maner Rd.
Smyrna, Georgia 30080

RE: Threatened and Endangered Species Information for License Extension for Plant Vogtle

Dear Mr. Abney,

I have checked our database, and there are no known occurrences of any federal or state threatened or endangered species within a mile of the project area. Please understand that our database does not represent a comprehensive biological inventory of the state. As an indication of species that may be found, I have enclosed a list of what is known to occur in Aiken and Barnwell counties. Highlighted species are ones of legal concern. 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 HollingJ@dnr.sc.gov.

Sincerely,

Julie Holling

Julie Holling
SC Department of Natural Resources
Heritage Trust Program

Enclosures

RARE, THREATENED, AND ENDANGERED SPECIES OF AIKEN COUNTY

STATUS	GRANK	SRANK	SCIENTIFIC NAME	COMMON NAME
ANIMALS:				
FE/SE	G3	S3	ACIPENSER BREVIROSTRUM	SHORTNOSE STURGEON
SC	G5T5	S2S3	AMBYSTOMA TIGRINUM TIGRINUM	EASTERN TIGER SALAMANDER
SC	G3G4	S?	ATRYTONE AROGOS	AROGOS SKIPPER
ST	G5	S5	CLEMMYS GUTTATA	SPOTTED TURTLE
SC	G5	S3?	CONDYLURA CRISTATA	STAR-NOSED MOLE
SE	G3G4	S2?	CORYNORHINUS RAFINESQUII	RAFINESQUE'S BIG-EARED BAT
SE	G3	S1	GOPHERUS POLYPHEMUS	GOPHER TORTOISE
FT/SE	G4	S2	HALIAEETUS LEUCOCEPHALUS	BALD EAGLE
SC	G2	S?	HETERODON SIMUS	SOUTHERN HOGNOSE SNAKE
SC	G5	S5	HYLA AVIVOCA	BIRD-VOICED TREEFROG
SC	G5	S?	LASIURUS CINEREUS	HOARY BAT
SC	G5	S2	MICRURUS FULVIUS	EASTERN CORAL SNAKE
SC	G5	S3S4	NEOTOMA FLORIDANA	EASTERN WOODRAT
SC	G5T5	S3S4	NEOTOMA FLORIDANA FLORIDANA	EASTERN WOODRAT
SC	G5	S2	NERODIA FLORIDANA	FLORIDA GREEN WATER SNAKE
FE/SE	G3	S2	PICOIDES BOREALIS	RED-COCKADED WOODPECKER
SC	G4	S3S4	PITUOPHIS MELANOLEUCUS	PINE OR GOPHER SNAKE
SE	G3	S1	RANA CAPITO	GOPHER FROG
SC	G5	S4	SCIURUS NIGER	EASTERN FOX SQUIRREL
SC	G5	S?	SEMINATRIX PYGAEA	BLACK SWAMP SNAKE
SC	G5	S4	SPILOGALE PUTORIUS	EASTERN SPOTTED SKUNK
SC	G5	S3?	URSUS AMERICANUS	BLACK BEAR
PLANTS:				
RC	G2G3	S1	AESCULUS PARVIFLORA	SMALL-FLOWERED BUCKEYE
SC	G4?	S?	AGALINIS LINIFOLIA	FLAX LEAF FALSE-FOXGLOVE
SC	G3	S?	ALLIUM CUTHBERTII	STRIPED GARLIC
SC	G5	SH	ANEMONE CAROLINIANA	CAROLINA ANEMONE
SC	G4?	S?	ARISTIDA CONDENSATA	PIEDMONT THREE-AWNED GRASS
SC	G3	S?	ASTRAGALUS MICHAUXII	SANDHILLS MILKVETCH
SC	G4	S?	ASTRAGALUS VILLOSUS	A MILK-VETCH
SC	G4?	S?	BOTRYCHIUM LUNARIOIDES	WINTER GRAPE-FERN
NC	G4	S?	CALAMOVILFA BREVIPILIS	PINE-BARRENS REED-GRASS
SC	G4G5	SR	CAREX CHEROKEENSIS	CHEROKEE SEDGE
SC	G4	S1	CAREX COLLINSII	COLLINS' SEDGE
SC	G4?	S?	CAREX ELLIOTTII	ELLIOTT'S SEDGE
SC	G4G5	S1	CAREX FOLLICULATA	LONG SEDGE
SC	G4	S?	CAREX SOCIALIS	SOCIAL SEDGE
RC	G4	S1	CLADRASTIS KENTUKEA	YELLOWWOOD
RC	G3	S2	COREOPSIS ROSEA	ROSE COREOPSIS
SC	G2G3	S?	CROTON ELLIOTTII	ELLIOTT'S CROTON
SC	G5	S?	CYSTOPTERIS PROTRUSA	LOWLAND BRITTLE FERN
SC	G5	S?	DELPHINIUM CAROLINIANUM	CAROLINA LARKSPUR
SC	G4	S?	DIRCA PALUSTRIS	EASTERN LEATHERWOOD
FE/SE	G2	S1	ECHINACEA LAEVIGATA	SMOOTH CONEFLOWER
SC	G3Q	S2	ECHINODORUS PARVULUS	DWARF BURHEAD
SC	G4G5	S?	ELEOCHARIS ROBBINSII	ROBBINS SPIKERUSH
SC	G2G3	SH	ELLIOTTIA RACEMOSA	GEORGIA PLUME
RC	G5	S1	ENEMION BITERNATUM	FALSE RUE-ANEMONE
SC	G4T2T4Q	S?	ERYNGIUM AQUATICUM VAR RAVENELII	MARSH ERYNGO
SC	G5	S1	EUONYMUS ATROPURPUREUS	WAHOO
SC	G4G5	S1	FORESTIERA LIGUSTRINA	UPLAND SWAMP PRIVET
SC	G5	S?	GAURA BIENNIS	BIENNIAL GAURA
SC	G?	S?	HALESIA PARVIFLORA	SMALL-FLOWERED SILVERBELL-TREE

NC	G2Q	S2	HYMENOCALLIS CORONARIA	SHOALS SPIDER-LILY
SC	G4	S3	ILEX AMELANCHIER	SARVIS HOLLY
SC	G4G5	S?	IPOMOPSIS RUBRA	RED STANDING-CYPRESS
SC	G5	S?	JUNIPERUS COMMUNIS	GROUND JUNIPER
NC	G3	S1	KALMIA CUNEATA	WHITE-WICKY
RC	G2	S?	LINDERA SUBCORIACEA	BOG SPICEBUSH
SC	G3G4	S?	LUDWIGIA SPATHULATA	SPATULATE SEEDBOX
SC	G2G3	S?	MACBRIDEA CAROLINIANA	CAROLINA BIRD-IN-A-NEST
SC	G?Q	S?	MAGNOLIA CORDATA	PIEDMONT CUCUMBER TREE
RC	G4	S1	MAGNOLIA PYRAMIDATA	PYRAMID MAGNOLIA
RC	G3	S2	MYRIOPHYLLUM LAXUM	PIEDMONT WATER-MILFOIL
SC	G4	S2	NESTRONIA UMBELLULA	NESTRONIA
SC	G3G5	S?	NOLINA GEORGIANA	GEORGIA BEARGRASS
SC	G3?	S?	PARONYCHIA AMERICANA	AMERICAN NAILWORT
SC	G3G4	S?	PELTANDRA SAGITTIFOLIA	SPOON-FLOWER
SC	G4	S?	PITYOPSIS PINIFOLIA	PINE-LEAVED GOLDEN ASTER
SC	G5	S1	PLATANTHERA LACERA	GREEN-FRINGE ORCHIS
SC	G5	S?	POTAMOGETON FOLIOSUS	LEAFY PONDWEED
FE/SE	G2	S1	PTILIMNIUM NODOSUM	HARPERELLA
SC	G3	S2	RHEXIA ARISTOSA	AWNED MEADOWBEAUTY
SC	G3	S2	RHODODENDRON FLAMMEUM	PIEDMONT AZALEA
SC	G5	S1	RHYNCHOSPORA ALBA	WHITE BEAKRUSH
SC	G3G4	S?	RHYNCHOSPORA INUNDATA	DROWNED HORNEDRUSH
SC	G4	S?	RHYNCHOSPORA STENOPHYLLA	CHAPMAN BEAKRUSH
SC	G5	S?	RORIPPA SESSILIFLORA	STALKLESS YELLOWCRESS
SC	G5T3T4	S?	RUELLIA CAROLINIENSIS SSP CILIOSA	A PETUNIA
SC	G4G5	S?	RUELLIA STREPENS	LIMESTONE PETUNIA
SC	G4?	S2	SAGITTARIA ISOETIFORMIS	SLENDER ARROW-HEAD
SC	G3	S1	SARRACENIA RUBRA	SWEET PITCHER-PLANT
SC	G3G4	S?	SCIRPUS ETUBERCULATUS	CANBY BULRUSH
SC	G4	S?	SOLIDAGO AURICULATA	EARED GOLDENROD
SC	G3	SR	SPOROBOLUS PINETORUM	CAROLINA DROPSEED
SC	G4T2T3	S1	STYLISMA PICKERINGII VAR PICKERINGII	PICKERING'S MORNING-GLORY
RC	G5	S1	SYNGONANTHUS FLAVIDULUS	YELLOW PIPEWORT
SC	G1G2Q	S1	THALICTRUM SUBROTUNDUM	RECLINED MEADOW-RUE
SC	G4G5	S?	TREPOCARPUS AETHUSAE	AETHUSA-LIKE TREPOCARPUS
SC	G3	S?	TRILLIUM DISCOLOR	FADED TRILLIUM
NC	G3	S1	TRILLIUM LANCIFOLIUM	NARROW-LEAVED TRILLIUM
NC	G3T2	S1	TRILLIUM PUSILLUM VAR PUSILLUM	LEAST TRILLIUM
FE/SE	G2	S1	TRILLIUM RELIQUUM	RELICT TRILLIUM
SC	G4G5	S?	XYRIS BREVIFOLIA	SHORT-LEAVED YELLOW-EYED GRASS
SC	G5	S?	XYRIS TORTA	TWISTED YELLOW-EYED-GRASS

RARE, THREATENED, AND ENDANGERED SPECIES OF BARNWELL COUNTY

STATUS..	GRANK..	SRANK..	SCIENTIFIC NAME...............	COMMON NAME..................
ANIMALS:				
SC	G4	S?	ANODONTA COUPERIANA	BARREL FLOATER
ST	G5	S5	CLEMMYS GUTTATA	SPOTTED TURTLE
SC	G5	S3?	CONDYLURA CRISTATA	STAR-NOSED MOLE
SE	G3G4	S2?	CORYNORHINUS RAFINESQUII	RAFINESQUE'S BIG-EARED BAT
SC	G5	S?	EGRETTA CAERULEA	LITTLE BLUE HERON
SC	G4	S?	ELLIPTIO CONGARAEA	CAROLINA SLABSHELL
FT/SE	G4	S2	HALIAEETUS LEUCOCEPHALUS	BALD EAGLE
SC	G2	S?	HETERODON SIMUS	SOUTHERN HOGNOSE SNAKE
SC	G5	S5	HYLA AVIVOCA	BIRD-VOICED TREEFROG
SC	G3G4	S?	LAMPSILIS CARIOSA	YELLOW LAMPMUSSEL
SC	G3	S?	LAMPSILIS SPLENDIDA	RAYED PINK FATMUCKET
SC	G5	S3S4	NEOTOMA FLORIDANA	EASTERN WOODRAT
FE/SE	G3	S2	PICOIDES BOREALIS	RED-COCKADED WOODPECKER
SC	G4	S3S4	PITUOPHIS MELANOLEUCUS	PINE OR GOPHER SNAKE
SC	G5	S?	PYGANODON CATARACTA	EASTERN FLOATER
SE	G3	S1	RANA CAPITO	GOPHER FROG
SC	G5	S4	SCIURUS NIGER	EASTERN FOX SQUIRREL
SC	G5	S?	UTTERBACKIA IMBECILLIS	PAPER PONDSHELL
SC	G4	S?	VILLOSA DELUMBIS	EASTERN CREEKSHELL
SC	G4Q	S?	VILLOSA VIBEX	SOUTHERN RAINBOW
PLANTS:				
SC	G3	S?	ALLIUM CUTHBERTII	STRIPED GARLIC
SC	G4	S?	AMPHICARPUM MUEHLENBERGIANUM	BLUE MAIDEN-CANE
SC	G3	S?	ASTRAGALUS MICHAUXII	SANDHILLS MILKVETCH
SC	G4	S?	ASTRAGALUS VILLOSUS	A MILK-VETCH
SC	G4?	S?	BAPTISIA LANCEOLATA	LANCE-LEAF WILD-INDIGO
SC	G3	S?	CAREX DECOMPOSITA	CYPRESS-KNEE SEDGE
RC	G4	S1	CARYA MYRISTICIFORMIS	NUTMEG HICKORY
SC	G2G3	S?	CROTON ELLIOTTII	ELLIOTT'S CROTON
FE/SE	G2	S1	ECHINACEA LAEVIGATA	SMOOTH CONEFLOWER
SC	G3Q	S2	ECHINODORUS PARVULUS	DWARF BURHEAD
SC	G5?	S?	ECHINODORUS TENELLUS	DWARF BURHEAD
SC	G4G5	S?	ELEOCHARIS ROBBINSII	ROBBINS SPIKERUSH
SC	G4	SR	ELEOCHARIS TRICOSTATA	THREE-ANGLE SPIKERUSH
SC	G5	S?	GAURA BIENNIS	BIENNIAL GAURA
SC	G?	S?	HALESIA PARVIFLORA	SMALL-FLOWERED SILVERBELL-TREE
RC	G3G4	S1	HELENIUM BREVIFOLIUM	SHORTLEAF SNEEZEWEED
SC	G4	S?	HELENIUM PINNATIFIDUM	SOUTHEASTERN SNEEZEWEED
RC	G2G3	S1	HYPERICUM ADPRESSUM	CREEPING ST. JOHN'S-WORT
SC	G4G5	S?	IPOMOPSIS RUBRA	RED STANDING-CYPRESS
RC	G2	S?	LINDERA SUBCORIACEA	BOG SPICEBUSH
SC	G2G3	S?	LOBELIA BOYKINII	BOYKIN'S LOBELIA
SC	G3G4	S?	LUDWIGIA SPATHULATA	SPATULATE SEEDBOX
SC	G2G3	S?	MACBRIDEA CAROLINIANA	CAROLINA BIRD-IN-A-NEST
SC	G5	S?	MENISPERMUM CANADENSE	CANADA MOONSEED
SC	G5	S?	MONARDA DIDYMA	OSWEGO TEA
RC	G3	S2	MYRIOPHYLLUM LAXUM	PIEDMONT WATER-MILFOIL
SC	G4	S2	NESTRONIA UMBELLULA	NESTRONIA
SC	G3G5	S?	NOLINA GEORGIANA	GEORGIA BEARGRASS
FE/SE	G2	S1	OXYPOLIS CANBYI	CANBY'S DROPWORT
SC	G3?	S?	PARONYCHIA AMERICANA	AMERICAN NAILWORT
SC	G5	S1	PLATANTHERA LACERA	GREEN-FRINGE ORCHIS
FE/SE	G2	S1	PTILIMNIUM NODOSUM	HARPERELLA

SC	G5	S1	QUERCUS SINUATA	DURAND'S WHITE OAK
SC	G3	S2	RHEXIA ARISTOSA	AWNED MEADOWBEAUTY
SC	G3	S2	RHODODENDRON FLAMMEUM	PIEDMONT AZALEA
SC	G3G4	S?	RHYNCHOSPORA INUNDATA	DROWNED HORNEDRUSH
SC	G4	S?	RHYNCHOSPORA TRACYI	TRACY BEAKRUSH
SC	G4?	S2	SAGITTARIA ISOETIFORMIS	SLENDER ARROW-HEAD
SC	G4	SR	SCLERIA RETICULARIS	RETICULATED NUTRUSH
SC	G4G5	S1	STILLINGIA AQUATICA	CORKWOOD
SC	G5	S?	TRAUTVETTERIA CAROLINIENSIS	CAROLINA TASSEL-RUE
SC	G3G5	S1	UTRICULARIA FLORIDANA	FLORIDA BLADDERWORT
SC	G4	S1	UTRICULARIA OLIVACEA	PIEDMONT BLADDERWORT
SC	G5	S?	VALLISNERIA AMERICANA	EEL-GRASS

Noel Holcomb, Commissioner
Dan Forster, Division Director

Georgia Department of Natural Resources
Wildlife Resources Division

Nongame Wildlife & Natural Heritage Section
Georgia Natural Heritage Program
2117 U.S. Hwy. 278 S.E., Social Circle, Georgia 30025-4714
(770) 918 6411, (706) 557-3032

June 29, 2005

Michael Abney
Fisheries Biologist
Georgia Power
5131 Maner Road
Smyrna, GA 30080

Subject: Known Occurrences of Conservation Areas and Special Concern Animals and Plants On or Near License Extension for Plant Vogtle, Burke County, Georgia

Dear Mr. Abney:

This is in response to your request of June 15, 2005. According to our records, within a three-mile radius of the project site there are the following Natural Heritage Database occurrences:

Cyprinella callisema (Ocmulgee Shiner) approx. 1.0 mi. NW of site
Cyprinella leedsi (Bannerfin Shiner) approx. 2.0 mi. SE of site
Savannah River [High Priority Stream] 0.2 mi. NE of site
Yuchi WMA [Georgia DNR] approx. 1.5 mi. SE of site

* Entries above proceeded by "US" indicates species with federal status (Protected, Candidate or Partial Status). Species that are federally protected in Georgia are also state protected; "GA" indicates Georgia protected species.

Recommendations:

A lack of survey information for this area may explain the small number of rare species occurrences. Rare species occurrences in the Savannah River are not well represented in our database. However, the Ocmulgee Shiner (Cyprinella callisema) and the Bannerfin Shiner (Cyprinella leedsi) are two fish species of concern that are found nearby. Please forward any new rare species information to our office if a survey is completed.

Also, please be aware that this project occurs near the Savannah River, a high priority stream. As part of an effort to develop a comprehensive wildlife conservation strategy for the state of Georgia, the Wildlife Resources division has developed and mapped a list of streams that are important to the protection or restoration of rare aquatic species and aquatic communities. High priority waters and their surrounding watersheds are a high priority for a broad array of conservation activities, but do not receive any additional legal protections. Please contact the Georgia Natural Heritage Program if you would like additional information on high priority waters.

Disclaimer:

Please keep in mind the limitations of our database. The data collected by the Georgia Natural Heritage Program comes from a variety of sources, including museum and herbarium records, literature, and reports from individuals and organizations, as well as field surveys by our staff biologists. In most cases the information is not the result of a recent on-site survey by our staff. Many areas of Georgia have never been surveyed thoroughly. Therefore, the Georgia Natural Heritage Program can only occasionally provide definitive information on the presence or absence of rare species on a given site. Our files are updated constantly as new information is received. **Thus, information provided by our program represents the existing data in our files at the time of the request and should not be considered a final statement on the species or area under consideration.**

If you know of populations of special concern species that are not in our database, please fill out the appropriate data collection form and send it to our office. Forms can be obtained through our web site (http://www.georgiawildlife.com) or by contacting our office. If I can be of further assistance, please let me know.

Sincerely,

Greg Krakow
Data Manager

IR 10015

United States Department of the Interior

Fish and Wildlife Service

105 West Park Drive, Suite D
Athens, Georgia 30606

West Georgia Sub Office
P.O. Box 52560
Ft. Benning, Georgia 31995-2560

Coastal Sub Office
4270 Norwich Street
Brunswick, Georgia 31520

OCT 3 2005

Mr. Michael Abernathy
Georgia Power Environmental Laboratory
5131 Maner Road
Smyrna, Georgia 30080

Re: FWS Log # 05-0551

Dear Mr. Abenathy:

Thank you for your letter dated June 27, 2005, regarding your preparation for a license extension for Plant Vogtle in Burke County on the Savannah River near Waynesboro, Georgia. Plant Vogtle is a nuclear power, electric generating plant in the Southern Company system.

You requested information on both terrestrial and aquatic federally listed species of concern, threatened species, and endangered species in the vicinity of Plant Vogtle. We have included a list of federal and state listed species in Burke County, Georgia, with habitat type and threat statements included in that list.

The federally-listed shortnose sturgeon (Acipenser brevirostrum) is under the jurisdiction of the National Oceanic and Atmospheric Administration, Fisheries.

Although not listed, the robust redhorse (*Moxostoma robustum*) is of extreme interest. Conservation efforts are being pursued to prevent listing of this fish species via the interagency Robust Redhorse Conservation Committee. The Savannah River, Georgia/ South Carolina is a verified location for natural populations of this fish. All resource concerns should take into consideration that the Savannah River is on the State's 303(d) list of impaired steams partially supporting their designated uses.

We appreciate your early communication and willingness to work with us to protect sensitive fish and all wildlife resources. We will provide further comments during your application process for either an early site permit or a pre-combined operating license. At that time we will provide comments and recommendations under the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 et seq.) and the Fish and Wildlife Coordination

Act of 1973, as amended (16 U.S.C. 1531 et seq.) and the Fish and Wildlife Coordination Act (48 Stat. 401, as amended, 16 U.S.C. 661 et seq.). If you have any questions regarding this matter, please contact our Coastal Georgia Sub-office supervisor, Strant Colwell, at (912) 265-9336.

Sincerely,

Strant T. Colwell

Sandra S. Tucker for
Field Supervisor

Enclosure

cc: FWS, Athens, Georgia

Listed Species in Burke County (updated May 2004)				
Species	**Federal Status**	**State Status**	**Habitat**	**Threats**
Bird				
Bald eagle *Haliaeetus leucocephalus*	T	E	Inland waterways and estuarine areas in Georgia.	Major factor in initial decline was lowered reproductive success following use of DDT. Current threats include habitat destruction, disturbance at the nest, illegal shooting, electrocution, impact injuries, and lead poisoning.
Red-cockaded woodpecker *Picoides borealis*	E	E	Nest in mature pine with low understory vegetation (<1.5m); forage in pine and pine hardwood stands > 30 years of age, preferably > 10" dbh	Reduction of older age pine stands and encroachment of hardwood midstory in older age pine stands due to fire suppression
Wood stork *Mycteria americana*	E	E	Primarily feed in fresh and brackish wetlands and nest in cypress or other wooded swamps	Decline due primarily to loss of suitable feeding habitat, particularly in south Florida. Other factors include loss of nesting habitat, prolonged drought/flooding, raccoon predation on nests, and human disturbance of rookeries.
Reptile				
Gopher tortoise *Gopherus polyphemus*	No Federal Status	T	Well-drained, sandy soils in forest and grassy areas; associated with pine overstory, open understory with grass and forb groundcover, and sunny areas for nesting	Habitat loss and conversion to closed canopy forests. Other threats include mortality on highways and the collection of tortoises for pets.
Amphibian				
Flatwoods salamander *Ambystoma cingulatum*	T	T	Adults and subadults are fossorial; found in open mesic pine/wiregrass flatwoods dominated by longleaf or slash pine and maintained by frequent fire. During breeding period, which coincides with heavy rains from Oct.-Dec., move to isolated, shallow, small, depressions (forested with emergent vegetation) that dry completely on a cyclic basis. Last breeding record for Burke County was in the 1940's.	Habitat destruction as a result of agricultural an silvicultural practices (e.g., clearclutting, mechanical site preparation), fire suppresion and residential and commercial development.
Invertebrate				
Atlantic pigtoe mussel *Fusconaia masoni*	No Federal Status	E	Found in unpolluted, fast-flowing water in coarse sand/gravel substrate.	
Fish				
Shortnose sturgeon[1] *Acipenser brevirostrum*	E	E	Atlantic seaboard rivers	Construction of dams and pollution, habitat alterations from discharges, dredging or disposal of material into rivers, and related development activities.
Plant				
Canby's dropwort *Oxypolis canbyi*	E	E	Peaty muck of shallow cypress ponds, wet pine savannahs, and adjacent sloughs and drainage ditches	Loss or alteration of wetland habitats
Georgia plume	No Federal	T	Sand ridges, dry oak ridges, evergreen hammocks, and sandstone outcrops in a variety	

Elliottia racemosa	Status		of sandy soil conditions ranging from moist to very dry
Indian olive *Nestronia umbellula*	No Federal Status	T	Dry open upland forests of mixed hardwood and pine
Ocmulgee skullcap *Scutellaria ocmulgee*	No Federal Status	T	Forested terraces, hardwood slopes and riverbanks of tributaries to the Ocmulgee, Oconee, and Savannah Rivers
Rosemary *Ceratiola ericoides*	No Federal Status	T	Driest, openly vegetated, scrub oak sandhills and river dunes with deep white sands of the Kershaw soil series
Sweet pitcher-plant *Sarracenia rubra*	No Federal Status	E	Acid soils of open bogs, sandhill seeps, Atlantic white-cedar swamps, wet savannahs, low areas in pine flatwoods, and along sloughs and ditches

[1]This species is the responsibility of the National Marine Fisheries Service.

ATTACHMENT D

THERMOPHILIC ORGANISM CORRESPONDENCE

Table of Contents

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World℠

MAR 23 2007

LR-07-0410

Mr. David Graves
South Carolina Department of Health
2600 Bull Street
Columbia, SC 29201

Re: Vogtle Electric Generating Plant – License Renewal
Request for Information on Thermophilic Organisms in the Savannah River

Dear Mr. Graves:

Southern Nuclear Operating Company is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for Vogtle Electric Generating Plant (VEGP) Units 1 and 2, located in Burke County, Georgia. The current operating licenses for Units 1 and 2 expire in 2027 and 2029, respectively. As part of the License Renewal application process, NRC requires applicants to "assess the impact of the proposed action on public health from thermophilic organisms in the affected water" (10 CFR 51.53). NRC guidance and supporting documentation focus on organisms such as *Naegleria fowleri,* which has been known to produce public heath concerns when present in high concentrations.

In preparation for the environmental impact statement, the NRC will be communicating with your organization during their review of the environmental report portion of VEGP's application. In an attempt to create a smooth transition we are contacting you early in the application process to identify any issues that need to be addressed or identify any information your office may need to expedite the NRC's review.

VEGP lies on the west bank of the Savannah River in the eastern sector of Burke County, Georgia, at River Mile 151, approximately 30 river miles upstream from the intersection of the Savannah River and U.S. Highway 301. The VEGP site encompasses approximately 3,169 acres, roughly one-half of which (1,778 acres) are undeveloped (old fields, forests, and wetlands) and managed as a wildlife preserve. The discharge for VEGP Units 1 and 2 enters the Savannah River via a submerged single port discharge pipe. Discharge limits and monitoring requirements are set forth in the VEGP National Pollutant Discharge Elimination System (NPDES) permit, GA0026786.

The VEGP existing discharge temperatures are significantly less than those known to be optimal for growth and survival of thermophilic organisms. SNC is aware of no information that suggests any concern about thermophilic organism concentrations in the river. SNC is consulting with your office for any information that may be available on any potential health effects associated with thermophilic organisms in discharges from steam electric generating facilities in the southeast. A letter confirming receipt of this correspondence and providing any concerns you may have is respectfully requested. The NRC will likely contact your office during the review of the VEGP License Renewal application regarding this matter.

This correspondence is provided to allow ample time for your review of this issue prior to being contacted by the NRC. Southern Nuclear will include a copy of this letter in the License Renewal application submittal to the NRC.

Please contact me at (205) 992-5807 or Mr. Dale Fulton (205) 992-7536 if you have any questions or require additional information.

Sincerely,

T. C. Moorer

Tom C. Moorer
Environmental Project Manager

Enclosures: Figures 2.1-1 and 2.1-2

Cc: T. E. Tynan
B. C. Terry
B. J. George
J. N. Stringfellow
M. A. Macfarlane
C. Myer
C. H. Huling
R. D. Just
J. M. Godfrey

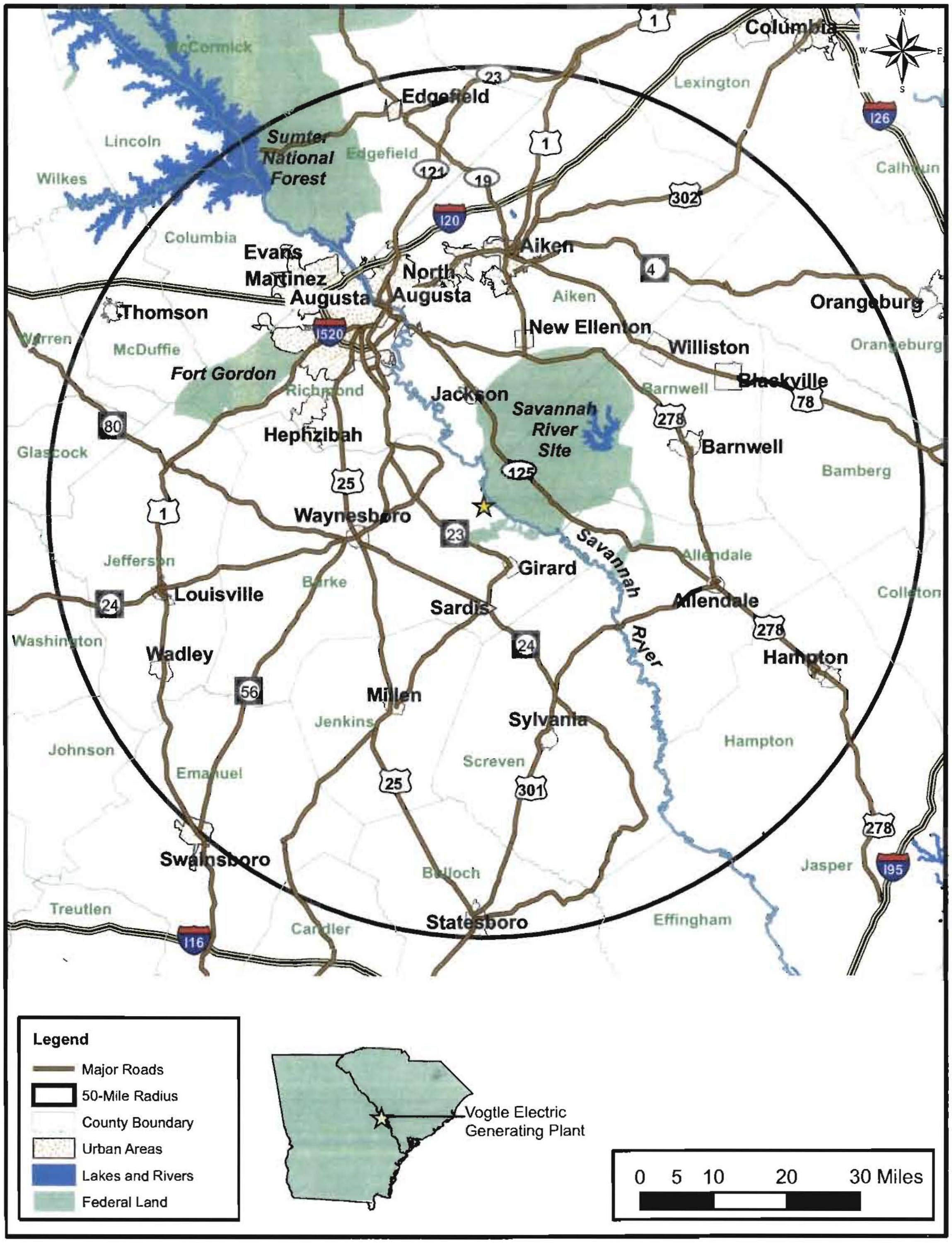

Figure 2.1-1 50-Mile Vicinity

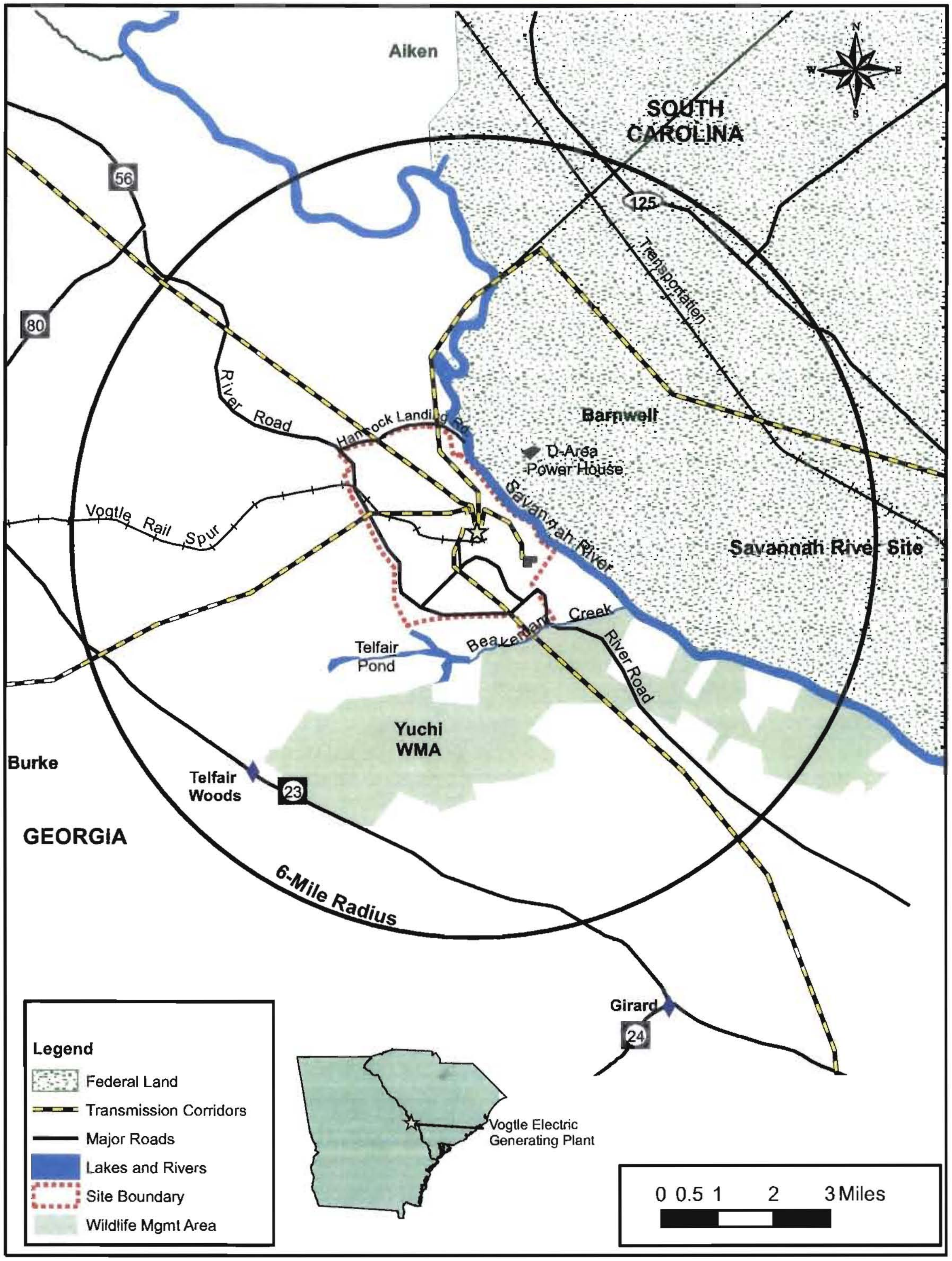

Figure 2.1-2 6-Mile Vicinity

D H E C
PROMOTE PROTECT PROSPER

C. Earl Hunter, Commissioner
Promoting and protecting the health of the public and the environment.

26 April 2007

Southern Nuclear
RECEIVED
MAY 09 2007
Vogtle Deployment

Tom Moorer
Environmental Project Manager
Southern Nuclear Operating Company, Inc.
40 Inverness Center Parkway
Birmingham, Alabama 35242

Re: Vogtle Electric Generating Plant – License Renewal
Thermophilic Organisms in the Savannah River

Dear Mr. Moorer:

We received your letter requesting information to identify any information our Agency may need to expedite the NRC's review. Thank you for contacting us and making us aware of some of the potential issues facing stakeholders in this early stage of the License Renewal process.

We currently do not monitor for *Naegleria fowleri* in the Waters of the State of South Carolina. To my knowledge, no information is available from our Agency concerning the potential health effects in South Carolina associated with *Naegleria fowleri* and the rare disease with which it is associated.

If I become aware of any information from South Carolina that may be of relevance to your project I will forward it your way.

Please contact me if you have additional questions.

Sincerely,

James B. Glover

James B. Glover, Ph.D., Manager
Aquatic Biology Section
The South Carolina Department of Health and Environmental Control
2600 Bull Street
Columbia, Sc 29201
Phone- 803-898-4081
Fax- 803-898-4200
Email- gloverjb@dhec.sc.gov

Cc: Chuck Gorman, Director; Water Monitoring, Assessment and Protection, SCDHEC
David Graves, Manager; Water Quality Monitoring Section, SCDHEC

Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World℠

MAR 23 2007

LR-07-0407

Ms. Linda MacGregor
Chief, Watershed Protection Branch
Environmental Protection Division
Georgia Department of Natural Resources
4220 International Parkway, Suite 101
Atlanta, GA 30354

Re: Vogtle Electric Generating Plant – License Renewal
Request for Information on Thermophilic Organisms in the Savannah River

Dear Ms. MacGregor:

Southern Nuclear Operating Company is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for Vogtle Electric Generating Plant (VEGP) Units 1 and 2, located in Burke County, Georgia. The current operating licenses for Units 1 and 2 expire in 2027 and 2029, respectively. As part of the License Renewal application process, NRC requires applicants to "assess the impact of the proposed action on public health from thermophilic organisms in the affected water" (10 CFR 51.53). NRC guidance and supporting documentation focus on organisms such as *Naegleria fowleri,* which has been known to produce public heath concerns when present in high concentrations.

In preparation for the environmental impact statement, the NRC will be communicating with your organization during their review of the environmental report portion of VEGP's application. In an attempt to create a smooth transition we are contacting you early in the application process to identify any issues that need to be addressed or identify any information your office may need to expedite the NRC's review.

VEGP lies on the west bank of the Savannah River in the eastern sector of Burke County, Georgia, at River Mile 151, approximately 30 river miles upstream from the intersection of the Savannah River and U.S. Highway 301. The VEGP site encompasses approximately 3,169 acres, roughly one-half of which (1,778 acres) are undeveloped (old fields, forests, and wetlands) and managed as a wildlife preserve. The discharge for VEGP Units 1 and 2 enters the Savannah River via a submerged single port discharge pipe. Discharge limits and monitoring requirements are set forth in the VEGP National Pollutant Discharge Elimination System (NPDES) permit, GA0026786.

The VEGP existing discharge temperatures are significantly less than those known to be optimal for growth and survival of thermophilic organisms. SNC is aware of no information that suggests any concern about thermophilic organism concentrations in the river. SNC is consulting with your office for any information that may be available on any potential health effects associated with thermophilic organisms in discharges from steam electric generating facilities in the southeast. A letter confirming receipt of this correspondence and providing any concerns you may have is respectfully requested. The NRC will likely contact your office during the review of the VEGP License Renewal application regarding this matter.

This correspondence is provided to allow ample time for your review of this issue prior to being contacted by the NRC. Southern Nuclear will include a copy of this letter in the License Renewal application submittal to the NRC.

Please contact me at (205) 992-5807 or Mr. Dale Fulton (205) 992-7536 if you have any questions or require additional information.

Sincerely,

T. C. Moorer

Tom C. Moorer
Environmental Project Manager

Enclosures: Figures 2.1-1 and 2.1-2

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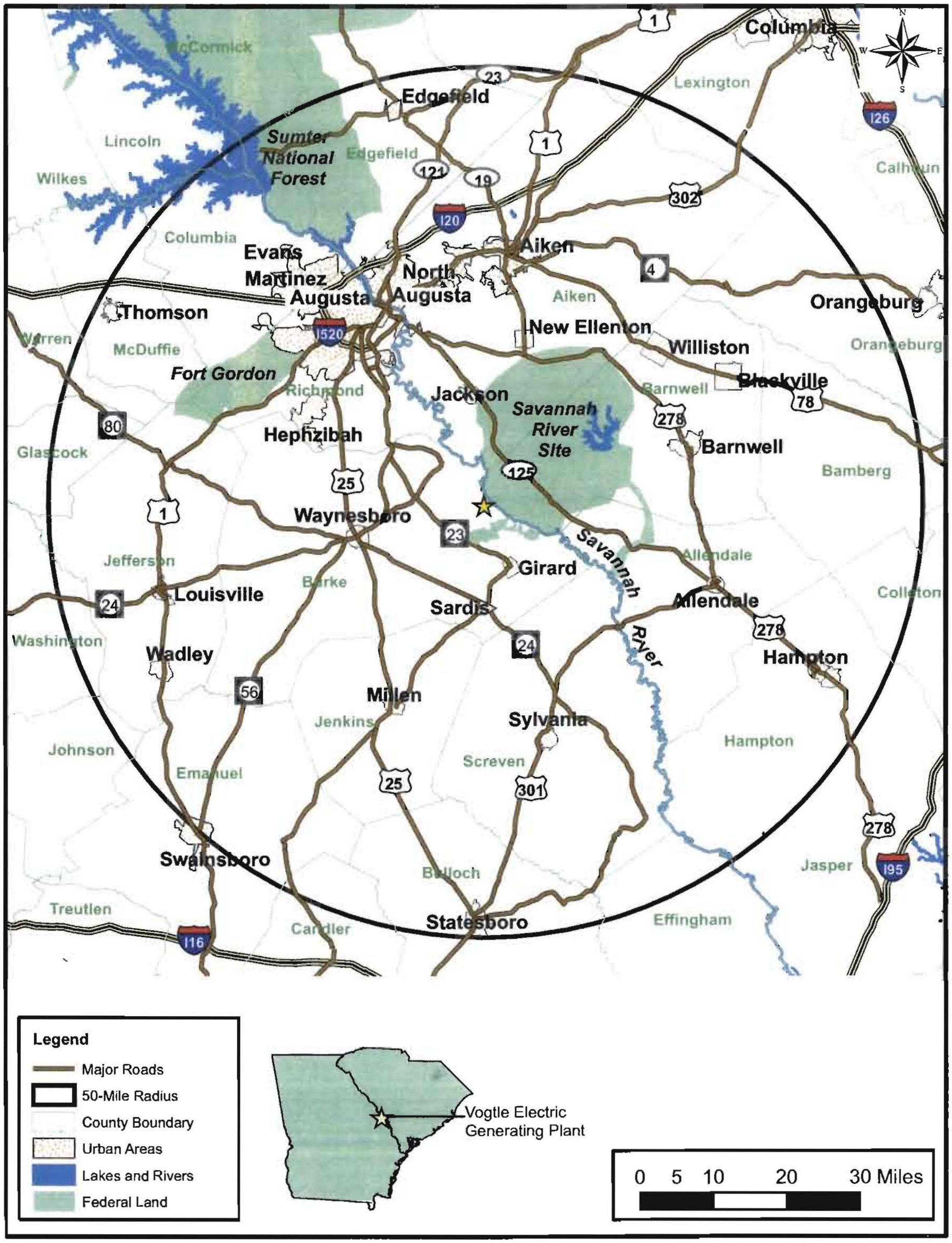

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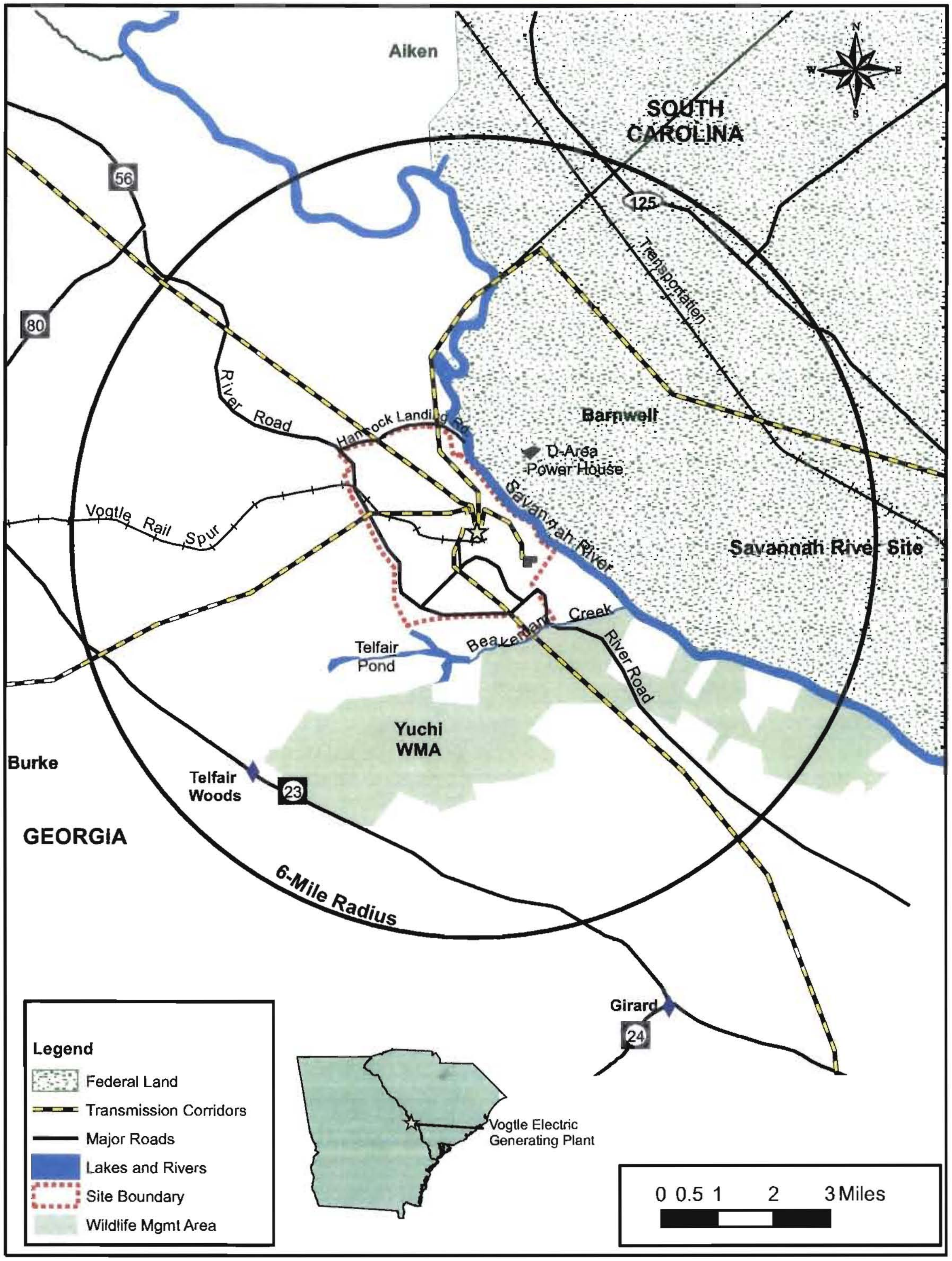

Figure 2.1-2 6-Mile Vicinity

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ATTACHMENT E

STATE HISTORIC PRESERVATION OFFICER CORRESPONDENCE

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Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295
Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World[SM]

MAR 23 2007

LR-07-0408

Dr. Ray Luce
Historical Preservation Division
Georgia Department of Natural Resources
156 Trinity Ave., SW, Suite 101
Atlanta, GA 30303

SUBJECT: Vogtle Electric Generating Plant – License Renewal
Request for Information on Historic and Archaeological Resources

Dear Dr. Luce:

Southern Nuclear Operating Company is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for Vogtle Electric Generating Plant (VEGP) Units 1 and 2. The current operating licenses for Units 1 and 2 expire in 2027 and 2029, respectively. As part of the License Renewal application process, NRC requires license applicants to "assess whether any historic or archaeological properties will be affected by the proposed project." NRC may also request an informal consultation with your office at a later date under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470), and Federal Advisory Council on Historic Preservation regulations (36 CFR 800). By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

VEGP lies on the west bank of the Savannah River in the eastern sector of Burke County, Georgia, at river Mile 151, approximately 23 river miles upstream from the intersection of the Savannah River and U.S. Highway 301. The VEGP site proper encompasses approximately 3,169 acres, roughly one-half of which (1,778 acres) are undeveloped (old fields, forests, and wetlands) and managed as a wildlife preserve. The Vogtle site is served by approximately 340 miles of transmission lines divided among six (6) corridors. One of the corridors, Vogtle-Wilson, connects Vogtle to the adjacent combustion turbine plant (Plant Wilson) and is contained entirely on the site property. The other corridors consist of three 230 KV lines: Vogtle -Savannah River Site; Vogtle-Goshen; and Vogtle-Augusta Newsprint (a nine mile loop off of Vogtle-Goshen line), and two 500 KV lines: Vogtle-Thallman, and Vogtle-Scherer. There are a number of cultural resource sites associated with Plant Vogtle and a significant fossil was discovered and excavated during the original plant construction. Georgiacetus Vogtlensis, a prehistoric whale, was discovered in 1984 during excavation for the site intake and is named for the site.

Southern Nuclear Operating Company and associated owners are currently corresponding with the NRC regarding the Early Site Permit (ESP) application for two additional reactors (Units 3 & 4) within VEGP's property boundary. The construction footprint for the new units will disturb approximately 500 total acres, with 310 acres consisting of the new units that will be lost to other uses. The ESP also includes an approximately 50 mile long new transmission corridor.

During our meeting with your staff on September 11, 2006, SNC submitted the *Intensive Archaeological Survey of the Proposed Expansion Areas at the Vogtle Electric Generating Plant* to you in conjunction with submitting the Early Site Permit application for your review and comments. SNC appreciates your review and comments dated October 4, 2006 as it relates to the proposed new units.

License Renewal activities will not include changes to current site conditions and SNC does not anticipate any impacts to historic or archaeological properties. A response to this letter would be greatly appreciated, including any additional information you may have regarding historic/archaeological properties or paleontological sites in the area of VEGP. A copy of this letter and your response will be included in the License Renewal application.

Please contact me at (205) 992-5807 or Mr. Dale Fulton (205) 992-7536 if you have any questions or require additional information.

Sincerely,

T. C. Moorer

Tom C. Moorer
Environmental Project Manager

Enclosures: Figures 2.1-1 and 2.1-2

Cc: T. E. Tynan
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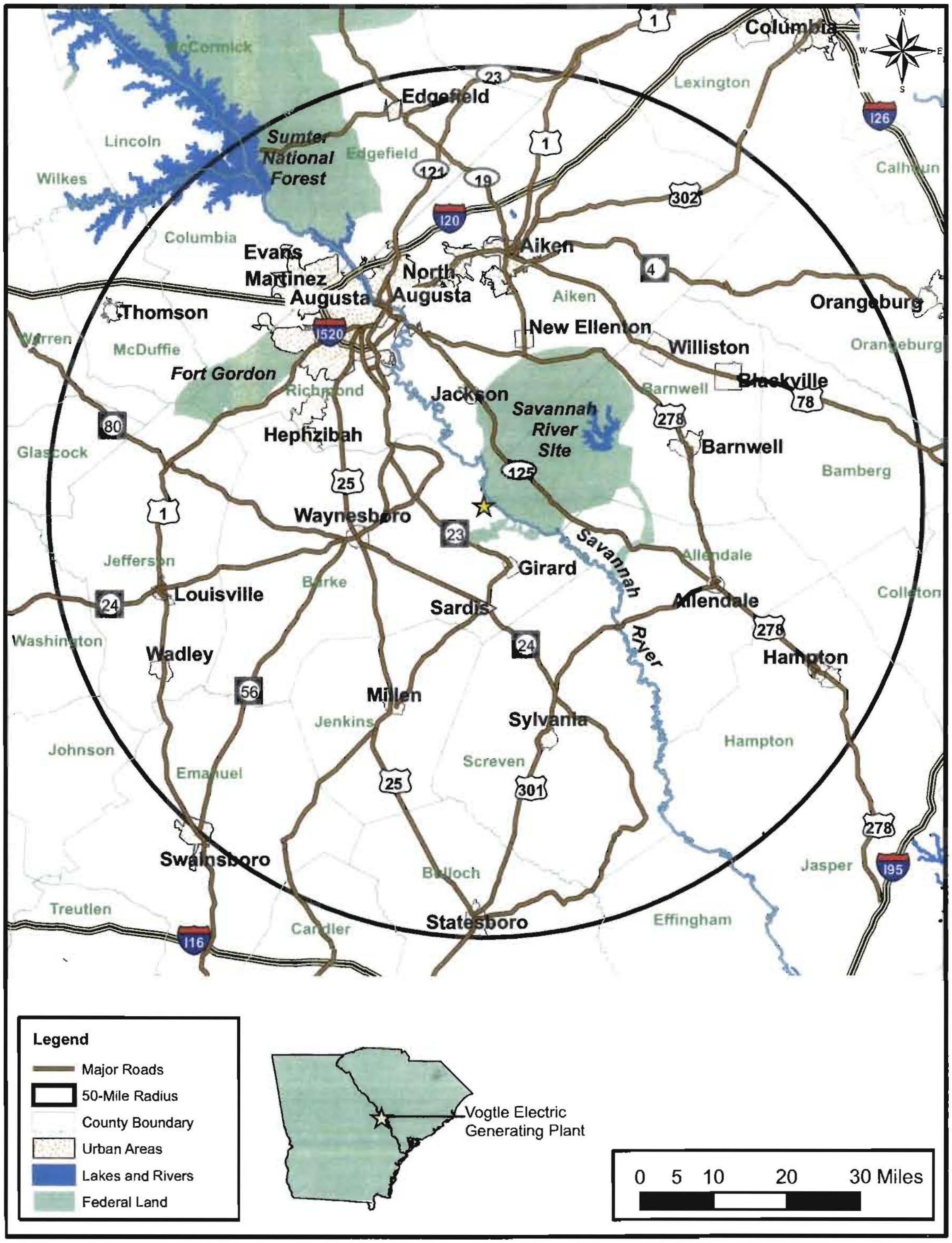

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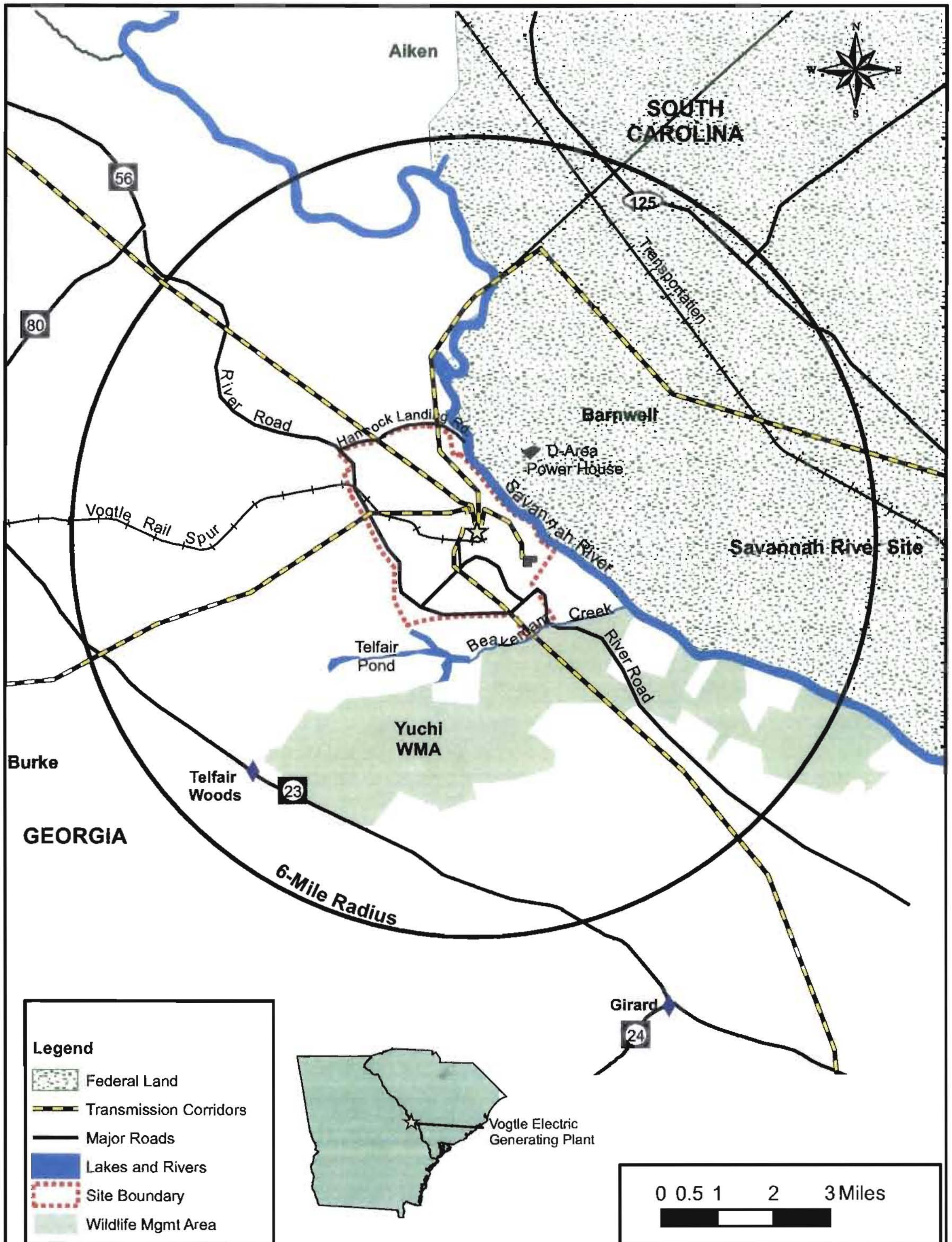

Figure 2.1-2 6-Mile Vicinity

Georgia Department of Natural Resources

Noel Holcomb, Commissioner

Historic Preservation Division

W. Ray Luce, Division Director and Deputy State Historic Preservation Officer
34 Peachtree Street, Suite 1600, Atlanta, Georgia 30303-2316
Telephone (404) 656-2840 Fax (404) 657-1040 http://www.gashpo.org

May 3, 2007

Tom C. Moorer
Environmental Project Manager
Southern Nuclear Operating Company, Inc.
40 Iverness Center Parkway
Birmingham, Alabama 35242

RE: Vogtle Electric Generating Plant Expansion
Burke County, Georgia
HP-060428-001

Dear Mr. Moorer:

The Historic Preservation Division (HPD) has received information submitted concerning the above referenced undertaking. Our comments are offered to assist the Nuclear Regulatory Commission (NRC) and its applicants in complying with provisions of Section 106 of the National Historic Preservation Act of 1966, as amended (NHPA).

Thank you for your coordination letter dated April 3, 2007. As you stated in that letter, you have received our October 4, 2006 letter. Please see that October 4th letter for our comments concerning cultural resources in the subject project's area of potential effect and the report *Intensive Archaeological Survey of the Proposed Expansion Areas at the Vogtle Electric Generating Plant, Burke County, Georgia*, prepared by New South Associates. All of our comments detailed in that letter remain the same. Again, please send us three final copies of the report that include the state site form for each site recorded.

Please refer to project number **HP-060428-001** in any future correspondence regarding this undertaking. If we may be of further assistance, please do not hesitate to contact me at (404) 651-6624, or Michelle Volkema, Environmental Review Specialist, at (404) 651-6546.

Sincerely,

Elizabeth Shirk

Elizabeth Shirk
Environmental Review Coordinator

ES:mav

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ATTACHMENT F

SEVERE ACCIDENT MITIGATION ALTERNATIVES

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ACRONYMS USED IN ATTACHMENT F

ABWR	advanced boiling water reactor
ACCW	auxiliary component cooling water
ADS	automatic depressurization system
AFW	auxiliary feedwater
AMG	accident management guideline
AOP	abnormal operating procedure
AOT	allowed outage time
AOV	air operated valve
ARV	atmospheric relief valve
ATWS	anticipated transient without scram
ATWT	anticipated transient without trip
BMMT	basemat melt through
BWR	boiling water reactor
CB	control building
CC	component cooling
CCF	common cause failure
CCP	centrifugal charging pump
CDF	core damage frequency
CHR	containment heat removal
CR	control room
CRD	control rod drive
CS	containment spray / core spray
CST	condensate storage tank
CT	cooling tower / combustion turbine
CUW	clean-up water
DG	diesel generator
ECCS	emergency core cooling system
ECWS	essential chilled water system
EDG	emergency diesel generator
EOP	emergency operating procedure
EPG	emergency procedure guideline
EPRI	electric power research institute
EPZ	emergency planning zone
ESF	engineered safeguard feature
ESFAS	ESF actuation system
ET	event tree
F&O	fact and observation
FP	fire protection
FPS	fire protection system
FT	fault tree
GE	general emergency
HEP	human error probability
HCLPF	high confidence of low probability of failure
HPCI	high pressure coolant injection
HPI	high pressure injection

ACRONYMS USED IN ATTACHMENT F

HPME	high pressure melt ejection
HPSI	high pressure safety injection
HRA	human reliability analysis
HVAC	heating ventilation and air-conditioning
HX	heat exchanger
IA	instrument air
IPE	individual plant examination
IPEEE	individual plant examination – external events
ISLOCA	interfacing system LOCA
LERF	large early release frequency
LOCA	loss of coolant accident
LOFW	loss of feedwater
LOSP / LOOP	loss of off-site power
LPI	low pressure injection
MAAP	modular accident analysis program
MACCS2	MELCOR accident consequences code system, version 2
MACR	maximum averted cost-risk
MCC	motor control center
MCR	main control room
MD	motor driven
MG	motor generator
MMACR	modified maximum averted cost-risk
MOV	motor operated valve
MR	maintenance rule
MSIV	main steam isolation valve
NCP	normal charging pump
NEI	nuclear energy institute
NPSH	net positive suction head
NRC	U.S. Nuclear Regulatory Commission
NSCW	nuclear service cooling water
OECR	off-site economic cost risk
OL	operating license
OSP	off-site power
PRA	probabilistic risk assessment
PSA	probabilistic safety assessment
PORV	pressure operated relief valve
PWR	pressurized water reactor
PZR	pressurizer
RAT	reserve auxiliary transformer
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCS	reactor coolant system
RDR	real discount rate
RHR	residual heat removal
RHRSW	residual heat removal service water
RLE	review level earthquake

ACRONYMS USED IN ATTACHMENT F

RPV	reactor pressure vessel
RRW	risk reduction worth
RWCU	reactor water clean-up
RWST	refueling water storage tank
SAMA	severe accident mitigation alternative
SBO	station blackout
SERF	small early release frequency
SG	steam generator
SGTR	steam generator tube rupture
SI	safety injection
SIP	safety injection pump
SLC	standby liquid control
SMA	seismic margins assessment
SNC	Southern Nuclear Operating Company
SRP	standard review plan
SRV	safety relief valve
SSC	structures, systems, and components
SSE	safe shutdown earthquake
SV	safety valve
SW	service water
SWGR	switchgear
SWS	service water system
TAF	top of active fuel
TD	turbine driven
TDP	turbine driven pump
TSC	technical support center
VEGP	Vogtle electric generating plant
VF	vessel failure
WOG	Westinghouse owners group

Attachment F
Severe Accident Mitigation Alternatives

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

F.1 METHODOLOGY

The methodology selected for this analysis is based on the Nuclear Energy Institute's (NEI's) SAMA Analysis Guidance Document [NEI 2005] and involves identifying SAMA candidates that have the highest potential for reducing plant risk and determining whether or not the implementation of those candidates is beneficial on a cost-risk reduction basis. The metrics chosen to represent plant risk include the core damage frequency (CDF), the dose-risk, and the off-site economic cost-risk. These values provide a measure of both the likelihood and consequences of a core damage event. The SAMA process consists of the following steps:

- Vogtle Electric Generating Plant (VEGP) Probabilistic Risk Assessment (PRA) Model – Use the VEGP Internal Events PRA model as the basis for the analysis (Section F.2). Incorporate external events contributions as described in Section F.5.1.8.

- Level 3 PRA Analysis – Use VEGP Level 1 and 2 Internal Events PRA output and site-specific meteorology, demographic, land use, and emergency response data as input in performing a Level 3 PRA using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section F.3).

- Baseline Risk Monetization – Use U.S. Nuclear Regulatory Commission (NRC) regulatory analysis techniques to calculate the monetary value of the unmitigated VEGP severe accident risk. This becomes the maximum averted cost-risk (MACR) that is possible (Section F.4).

- Phase I SAMA Analysis – Identify potential SAMA candidates based on the VEGP PRA, Individual Plant Examination – External Events (IPEEE), and documentation from the industry and NRC. Screen out Phase I SAMA candidates that are not applicable to the

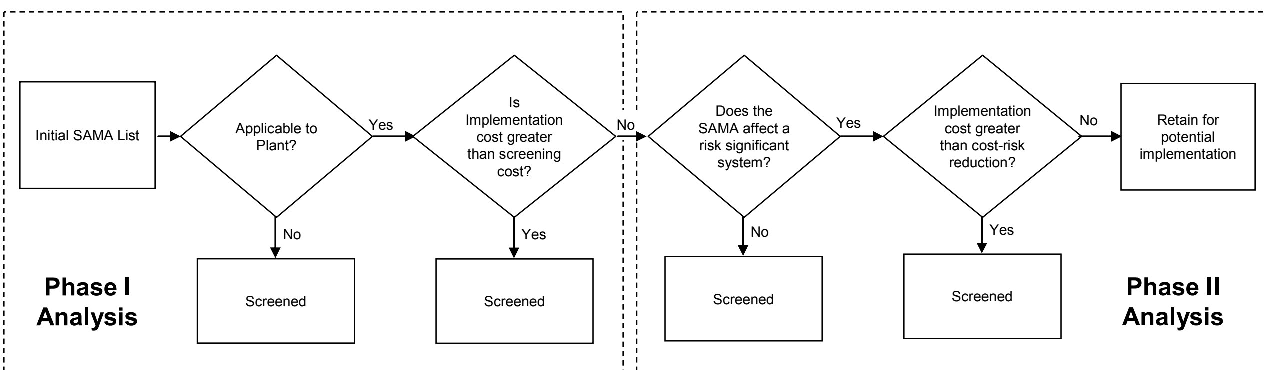
VEGP design or are of low benefit in pressurized water reactors (PWRs) such as VEGP, candidates that have already been implemented at VEGP or whose benefits have been achieved at VEGP using other means, and candidates whose estimated cost exceeds the possible MACR (Section F.5).

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

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

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

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



F.2 VEGP PRA MODEL

Since the VEGP Individual Plant Examination (IPE) [SNC 1992], the VEGP PRA model has been updated periodically and as needed. Table F.2-1 shows the history of VEGP PRA model updates.

The PRA model used for VEGP SAMA Analysis was the VEGPL2UP model. The VEGPL2UP model is based on VEGP PRA model revision 3 which was issued in February 2006.

VEGP PRA Model Revision 3

The VEGP PRA model revision 3 is an at-power, internal events, Level 1 and limited Level 2 (LERF only) model and is the most extensive update of the VEGP PRA model since the IPE. In VEGP PRA model revision 3, all Level 1 PRA tasks from the selection of initiating events to the final quantification were practically re-done in order to reflect the current as-built and as-operated plant configuration, previous operating experiences of the VEGP, and to incorporate new methodologies and data base developed by the NRC and industry. Listed below are the major items updated in VEGP PRA model revision 3.

Resolution of the B Finding & Observations from VEGP PRA peer review by Westinghouse Owners Group (WOG) peers,

Incorporation of plant changes such as design changes and procedure changes made since the last review and incorporation of changes to the end of 2004 (for some, to the latter portion of 2005),

Redefinition/regrouping of the VEGP PRA initiating events definitions (internal events) to better reflect VEGP specific situations using new information available since the VEGP IPE,

Re-development of event trees for VEGP PRA based on VEGP procedures, VEGP specific Modular Accident Analysis Program (MAAP) analyses, and new WOG reports. MAAP analyses for most of the event tree sequences were performed. Station blackout (SBO)was modeled by using 5 different event trees depending on the Reactor Coolant Pump (RCP) seal leak rates and stuck open pressurizer valve. In each SBO event tree, scenarios were developed according to the availability of auxiliary feedwater (AFW) before and after battery depletion, steam generator (SG) depressurization, and the rate of inventory loss (MAAP runs were performed for all these scenarios),

- Development of new fully integrated event tree/fault tree models for interfacing system LOCAs,
- Update of the frequency of VEGP initiating events by Bayesian update using VEGP collected event data from 1995-2004,

- Update of maintenance unavailability of major components using unavailability data collected from the beginning of the implementation of Maintenance Rule to the end of 2004,

- Update of common cause failure (CCF) probabilities using alpha factors from VEGP specific common cause failure analysis,

- Update of human error probabilities (HEPs) using information from the VEGP human reliability analysis (HRA) update using the EPRI HRA Calculator (performed by Scientech) and enhancement of the analysis of dependency among operator actions, and

- Integration of fault tree model and evaluation of core damage frequency (CDF) and large early release frequency (LERF).

Furthermore, all WOG peer review "B" findings (there were no "A" findings for VEGP PRA) were addressed in PRA model revision 3. Table F.2-2 shows how each of the "B" findings was addressed in VEGP PRA model revision 3.

VEGPL2UP PRA Model

In the VEGPL2UP model, which was used for SAMA analysis, a full scope at-power, internal events Level 2 model was developed by directly coupling the Level 1 accident sequences and linked fault trees from the VEGP PRA model revision 3 with newly available Level 2 event trees (NUREG/CR-6595 and WCAP-15341-P). The Level 2 logic in the VEGPL2UP model includes not only LERF logic but also other various Level 2 end states. In addition, the Level 1 linked fault tree models were modified to treat success terms in event trees appropriately.

The linked fault trees for release categories used for SAMA were then constructed by grouping Level 2 end state linked fault trees.

F.2.1 REFINED LEVEL 2 RELEASE CATEGORIES

The initial development of the VEGPL2UP model resulted in five different release categories: INTACT, LERF, SERF, LATE, and LATESGTR. A brief description of these release categories is provided in the table below.

Initial VEGP Level 2 Release Categories

RELEASE CATEGORY	DESCRIPTION
INTACT	Intact Containment: Containment remains intact including accident sequences that do not lead to containment failure in the long term. The release of fission products (and attendant consequences) is determined from the nominal leakage rate for the plant.
LERF	Large Early Release Frequency: This release category includes those scenarios that lead to large and early releases that have the potential for serious offsite health effects. This category includes containment bypass scenarios, early steam generator tube ruptures, early containment failure due to severe accident phenomena scenarios at or near the time of vessel failure, and containment isolation failure scenarios.
SERF	Small Early Release Frequency: This release category is assigned for all potential LERF sequences that have the source term reduced due to some phenomenological means. Currently, no credit is taken for reducing LERF scenarios to non-LERF (or SERF) releases in the VEGP Level 2 model and as such, the SERF is always zero.
LATE	Late Release: This release category is assigned for all sequences in which the containment fails late. Two subdivisions were previously created. The first subdivision was for those sequences that result in containment failure from base-mat melt-through (BMMT) due to concrete attack from molten core debris. The second subdivision was for those sequences that result in containment over-pressurization following loss of containment heat removal.
LATESGTR	Late Steam Generator Tube Rupture (SGTR) Release: This release category is assigned to all long term SGTR scenarios that result in core damage. These cases only result in core damage in the very long time frame after condensate storage tank (CST) depletion results in the unavailability of AFW.

Based on the definitions above and a review of VEGP-specific MAAP results, further subdivisions were provided to account for different phenomenological effects. These phenomenological effects include the availability of long term AFW and the release path (i.e. from containment or from bypass of containment). After implementing these further subdivisions, the table below provides the refined definitions of the release categories.

Refined VEGP Level 2 Release Categories

RELEASE CATEGORY	DESCRIPTION
INTACT	Containment remains intact including accident sequences that do not lead to containment failure in the long term. The release of fission products (and attendant consequences) is determined from the nominal leakage rate for the plant.
LATE-BMMT-AFW	Late containment failure due to base-mat melt-through with long term AFW available.
LATE-BMMT-NOAFW	Late containment failure due to base-mat melt-through with long term AFW not available.
LATE-CHR-AFW	Late containment failure due to late overpressure with containment heat removal unavailable, but with long term AFW available.
LATE-CHR-NOAFW	Late containment failure due to late overpressure with containment heat removal unavailable, and with long term AFW also unavailable.
LATE-SGTR	This release category is assigned to all long term SGTR scenarios that result in core damage.
LERF-BYPASS	This release category is assigned to that subset of LERF bypass scenarios that result from interfacing system LOCA (ISLOCA) initiators.
LERF-ISO	This release category includes those sequences that lead to early release due to an undetected pre-existing or subsequent containment isolation failure.
LERF-CFE	This release category includes those sequences that result in early containment failure due to severe accident phenomena at or near the time of vessel failure. Based on current Level 2 model assumptions these sequences are currently zero, but are included as a separate category for potential sensitivity study investigation.
LERF-SGTR	This release category is assigned to that subset of LERF bypass scenarios that result from early SGTR scenarios.
SERF	This release category is assigned to all early releases that have the source term reduced from LERF due to some phenomenological means. Based on current Level 2 model assumptions these sequences are currently zero, but are included as a separate category for potential sensitivity study investigation.

F.2.2 VEGPL2UP PRA MODEL RESULTS

The CDF structure for use in the Level 2 analysis was re-constructed directly from the Level 1 event tree structure with the success terms incorporated. The previous Vogtle Level 1 base model was not constructed in this way as it does not contain the success branches from the event tree logic in the quantification of the sequence contribution to the CDF total. Consequently the base model CDF is slightly lower (by about 1.5%) than the base model CDF results at the same truncation level. In any event, using a truncation frequency of 5.0E-12, the base model CDF is 1.552E-05 without success branches accounted for, and is 1.529E-05 with success branches accounted for in the quantification process.

The quantification results for the Level 2 analysis using a truncation frequency of 5.0E-12, is 1.548E-05 for all of the release category endstates. The slight increase (by about 1.2%) in the Level 2 model total compared to the Level 1 CDF total with success branches accounted for in the quantification process is due to the generation of additional cutsets that are valid in the Level 2 model, but are non-minimal in the Level 1 model. These cutsets are mostly attributable to the handling of ac power recovered sequences. The table below lists the total for each endstate which is used as the base case results for the VEGP SAMA analysis. Most of the frequency comes from the damage class LATE, which is 98.7% of the total Level 2 frequency. LERF is a distant second with a little more than 1%.

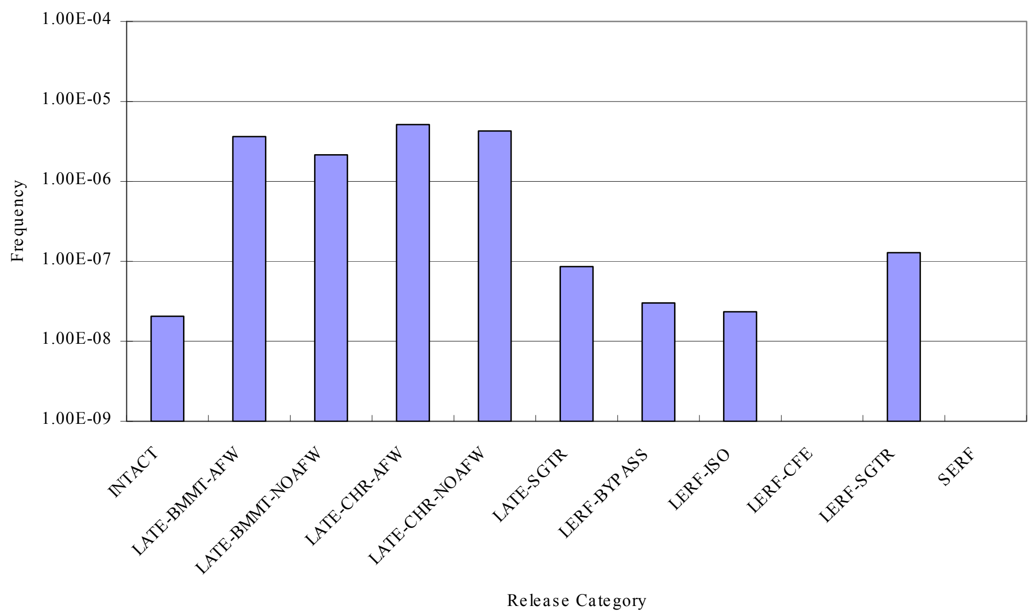
Endstate Frequency Totals

ENDSTATE	FREQUENCY	PERCENT TOTAL
INTACT-TOTAL	2.06E-08	0.1%
LATE-TOTAL	1.53E-05	98.7%
LERF-TOTAL	1.82E-07	1.2%
SERF-TOTAL	0.00E+00	0.0%
TOTAL:	1.55E-05	100.0%

An additional look at the results is provided based on the refined release categories that have been separately defined in support of the SAMA analysis.

The figure below shows the base case results with the refined release category grouping implemented. Note that the LATE category that contributes to about 98.7% of the total has been subdivided into four different categories that are fairly evenly distributed between the four categories. The INTACT contribution of 0.1% does not change since there are no subdivisions included. The LERF category has been subdivided into three contributing (i.e. non-zero) categories with the LERF due to SGTR scenarios comprising about 70% of the LERF total. The

LERF-CFE and SERF categories are zero in the base case model based on the current assumptions in the Level 2 model.



Refined Release Category Contributions

The table which follows provides more details supporting the information in the figure above.

Refined Release Category Frequency Totals

RELEASE CATEGORY	DESCRIPTION	FREQUENCY	PERCENT
INTACT	Containment remains intact	2.06E-08	0.2%
LATE-BMMT-AFW	Late containment failure due to base-mat melt-through with AFW available	3.64E-06	23.5%
LATE-BMMT-NOAFW	Late containment failure due to BMMT with AFW not available	2.15E-06	13.9%
LATE-CHR-AFW	Late overpressure containment failure due to containment heat removal (CHR) unavailable, but with AFW available	5.14E-06	33.2%
LATE-CHR-NOAFW	Late overpressure containment failure due to CHR failure, and with AFW unavailable	4.26E-06	27.5%
LATE-SGTR	Long term SGTR scenarios that result in a late (i.e. beyond 30 hours) core damage scenario	8.59E-08	0.6%
LERF-BYPASS	LERF containment bypass scenarios that result from ISLOCA initiators	3.03E-08	0.2%

Refined Release Category Frequency Totals

RELEASE CATEGORY	DESCRIPTION	FREQUENCY	PERCENT
LERF-ISO	LERF scenarios due to undetected pre-existing or subsequent containment isolation failure	2.34E-08	0.2%
LERF-CFE	LERF sequences with early containment failure due to severe accident phenomena at or near the time of vessel failure	0.00E+00	0.0%
LERF-SGTR	LERF bypass scenarios that result from early SGTR scenarios	1.28E-07	0.8%
SERF	Early releases that have the source term reduced from LERF due to some phenomenological means	0.00E+00	0.0%
Total:	Sum of all of the contributing release categories.	1.55E-05	100.0%

Each of the release categories defined above has an associated consequence as discussed in Section F.3. The base case CDF of 1.55E-05 and the frequencies and doses associated with the different release categories are then used to represent the base case results for the VEGP SAMA analysis. Section F.4 describes how this information is used to determine a baseline risk monetization, and to establish the maximum benefit that could be achieved if all risk for reactor operation were eliminated.

- Section F.5 then provides details of the screening process that was used for Phase I SAMA candidates that are not applicable to the VEGP design or are of low benefit in pressurized water reactors (PWRs) such as VEGP, candidates that have already been implemented at VEGP or whose benefits have been achieved at VEGP using other means, and candidates whose estimated cost exceeds the possible maximum benefit that could be obtained. For all of those SAMA items that remain, changes to the CDF and various release categories for proposed SAMAs are then used in the Phase II cost benefit analysis as described in Section F.6 of this report.

F.3 LEVEL 3 PRA ANALYSIS

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

F.3.1 ANALYSIS

The MACCS2 computer code [NRC 1998] was used to determine two types of consequences of severe accidents: human health consequences in terms of dose and economic consequences in terms of cost for VEGP. For human health impacts, collective dose to the 50-mile population was calculated. Economic costs include the costs associated with short-term relocation of people, decontamination of property and equipment, interdiction of food supplies, land, and equipment use, and condemnation of property.

The MACCS2 code was specifically developed for the NRC to evaluate severe accidents at nuclear power plants. It primarily addresses the air pathway, but it does calculate dose from runoff and deposition on surface water. The exposure pathways modeled include external exposure to the passing plume, external exposure to material deposited on the ground and skin, inhalation of material in the passing plume and re-suspended from the ground after deposition, and ingestion of contaminated food and surface water.

The input parameters given with the MACCS2 “Sample Problem A”, which include the COMIDA2 food model [NRC 1989] formed the basis for the present analysis. These generic values were supplemented with parameters specific to VEGP and the surrounding area. Site-specific data included population distribution, economic parameters, and agricultural production. Parameters descsribing the costs of evacuation, relocation and decontamination were escalated from the time of their formulation (1986) to represent more recent (2006) costs. Plant-specific release data included the time-activity distribution of radionuclides and release frequencies. The modeled behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points (i.e., declaration of a general emergency) and evacuation time estimates [IEM 2006]. These data were then used in combination with site specific meteorology to simulate the probability distribution of impact risks (exposure and economic) to the surrounding population (within 50 miles) from the representative accident sequences at VEGP.

F.3.2 POPULATION

The population distribution was based on the 2000 census as accessed by SECPOP2000 [NRC 2003]. The baseline population was determined for each of the sixteen directions and each of ten concentric distance rings with outer radii at 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles surrounding the site. The transient population within 10 miles of the site was included. County growth rates were applied to estimate the population at the year 2040.

F.3.3 ECONOMY AND AGRICULTURE

MACCS2 requires the spatial distribution of certain agriculture and 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 again done by applying the SECPOP2000 program, changing the regional economic data format to comply with MACCS2 input requirements. In this case, SECPOP2000 was used to access data from the 1997 National Census of Agriculture. The program's specification of crop production parameters for the 50-mile region (e.g., fraction of farmland devoted to grains, vegetables, etc.) was also applied.

In addition, generic economic data that are applied to the region as a whole were revised from the MACCS2 sample problem input in order to account for cost escalation since 1986, the year that input was first specified. A factor of 1.84, representing cost escalation from 1986 to 2006 was applied to parameters describing cost of evacuating and relocating people, land decontamination, and property condemnation.

F.3.4 RADIONUCLIDE RELEASE

Three aspects need to be considered regarding the radionuclide release for use with MACCS2. The three relevant pieces of information are the initial core inventory, the magnitude and timing of releases for each release category, and the elevation of the releases. Each of those aspects is described below. The radionuclide release information is then combined with the population data (see Section F.3.2), the economy and agriculture information (see Section F.3.3), the evacuation information (see Section F.3.5), and the meteorological information (see Section F.3.6) to determine the sum of the exposure (50-mile dose) and economic (50-mile economic costs) risks from each chosen representative accident sequence. The dose and economic cost data are then combined with the calculated frequencies for each release category to determine the overall annualized risk as described in Section F.3.7.

The first aspect is to consider the initial core inventory. The core inventory corresponds to the end-of-cycle values for VEGP operating at 3,565 MWt, as determined by the ORIGEN code. A scaling factor of 1.02 was then applied to represent operation at 3,636 MWt. The table below gives the estimated VEGP core inventory.

Estimated VEGP Core Inventory

NUCLIDE	CORE INVENTORY (CURIES)	NUCLIDE	CORE INVENTORY (CURIES)	NUCLIDE	CORE INVENTORY (CURIES)
Co-58	9.28E+05	Ru-103	1.61E+08	Cs-136	5.84E+06
Co-60	7.10E+05	Ru-105	1.09E+08	Cs-137	9.91E+06
Kr-85	9.08E+05	Ru-106	4.76E+07	Ba-139	1.81E+08
Kr-85m	2.64E+07	Rh-105	9.74E+07	Ba-140	1.81E+08
Kr-87	4.83E+07	Sb-127	9.81E+06	La-140	1.86E+08
Kr-88	6.89E+07	Sb-129	3.31E+07	La-141	1.67E+08
Rb-86	2.74E+05	Te-127	9.64E+06	La-142	1.62E+08
Sr-89	9.68E+07	Te-127m	1.49E+06	Ce-141	1.69E+08
Sr-90	7.36E+06	Te-129	3.12E+07	Ce-143	1.55E+08
Sr-91	1.19E+08	Te-129m	8.52E+06	Ce-144	1.21E+08
Sr-92	1.28E+08	Te-131m	1.54E+07	Pr-143	1.52E+08
Y-90	4.99E+06	Te-132	1.44E+08	Nd-147	6.59E+07
Y-91	1.25E+08	I-131	1.01E+08	Np-239	2.07E+09
Y-92	1.28E+08	I-132	1.47E+08	Pu-238	3.40E+05
Y-93	1.49E+08	I-133	2.06E+08	Pu-239	3.20E+04
Zr-95	1.72E+08	I-134	2.21E+08	Pu-240	3.70E+04
Zr-97	1.72E+08	I-135	1.91E+08	Pu-241	9.36E+06
Nb-95	1.73E+08	Xe-133	2.02E+08	Am-241	6.80E+03
Mo-99	1.86E+08	Xe-135	4.56E+07	Cm-242	2.76E+06
Tc-99m	1.61E+08	Cs-134	2.18E+07	Cm-244	3.29E+05

Source: SNC 2006 except cobalt inventories based on PWR inventory in MACCS2 sample problem A multiplied by 3636/3412 (the VEGP SAMA power level divided by the sample problem A power level).

VEGP nuclide release categories, as determined by the MAAP computer code, were then related to the MACCS2 categories as shown below.

MACCS2 Release Categories versus VEGP MAAP Release Categories

MACCS RELEASE CATEGORIES	VEGP RELEASE CATEGORIES
Xe/Kr	1 – noble gases
I	2 – CsI
Cs	2 & 6 – CsI and CsOH
Te	3 & 11- TeO_2 & Te_2
Sr	4 – SrO
Ru	5 – MoO_2 (Mo is in Ru MACCS category)
La	8 – La_2O_3
Ce	9 – CeO_2 & UO_2
Ba	7 – BaO
Sb (supplemental category)	10 – Sb

The second aspect is to consider the magnitude and timing of the radionuclide releases. Multiple release duration periods were defined which represented the time distribution of each category's releases. Release inventories of each of the multiple chemical forms of the Cs and Te releases were available from the MAAP code output. Representative MAAP cases for each of the release categories were chosen based on a review of the Level 2 model cutsets and the dominant types of scenarios that contributed to the results. A brief description of each of those MAAP cases is provided in Table F.3.1, and a summary of the release magnitude and timing for those cases is provided in Table F.3.2.

The third aspect of the release that has to be considered is the elevation of the release. At VEGP, the containment building has an outside diameter of 147.5 feet and a height of 231.75 feet. The auxiliary building, from which the two SGTR sequence nuclides are released, has a minimum width of 124 feet and a height of 46 feet. All releases were modeled as occurring at ground level. The thermal content of each of the releases was assumed to be the same as ambient, i.e., buoyant plume rise was not modeled. Each of these assumptions was considered in sensitivity analyses, presented in Section F.7.3 of this report.

F.3.5 EVACUATION

Reactor trip for each sequence was taken as time zero relative to the core containment response times. A general emergency (GE) is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public; it was assumed here that the declaration would coincide with the onset of core damage. In addition to the magnitude and timing of the relapses for each category, Table F.3.2 also shows the resulting declaration times.

The MACCS2 user's guide input parameters of 95 percent of the population within 10 miles of the plant emergency planning zone (EPZ) evacuating and 5 percent not evacuating were employed. These values have been used in similar studies [NRC 1999 and SNC 2000] and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the Emergency Planning Zone [NRC 1989].

The evacuees are assumed to begin evacuating 42 minutes [IEM 2006; 95 percent mobilization] after a general emergency has been declared at an evacuation radial speed of 2.20 m/sec. This speed is derived from the time to evacuate the entire EPZ under adverse weather conditions for the year 2010, the year of the evacuation study. The evacuation speed was projected to year 2040 conditions by conservatively assuming that all of the roads in 2010 transported traffic at their maximum throughput and that no new roads would be constructed (although the roads would be maintained at 2010 conditions). The 2040 evacuation speed was then the 2010 speed multiplied by the ratio of 2010 to 2040 EPZ (10-mile) populations. That estimated 2040 evacuation speed, 2.20 m/sec, was used in the risk analysis. The evacuation speed was considered further in the sensitivity analyses presented in Section F.7.3 of this report.

F.3.6 METEOROLOGY

Validated annual sequential hourly meteorology onsite data sets from 1998 through 2002 were investigated for use in MACCS2. Respectively, 1.4, 1.0, 1.9, 4.6 and 7.4% of the hourly data points of interest (10-meter wind speed, 10-meter wind direction, multi-level temperatures used to simulate stability class, and precipitation) were missing for those years. Data gaps were filled in (in order of preference) by using corresponding data from another level (taking the relationship between the levels as determined from immediately preceding hours), interpolation (if the data gap was less than 4 hours), and using data from the same hour and a nearby day of a previous year.

The 1999 data set was found to result (see subsequent discussion of sensitivity analysis) in the largest dose and economic cost risk. Given that it was also the most complete data set, the 1999 hourly sequential meteorology was used to create the one-year sequential hourly data set used in the baseline MACCS2 runs. Ten-meter wind speed and direction were combined with precipitation and atmospheric stability (specified according to the vertical temperature gradient as measured between the 60- and 10-meter levels) to create the hourly data. Hourly stability was classified according to the scheme used by the NRC [NRC 1983].

Atmospheric mixing heights were specified for AM and PM hours for each season of the year. These values ranged from 280 meters for fall AM to 1800 meters for summer PM [EPA 1972].

F.3.7 MACCS2 RESULTS

The resulting annual risk from the analyzed VEGP releases is provided in the table which follows. The largest dose and economic consequences (i.e., assuming the event takes place) is from the LERF-BYPASS scenario. All of the noble gases and almost all of the iodine and cesium are released shortly after a general emergency is declared for this sequence. As such, it closely represents a bounding accident scenario. Any scenario (e.g., beyond design basis external event initiators) not encompassed by the sequences analyzed here would be expected to have impacts (i.e., dose and costs) not significantly greater than those presented here. Although the risk from the analyzed high consequence sequences such as LERF-BYPASS and LERF-SGTR are ameliorated by their small frequency of occurrence, beyond design basis external events will likely have similar frequencies.

MACCS2 Results for VEGP by Release Category

Release Category	Annual Frequency	Population Dose Risk (person-rem/yr) (0-50 miles)	Total Economic Cost Risk ($/yr) (0-50 miles)
INTACT	2.06E-08	7.89E-05	$0
LATE-BMMT-AFW	3.64E-06	5.24E-02	$15
LATE-BMMT-NOAFW	2.15E-06	1.81E-01	$58
LATE-CHR-AFW	5.14E-06	8.27E-02	$45
LATE-CHR-NOAFW	4.26E-06	1.66E-01	$123
LATE-SGTR	8.59E-08	2.09E-01	$446
LERF-BYPASS	3.03E-08	1.84E-01	$215
LERF-ISO	2.34E-08	1.94E-02	$47
LERF-CFE	0.00E+00	0.00E+00	$0
LERF-SGTR	1.28E-07	3.37E-01	$776
TOTAL	1.55E-05	1.54	$1,725

In summary, the annual (i.e. multiplying the above numbers by one year) baseline population dose risk within 50 miles of VEGP is calculated to be 1.54 person-rem and the total annual economic risk is calculated to be $1,725.

F.4 BASELINE RISK MONETIZATION

This section explains how Southern Nuclear Operating Company (SNC) calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). SNC also used this analysis to establish the maximum benefit that could be achieved if all risk for reactor operation were eliminated.

F.4.1 OFF-SITE EXPOSURE COST

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

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

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 (RDR) (as fraction) = 0.03 per year. Note that a value of 0.03 instead of a 0.07 value that is recommended in the NEI guidance [NEI 2005] is assumed for the base case assessments based on recently experienced inflation rates which provide more reasonable estimates of future expectations. This should provide conservative results compared to the use of a 0.07 value. Sensitivity to this assumption is explored by using a 0.07 value for this parameter in Section F.7.1.
Z_{pha}	=	monetary value of public health (accident) risk per year before discounting ($ per year)

The Level 3 analysis showed an annual off-site population dose risk of about 2.04 person-rem. The calculated value for C using 20 years and a 3 percent discount rate is approximately 15.04. Therefore, calculating the discounted monetary equivalent of accident dose-risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (15.04). The calculated off-site exposure cost is estimated to be $61,362.

F.4.2 OFF-SITE ECONOMIC COST RISK

The Level 3 analysis showed an annual off-site economic risk of $1,412. 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 $21,236.

F.4.3 ON-SITE EXPOSURE COST RISK

Occupational health was evaluated using NRC methodology that involves separately evaluating immediate and long-term doses [NRC 1997].

For immediate dose, NRC recommends using the following equation:

Equation 1:

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

Where:

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

R = monetary equivalent of unit dose ($2,000 per person-rem)

F = accident frequency (1.55E-05 events per year)

D_{IO} = immediate occupational dose [3,300 person-rem per accident (NRC estimate)]

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

$_A$ = subscript denoting after implementation of proposed action

r = RDR (0.03 per year)

t_f = years remaining until end of facility life (20 years).

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

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

$$= 2{,}000 * 1.55\text{E-}05 * 3{,}300 * \{[1 - \exp(-0.03 * 20)]/0.03\}$$

$$= \$1{,}539$$

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

Equation 2:

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

Where:

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

D_{LTO} = long-term dose [20,000 person-rem per accident (NRC estimate)]

m = years over which long-term doses accrue (as long as 10 years)

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

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

= $2{,}000 * 1.55E\text{-}05 * 20{,}000 * \{[1 - \exp(-0.03*20)]/0.03\} * \{[1 - \exp(-0.03*10)]/(0.03*10)\}$

= $8,056

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

W_O = $W_{IO} + W_{LTO}$ = ($1,539 + $8,056) = $9,595

F.4.4 ON-SITE CLEANUP AND DECONTAMINATION COST

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

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

Where:

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

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

r = RDR (0.03 per year)

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

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

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

Where:

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

r = RDR (0.03)

t_f = 20 years (license renewal period)

The resulting net present value of cleanup integrated over the license renewal term, $1.95E+10, must be multiplied by the total CDF (1.55E-05) to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is $302,094.

F.4.5 REPLACEMENT POWER COST

Long-term replacement power costs were determined following NRC methodology in NUREG/BR-0184 [NRC 1997]. The net present value of replacement power for a single event, PV_{RP}, was determined using the following equation:

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

Where:

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

r = RDR (0.03)

t_f = 20 years (license renewal period)

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

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

Where:

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

After applying a correction factor to account for VEGP size relative to the generic reactor described in NUREG/BR-0184 (i.e., 1215 megawatt electric/910 megawatt electric) the replacement power costs are determined to be 7.38E+09 ($-year). Multiplying this value by the CDF (1.55E-05) results in a replacement power cost of $114,350.

F.4.6 TOTAL COST RISK

The total cost risk represents the maximum averted cost risk if all risks were eliminated. The sum of the baseline costs for the on-line internal events contributions is as follows:

Off-site exposure cost	=	$61,362
Off-site economic cost	=	$21,236
On-site exposure cost	=	$9,595
On-site cleanup cost	=	$302,094
Replacement Power cost	=	$114,350
Total cost	=	$508,637

The MACR based on on-line internal events contributions, which is rounded to next highest thousand ($509,000) for SAMA calculations.

As described in Section F.5.1.8, the internal events MACR is doubled to account for external events contributions. The resulting modified MACR (MMACR) is $1,018,000 and was used in the Phase I screening process.

F.5 PHASE I SAMA ANALYSIS

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

F.5.1 SAMA IDENTIFICATION

The initial list of SAMA candidates for VEGP was developed from a combination of resources including:

- Current VEGP PRA results
- Industry Phase II SAMAs
- VEGP IPE [SNC 1992]
- VEGP IPEEE [SNC 1995]

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

In addition to the "Industry Phase II SAMA" review identified above, an industry based SAMA list was used in a different way to aid in the development of the VEGP specific SAMA list. While the industry SAMA review cited above was used to identify SAMAs that might have been overlooked in the development of the VEGP SAMA list due to PRA modeling issues, a generic SAMA list was used as an idea source to identify the types of changes that could be used to address the areas of concern identified through the VEGP importance list review. For example, if long term dc power availability was determined to be an important issue for VEGP, the industry list would be reviewed to determine if a plant enhancement had already been conceived that would address Vogtle's needs. If an appropriate SAMA was found to exist, it would be used in the VEGP list to address the dc power issue; otherwise, a new SAMA would be developed that would meet the site's needs. This generic list was compiled as part of the development of several industry SAMA analyses and has been provided as Table A-1 of Addendum 1 to this attachment for reference purposes.

F.5.1.1 LEVEL 1 VEGP IMPORTANCE LIST REVIEW

The VEGP PRA was used to generate a list of events sorted according to their risk reduction worth (RRW) values. The top events in this list are those events that would provide the greatest reduction in the VEGP CDF if the failure probability were set to zero. The events were reviewed down to the 1.02 level, which corresponds to about a 2.0 percent change in the CDF given 100 percent reliability of the event. If the dose-risk and off-site economic cost-risk were also assumed to be reduced by a factor of 1.02, the corresponding averted cost-risk would be approximately $9,974. Applying a factor of 2 to estimate the potential impact of external events (refer to Section F.5.1.8); the result is about $19,948. This is less than what is considered to be the lower end of implementation costs for potential plant changes, especially given that this estimate is based on complete reliability of the proposed change. The lower end of the cost of implementation for a SAMA is based on the cost of a procedural change, which has been estimated to be about $50,000 [CPL 2004]. No further review of the importance listing was performed below the 1.02 level. Table F.5-1 documents the disposition of each event in the Level 1 VEGP RRW list with RRW values of 1.02 or greater.

F.5.1.2 LEVEL 2 VEGP IMPORTANCE LIST REVIEW

A similar review was performed on the importance listings from the Level 2 results. In this case, a composite file based on the top 81 percent of all dose-risk was used to identify potential SAMAs. The composite file was composed of the results from the ISLOCA, SGTR, Early Containment Failure, and Late CHR failure release categories. This method was chosen to prevent high frequency-low consequence events from dominating the importance listing.

The Level 2 RRW values were reviewed down to the 1.02 level. As described for the Level 1 RRW list, events below the 1.02 threshold value are estimated to yield an averted cost-risk less than $19,948 and are not considered to be likely candidates for identifying cost effective SAMAs. As such, the events with RRW values below 1.02 were not reviewed. Table F.5-2 documents the disposition of each event in the composite Level 2 VEGP RRW list with RRW values greater than 1.02.

F.5.1.3 INDUSTRY SAMA ANALYSIS REVIEW

The SAMA identification process for VEGP is primarily based on the PRA importance listings, the IPE, and the IPEEE. In addition to these plant-specific sources, selected industry SAMA submittals were reviewed to identify any Phase II SAMAs that were determined to be potentially cost beneficial at other plants. These SAMAs were further analyzed and included in the VEGP SAMA list if they were considered to be potentially cost beneficial for VEGP.

While many of these SAMAs are ultimately shown not to be cost beneficial, some are close contenders and a small number have been estimated to be cost beneficial at other plants. Use of the VEGP importance ranking should identify the types of changes that would most likely be cost beneficial for VEGP, but review of selected industry Phase II SAMAs may capture potentially important changes not identified for VEGP due to PRA modeling differences or SAMAs that represent alternate methods of addressing risk. Given this potential, it was considered prudent to include a review of selected industry Phase II SAMAs in the VEGP SAMA identification process.

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

- V.C. Summer [SCE 2002]
- Farley [SNC 2003]
- Palisades [NMC 2005]
- Wolf Creek [WCN 2006]
- Pilgrim [ENT 2006]
- Susquehanna [PPL 2006]

Four PWR and two boiling water reactor (BWR) sites were chosen from available documentation to serve as the Phase II SAMA sources. Few of the Phase II SAMAs from these sources were included in the initial VEGP SAMA list. Many of the industry Phase II SAMAs were already represented by other SAMAs in the VEGP list, were known not to impact important plant systems, or were judged not to have the potential to be close contenders for VEGP.

These SAMAs were not considered further. The following provides a summary of some of the issues considered during the review of the industry SAMAs.

F.5.1.3.1 V.C. Summer

V.C. Summer used a generic SAMA list as its starting point similar to that used at most other sites. Some of the SAMAs included in the Phase II list were, however, related to important issues at Vogtle. One SAMA provided a potentially cost beneficial means of preventing seal LOCAs:

V.C. Summer SAMA 3 – This SAMA suggests using the hydrostatic test pump as an alternate means of providing seal injection. Since seal LOCAs are very important for Vogtle, this idea has been added to the VEGP SAMA list (SAMA 11).

Another SAMA included a change related to ISLOCAs not included in the other Phase II SAMA lists:

V.C. Summer SAMA 12 - This SAMA suggested that the plant ensure all ISLOCA releases are scrubbed. This is an unconventional approach that was added for inclusion on the VEGP SAMA list since containment bypass events contribute to about 10% of the total dose for Vogtle (SAMA 12).

One additional SAMA was deemed as potentially useful for Vogtle:

V.C. Summer SAMA 24 - This SAMA suggested that an automatic swap over to recirculation on refueling water storage tank (RWST) depletion be implemented. Since this function is only partially automated at Vogtle, this idea has also been added to the VEGP SAMA list (SAMA 13).

F.5.1.3.2 Farley

While a generic SAMA list similar to the one used for V.C. Summer was used in the Farley SAMA submittal, two items of note were passed to the Phase II list related to important issues for VEGP. The first item was the consideration of using the existing hydro test pump for RCP seal Injection. This idea is redundant to V.C. Summer SAMA 3 described above, however, which has been added as SAMA 11 for VEGP. The second item of interest related to ISLOCAs:

Farley SAMA 89 – This SAMA suggested installation of additional instrumentation for ISLOCAs. This idea was added to the VEGP SAMA list since containment bypass events contribute to about 10% of the total dose for Vogtle (SAMA 14).

F.5.1.3.3 Palisades

This analysis relied on a generic SAMA list and few plant specific insights were available that might pertain specifically to Westinghouse PWRs. Two SAMAs were passed to the Phase II list for Palisades that could also be beneficial for Vogtle. Palisades SAMA 3 referred to the installation of a direct drive diesel injection pump. This is very similar to the previously identified SAMA 1 (permanent self-powered pump to back up NCP) for VEGP and no additional SAMAs are suggested from this item. Palisades SAMA 10 referred to the installation of a power independent turbine driven AFW. This is similar to the previously identified SAMA 5 (permanent dedicated generator for one motor driven AFW pump) for VEGP and no additional SAMAs are suggested from this item. Based on these considerations, these items were not included in the VEGP SAMA list.

F.5.1.3.4 Wolf Creek

Wolf Creek's SAMA list is based on an industry SAMA list similar to those used by V.C. Summer, Farley, and Palisades. The similarity of design compared to Vogtle was also deemed important in reviewing the SAMAs identified for Wolf Creek. There were several items that were identified that could also be beneficial for Vogtle.

Wolf Creek SAMA 1 – This SAMA suggested installation of a permanent dedicated generator for the NCP. This is deemed to be redundant to existing SAMA 1 for Vogtle for a permanent self-powered pump to back up the normal charging pump (NCP) system. However, since this provides a slightly alternative design method, this idea has also been added to the VEGP SAMA list (SAMA 15).

Wolf Creek SAMA 3 – This SAMA suggested implementation of ac cross-tie capability. This is very similar to the previously identified SAMA 4 (opposite unit AC-cross-tie capability) for VEGP and no additional SAMAs are suggested from this item.

Wolf Creek SAMA 4 – This SAMA suggested alternate means for ISLOCA isolation by replacing existing valves or enhancing procedures. The procedure enhancement idea was added to the VEGP SAMA list since containment bypass events contribute to about 10% of the total dose for Vogtle (SAMA 16).

Wolf Creek SAMA 7 – This SAMA indicated implementation of manual recirculation with auto initiation failure. Procedures already exist at Vogtle to provide guidance to accomplish switchover from injection to recirculation manually if the automatic actuation of the sump valve is unsuccessful. Switchover from injection to recirculation and coping with the failure to switchover is a key operator action modeled in the PRA. However, since this item is only partially automated at VEGP (it does not include the charging and safety injection (SI) pumps), complete automation of this function has also been added to the VEGP SAMA list (SAMA 13) based on the V.C. Summer SAMA 24 discussion provided above.

Wolf Creek SAMA 14 – This SAMA suggested a permanent dedicated generator for the NCP and motor driven AFW. Similar ideas are already considered for VEGP in SAMA 1 (permanent self-powered pump to back up NCP) and SAMA 5 (permanent dedicated generator for one motor driven AFW pump) and no additional SAMAs are suggested from this item.

F.5.1.3.5 Pilgrim

The Pilgrim Phase II SAMA list, while based on an industry SAMA list similar to those for the PWRs examined as part of this task, mostly included BWR specific issues or items that have already been included for Vogtle such as dedicated pumps, alternate power sources, or enhancing cross-tie capabilities. Therefore, there were no additional SAMA items added to the VEGP list from the review of the Pilgrim Phase II SAMA list.

F.5.1.3.6 Susquehanna

Of the Phase II SAMAs considered for Susquehanna, only a limited number were found to be potentially applicable to VEGP. One such SAMA was Phase II SAMA 2, which suggests improving the 4kV ac cross-tie capabilities. This item has already been identified for VEGP as SAMA 4 (Improve opposite unit ac cross-tie capabilities). Susquehanna SAMA 6 suggested procurement of a spare 480V ac portable station generator to support 480V loads to ensure long term availability of the battery chargers. This is very similar to the previously identified

SAMA 5 (permanent dedicated generator for one motor driven AFW pump) for VEGP and no additional SAMAs are suggested from this item. Based on these considerations, these items were not included in the VEGP SAMA list.

F.5.1.3.7 Industry SAMA identification Summary

Important issues for VEGP are addressed by the SAMAs developed through the PRA importance list review. The plant changes suggested as part of that review were developed to meet the specific needs of the plant such that those SAMAs are more likely to provide effective means of risk reduction than SAMAs taken from other sites. However, a review of the SAMA analysis submittals from six other sites did result in the identification of additional SAMA candidates which address important safety functions. As the approaches taken to reduce risk by these SAMAs are credible alternatives to those based on the importance list review, they were included for consideration:

SAMA 11: Use the hydrostatic test pump as an alternate means of providing seal injection (V.C. Summer, Farley)

SAMA 12: Ensure all ISLOCA releases are scrubbed (V.C. Summer)

SAMA 13: Completely automate swap over to recirculation on RWST depletion (V.C. Summer, Wolf Creek)

SAMA 14: Install additional instrumentation for ISLOCA detection (Farley)

SAMA 15: Install permanent dedicated generator for NCP (Wolf Creek)

SAMA 16: Enhance procedures for ISLOCA response (Wolf Creek)

F.5.1.4 VEGP IPE

The VEGP IPE [SNC 1992] generated a list of risk-based insights and potential plant improvements. Typically, changes identified in the IPE process are implemented and closed out; however, there are some items that are not completed within the industry due to high projected costs or other criteria. Because the criteria for implementation of a SAMA may be different than what was used in the post-IPE decision-making process, these recommended improvements are re-examined in this analysis.

While the IPE concluded that there were no vulnerabilities at VEGP, three potential plant improvements were identified and considered for implementation at the plant. The following table summarizes the status of these plant improvements.

Improvement Considered	VEGP Status	Included On VEGP SAMA List?
1. Opening of dc power room doors on loss of control building ESF electrical HVAC (either CBHVAC fan or NSCW and ECWS). Procedures have been implemented which call for locally opening the doors to the important electrical rooms because of loss of cooling. When the doors are opened, natural circulation will provide sufficient cooling (Temperatures<130°F) and 125V dc power will remain available for use during an accident situation.	Implemented	No, already implemented.
2. Manual control of AFW turbine-driven pump during a loss of all ac power and dc power. Procedures are in place for operating the TD AFWP manually. Additionally, the loss of all ac power procedure has been enhanced to direct the control room to dispatch an operator to attempt local manual operation of the TDAFWP upon loss of dc power	Implemented	No, already implemented.
3. Establishment of one NSCW pump operation on a loss of NSCW initiating event. The current Loss of NSCW Abnormal Operating Procedure (AOP) has been revised so that a loop between the loss of NSCW AOP and the loss of ACCW AOP does not occur. In addition, instructions are provided to reduce ACCW loads to keep the RCP seals cooled and to establish one-pump NSCW operation similar to that performed in a similar procedure during shutdown. After establishment of one-pump NSCW operation, the procedure can return a centrifugal charging pump to service to provide makeup and seal injection.	Implemented	No, already implemented.

Given that all three improvements were completed, they have not been added to the VEGP SAMA list.

F.5.1.5 VEGP IPEEE

Similar to the IPE, there may be a number of proposed plant changes that were previously rejected based on non-SAMA criteria that should be re-examined. In addition, there may be issues that are in the process of being resolved, which could be important to the disposition of some SAMAs. The IPEEE was used to identify these items. There were 24 equipment open items for each unit, mostly seismic interaction issues. They included a gap between the battery rack end rails and batteries, potential interactions between the diesel generators and crane controller, etc. All of these issues have been addressed as documented in a letter to the NRC dated March 31, 1998 [SNC 1998].

An effort was also made to use the IPEEE to develop new SAMAs based on a review of the original results. However, the VEGP IPEEE was not maintained as a "living" analysis. This limits the capability of the models that make up the IPEEE as they do not include the latest PRA practices nor do they necessarily represent the current plant configuration or operating characteristics. The fact that the models are not currently in a quantifiable state presents further difficulty because the results are limited to what has been retained from the original analysis. These factors limit the qualitative insights and quantitative estimates that can be made with regard to external events contributors.

On a larger scale, given that the industry has generally not pursued external events modeling at a level consistent with internal events models, the technology for external events analysis is not as robust or refined. The result is that the CDF values yielded by the internal and external events models are not necessarily comparable. External events models are considered to be useful tools for identifying important accident sequences and mitigative equipment, but the quantitative results should not be directly combined with those from the internal events models. In this analysis, external events contributions are estimated for the reasons described above.

F.5.1.6 USE OF EXTERNAL EVENTS IN THE VEGP SAMA ANALYSIS

The IPEEE was used in the VEGP SAMA analysis primarily to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences. The types of events considered in the VEGP external events analysis included:

- Internal Fires (Section F.5.1.6.1)

- Seismic Events (Section F.5.1.6.2)
- High Wind Events, External Flooding, Transportation and Nearby Facility Accidents, and Other External Hazards (Section F.5.1.6.3)

Due to limitations of the external events modeling processes, the results of these kinds of analyses are not necessarily compatible with those of the internal events analysis. As a result, each of the external event contributors must be considered in a manner suiting the type of analysis performed. A summary of the review process used to identify SAMAs is provided for each of the external event types listed above followed by a description of the method used to quantitatively incorporate external events contributions into the SAMA analysis.

F.5.1.6.1 Internal Fires

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

In general, fire PRAs are useful tools to identify design or procedural items that could be clear areas of focus for improving the safety of the plant. Fire PRAs use a structure and quantification technique similar to that used in the internal events PRA. Since less attention historically has been paid to fire PRAs, conservative modeling is common in a number of areas of the fire analysis to provide a "bounding" methodology for fires. This concept is contrary to the base internal events PRA, which has had more analytical development and is judged to be closer to a realistic assessment (i.e., best estimate) of the plant. There are a number of fire PRA topics involving technical inputs, data, and modeling that prevent the effective comparison of the CDF between the internal events PRA and the fire PRA. These areas are identified as follows:

PRA Topic	Comment
Initiating Events:	The frequency of fires and their severity are generally conservatively overestimated. A revised NRC fire events database indicates the trend toward lower frequency and less severe fires. This trend reflects the improved housekeeping, reduction in transient fire hazards, and other improved fire protection (FP) steps at plants.
System Response:	FP measures such as sprinklers, CO_2, and fire brigades may be given minimal (conservative) credit in their ability to limit the spread of a fire.
Sequences:	Sequences may subsume a number of fire scenarios to reduce the analytic burden. The subsuming of initiators and sequences is done to envelope those sequences included. This results in additional conservatism.
Fire Modeling:	Fire damage and fire spread are conservatively characterized. Fire modeling presents bounding approaches regarding the immediate effects of a fire (e.g., all cables in a tray are always failed for a cable tray fire) and fire propagation.
HRA:	There is little industry experience with crew actions under conditions of the types of fires modeled in fire PRAs. This has led to conservative characterization of crew actions in fire PRAs. Because the CDF is strongly correlated with crew actions, this conservatism can have a profound effect on the calculated fire PRA results.
Level of Detail:	The fire PRAs may have reduced level of detail in the mitigation of the initiating event and consequential system damage.
Quality of Model:	The peer review process for fire PRAs is not as developed as internal events PRAs. For example, no industry standard, such as NEI 00-02, exists for the structured peer review of a fire PRA. This may lead to less assurance of the realism of the model.

The fire analysis performed for the Vogtle IPEEE, submitted to the NRC in 1995, employed a scenario-based PRA approach which assessed the risk of core damage induced by fire and smoke hazards in all important plant locations. This approach met the intent of NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," June 1991.

In this analysis, core damage frequency (CDF) due to fire was calculated based on the total of all the fire scenarios. The plant-specific data collected for fire scenario development and analysis reflect the plant configuration as of October 1993. At the time of the IPEEE analysis, the plant risk model used in the detailed analysis for estimating the core damage frequency (CDF) of the fire scenarios was based on revision 1 of the Vogtle IPE submittal internal events PRA approved in September 1994. Revision 1 was developed with Westinghouse PRA software utilizing a large event tree support states model methodology. Based on this model, the calculated fire CDF represented approximately less than 21 percent of the Vogtle internal events CDF. A fire large early release frequency (LERF) was not calculated. This fire analysis has not been updated since the IPEEE submittal.

Loss of offsite power (LOSP) was the dominant contributor to core damage in the Vogtle IPE submittal internal events PRA described. The fire high risk areas identified in the IPEEE fire analysis involved the main control room, switchgear rooms, and other areas affecting electrical power supply and control (electrical raceways, cable spreading, and electrical penetration rooms) in which a fire could lead to a station blackout (SBO) with loss of RCP seal cooling resulting in core uncovery due to a seal LOCA.

Since the IPEEE, the Vogtle internal events PRA has been converted from a large event tree model to a linked fault tree model using CAFTA software. Various improvements and enhancements to the model have been made and the total CDF has been reduced from 4.90E-05/yr to 1.55E-05/yr. However, SBO and LOSP initiating events are still dominant contributors which account for approximately 69 percent of the CDF in the current Vogtle internal events linked fault tree PRA model. Steam generator tube rupture (SGTR) and interfacing systems LOCA (ISLOCA), whose frequencies would not be increased due to fire events, account for approximately 70 percent and 17 percent of the LERF, respectively.

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

While the ability to directly compare the results of the internal events and fire models is limited, information is available that may be used to identify the most important contributors for VEGP. The IPEEE document provides some information related to equipment failures by dominant fire scenarios. This information has been summarized in the table below for the ten largest contributing fire scenarios.

Fire Scenario and Designator	CDF	Major Equipment Failed
1) Main Control Room Fire Damaging Section 1A of Electrical Auxiliary Board 1-1816-U3-007 (CONT-46)	1.28E-06	Section 1A of 1-1816-U3-007, RAT 1NXRA, and RAT 1NXRB.
2) Sequencer Fire (small) in Train A 4.16 kV Switchgear Room (1-CB-LA-G-91-L-F3)	7.60E-07	Sequencer 1-1823-U3-001, 4.16 kV Train A (and all associated Train A equipment), RAT 1NXRA, DG 1A, Train C TD AFW
3) Switchgear Fire (large) in Train B 4.16 kV Switchgear Room (1-CB-LA-H-92-L-O1)	6.19E-07	4.16 kV Train B, RAT 1NXRA, RAT 1NXRB, DG 1B, Train C TD AFW
4) Transient Fire (large) in the Level A Corridor and Cable Chase (1-CB-LA-N-85-L-R2)	4.20E-07	4.16 kV Train A, RAT 1NXRA, RAT 1NXRB, DG 1A, Train C TD AFW
5) Transient Fire (large) in the Train B Electrical Penetration Area (1-CB-LA-I-88-L-R2)	3.36E-07	Train B NSCW pumps (1-1202-P4-002, 004, and 006), Train B CVCS charging pump (1-1208-P6-003), Train B CCW pumps (1-1203-P4-002, 004, and 006), Train B MD AFW Pump 1B, Reactor head vent letdown to pressurizer tank valve HV-0442B, CVCS head vent letdown valves HV-8095B and 8096B
6) Transient Fire (small) in the Train B Electrical Raceway Room (1-CB-LA-R-97-L-G1)	2.29E-07	4.16 kV Train B, RAT 1NXRB, DG 1B, Train B AFW, Train C TD AFW, Main Steam ADVs 1-PV-3010 and 3020, Pressurizer PORV 1-PV-0456A and block valve 1-HV-8000B, Reactor head vent letdown to pressurizer tank valve HV-0442B, CVCS head vent letdown valves HV-8095B and 8096B
7) Transient Fire (large) in the Train A Electrical Mezzanine (1-CB-LB-A-73-L-R2)	2.01E-07	480 V Switchgear 1AB04 and 1AB05, 13.8 kV Switchgear 1NAB, CB HVAC Train A, Train A MD AFW, Pressurizer PORV 1-PV-0455A and block valve 1-HV-8000A, Reactor head vent letdown to pressurizer tank valve HV-0442A, CVCS head vent letdown valves HV-8095A and 8096A
8) Transient Fire (large) in Train A 4.16 kV Switchgear Room (1-CB-LA-G-91-L-R4)	1.96E-07	4.16 kV Train A, RAT 1NXRA, DG 1A, Train C TD AFW, Main Steam ADVs 1-PV-3000 and 3030
9) Cable Fire in the Lower (Train A) Cable Spreading Room (1-CB-LA-K-95-L-G2)	1.69E-07	4.16 kV Train A, RAT 1NXRA, DG 1A, Train C TD AFW, Main Steam ADVs 1-PV-3000 and 3030, CVCS minflow isolation valve HV-8509A, Pressurizer PORV 1-PV-0455A and block valve HV-8000A
10) Cable Fire in Lower (Train A) Cable Spreading Room (1-CB-LA-K-95-L-G3)	1.69E-07	Same as 1-CB-LA-K-95-L-G2 but involving self-ignition of different set of cables.

Considering that the total VEGP fire risk was only estimated to be 1.01E-5/yr, the table above demonstrates that the risk is distributed among several contributing Fire Areas. In addition, while fires in each of these areas results in the loss of a wide range of equipment, it is typically limited to a single division. As a result, redundant equipment is often available to mitigate the fire events. Further discussion is provided for each of the fire scenarios below.

1) Fire Scenario CONT-46 in Main Control Room

A fire in the control room in section 1A of electrical auxiliary board 1-1816-U3-007 could cause the power supply breakers from both reserve auxiliary transformers (RATs), and diesel generator 1A and 1B to open. If operator recovery action fails, a loss of all essential ac power is assumed to occur. The loss of the RATs also leads to all non-Class 1E equipment to be unavailable (e.g. condensate, normal chilled water, steam dumps, etc.). A loss of all essential ac power in conjunction with failure of the turbine-driven AFW pump due to causes other than fire, would lead to core damage.

SAMA 5 (permanent dedicated generator for one motor driven AFW pump) and SAMA 8 (implementation of an alternate ac power source) would both help to reduce the risk from this fire scenario. No additional SAMAs are suggested.

2) Fire Scenario 1-CB-LA-G-91-L-F3 (Sequencer Fire (small) in Train A 4.16 kV Switchgear Room)

This scenario results in a loss of all essential ac power if recovery actions to close the Train A breakers to RAT 1NXRA or diesel generator (DG) 1A fail and if Train B essential ac power fails due to causes other than fire. This combined with failure to locally open the HV-5106 steam admission valve for TD AFW pump operation can lead to core damage. Local operation of the TD AFW system is proceduralized and trained at VEGP (refer to IPE insight 2 in Section F.5.1.4). However, SAMA 5 (permanent dedicated generator for one motor driven AFW pump) and SAMA 8 (implementation of an alternate ac power source) would help to reduce the risk from this fire scenario given those failures. In addition, however, even if recovery of essential ac power is successful, train A of NSCW may still be unavailable due to loss of 480-V MCC 1ABB which powers the cooling tower loop A return valve 1-HV-1668A and bypass valve 1-HV-1668B which are assumed closed in the analysis. Therefore, SAMA 6 (add bypass line around NSCW

CT return valves) would also help to reduce the risk from this fire scenario. No additional SAMAs are suggested.

3) Fire Scenario 1-CB-LA-H-92-L-O1 (Switchgear Fire (large) in Train B 4.16 kV Switchgear Room)

Since the Train B switchgear is the source of the fire, no recovery of Train B essential ac power was postulated. Therefore, if DG 1A fails which energizes the Train A 4.16 kV switchgear (since the RAT A is also unavailable due to the fire), fails due to causes other than a fire, a loss of all essential ac power could occur. This combined with failure to locally open the HV-5106 steam admission valve for TD AFW pump operation can lead to core damage. SAMA 5 (permanent dedicated generator for one motor driven AFW pump) and SAMA 8 (implementation of an alternate ac power source) would help to reduce the risk from this fire scenario given those failures. No additional SAMAs are suggested.

4) Fire Scenario 1-CB-LA-N-85-L-R2 (Transient Fire (large) in the Level A Corridor and Cable Chase)

This scenario is very similar to the second scenario described above in that it results in a loss of all essential ac power if recovery actions to close the Train A breakers to RAT 1NXRA or DG 1A fail and if Train B essential ac power fails due to causes other than fire. This combined with failure to locally open the HV-5106 steam admission valve for TD AFW pump operation can lead to core damage. SAMA 5 (permanent dedicated generator for one motor driven AFW pump) and SAMA 8 (implementation of an alternate ac power source) would both help to reduce the risk from this fire scenario given those failures. No additional SAMAs are suggested.

5) Fire Scenario 1-CB-LA-I-88-L-R2 (Transient Fire (large) in the Train B Electrical Penetration Area)

A fire in the Train B electrical penetration area could lead to loss of most of the Train B equipment. Failure of possible recovery actions in conjunction with a loss of AFW Train A and C (turbine driven pump), main feedwater, and NSCW train A, due to causes other than fire, would lead to core damage. SAMA 5 (permanent dedicated generator for one motor driven AFW pump) and SAMA 11 (use the hydrostatic test pump as an alternate means of providing seal injection) would both help to reduce the risk from this fire scenario given those failures. No additional SAMAs are suggested.

6) Fire Scenario 1-CB-LA-R-97-L-G1 (Transient Fire (small) in the Train B Electrical Raceway Room)

This scenario is very similar to the third scenario described above in that it results in a loss of all essential ac power if recovery actions to close the Train B breakers to RAT 1NXRB or DG 1B fail and if Train A essential ac power fails due to causes other than fire. This combined with failure to locally open the HV-5106 steam admission valve for TD AFW pump operation can lead to core damage. SAMA 5 (permanent dedicated generator for one motor driven AFW pump) and SAMA 8 (implementation of an alternate ac power source) would both help to reduce the risk from this fire scenario given those failures. No additional SAMAs are suggested.

7) Fire Scenario 1-CB-LB-A-73-L-R2 (Transient Fire (large) in the Train A Electrical Mezzanine)

A fire in the Train A mezzanine area could lead to loss of much of the Train A equipment. Failure of possible recovery actions in conjunction with a loss of AFW Train C (turbine driven pump) and a loss of all essential ac power due to causes other than fire, would lead to core damage. SAMA 5 (permanent dedicated generator for one motor driven AFW pump) and SAMA 8 (implementation of an alternate ac power source) would both help to reduce the risk from this fire scenario given those failures. No additional SAMAs suggested.

8) Fire Scenario 1-CB-LB-A-73-L-R2 (Transient Fire (large) in Train A 4.16 kV Switchgear Room)

This scenario is assumed to lead to an inadvertent safety injection because various cables to several pressurizer spray valves are located in this room. A failure of the turbine-driven AFW pump was also assumed because of loss of cables to the HV-5106 steam admission valve. Failure to locally open this valve in conjunction with a loss of all essential ac power, would lead to core damage. SAMA 5 (permanent dedicated generator for one motor driven AFW pump) and SAMA 8 (implementation of an alternate ac power source) would both help to reduce the risk from this fire scenario given those failures. No additional SAMAs are suggested.

9) Fire Scenario 1-CB-LA-K-95-L-G2 (Cable Fire in the Lower (Train A) Cable Spreading Room)

This scenario is very similar to the previous scenario and is assumed to lead to an inadvertent safety injection due to failure of three pressurizer pressure transmitters and various cables to several pressurizer spray valves are located in this room. A failure of the turbine-driven AFW pump was also assumed because of loss of cables to the HV-5106 steam admission valve. Failure to locally open this valve in conjunction with a loss of all essential ac power, would lead to core damage. SAMA 5 (permanent dedicated generator for one motor driven AFW pump) and SAMA 8 (implementation of an alternate ac power source) would both help to reduce the risk from this fire scenario given those failures. No additional SAMAs are suggested.

10) Fire Scenario 1-CB-LA-K-95-L-G3 (Cable Fire in the Lower (Train A) Cable Spreading Room)

This scenario is the same as the previous scenario, but involves self-ignition of a different set of cables. Equipment failure impacts and core damage scenarios are the same. No additional SAMAs are suggested.

Fire SAMA Identification Summary

Based on the review of the VEGP dominant fire area results from the IPEEE, it was found that while fires in the dominant areas result in the loss of a wide range of equipment, it is typically limited to a single division. As a result, redundant equipment is often available to mitigate the fire events. Based on this limited scope review, it was determined that SAMAs based on insights from the current internal events PRA model have already been identified that would also potentially lead to reductions in the fire risk.

F.5.1.6.2 Seismic Events

The EPRI seismic margins methodology [EPRI 1991] is used to identify the minimal set of equipment required to safely shut the reactor down and to determine if that equipment is capable of surviving the Review Level Earthquake (RLE). Equipment that is not capable of withstanding the RLE is identified and required to be addressed. While methods exist for using this information to develop a seismically induced core damage frequency, this was not performed as part of the VEGP IPEEE. It should also be noted that even in a seismic analysis developed to yield a CDF, the pedigree of information is not equivalent to what is used in the internal events models. Given that there is a limited amount of seismic response information available for nuclear power plants, analysis techniques developed to model the plant response often compensate by ingraining a conservative bias in their methodologies to prevent overestimating the capabilities of the plants. While seismic risk evaluations are helpful in the identification of potential plant weaknesses, the methodologies have not evolved to a point where the results can be directly compared with the internal events models.

A seismic margins assessment (SMA) using EPRI methodology was performed for resolution of the seismic portion of the IPEEE. The SMA review level earthquake for Vogtle is a 0.3 g peak ground acceleration (PGA) NUREG/CR-0098 spectrum. Vogtle structures and equipment were designed for a safe shutdown earthquake (SSE) defined by a Regulatory Guide 1.60 spectrum tied to a PGA of 0.2 g. However, due to conservatisms applied to the demand and/or evaluation techniques, most of the seismic category I structures and equipment were designed and qualified for a 0.3 g PGA capacity.

Based on the results of the SMA evaluations, Vogtle Units 1 and 2 have a high-confidence-low-probability-of-failure (HCLPF) capacity of at least 0.3 g PGA. Additionally, there were 24 equipment open items for each unit, mostly seismic interaction issues. They included a gap between the battery rack end rails and batteries, potential interactions between the diesel generators and crane controller, etc. All of these issues have been addressed as documented in a letter to the NRC dated March 31, 1998 [SNC 1998].

Seismic SAMA Identification Summary

Based on the review of the VEGP seismic analysis, no seismic specific SAMAs have been included on the VEGP SAMA list.

F.5.1.6.3 High Wind Events, External Flooding, Transportation and Nearby Facility Accidents, and Other External Hazards

This category included high winds, external floods, transportation and nearby facility accidents or other external events involving plant unique hazards.

The progressive screening approach described in NUREG-1407 was used to identify potential vulnerabilities at Vogtle due to high winds, floods, transportation and nearby facilities accidents, and "other" hazards. The progressive screening approach consisted of the following steps:

1. Review of the Vogtle-specific hazard data and licensing bases, including the resolution of each issue or event.

2. Identification of significant plant changes since issuance of the Vogtle operating license (OL) as they related to high winds, floods, military and industrial facilities within 5 miles of Vogtle, onsite storage or other activities involving hazardous materials, transportation, developments that could affect the original design conditions, and other hazards.

3. Determination whether the Vogtle design met the 1975 Standard Review Plan (SRP), NUREG-75/087 criteria.

The review of the Vogtle-specific hazard data and licensing bases regarding high winds, floods, transportation and nearby facility accidents, and other external hazards, was accomplished by a review of the pertinent sections of the Vogtle Final Safety Analysis Report.

Because both units of Vogtle were granted operating licenses within 10 years prior to the IPEEE analyses, and based on the NRC Safety Evaluation Report NUREG-1137, using the Standard Review Plan (SRP), NUREG-0800, the determination of conformance was a straightforward verification. The conclusion of the review was that Vogtle conforms to the SRP (NUREG-75/087) criteria, which was the predecessor SRP to NUREG-0800 [NRC 1987].

For hazards originated from transportation and nearby facility accidents which normally would be outside plant control, updated data was gathered revealing conformance to the SRP.

A plant walkdown was conducted for high winds, floods, and other hazards to confirm the documentation used in the design review process and to look for any changes to the plant. The walkdown was conducted by Southern Nuclear Operating Company personnel based on a written procedure. No significant changes related to high winds, floods, and other hazards were found to have occurred since the operating licenses were issued.

Based on the reviews and walkdowns the Vogtle design met the SRP criteria in all reviewed areas and no potential vulnerabilities related to high winds, external floods, transportation and nearby facility accidents, or other external events involving plant unique hazards were identified.

Other External Hazard SAMA Identification Summary

Based on the review of the VEGP High Wind Events, External Flooding, Transportation and Nearby Facility Accidents, and Other External Hazards analysis, no additional SAMAs have been included on the VEGP SAMA list.

F.5.1.7 INTERNAL FLOODING

Based on the IPE analysis, all of the flooding zones at VEGP were eliminated from further consideration during the qualitative analysis. None of the zones were found to contribute significantly to core damage frequency as a result of a flooding or spray event. The results of this analysis are consistent with the previous VEGP flooding analysis that was performed as part of the VEGP licensing basis. It should also be noted that VEGP is one of the most recently licensed nuclear plants in the United States, and as such, it has been designed to mitigate and limit the effects due to internal flooding events.

Based on this assessment and the high costs associated with installing additional systems that could mitigate all flood scenarios or combinations of scenarios, no further investigation of internal flooding based SAMAs is considered to be warranted.

F.5.1.8 QUANTITATIVE STRATEGY FOR EXTERNAL EVENTS

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

The first part of this process is used in the Phase I analysis and is based on the assumption that the risk posed by external and internal events is approximately equal. For VEGP, the external events analysis, which has been identified as a conservative analysis, yielded a CDF of only 1.01E-05/yr for the quantified event types (Fire). While no CDF was quantified for the seismic, high wind, flood, and transportation and nearby facility event types, fire risk is typically the largest of these contributors. Additionally, at the time of the IPE, fire risk represented less than 21 percent of the internal events risk. Therefore, to account for the contribution from other external events contributors, it is not unreasonable to assume that the total contribution would be comparable to (or no worse than) the current internal events CDF of 1.55E-05 per year.

Given that the risk is assumed to be equal, the MACR calculated for the internal events model has been doubled to account for external events contributions. This total is referred to as the modified MACR (MMACR). The MMACR is used in the Phase I screening process to represent the maximum achievable benefit if all risk related to on-line power operations was eliminated. Therefore, those SAMAs with costs of implementation that are greater than the MMACR were eliminated from further review.

The second stage of this strategy is to also apply the doubling factor to the Phase II analysis. Any averted cost-risk calculated for a SAMA was multiplied by two to account for the corresponding reduction in external events risk.

The third stage of the process is used for SAMAs that were identified based on IPEEE insights. For these cases, IPEEE insights and the Internal Events PRA are used, as appropriate, to develop an averted cost-risk for the SAMA that accounts for the external and internal events risk reductions. For instance, the IPEEE typically provides information that can be used to estimate bounding changes in risk that would be realized if the SAMAs were implemented. These risk changes are used to approximate averted cost-risks based on external events contributions. Then, if it can be determined that the SAMA would impact the internal events model, the PRA is used to quantify the averted cost-risk based on its internal events contributions. The cost-risks from the external and internal events results are then added to yield the total for the SAMA. In some cases, the SAMAs do not impact the internal events models and the calculations do not require the use of the PRA model. It should be noted that no unique SAMAs were identified from the IPEEE, therefore it was not necessary to perform the third stage for VEGP. Instead all analyzed SAMAs used the direct factor of two on the MMACR and averted cost-risk to account for the external events risk.

F.5.2 PHASE I SCREENING

The initial list of SAMA candidates is presented in Table F.5-3. The process used to develop the initial list is described in Section F.5.1.

The purpose of the Phase I analysis is to use high-level knowledge of the plant and SAMAs to preclude the need to perform detailed cost-benefit analyses on them. The following screening criteria were used:

Applicability to the Plant: If a proposed SAMA does not apply to the VEGP design, it is not retained.

Implementation Cost Greater than Screening Cost: If the estimated cost of implementation is greater than the modified Maximum Averted Cost-Risk, the SAMA cannot be cost beneficial and is screened from further analysis.

Table F.5-3 provides a description of how each SAMA was dispositioned in Phase I. Those SAMAs that required a more detailed cost-benefit analysis are evaluated in Section F.6.

F.6 PHASE II SAMA ANALYSIS

Not all of the Phase II SAMA candidates require detailed analysis. The Phase II process allows for the screening of SAMAs known to be related to non-risk significant systems or to components/functions with low importance rankings. Due to the nature of the PRA-based process used to develop the SSES SAMA list, there are limited avenues for SAMAs of this type to be included in the list. However, potential pathways do exist:

Inclusion of unresolved proposed plant changes from previous VEGP risk analyses,

Inclusion of SAMAs based on the results of conservative modeling methods.

While no calculations are required for eliminating a SAMA that is linked to a non-risk significant system or components, some quantitative efforts are usually required to screen SAMAs that were developed to address risk contributors based on conservative modeling techniques. These cases are identified in Table F.6-1 and discussed in detail in the SAMA specific subsections of F.6.

For SAMAs requiring detailed analysis, 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 is defined by the following equation:

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

If the net value of the SAMA is negative, the cost of implementation is larger than the benefit associated with the SAMA and the SAMA is not considered beneficial. The baseline cost-risk of plant operation was derived using the methodology presented in Section F.4. The cost-risk of plant operation with the SAMA implemented is determined in the same manner with the exception that the revised PRA results reflect implementation of the SAMA.

The implementation costs used in the Phase II analysis include both VEGP specific estimates developed by plant personnel and estimates taken from other SAMA submittals for those SAMAs that were determined to be highly similar. It should be noted that the VEGP specific implementation costs do not include replacement power costs that may be incurred due to consequential shutdown time.

Sections F.6.1 – F.6.13 describe the detailed cost-benefit analysis that was used for each of the remaining candidates.

F.6.1 SAMA NUMBER 1: PERMANENT, SELF-POWERED PUMP TO BACKUP NCP

This SAMA addresses one of the largest VEGP risk contributors, which are seal LOCAs that develop due to loss of seal cooling from various initiators. The installation of a permanent self-powered pump to provide backup to the NCPs is a means of reducing the probability that seal injection will be unavailable in those scenarios. In order to limit the size of potential seal LOCAs, a requirement of this SAMA is that it must provide the capability to rapidly align the backup pump so that seal cooling can be restored within 13 minutes of the initial seal cooling loss.

This SAMA would potentially reduce the risk from the following scenarios by preventing RCP seal LOCAs:

SBO, Loss of RCP seal injection, Loss of ACCW and Loss of NSCW

Risks from ISLOCAs (through RCP seal return line) initiated from the above scenarios would also be reduced

<u>Assumptions:</u>

1) The pump is self-powered and independent from any existing support systems such as electrical power, actuation, and cooling.

2) No common cause failure potential between the new pump and any other existing pumps including NCP.

3) For the purposes of this analysis, the total failure probability of the operator errors and hardware was assumed to be 1.0E-1. Lower values for this estimate are not suggested given the short time available to start and align the backup NCP, and the high stress factor that would be present in the loss of seal cooling scenarios.

Modeling of the new pump

Addition of the new pump to back NCP's RCP seal injection may be modeled in event trees of the above scenarios in such a way that if the new pump is successful, after SBO or after total loss of RCP seal injection occurred in the other initiating events, no significant RCP seal LOCA occurs and events can be mitigated without any need of inventory makeup. If the new pump also fails, then RCP seal LOCA scenarios with 4 different leakage rates (21, 76, 182, and 480 gpm per RCP, as modeled in the base line PRA model), would occur. Figure F.6.1 shows the necessary event tree change.

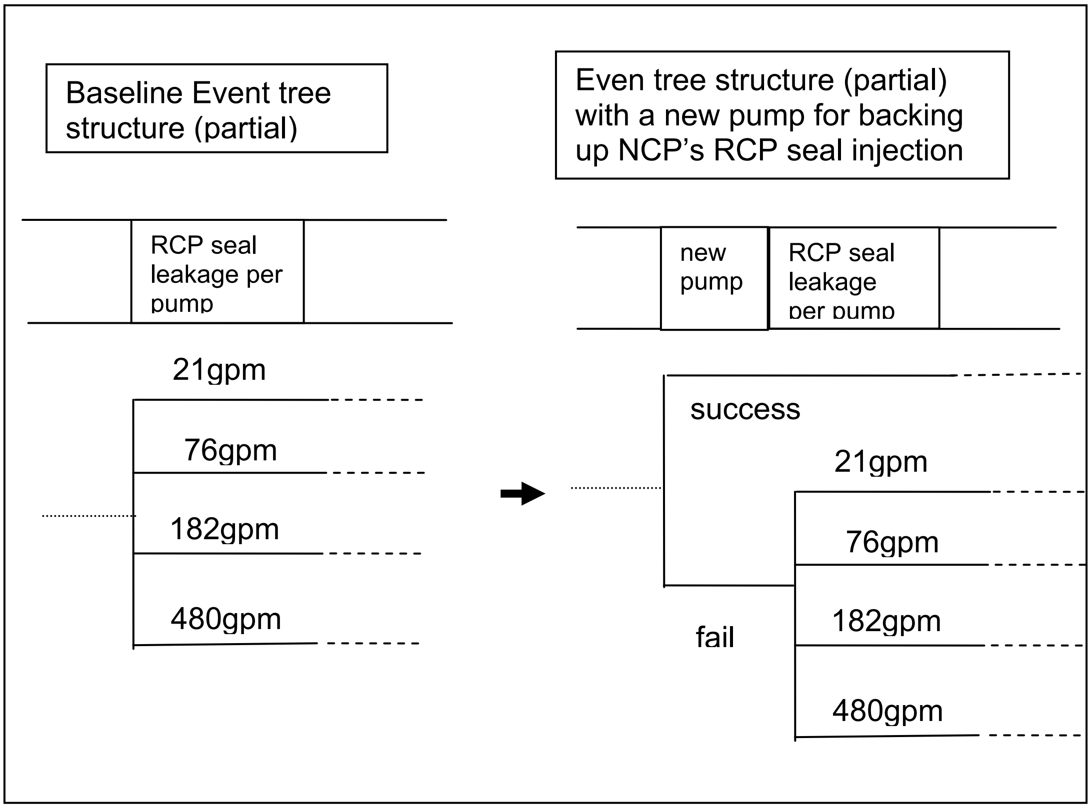


Figure F.6.1
Event tree change when a new pump is added to Backup NCP's RCP seal injection

With the event tree change, there are 5 groups of scenarios depending on the failure/success of the new pump and RCP seal leak rate as the followings:

1) Scenarios with the success of the new pump, no significant RCP seal LOCA,

2) Scenarios with the failure of the new pump and 21 gpm per pump RCP seal leakage,

3) Scenarios with the failure of the new pump and 76 gpm per pump RCP seal leakage,

4) Scenarios with the failure of the new pump and 182 gpm per pump RCP seal leakage, and

5) Scenarios with the failure of the new pump and 480 gpm per pump RCP seal leakage.

Note that all 5 scenarios also include initiating events and/or combination of failures which caused failures of both RCP seal injection and thermal barrier cooling by the existing systems. Total loss of RCP cooling occurs when both RCP seal injection and RCP thermal barrier cooling are lost. RCP seal leakage would be 21 gpm per pump during the first 13 minutes after the total loss of RCP seal cooling and could increase to 21, 76, 182, or 480 gpm per pump after 13 minutes.

Since scenarios with 21 gpm per pump RCP seal leakage would not require inventory makeup to prevent core damage, they were treated in a similar way as transients scenarios were treated in the current VEGP PRA model.

Thus, event scenarios involving the success of new pump (NPMP-S) may be logically integrated into those for the 21gpm per pump case without developing its own event tree.

A fault tree for the failure of the new pump could be developed. However, since it was assumed that the new pump is independent from any existing support systems and that there is no common cause failure between the new pump and any existing pumps, the failure of the new pump may be modeled as a single basic event for simplicity.

The cost of this enhancement has been estimated to be $2.7M based on a conceptual design of the backup pump [SNC 2007a]. As the cost of implementation is greater than the MMACR, this SAMA would not normally be retained for Phase II analysis. However, this SAMA has been retained for Phase II analysis to determine the maximum averted cost should a lower cost alternative be identified (e.g. SAMA 15).

Results

Implementation of this SAMA yields a reduction in the CDF [SNC 2007j], dose-risk, and offsite economic cost-risk (OECR). The results are summarized in the following table.

	CDF (/yr)	**Dose-Risk**	**OECR**
Base Results	1.55E-05	2.04	$1,412
SAMA 1 Results	8.14E-06	1.69	$1,389
Percent Change	47.5	17.2	1.6

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency (/yr)$_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency (/yr)$_{SAMA}$	1.04E-08	3.03E-08	1.29E-07	8.59E-08	4.99E-06	2.88E-06	2.06E-08	**8.14E-06**
Dose-Risk$_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-Risk$_{SAMA}$	0.01	0.19	0.36	0.21	0.62	0.30	0.00	**1.69**
OECR$_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
OECR$_{SAMA}$	$21	$160	$773	$416	$14	$5	$0	**$1,389**

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

SAMA Number 1 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$591,828	$426,172	$2,700,000	-$2,273,828

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

F.6.2 SAMA NUMBER 2: MAINTAIN FULL-TIME BLACK START CAPABILITY OF THE WILSON SWITCHYARD COMBUSTION TURBINES

Currently, the black start of plant Wilson combustion turbines (and black start DGs) is credited only during 14 Day DG allowed outage time (AOT). SAMA 2 will enable the black start of plant Wilson combustion turbines (and black start DGs) all the time.

In order to represent this SAMA, the failure of the combustion turbines and black start DGs combined was modeled as a single basic event APWCT12DG----F with failure probability of 0.05. In the base model, if the plant is not in 14 DAY DG AOT, flag FL-DG-NOT14DAOT is set to TRUE. For this evaluation, the flag was set to FALSE.

The cost of this enhancement has been estimated to be $50,000 to account for the cost of additional training on the operation of Plant Wilson [SNC 2007b]. No physical modifications are required. To maintain full-time black start capability, daily operator log items would need to be added to ensure the Wilson black-start CTs/DG are ready to be started. In addition, two dedicated and trained operators will be required to operate the SAT and Plant Wilson. If the existing Vogtle Operations crew cannot spare two qualified individuals during a loss of offsite power event, the crew size will need to be expanded to meet the requirements. This analysis assumes that an expanded crew size is not required. No new procedures will need to be developed as one already exists for performing a CTG black start. The estimate is for both units since Plant Wilson is common to both such that $25,000 per unit is used in the cost benefit analysis below.

Results

Implementation of this SAMA yields a reduction in the CDF [SNC 2007j], dose-risk, and offsite economic cost-risk (OECR). The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 2 Results	8.87E-06	1.28	$1,183
Percent Change	42.8	37.3	16.2

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency (/yr)$_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency (/yr)$_{SAMA}$	1.38E-08	3.03E-08	9.60E-08	8.50E-08	2.93E-06	5.69E-06	2.06E-08	**8.87E-06**
Dose-Risk$_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-Risk$_{SAMA}$	0.01	0.19	0.26	0.21	0.24	0.37	0.00	**1.28**
OECR$_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
OECR$_{SAMA}$	$27	$160	$575	$411	$4	$6	$0	**$1,183**

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

SAMA Number 2 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$600,904	$417,096	$25,000	$392,096

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

F.6.3 SAMA NUMBER 4: AC CROSS-TIE CAPABILITY

SAMA 4 includes preparation of procedures and operator training for cross-tying an opposite unit DG during a SBO. Currently, no procedures and training except for the power option book in the Technical Support Center (TSC) room are available. Implementation of SAMA 4 will increase the success of operators cross tying to the opposite unit EDG.

Modeling

SAMA 4 would only improve human error probabilities (HEPs) related to the cross-tying to the opposite unit EDG. In the base case model,there are no step-by-step procedures or training available. The HEP for the operator action is estimated to be 1.0 (always fails) unless there are 7 hours or more available to perform the action. After reviewing the HRA update for VEGP PRA R2 in the EPRI HRA calculator, it was determined that SAMA 4 would have a direct major impact in the cognitive error portion of the HRA evaluation. Implementation of SAMA 4 would also make HEPs with available time less than 7 hours less than 1.0 because, with procedures and training, it would be much easier and take much shorter time for operators to figure out the need of the cross-tying and perform the required task. Thus, it was assumed that the HEP would be 0.5 if the available time is less than 7 hours.

The table below compares the HEPs before and after SAMA 4 implementation.

BASIC EVENTS	DESCRIPTIONS	HEPS, BASE CASE	HEPS AFTER SAMA 4 IMPLEMENTATION
OA-XTIE-DGS-GH	OP. FAILS TO X-TIE DGS GIVEN PLANT WILSON FAILED - GENERAL CASE, NO #SBO IE	1.0	0.5
OA-XTIEDGS-1HR	OPERATOR FAIL TO X-TIE A DG IN OPPSOITE UNIT WITHIN 1 HR AFTER SBO	1.0	0.5
OA-XTIEDGS-2HR	OPERATOR FAIL TOX-TIE A DG IN OPPOSITE UNIT WITHIN 2HR AFTER SBO	1.0	0.5
OA-XTIEDGS-4HR	OPERATOR FAIL TO X-TIE A DG IN OPPOSITE UNIT WITHIN 4 HRS AFTER SBO	1.0	0.5
OA-XTIEDGS-6HR	OPERATOR FAIL TO X-TIE A DG IN OPPOSITE UNIT WITHIN 6 HRS AFTER SBO	1.0	0.5
OA-XTIEDGS-7HR	OPERATOR FAIL TO X-TIE A DG IN OPPOSITE UNIT WITHIN 7 HRS AFTER SBO	2.5E-01	1.6E-1
OA-XTIEDGS-8HR	OPERATOR FAIL TO X-TIE A DG IN OPPOSITE UNIT WITHIN 8 HRS AFTER SBO	2.5E-01	1.6E-1
OA-XTIEDGS-10HR	OPERATOR FAIL TO X-TIE A DG IN OPPOSITE UNIT WITHIN 10 HRS AFTER SBO	1.4E-01	8.9E-2
OA-XTIEDGS-14HR	OPERATOR FAIL TO X-TIE A DG IN OPPOSITE UNIT WITHIN 14 HRS AFTER SBO	1.4E-01	8.9E-2

Currently no procedures or training exist for cross tying the diesel generators to the opposite unit during a station blackout. Implementation of this SAMA would require a thorough review of the "power options book" in the TSC and electrical schematics to develop a procedure and training module for Operations to use in the event of a SBO. The cost of this enhancement has been estimated to be $50,000 [SNC 2007d] for developing, implementing, and training on a new procedure. The estimated cost is for both units which equates to a $25,000 per unit for use in the cost benefit analysis.

Results

Implementation of this SAMA yields a reduction in the CDF [SNC 2007j], dose-risk, and offsite economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 4 Results	1.21E-05	1.66	$1,290
Percent Change	21.9	18.6	8.6

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency $(/yr)_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency $(/yr)_{SAMA}$	1.80E-08	3.03E-08	1.11E-07	8.54E-08	6.14E-06	5.73E-06	2.06E-08	**1.21E-05**
Dose-Risk_{BASE}	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-Risk_{SAMA}	0.02	0.19	0.31	0.21	0.55	0.38	0.00	**1.66**
$OECR_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
$OECR_{SAMA}$	$36	$160	$665	$413	$10	$6	$0	**$1,290**

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

SAMA Number 4 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$806,504	$211,496	$25,000	$186,496

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

F.6.4 SAMA NUMBER 6: ADD BYPASS LINE AROUND NSCW CT RETURN VALVES

SAMA 6 is to install bypass line and valve around the NSCW cooling tower (CT) return isolation valves (HV1668A for CT1 and 1669A for CT2). When the cooling tower return isolation valves fail to re-open after closing on loss of offsite power (LOSP), automatic quick opening of the bypass valve will prevent the trips of emergency DGs (EDGs) on high cooling water temperature.

Modeling

The following assumptions were made for modeling SAMA 6:

1) As assumed in the base case model, cooling towers are required all the time for accident mitigation.

2) SAMA 6 implementation will add a bypass valve around each CT tower return line isolation valve.

3) The bypass valves will be normally closed. When loss of flow is sensed down stream of the cooling tower return isolation valve (due to failure to reopen after closing on LOSP), the bypass valve will automatically open.

4) The automatic opening of the bypass valve is fast enough to prevent the trip of EDGs on high cooling water temperature.

5) The bypass valves are dc powered motor operated valves and they are designed so that there are no common cause failure potential among the cooling tower return isolation valves and the bypass valves.

6) CT1 return isolation valve bypass valve requires 125V dc power from battery 1AD1 (battery chargers are assumed not available because LOSP and EDGs may not operate without cooling water) for its actuation signal and motive power. For CT2 return isolation valve bypass valve, power from 125V dc battery BD1 is needed.

Besides the modeling assumptions listed above, failure data for new valves were also provided. It was assumed that the failure probability of the new bypass valve is the same as HV1668A (or 1669A):

a) Random failure to open: 6.26E-3

b) Common cause failure: 2.66E-4

c) The failure of the actuation circuit was modeled as undeveloped events. It was assumed that the failure probabilities of these undeveloped events are the same as the sum of the basic events for HV1668A (or 1669A) actuation signal failure: 3.69E-3

The cost of this enhancement has been estimated to be $525K per unit based on a conceptual design of a modification that would provide a 10" bypass line from the diesel generator cooler return line to downstream of the return isolation valve [SNC 2007f]. Note that this design estimate was for an AOV since it was initially thought that an AOV would provide a lower cost alternative to the DC MOV specification. However, additional requirements on the AOV design were found necessary to provide the full benefit as analyzed in the SAMA where the major benefit is from loss of offsite power sequences where instrument air is likely not available for the full PRA mission time. Therefore, additional hardware changes such as a dedicated air tank and/or multiple check valves would be required to fully obtain the benefit determined from the SAMA analysis. Similarly, a DC MOV would likely incur additional expenses for implementation (compared to the AOV cost estimate) since the motor operator would require detailed battery calculations which may lead to potentially requiring additional batteries. At a minimum an inverter, heavy gauge cabling, and possibly additional pipe supports to hold the weight of the motor would be additional expenses that were not include in the AOV cost estimate. As such, it judged that the original cost estimate of $525,000 is the minimum cost that would be incurred to implement the necessary hardware changes for this SAMA.

Results

Implementation of this SAMA yields a reduction in the CDF [SNC 2007j], dose-risk, and offsite economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 6 Results	1.05E-05	1.72	$1,343
Percent Change	31.6	15.7	4.9

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency (/yr)$_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency (/yr)$_{SAMA}$	1.56E-08	3.03E-08	1.20E-07	8.57E-08	7.26E-06	2.98E-06	2.06E-08	**1.05E-05**
Dose-Risk$_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-Risk$_{SAMA}$	0.01	0.19	0.33	0.21	0.68	0.30	0.00	**1.72**
OECR$_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
OECR$_{SAMA}$	$31	$160	$719	$415	$13	$5	$0	**$1,343**

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

SAMA Number 6 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$722,314	$295,686	$525,000	-$229,314

Given that the cost of implementation is more than the averted cost-risk for this SAMA, the net value is negative.

F.6.5 SAMA NUMBER 7: IMPLEMENT ENHANCED RCP SEAL DESIGN

It was assumed that SAMA 7 limits the RCP seal leakage after total loss of RCP seal cooling to less than or equal to 21 gpm (in other words, no inventory makeup is necessary to prevent core damage).

Thus, for the SAMA 7 evaluation, the probabilities of RCP seal leakage event with grater than 21 gpm per pump leak were set to 0 and the probability of RCP seal leak with 21 gpm per pump was set to 1.0 as follows:

Basic Event	Base Case Probability	SAMA 7 Probability	Remarks
RCPSL-21GPM	0.79	1.0	RCP seal leak @21 gpm
RCPSL-76GPM	0.01	0.0	RCP seal leak @76 gpm
RCPSL-182GPM	0.1795	0.0	RCP seal leak @182 gpm
RCPSL-480GPM	0.0025	0.0	RCP seal leak @480 gpm
RCPSL-GT21GPM	0.21	0.0	RCP seal leak greater than 21 gpm
RCPSEAL1	0.0125	0.0	Probability of #1 RCP seal failure given total loss of RCP seal cooling

The cost of installation of a new enhanced RCP seal which is currently in development by Westinghouse has been estimated to be $1.05M [SNC 2007g]. This slightly exceeds the MMACR, but it was decided to further explore this issue to determine the maximum averted cost risk should the actual cost of implementation be slightly lower or if alternative methods arise that would lead to the same impact (i.e. greatly reduce or eliminate the potential for RCP seal LOCAs).

Results

Implementation of this SAMA yields a reduction in the CDF [SNC 2007j], dose-risk, and offsite economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 7 Results	7.36E-06	1.65	$1,392
Percent Change	52.5	19.1	1.4

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency (/yr)$_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency (/yr)$_{SAMA}$	9.64E-09	3.03E-08	1.30E-07	8.59E-08	4.52E-06	2.57E-06	2.06E-08	**7.36E-06**
Dose-Risk$_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-Risk$_{SAMA}$	0.01	0.19	0.36	0.21	0.69	0.29	0.00	**1.65**
OECR$_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
OECR$_{SAMA}$	$19	$160	$779	$416	$13	$5	$0	**$1,392**

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

SAMA Number 7 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$546,704	$471,296	$1,050,000	-$578,704

Given that the cost of implementation is more than the averted cost-risk for this SAMA, the net value is negative.

F.6.6 SAMA NUMBER 9: IMPLEMENT AUTOMATIC INITIATION OF HPI ON LOW RCS LEVEL AFTER AC RECOVERY DURING AN SBO

Automatic initiation of high pressure injection (HPI) after ac power is recovered during a station blackout will reduce the failure probability of HPI in SBO scenarios which need inventory makeup.

Modeling

Operators are directed to reset SI and start HPI (CCPs and SIPs) after ac power is recovered (VEGP EOP 19102 ECA 0.2). There is no automatic start of HPI after ac power recovery. Failure to manual start of HPI is modeled as basic event OAR_HISBOACR-H (probability = 2.70E-2) in the base case model. SAMA 9 implementation was modeled by replacing basic event OAR_HISBOACR-H under gate #HPI-SBO-ACR with an AND gate that includes a new event A-HISIG-SBO-ACR to represent the failure of auto initiation system for HPI after ac recovered in SBO. ACR was modeled as an undeveloped event. It was assumed that the probability of A-HISIG-SBO-ACR is the same as the probability of basic event 1SACC--SAFACTXCC (ESFAS TRAINS A AND B UNAVAILABLE DUE TO COMMON CAUSE FAILURE), which is 6.42E-4. In the modified logic, if auto initiation and operator action to manually start HPI fail, then HPI initiation fails (i.e. all CCPs and SIPs would not start) after ac power is recovered in SBO scenarios.

The cost of this enhancement has been estimated to be $250K per unit based on a conceptual design to install isolated circuitry that would automatically start HPI if a SI signal is present when ac power is restored [SNC 2007i].

Results

Implementation of this SAMA yields a reduction in the CDF [SNC 2007j], dose-risk, and offsite economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	**Dose-Risk**	**OECR**
Base Results	1.55E-05	2.04	$1,412
SAMA 9 Results	1.50E-05	2.03	$1,412
Percent Change	3.2	0.5	0.0

A further breakdown of this information is provided below according to release category.

Release Category	**LERF ISO**	**LERF BYPASS**	**LERF SGTR**	**LATE SGTR**	**LATE CHR**	**LATE BMMT**	**Leakage / INTACT**	**Total**
Frequency (/yr)$_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency (/yr)$_{SAMA}$	2.30E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.36E-06	2.06E-08	**1.50E-05**
Dose-Risk$_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-Risk$_{SAMA}$	0.02	0.19	0.35	0.21	0.89	0.37	0.00	**2.03**
OECR$_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
OECR$_{SAMA}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**

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

SAMA Number 9 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$992,540	$25,460	$250,000	-$224,540

Given that the cost of implementation is more than the averted cost-risk for this SAMA, the net value is negative.

F.6.7 SAMA NUMBER 10: ADDITIONAL TRAINING AND/OR PROCEDURAL ENHANCEMENT TO IMPLEMENT TIMELY RCS DEPRESSURIZATION

Enhanced training and/or procedure enhancements could reduce the potential for thermally induced steam generator tube ruptures, thereby reducing the overall Level 2 risk contribution. As this improvement was identified from the Level 2 model review, the focus of the change was on the Level 2 model results. No CDF changes were explored.

A detailed review of the Level 2 model containment event trees was performed to obtain the necessary information required to assess the potential risk reduction from this plant improvement. It was found that perfect credit for timely RCS depressurization in the Level 2 model would lead to the following changes in the sequence results:

Original Level 2 Sequence	Revised Level 2 Sequence	Previous End State Assignment	Revised Endstate Assignment	Endstate Change Required?
NON-SBO Event Tree				
INTACT02	LATE06	INTACT	LATE-BMMT-NOAFW	**Yes**
LATE03	LATE06	LATE-CHR-NOAFW	LATE-BMMT-NOAFW	**Yes**
LERF02	LERF05	LERF-CFE	LERF-CFE	**No**
INTACT03	INTACT04	INTACT	INTACT	**No**
LATE04	LATE06	LATE-BMMT-NOAFW	LATE-BMMT-NOAFW	**No**
LATE05	LATE07	LATE-CHR-NOAFW	LATE-CHR-NOAFW	**No**
LERF03	LERF05	LERF-CFE	LERF-CFE	**No**
LERF04	LATE06	LERF-SGTR	LATE-BMMT-NOAFW	**Yes**
SBO Event Tree				
INTACT07	INTACT09	INTACT	INTACT	**No**
SERF04	SERF06	SERF	SERF	**No**
LATE11	LATE13	LATE-CHR-NOAFW	LATE-CHR-NOAFW	**No**

Original Level 2 Sequence	Revised Level 2 Sequence	Previous End State Assignment	Revised Endstate Assignment	Endstate Change Required?
LERF11	LERF14	LERF-CFE	LERF-CFE	**No**
INTACT08	INTACT09	INTACT	INTACT	**No**
SERF05	SERF06	SERF	SERF	**No**
LATE12	LATE13	LATE-CHR-NOAFW	LATE-CHR-NOAFW	**No**
LERF12	LERF14	LERF-CFE	LERF-CFE	**No**
LERF13	LATE13	LERF-SGTR	LATE-CHR-NOAFW	**Yes**

The base case results were then adjusted to re-assign the Level 2 model endstates as defined above. This did not require re-quantification of the model; it only required re-assignment of the existing frequencies from one Level 2 release category to another as defined above.

Results

Implementation of this SAMA yields a reduction in the CDF, dose-risk, and offsite economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 10 Results	1.55E-05	2.00	$1,317
Percent Change	0.0	2.0	6.7

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency (/yr)$_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency (/yr)$_{SAMA}$	2.34E-08	3.03E-08	1.12E-07	8.59E-08	9.39E-06	5.84E-06	2.06E-08	**1.55E-05**
Dose-Risk$_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-Risk$_{SAMA}$	0.02	0.19	0.31	0.21	0.88	0.39	0.00	**2.00**
OECR$_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
OECR$_{SAMA}$	$46	$160	$672	$416	$17	$6	$0	**$1,317**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table. Note that the procedural change / enhanced training cost estimate of $50,000 has been reduced by a factor of two to obtain a per-unit cost basis.

SAMA Number 10 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$1,011,536	$6,464	$25,000	-$18,536

Given that the cost of implementation is more than the averted cost-risk for this SAMA, the net value is negative.

F.6.8 SAMA NUMBER 11: USE HYDROSTATIC TEST PUMP AS AN ALTERNATE MEANS OF PROVIDING SEAL INJECTION

For Vogtle, a dominant contributor to the current risk profile is that without RCP seal cooling, it is assumed (based on Westinghouse and NRC consensus modeling) that an RCP seal LOCA of sufficient magnitude to require Reactor Coolant System (RCS) injection occurs within 13 minutes. This SAMA would be similar to SAMA 1, but the impact would be limited to loss of NSCW scenarios since it would not be effective at eliminating seal LOCAs in SBO scenarios since the power to the hydro pump would be unavailable in the SBO scenarios as well.

The cost estimate is assumed to be better represented by the Farley estimate of $580,000 instead of the V.C. Summer estimate of $150,000 since SAMA11 includes installation of new piping and valves so that an operator can align the hydro test pump for RCP seal injection from the main control room within the 13 minutes after a loss of NSCW occurs. The RCP seal injection must be restored within 13 minutes or earlier to prevent significant RCP seal leakage based on the WOG RCP seal LOCA model accepted by the NRC (WCAP-16141, August 2003).

To bound the potential benefits from this case, it was assumed that 90% of all Loss of NSCW scenarios were avoided. The 90% reduction accounts for the fact that most all of the Loss of NSCW events result in core damage because of the subsequent RCP seal LOCA that occurs, and 10% likelihood of success is assumed to be representative of a best-case scenario for avoiding core damage in these scenarios since very quick operator action would be required and since a loss of NSCW has other deleterious effects on the VEGP systems.

Results

Implementation of this SAMA yields a reduction in the CDF, dose-risk, and offsite economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 11 Results	1.39E-05	1.95	$1,405
Percent Change	10.1	4.4	0.5

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency $(/yr)_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency $(/yr)_{SAMA}$	2.00E-08	3.03E-08	1.28E-07	8.59E-08	7.86E-06	5.79E-06	2.06E-08	**1.39E-05**
Dose-$Risk_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-$Risk_{SAMA}$	0.02	0.19	0.35	0.21	0.80	0.38	0.00	**1.95**
$OECR_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
$OECR_{SAMA}$	$40	$160	$767	$416	$16	$6	$0	**$1,405**

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

SAMA Number 11 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$926,330	$91,670	$580,000	-$488,330

Given that the cost of implementation is more than the averted cost-risk for this SAMA, the net value is negative.

F.6.9 SAMA NUMBER 12: ENSURE ALL ISLOCA RELEASES ARE SCRUBBED

This SAMA would scrub all ISLOCA releases. One example is to plug all drains in the break areas so that the break location would quickly be covered with water.

The cost of implementation of this SAMA has not been estimated in detail, but rather it was passed to Phase II to determine the maximum averted cost risk associated with this potential SAMA.

In order to bound the potential risk reduction from this SAMA, the CDF and Level 2 contributions from all ISLOCA scenarios were totally removed from the results.

Results

Implementation of this SAMA yields a reduction in the CDF, dose-risk, and offsite economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 12 Results	1.54E-05	1.85	$1,252
Percent Change	0.3	9.3	11.3

A further breakdown of this information is provided below according to release category.

RELEASE CATEGORY	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	LEAKAGE/ INTACT	TOTAL
Frequency $(/yr)_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency $(/yr)_{SAMA}$	2.34E-08	0.00E+00	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.54E-05**
Dose-$Risk_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-$Risk_{SAMA}$	0.02	0.00	0.35	0.21	0.89	0.38	0.00	**1.85**
$OECR_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
$OECR_{SAMA}$	$46	$0	$672	$416	$17	$6	$0	**$1,252**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table. Note that even if a minimum hardware change amount of $100,000 is assumed for the assessment, the averted cost-risk does not support implementation of the SAMA.

SAMA Number 12 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$998,894	$19,106	>$100,000	<-$80,894

Given that the cost of implementation is more than the averted cost-risk for this SAMA, the net value is negative.

F.6.10 SAMA NUMBER 13: COMPLETELY AUTOMATE SWAP OVER TO RECIRCULATION ON RWST DEPLETION

This SAMA would ensure that automatic swap over to recirculation would occur in cases where high pressure injection from the charging and SI pumps is required (compared to the current capability at VEGP that only automates the swap over for low pressure injection).

The impact of this SAMA on CDF has been estimated by setting all of the operator error terms for this action to a negligible value as shown below. This list includes all those basic events that refer to high pressure recirculation. The model was reviewed and there were no dependent operator action terms that needed to be adjusted for this assessment. These changes are then expected to bound the potential risk reduction that could be obtained by automating this function.

Operator Action Event	Description	Original Value	Revised Value
OAL_HPML-----H	OPERATOR FAILS TO ESTABLISH HIGH PRESSURE HOT LEG RECIRC - MLO	8.31E-04	1.00E-05
OAR_HPATA----H	OPERATOR FAILS TO ESTABLISH HPR DURING ATWT - W CCU SUCC (CS NOT ACTUATED)	2.30E-03	1.00E-05
OAR_HPATB----H	OPERATOR FAILS TO ESTABLISH HPR DURING ATWT - W CCU FAILED (CS ACTUATED)	2.30E-03	1.00E-05
OAR_HPML-----H	OPERATOR FAILS TO ESTABLISH HIGH PRESSURE RECIRC - MLO	2.30E-03	1.00E-05
OAR_HPSBO----H	OPERATOR FAILS TO ESTABLISH HIGH PRESSURE RECIRC - SBO	2.00E-03	1.00E-05
OAR_HPSG-----H	OPERATOR FAILS TO ESTABLISH HIGH PRESS RECIRC - SGTR	2.30E-03	1.00E-05
OAR_HPSL-----H	OPERATOR FAILS TO ESTABLISH HPR – SLOCA	2.00E-03	1.00E-05
OAR_HPSLA----H	OPERATOR FAILS TO ESTABLISH HPR - SLOCA WITH CCUS AVAILABLE	2.00E-04	1.00E-05

Operator Action Event	Description	Original Value	Revised Value
OAR_HPSLB----H	OPERATOR FAILS TO ESTABLISH HPR - SLOCA WITH CCUS NOT AVAILABLE	2.30E-03	1.00E-05
OAR_HPSSI----H	OPERATOR FAILS TO ESTABLISH HPR - SSBI	2.30E-03	1.00E-05
OAR_HPSSO----H	OPERATOR FAILS TO ESTABLISH HPR - SSBO	2.30E-03	1.00E-05
OAR_HPTR-----H	OPERATOR FAILS TO ESTABLISH HPR FOR LONG TERM F&B - TRANSIENT WITH CCU AVAI	2.30E-03	1.00E-05
OAR_LTFB-TRA-H	OP. FAILS TO ESTAB. HPR FOR LONG TERM F&B - TRANS, CCU AVAIL.	4.80E-03	1.00E-05
OAR_LTFB-TRB-H	OPERATOR FAILS TO ESTABLISH HPR FOR LONG TERM F&B - TRANSIENT WITH CCU FAIL	4.80E-03	1.00E-05
OAR_LTFB_SLA-H	OPERATOR FAILS TO ESTABLISH HPR FOR LONG TERM F&B -SLO WITH CCUS	4.80E-03	1.00E-05
OAR_LTFB_SLB-H	OPERATOR FAILS TO ESTABLISH HPR FOR LONG TERM F&B -SLO WITHOUT CCUS	1.20E-02	1.00E-05

The cost of implementation of this SAMA has not been estimated in detail, but rather it was passed to Phase II to determine the maximum averted cost risk associated with this potential SAMA.

Results

Implementation of this SAMA yields a reduction in the CDF, dose-risk, and offsite economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 13 Results	1.53E-05	1.99	$1,334
Percent Change	1.5	2.5	5.5

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency (/yr)$_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency (/yr)$_{SAMA}$	2.32E-08	3.03E-08	1.15E-07	8.59E-08	9.40E-06	5.60E-06	2.05E-08	**1.53E-05**
Dose-Risk$_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-Risk$_{SAMA}$	0.02	0.19	0.32	0.21	0.89	0.36	0.00	**1.99**
OECR$_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
OECR$_{SAMA}$	$46	$160	$689	$416	$17	$6	$0	**$1,334**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table. Note that even if a minimum hardware change amount of $100,000 is assumed for the assessment, the averted cost-risk does not support implementation of the SAMA.

SAMA Number 13 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$1,000,272	$17,728	>$100,000	<-$82,272

Given that the cost of implementation is more than the averted cost-risk for this SAMA, the net value is negative.

F.6.11 SAMA NUMBER 14: INSTALL ADDITIONAL INSTRUMENTATION FOR ISLOCA DETECTION

This SAMA would provide additional confidence that detection and response to ISLOCAs could be implemented to reduce the risk from these types of events.

The cost of implementation for this SAMA was estimated to be $425,000 for Farley [SNOC 2003]. A similar cost is assumed to be applicable for Vogtle.

Similar to SAMA 12, in order to bound the potential risk reduction from this SAMA, the CDF and Level 2 contributions from all ISLOCA scenarios were totally removed from the results.

Results

Implementation of this SAMA yields a reduction in the CDF, dose-risk, and offsite economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 14 Results	1.54E-05	1.85	$1,252
Percent Change	0.3	9.3	11.3

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency (/yr)$_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency (/yr)$_{SAMA}$	2.34E-08	0.00E+00	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.54E-05**
Dose-Risk$_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-Risk$_{SAMA}$	0.02	0.00	0.35	0.21	0.89	0.38	0.00	**1.85**
OECR$_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
OECR$_{SAMA}$	$46	$0	$672	$416	$17	$6	$0	**$1,252**

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

SAMA Number 14 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$998,894	$19,106	$425,000	<-$405,894

Given that the cost of implementation is more than the averted cost-risk for this SAMA, the net value is negative.

F.6.12 SAMA NUMBER 15: INSTALL PERMANENT DEDICATED GENERATOR FOR NCP

This SAMA provides a means of limiting the size of a seal LOCA by providing an alternate power source that can be automatically or rapidly aligned to the NCP from the main control room (MCR). This is an alternative approach to SAMA 1 that provided for a backup NCP, but with similar impacts. Long term secondary side cooling can be provided through the operation of the turbine driven AFW pump using existing VEGP procedures. This arrangement would make it possible to provide adequate core cooling in extended SBO evolutions.

The cost of implementation for providing a dedicated diesel generator for the advanced boiling water reactor (ABWR) feedwater or condensate pumps was estimated to be $1.2 million in 1994 [GE 1994]. The capacity of the generator required for the ABWR application likely exceeds that required for the VEGP NCP. As a result, the ABWR cost has been reduced by 25 percent but not inflated to 2007 dollars to estimate a cost of implementation for this SAMA ($900,000).

Results

Implementation of this SAMA yields a reduction in the CDF [SNC 2007j], dose-risk, and offsite economic cost-risk. The results are assumed to be the same as for SAMA 1 and are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 15 Results	8.14E-06	1.69	$1,389
Percent Change	47.5	17.2	1.6

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency (/yr)$_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency (/yr)$_{SAMA}$	1.04E-08	3.03E-08	1.29E-07	8.59E-08	4.99E-06	2.88E-06	2.06E-08	**8.14E-06**
Dose-Risk$_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-Risk$_{SAMA}$	0.01	0.19	0.36	0.21	0.62	0.30	0.00	**1.69**
OECR$_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
OECR$_{SAMA}$	$21	$160	$773	$416	$14	$5	$0	**$1,389**

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

SAMA Number 15 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$591,828	$426,172	$900,000	-$473,828

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

F.6.13 SAMA NUMBER 16: ENHANCE PROCEDURES FOR ISLOCA RESPONSE

This SAMA would provide additional confidence that the response to ISLOCAs could be implemented to reduce the risk from these types of events.

Similar to SAMA 12, in order to bound the potential risk reduction from this SAMA, the CDF and Level 2 contributions from all ISLOCA scenarios were totally removed from the results.

The cost estimate of procedure changes is on the order of $50,000 [CPL 2004]. This is divided by a factor of two to get a per-unit cost.

Results

Implementation of this SAMA yields a reduction in the CDF, dose-risk, and offsite economic cost-risk. The results are summarized in the following table.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 16 Results	1.54E-05	1.85	$1,252
Percent Change	0.3	9.3	11.3

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency $(/yr)_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency $(/yr)_{SAMA}$	2.34E-08	0.00E+00	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.54E-05**
Dose-Risk_{BASE}	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Dose-Risk$_{SAMA}$	0.02	0.00	0.35	0.21	0.89	0.38	0.00	**1.85**
OECR$_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
OECR$_{SAMA}$	$46	$0	$672	$416	$17	$6	$0	**$1,252**

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

SAMA Number 16 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$998,894	$19,106	$25,000	-$5,894

Given that the cost of implementation is more than the averted cost-risk for this SAMA, the net value is negative.

F.7 UNCERTAINTY ANALYSIS

Sensitivity cases were run for the following conditions to assess their impact on the overall SAMA evaluation:

- Use the 95th percentile PRA results in place of the mean PRA results.
- Use a real discount rate of 7 percent, instead of the 3 percent value used in the base case analysis.
- Use alternate MACCS2 input variables for selected cases.

Each of these potential areas of uncertainty is discussed in turn in the sections which follow.

F.7.1 95TH PERCENTILE PRA RESULTS

The results of the SAMA analysis can be impacted by implementing conservative values from the PRA's uncertainty distribution. If the best estimate failure probability values were consistently lower than the "actual" failure probabilities, the PRA model would underestimate plant risk and yield lower than "actual" averted cost-risk values for potential SAMAs. Re-assessing the cost benefit calculations using the high end of the failure probability distributions is a means of identifying the impact of having consistently underestimated failure probabilities for plant equipment and operator actions included in the PRA model. This sensitivity uses the 95th percentile results to examine the impact of uncertainty in the PRA model.

Typical PRA uncertainty calculations identify the 95th percentile CDF as between 1.5 and 2.5 times the mean point estimate CDF values. Therefore, although a detailed uncertainty distribution is not available from the VEGP PRA model at this time, a factor of 2.0 greater than the CDF point estimate produced by the VEGP PRA is used as a reasonable approximation for the uncertainty analysis.

F.7.1.1 PHASE I IMPACT

For Phase I screening, use of the 95th percentile PRA results will increase the MMACR and may prevent the screening of some of the higher cost modifications. However, the impact on the overall SAMA results due to the retention of the higher cost SAMAs for Phase II analysis is typically small. This is due to the fact that the benefit gleaned from the implementation of those SAMAs must be extremely large in order to be cost beneficial.

The impact of uncertainty in the PRA results on the Phase I SAMA analysis has been examined. The MMACR is the primary Phase I criteria affected by PRA uncertainty. Thus, this portion of this sensitivity is focused on recalculating the MMACR using the 95th percentile PRA results and re-performing the Phase I screening process.

As discussed above, the 95th PRA results can be assumed to be approximately a factor of 2.0 greater than point estimate CDF. In order to simulate the use of the 95th percentile results for the Level 2 and 3 models, the same scaling factor calculated for the Level 1 results was assumed to apply to the Level 2 and 3 models. Because the MMACR calculations scale linearly with the CDF, dose-risk, and offsite economic cost-risk, the 95th percentile MMACR can be calculated by multiplying the base case MMACR by 2.0. This results in a 95th percentile MMACR of $2,036,000.

The initial SAMA list has been re-examined using the revised MMACR to identify SAMAs that would be retained for the Phase II analysis. Those SAMAs that were previously screened due to costs of implementation that exceeded $1.02 million are now retained if the costs of implementation are less than $2.04 million. Of the SAMAs screened in the Phase I analysis, only SAMA 5 (permanent dedicated generator for one motor driven AFW pump with an estimated cost of $1.76M per unit) would be retained based on the use of the 95th percentile MMACR of $2.04M instead of the base MMACR value of $1.02M. The Phase II analysis for the SAMA 5 evaluation is shown below in Section F.7.1.2.

F.7.1.2 SAMA NUMBER 5: PERMANENT, DEDICATED GENERATOR FOR ONE MOTOR DRIVEN AFW PUMP AND A BATTERY CHARGER

SAMA 5 will provide the ability of using one motor driven AFW pump in addition to the turbine driven AFW in a station blackout (SBO).

Modeling

For the modeling of SAMA 5, the following assumptions were made:

1. A MDAFW pump needs 4.16V ac power for its pump motor and 125V dc power for pump control. Also 480V ac power is needed to close the pump's min-flow valve to prevent flow diversion to the CST. The dedicated generator system includes 4.16kV ac generator, transformer for the 480V ac battery charger, and associated buses and breakers and it is capable of providing 4.16kV ac, 480V ac, and 125V dc which are needed for one motor driven AFW pump.

2. The dedicated generator system is used only during SBO scenarios. Operators need to start the generator and align the power needed for the start and operation of one MDAFW pump.

3. The generator system can be aligned to either one of the motor driven pumps, but the generator system cannot serve both pumps simultaneously.

4. There is no automatic actuation of the pump after power alignment. Thus, operators need to actuate the pump manually after power alignment. After start, pump control is provided by the control circuitry which is fed from 125V dc from the dedicated system.

To incorporate the implementation of SAMA 5, the base case fault tree model was modified to represent the assumptions described above and the model was solved.

The cost of this enhancement has been estimated to be $3.52M based on a conceptual design of a shared diesel between the units [SNC 2007e]. This equates to a $1.76M per unit cost for the performance of the cost benefit analysis.

Results

Implementation of this SAMA yields a reduction in the CDF [SNC 2007j], dose-risk, and offsite economic cost-risk. The results are summarized in the following table. Note that the results are presented using the point estimate PRA model results (not the 95th percentile values) for consistency with the other SAMA evaluations presented in Sections F.6.1 through F.6.12. The impact if the 95th percentile results are used is presented in Section F.7.1.3 along with the corresponding results from the other unscreened SAMAs.

	CDF (/yr)	Dose-Risk	OECR
Base Results	1.55E-05	2.04	$1,412
SAMA 5 Results	1.37E-05	1.78	$1,320
Percent Change	11.5	12.9	6.5

A further breakdown of this information is provided below according to release category.

Release Category	LERF ISO	LERF BYPASS	LERF SGTR	LATE SGTR	LATE CHR	LATE BMMT	Leakage / INTACT	Total
Frequency (/yr)$_{BASE}$	2.34E-08	3.03E-08	1.28E-07	8.59E-08	9.40E-06	5.79E-06	2.06E-08	**1.55E-05**
Frequency (/yr)$_{SAMA}$	2.16E-08	3.03E-08	1.14E-07	8.59E-08	7.73E-06	5.71E-06	2.06E-08	**1.37E-05**
Dose-Risk$_{BASE}$	0.02	0.19	0.35	0.21	0.89	0.38	0.00	**2.04**
Dose-Risk$_{SAMA}$	0.02	0.19	0.31	0.21	0.66	0.39	0.00	**1.78**
OECR$_{BASE}$	$46	$160	$767	$416	$17	$6	$0	**$1,412**
OECR$_{SAMA}$	$43	$160	$683	$416	$12	$6	$0	**$1,320**

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

SAMA Number 5 Net Value

Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk	Cost of Implementation	Net Value
$1,018,000	$901,320	$116,680	$1,760,000	-$1,643,320

Given that the cost of implementation is more than the averted cost-risk for this SAMA, the net value is negative.

F.7.1.3 OVERALL PHASE II IMPACT

In order to estimate the impact of using the 95th percentile PRA results in the Phase II SAMA analysis, the same process used to calculate the revised MMACR was applied to each of the Phase II SAMAs (the averted cost-risk for each SAMA was increased by a factor of 2.0 over the base case).

The following table provides a summary of the impact of using the 95th percentile PRA results in the detailed cost-benefit calculations that have been performed.

Results Summary for the 95th Percentile PRA Results

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effective-ness?
1	$2,700,000	$426,172	-$2,273,828	$852,344	-$1,847,656	No
2	$25,000	$417,096	$392,096	$834,192	$809,192	No
4	$25,000	$211,496	$186,496	$422,992	$397,992	No
5	$1,760,000	$116,680	-$1,643,320	$233,360	-$1,526,640	No
6	$525,000	$295,686	-$229,314	$591,372	$66,372	Yes
7	$1,050,000	$471,296	-$578,704	$942,592	-$107,408	No
9	$250,000	$25,460	-$224,540	$50,920	-$199,080	No
10	$25,000	$6,464	-$18,536	$12,928	-$12,072	No
11	$580,000	$91,670	-$488,330	$183,340	-$396,660	No
12	>$100,000	$19,106	-$80,894	$38,212	-$61,788	No
13	>$100,000	$17,728	-$82,272	$35,456	-$64,544	No
14	$425,000	$19,106	-$405,894	$38,212	-$386,788	No
15	$900,000	$426,172	-$473,828	$852,344	-$47,656	No
16	$25,000	$19,106	-$5,894	$38,212	$13,212	Yes

Of the SAMAs classified as "not cost beneficial" in the baseline Phase II analysis, two additional SAMAs (SAMA 6 and SAMA 16) were found to be cost beneficial when the 95th percentile PRA results were applied. The use of the 95th percentile PRA results is not considered to provide the most realistic assessment of the cost effectiveness of a SAMA; however, these two additional SAMAs could be considered for implementation to address the uncertainties inherent in the SAMA analysis.

SAMA 6 represents the implementation of a bypass line for the cooling tower return isolation valves. The minimum cost of this enhancement has been estimated to be $525K per unit based on a conceptual design of a modification that would provide a 10" bypass line from the diesel generator cooler return line to downstream of the return isolation valve [SNC 2007f]. Given that the net value is a largely negative (-$229,314) in the base case and barely positive ($66,372) when the 95th percentile results are used makes this an unlikely candidate for consideration at the site. Additionally, as is noted in Section F.6.4, extra expenses compared to the original cost estimate would likely be required to obtain the full benefit as analyzed in the PRA representation for the SAMA. These considerations would make it less likely to be realistically cost beneficial.

Since SAMA 16 was evaluated using a bounding PRA model representation by eliminating all risk from ISLOCA events, even the marginal benefit of just $13,212 using the 95th percentile PRA results is overstated. Additionally, procedures to deal with these types of events already exist (EOP 19112-C ECA1.2) for isolation of ISLOCA paths through RHR and SIS (intermediate head safety injection). Given that the net value is a negative (-$5,894) in the base case and only slightly more positive ($13,212) when the 95th percentile results are used combined with the considerations above make this an unlikely candidate for realistic consideration at the site.

F.7.2 REAL DISCOUNT RATE

A sensitivity study has been performed in order to identify how the conclusions of the SAMA analysis might change based on the value assigned to the real discount rate (RDR). Note that a value of 0.03 instead of a 0.07 value that is recommended in the NEI guidance [NEI 2005] was assumed for the base case assessments based on recently experienced inflation rates which provide more reasonable estimates of future expectations. The original RDR of 3 percent has been changed to 7 percent and the modified maximum averted cost-risk was re-calculated using the methodology outlined in Section F.4. The Phase I screening against the MMACR was re-examined using the revised MMACR to identify any SAMA candidates that could be screened from further analysis based on the premise that their costs of implementation exceeded all possible benefit. In addition, the Phase II analysis was re-performed using the 7 percent RDR.

Implementation of the 7 percent RDR reduced the MMACR by almost 20 percent compared with the case where a 3 percent RDR was used. This corresponds to a decrease in the MMACR from $1,018,000 to $818,000. The Phase I SAMA list was reviewed to determine if such a decrease in the MMACR would impact the disposition of any SAMAs. It was determined that SAMA 7 (installation of enhanced RCP seals) would have more readily screened out in the Phase I analysis if an RDR of 7 percent were used in place of the 3 percent value.

The Phase II SAMAs are dispositioned based on PRA insights or detailed analysis. All of the PRA insights used to screen the SAMAs are still applicable given the use of the 7 percent real discount rate as the change only strengthens the factors used to screen them. The SAMA candidates screened based on these insights are considered to be addressed and are not investigated further.

The remaining Phase II SAMAs were dispositioned based on the results of a SAMA specific cost-benefit analysis. This step has been re-performed using the 7 percent real discount rate to calculate the net values for the SAMAs.

As shown below, the determination of cost effectiveness does not change for any of the Phase II SAMAs when the 7 percent RDR was used in lieu of 3 percent. SAMAs 2 and 4 are still shown to be cost beneficial, and the remaining SAMAs are not cost beneficial.

Phase II Results Summary for 7 Percent RDR Sensitivity

SAMA ID	Cost of Implemen-tation	Averted Cost- Risk (7 percent RDR)	Net Value (7 percent RDR)	Averted Cost- Risk (3 percent RDR)	Net Value (3 percent RDR)	Change in Cost Effective-ness?
1	$2,700,000	$347,002	-$2,352,998	$426,172	-$2,273,828	No
2	$25,000	$336,358	$311,358	$417,096	$392,096	No
4	$25,000	$170,574	$145,574	$211,496	$186,496	No
5	$1,760,000	$93,710	-$1,666,290	$116,680	-$1,643,320	No
6	$525,000	$240,108	-$284,892	$295,686	-$229,314	No
7	$1,050,000	$383,746	-$666,254	$471,296	-$578,704	No

SAMA ID	Cost of Implemen-tation	Averted Cost- Risk (7 percent RDR)	Net Value (7 percent RDR)	Averted Cost- Risk (3 percent RDR)	Net Value (3 percent RDR)	Change in Cost Effective-ness?
9	$250,000	$20,806	-$229,194	$25,460	-$224,540	No
10	$25,000	$4,750	-$20,250	$6,464	-$18,536	No
11	$580,000	$74,544	-$505,456	$91,670	-$488,330	No
12	>$100,000	$13,972	-$86,028	$19,106	-$80,894	No
13	>$100,000	$13,976	-$86,024	$17,728	-$82,272	No
14	$425,000	$13,972	-$411,028	$19,106	-$405,894	No
15	$900,000	$347,002	-$552,998	$426,172	-$473,828	No
16	$25,000	$13,972	-$11,028	$19,106	-$5,894	No

F.7.3 MACCS2 INPUT VARIATIONS

Perturbations to some MACCS2 inputs were investigated to determine their effects on annual risk. The dose risk was chosen to represent that "risk." Among the parameters analyzed, release height, release heat, evacuation speed and meteorological data year have been discussed previously in Section F.3. Plume reference time (i.e., the point on each plume segment that represents its decay, dry deposition and dispersion behavior) was chosen as 0.5 (mid-segment) for the base case; the effect of choosing the leading edge of the segment was considered. The effect of building wake on the risk was determined because the proximity of the VEGP containment and auxiliary buildings introduces uncertainty as to local air flow around these buildings.

Severe meteorological conditions in the last spatial segment of the model domain (40-50 miles) were chosen to assure conservatively high impacts and risks. Most especially, perpetual rainfall was imposed on this segment so that a conservatively large quantity of the nuclides released in each scenario were deposited (via wet deposition) within the model domain.

The table below gives the sensitivity of the risk to the choice of these parameters. The table also discusses the reason for considering that parameter and the result. Release height and release heat are parameters which could affect the risk such that increases on the order of 10% are seen. However, the baseline modeling conservatism of specifying rainfall in the spatial ring from 40-50 miles is seen to more than balance any increases that might be due to not accounting for the two release parameters.

Sensitivity of VEGP Baseline Dose Risk to Parameter Changes

Parameter	Input Discussion	Ratio to 50-Mile Baseline Population Dose Risk	Output Discussion
Annual Met Data Set	Each year 1998-2002	92% (2001) to 97% (2000)	1999 chosen as baseline. Maximum dose and cost risk, most complete data set.
2010 Evacuation Speed	Baseline updated 2006 study (evacuation time estimate for 2010) with 2040 population, assumed EPZ roads at saturation in former.	99%	Faster 2010 evacuation speed results in slight decrease in pop-dose. 0-10 mile dose is minor contributor to 50-mile dose.
Release Height (top of containment)	Baseline assumed ground level release except for tube rupture (aux bldg roof vents). Ground level releases changed to top of containment building.	110%	Increase in release height decreases close-in deposition. Larger downwind population affected by relatively un-depleted plume.
Release Heat (1 MW per segment)	Baseline assumed no heat. Up to 4 segments released per scenario.	103%	Effect of buoyant plume rise is similar to increase in release height.
Release Heat (10 MW per segment)	Baseline assumed no heat. Large value to bound effects.	114%	Increase in buoyancy increases downwind pop-dose. See release height notes above.
Plume Segment Reference Time, REFTIM (0)	Point along each plume segment which represents travel time (decay) and plume location for entire segment. Baseline assumed 0.5 (mid-point). 0 (leading edge) assumed for sensitivity. MACCS sample problem includes both 0 and 0.5 for different segments.	97%	Segment mid-point is most representative. Leading edge corresponds to longer transport time and greater decay.

Sensitivity of VEGP Baseline Dose Risk to Parameter Changes

Parameter	Input Discussion	Ratio to 50-Mile Baseline Population Dose Risk	Output Discussion
Wake Effects, SIGYINIT, SIGZINIT	Baseline determined from release building (containment or auxiliary) dimensions. Minimum horizontal length of aux bldg chosen for releases from that bldg; containment is round. Uncertainty due to proximity of buildings. Sensitivity bases wake parameter on maximum horizontal aux bldg dimension for all (containment and aux bldg) releases.	100%	Minor decrease in dose very near release. Effect on 50-mile dose not noticeable.
Meteorology specification in last spatial segment, LIMSPA	Rainfall imposed at all times from 40 to 50 miles from release to force conservative population exposure.	71%	Entire decrease is due to removing perpetual rainfall (wet deposition) and specifying measured meteorology in ring from 40 to 50 miles from site.

F.7.3.1 IMPACT ON SAMA ANALYSIS

Several different Level 3 input parameters have been examined as part of the VEGP MACCS2 sensitivity analysis. The primary reason for performing these sensitivity runs was to identify any reasonable changes that could be made to the Level 3 input parameters that would impact the conclusions of the SAMA analysis. While the table in Section F.7.3 summarizes the changes to the dose-risk estimates for each sensitivity case, it was necessary to determine if any of these changes would result in the retention of the SAMAs that were screened using the baseline results.

Of all the MACCS2 sensitivity cases, the largest increase in dose-risk was 12 percent associated with parameter 'Release Heat (10 MW per segment)'. Based on this relatively small change, it was judged that the 95th percentile PRA results sensitivity (which utilized a factor of 2.0 on the MMACR and the averted cost risk for each case) bounds the uncertainty associated the MACCS2 results and no additional investigation on the potential impact to the SAMAs is warranted.

F.8 CONCLUSIONS

The benefits of revising the operational strategies in place at VEGP and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. However, use of the PRA in conjunction with cost-benefit analysis methodologies provides an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on offsite dose and economic impacts.

The results of this study indicate that of the identified potential improvements that can be made at VEGP, two are cost beneficial based on the methodology applied in this analysis and warrant further review for potential implementation:

- SAMA 2: Maintain full-time black start capability of the Plant Wilson combustion turbines.
- SAMA 4: Prepare procedures and operator training for cross-tying an opposite unit DG.

SAMAs 2 and 4 have the potential to measurably impact plant risk for a relatively small cost. These two SAMAs could be considered to be cost beneficial alone, but given the similarities between these two SAMAs, implementation of any one of them could make the averted cost risk of implementation of the remaining SAMA not cost beneficial as the relevant risk factors would be addressed.

While these results are believed to accurately reflect potential areas for improvement at the plant, SNC notes that this analysis should not necessarily be considered a formal disposition of these proposed changes as other engineering reviews are necessary to determine ultimate implementation. SNC will consider further the two SAMAs (2 and 4) identified in the analysis through the appropriate VEGP action process.

The results of the uncertainty analysis for this study (95^{th} percentile PRA results) indicate that the following additional SAMAs are potentially cost beneficial:

- SAMA 6: Implementation of a bypass line for the cooling tower return isolation valves

- SAMA 16: Enhance procedures for ISLOCA response

For these two SAMAs, however, it is noted that optimistic cost estimates or PRA model assumptions are likely leading to overestimating the potential averted costs in these cases. Additionally, since even with these conservatisms, the net values are negative in the base case Phase II analysis of these SAMA candidates, and are only slightly positive in the 95th percentile sensitivity case. Consequently, these SAMAs are unlikely candidates for realistic consideration at the site.

F.9 TABLES

TABLE F.2.1 THE HISTORY OF THE VEGP PRA MODEL

Model	SNC calculation ID	Date	Scope	Updated Items	Updated By	Remarks
IPE	WCAP-13553 (Westinghouse report)	11/1992	At-power, internal and external, CDF and Level 2	The original PRA model	SNC and Westinghouse	
Rev. 0	SAIC prepared reports (but no SNC cal.)	3/1998	At-power, internal, CDF and LERF	Conversion from large ET/small FT model to small ET/large FT model (linked fault tree model)	SNC and SAIC	PRA software changed from WESQT/GRAFTER (Westinghouse Event Tree and Fault tree software to CAFTA)
Rev. 0a	PSA-V-98-006	11/1998	At-power, internal, CDF and LERF	Addition of credit for plant Wilson (SBO recovery)	SNC	
Rev. 0b	PSA-V-98-007	11/1998	At-power, internal, CDF and LERF	Addition of maintenance basic events to facilitate MR analysis	SNC	
Rev. 0c	PSA-V-98-009	8/1999	At-power, internal, CDF and LERF	Modularized some sub fault trees, remove unused logic, and corrected minor error	SNC	
Rev. 1	PSA-V-99-002	9/1999	At-power, internal, CDF and LERF	Enhanced treatment of operator action dependency, removed circular logic, and minor corrections and improvements	SNC	
Rev. 2	PSA-V-99-012	1/2000	At-power, internal, CDF and LERF	Update of plant specific failure data update, incorporation of plant changes	SNC	
Rev. 2a	PSA-V-00-003	12/2000	At-power, internal, CDF and LERF	Additional newly identified (by WOG) RCP seal LOCA failure modes, and minor changes to facilitate MR and MOV/AOV risk ranking	SNC	

TABLE F.2.1
THE HISTORY OF THE VEGP PRA MODEL

Model	SNC calculation ID	Date	Scope	Updated Items	Updated By	Remarks
Rev. 2b	PSA-V-00-020	11/2000	At-power, internal, CDF and LERF	Improved recovery tree for recovery analysis	SNC	
Rev. 2c	PSA-V-00-030	11/2001	At-power, internal, CDF and LERF	Revised LERF model based on new WOG LERF modeling guidelines, minor changes to facilitate RI-ISI analysis, removed circular logic in normal charging and emergency boration fault trees	SNC	
Rev. 2cx	PSA-V-02-005	2/2002	At-power, internal, CDF and LERF	Enhanced dc support fault tree (circular logic-cut tree) for EDGs	SNC	
Rev. 2cy	PSA-V-03-002	11/2003	At-power, internal, CDF and LERF	Resolved some of the issues from WOG PRA peer review B F&Os, removed Containment penetrations ≤ 4" diameter from Containment Isolation fault tree in LERF logic by applying the standard WOG definition of LERF	SNC	
Rev. 3	PRA-BC-V-06-001	2/2006	At-power, internal, CDF and LERF	The most extensive update ever done since the IPE. Resolved all WOG PRA peer review B F&Os (there was no A F&O for VEGP) (see Table F.2-2 for details)	SNC	All level 1 PRA tasks from the selection of initiating events to the final quantification were practically re-done.

TABLE F.2.1
THE HISTORY OF THE VEGP PRA MODEL

Model	SNC calculation ID	Date	Scope	Updated Items	Updated By	Remarks
VEGPL2UP Model	P0293060001-2707 (ERIN report)	11/2006	At-power, internal, CDF and full level 2	- Based on Rev.3 Level 1 logic - Developed full level 2 fault tree modeling using direct Level 1 and level 2 logic coupling (guidelines: NUREG/CR-6595 and WCAP-16341-P), - Added containment penetrations (2 to 4" in diameter) which had been deleted previously in revision 2cy back to containment isolation failure tree for LERF, - Incorporated success terms both in level 1 and level 2 logic, - Corrected an inconsistency in WCAP-16141 (RCP seal failure probabilities).	SNC and ERIN	This updated model was used for SAMA analysis SNC provided methodology and directions, and review comments. ERIN constructed the Level 2 logic into the model.
Rev. 4	Not assigned	To be issued in 2007	At-power, internal, CDF and full level 2	To incorporate changes made in VEGPL2UP model into formal VEGP PRA model, Some enhancements in recovery tree rules.	SNC	

TABLE F.2.2
RESOLUTION OF VEGP PRA WOG PEER REVIEW FINDINGS IN VEGP PRA R3

Facts & Observations (F&Os)	Issues (All Significance Level B, No "A" F&Os)	Resolutions in VEGP PRA Revision 3
IE-06	CCF of NSCW pumps among pumps with different operating cycles & histories in special initiating events should be based on plant specific CCF analysis.	CCF of NSCW pumps with different operating cycle & histories were re-evaluated through a detailed VEGP plant specific CCF analysis using NRC CCF database and considering VEGP specific design features.
AS-04	The success state of ISLOCA and SGTR after 24 hours should be no core damage and "a stable" state	Basically, for revision 3, MAAP analyses for determination of success criteria ran for 30 hours for most of the accident sequences. The 30 hr duration included a 24 hour mission time plus 6 additional hours. Generally, if core damage did not occur within 30 hours, it was assumed that core damage had been avoided. This approach would prevent sequences which would result in core damage just after PRA mission time (24 hours) from being categorized as non-core damage sequences. Furthermore, the following modifications were made in ISLOCA and SGTR modeling: • Each ISLOCA potential path is re-examined using event tree approach and identified ISLOCA paths were modeled as fault trees. The success state of ISLOCA was isolation of ISLOCA path by closing (auto or manual) isolation valves before RWST depletion. Inventory makeup until the ISLOCA path is isolated is also required for the success. • If ISLOCA break size was smaller than or equal to 1.0" in diameter, additional success state was considered: the plant would be in stable condition if the RCS was cooled down and depressurized to minimize the leak with AFW and high pressure injection available. Once depressurized, ECCS injection flow requirement would be minimal. For ISLOCA path which could not be isolated by isolation valves and had break size greater than 1" in diameter, core damage was assumed. (continued on next page)

TABLE F.2.2
RESOLUTION OF VEGP PRA WOG PEER REVIEW FINDINGS IN VEGP PRA R3

Facts & Observations (F&Os)	Issues (All Significance Level B, No "A" F&Os)	Resolutions in VEGP PRA Revision 3
AS-04 (continued)	The success state of ISLOCA and SGTR after 24 hours should be no core damage and "a stable" state	(continued) In revision 3, SGTR event tree was revised to reflect EOPs and actual scenarios more accurately. For SGTR, obtaining long term stable state was an issue only when SG Valves stuck open after the SG was overfilled due to failure of SG isolation because if no recovery actions are taken, there would be a continuous primary-to-secondary-to-atmosphere leakage. The MAAP analysis for VEGP for such case showed that core damage would not occur within 30 hours even when SG ARV or SVs stuck open and all CCPs, SIPs, and 200% AFW flow are running. This was because VEGP has relatively large RWST inventory (~700,000 gal). Thus, even without additional RWST water (refilling RWST), operator would have more than enough time to cool down and depressurize the RCS to stop or minimize SG tube leak and stabilize the plant. MAAP analyses also showed that in case of stuck open SG valves due to overfilling, continuous high pressure injection was not critical mitigating function to prevent core damage. Core damage would not occur even after depletion of the RWST as long as AFW was supplied. MAAP analyses showed that 1 CST (VEGP has 2 CSTs) will be enough to prevent core damage for more than 35.5 hours. In revision 3, however, it was conservatively assumed that additional AFW water source either from the secondary CST or makeup from demin tank (automatic or manual) would be required to prevent core damage for such cases. With the additional AFW supply, the plant would be in stable state much beyond 70 hours.

TABLE F.2.2
RESOLUTION OF VEGP PRA WOG PEER REVIEW FINDINGS IN VEGP PRA R3

Facts & Observations (F&Os)	Issues (All Significance Level B, No "A" F&Os)	Resolutions in VEGP PRA Revision 3
AS-05	For some ISLOCA paths, ECCS can not be credited. An ISLOCA through RHR suction or injection lines may result in a leak rate much greater than 120 gpm used in VEGP IPE if RHR HX ruptures due to over-pressurization.	ISLOCA paths were re-identified using event tree method and modeled as fully developed fault trees. Impacts of an ISLOCA to the mitigating systems were modeled in the ISLOCA core damage fault trees. In ISLOCA paths through RHR, it was assumed that the break location would be at the RHR HX and the size of the break was defined by the size of the piping in the path ways: 6" in diameter break for ISLOCA though RHR injection paths, 12" in diameter break for ISLOCA through hot leg suction line. For an ISLOCA through a RHR hot leg suction line, it was assumed that core damage would directly occur because it would cause a 12" diameter break and the path could not be isolated (no isolation valve between hot leg suction and RHR HX). ECCS operation would not affect the consequences. An ISLOCA in an RHR injection line would cause a 6" diameter LOCA. 6" break (highest end of medium LOCA category) can be handled by 2 of 4 CCPs/SIPs until RWST depletion. In order to prevent core damage, however, operators must isolate the ISLOCA path by closing RHR injection isolation motor operated valves. For the isolation be successful, operator must close the valve before RWST is depleted. Core damage was assumed if operator failure or high pressure injection failure occurred. High pressure injection by charging pumps or safety injection by safety injection pumps was not credited in ISLOCA scenarios if any of the flow paths in the system was involved in the scenarios. For example, safety injection systems were not credited for inventory makeup in the ISLOCA through cold leg injection lines of the safety injection system. Also, see resolution to AS-04 for the success state of an ISLOCA.

TABLE F.2.2
RESOLUTION OF VEGP PRA WOG PEER REVIEW FINDINGS IN VEGP PRA R3

Facts & Observations (F&Os)	Issues (All Significance Level B, No "A" F&Os)	Resolutions in VEGP PRA Revision 3
AS-08	Some SGTR sequences modeled as non LERF scenarios may be actually LERF sequences	SGTR event tree was revised. All SGTR core damage sequences are considered as LERF sequences. Exceptions were SGTR-1, SGTR-2, and SGTR-3 sequences. These sequences were not considered as LERF sequence because MAAP analyses showed that without refilling RWST and without having additional AFW water source core damage would not occur within 30 hrs into the event (late core damage sequence)
DA-02	MGL factors used for evaluating VEGP IPE CCF probabilities seem to be too low as compared generic industry data.	VEGP Plant specific CCF analysis was redone using NRC CCF database in order to estimate VEGP specific CCF factors considering VEGP specific defenses against CCF events. Alpha factor model, which is more statistically correct than MGL method, was used for the update. VEGP specific environments, procedures, designs, operations, and implemented measures to prevent CCF were considered in the analysis.
DA-03	The same MGL factors were used for pump failure to start and failure to run CCFs.	VEGP plant specific CCF analysis for the pumps as well as other major components was updated. CCFs for a pump failure to run were evaluated using only CCFs of pump failure to run events. CCFs for a pump failure to start were separately evaluated using only failure to start events. Pumps in different systems were evaluated separately.
DA-04	The probability of safety valve to re-close after passing two phase flow should be higher than that after passing only steam in ATWT and SGTR overfill.	For ATWT, a higher number was used for PZR Safety Valves to fail to reseat because PZR safety valves are not designed for passing two phase flow. However, PZR PORVs are designed for passing either steam or water (Table 5.4.13-1 of VEGP FSAR), thus failure probability was not changed to a higher value. For SGTR overfill, it was conservatively assumed that SG overfill would cause relief or safety valves to stick open.
HR-02	No reference analysis is available for operator action timing.	HRA was updated using the EPRI HRA-Calculator. Review of training materials, interview with operators and instructors, and timing information VEGP-specific, scenario-specific MAAP runs were used as inputs to the HRA update.

TABLE F.3.1
REPRESENTATIVE MAAP LEVEL 2 CASE DESCRIPTIONS FOR VEGP AND KEY EVENT TIMINGS

Case	Release Category	Representative Case Description	SG Dry(1) (Hrs)	Tcu(2) (Hrs)	Tcd(3) (Hrs)	Tvf(4) (Hrs)	Tcf(5) (Hrs)	Tend(6) (Hrs)	Noble Gas Fraction	CsI(7) Fraction
Case 1	INTACT	LOFW, No AFW, NO induced ruptures, VF @ high pressure (HPME occurs), fan coolers OK	1.00	1.70	2.10	3.40	NA	48	3.0E-03	1.5E-05
Case 2a	LATE-BMMT-AFW	SBO, 76 gpm seal LOCA @ 13min, RCS depressurized, fan coolers OK, w/ AFW	54.00	16.48	18.68	25.06	95	120	4.9E-01	2.9E-04
Case 2b	LATE-BMMT-NOAFW	SBO, 76 gpm seal LOCA @ 13min, RCS depressurized, Fan Coolers OK, w/o AFW	0.94	1.17	1.49	2.94	41	72	6.6E-01	3.1E-03
Case 3a	LATE-CHR-AFW	Same as 2a w/o fan coolers	51.90	16.49	18.68	25.11	95	120	9.0E-01	1.2E-04
Case 3b	LATE-CHR-NOAFW	Same as 2b w/o fan coolers	0.94	1.17	1.49	2.78	41	72	9.9E-01	3.1E-03
Case 4	LATE-SGTR	LOFW, w/ AFW, induced ruptures, VF @ high pressure (HPME occurs), fan coolers OK	22.30	23.50	24.60	27.70	NA	48	9.9E-01	4.1E-01
Case 5	LERF-BYPASS	ISLOCA (2' ID) w/o injection	NA	0.02	0.13	1.20	NA	48	1.0E+00	9.6E-01
Case 6a	LERF-ISO-FAN	SBO, 76 gpm seal LOCA @ 13min, RCS depressurized, w/ fan coolers, w/o AFW	0.90	1.20	1.50	2.90	0	48	1.0E+00	3.7E-02
Case 6b	LERF-ISO-NOFAN	SBO, 76 gpm seal LOCA @ 13min, RCS depressurized, w/o fan coolers, w/o AFW	0.90	1.20	1.50	2.90	0	48	1.0E+00	3.7E-02
Case 7	LERF-CFE	LOFW, No AFW, NO induced ruptures, VF @ high pressure > HPME, fan coolers OK, containment failure at vessel breach	1.00	1.70	2.10	3.40	3.4	48	7.0E-01	1.9E-02
Case 8	LERF-SGTR	SBO w/o injection, 76 gpm seal LOCA at 13 min, induced SGTR at 2.5 hr with SG PORV stuck open	1.80	2.20	2.70	4.80	NA	48	8.3E-01	3.8E-01
Case 9	SERF	LOFW, w/ AFW, NO induced ruptures, VF @ high pressure (HPME occurs), fan coolers OK, small containment failure at vessel breach	22.30	23.50	24.55	26.60	26.6	48	3.7E-01	3.7E-03

Notes to Table F.3.1
(1) SG Dry -Time of steam generator dryout
(2) Tcu - Time of core uncovery
(3) Tcd - Time of core damage (maximum core temperature > 1800°F)
(4) Tvf - Time of vessel breach
(5) Tcf – Time of containment failure
(6) Tend – Time at end of run
(7) CsI – Cesium iodide release

TABLE F.3.2
VEGP SOURCE TERM MAGNITUDE AND TIMING RESULTS

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-SGTR	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	SERF
Bin Frequency	2.06E-08	3.64E-06	2.15E-06	5.14E-06	4.26E-06	8.59E-08	3.03E-08	2.34E-08	0.00E+00	1.28E-07	0.00E+00
MAAP Run	Case 1	Case 2a	Case2b	Case 3a	Case 3b	Case 4	Case 5	Case 6b	Case 7	Case 8	Case 9
Run Duration	48 hr	120 hr	72 hr	96 hr	72 hr	48 hr	48 hr	48 hr	48 hr	48 hr	48 hr
Time after Scram when General Emergency is declared [3]	2.1 hr	18.7 hr	1.5 hr	3.1 hr	1.2 hr	24.6 hr	.13 hr	1.5 hr	2.1 hr	2.7 hr	24.6 hr
Fission Product Group:											
1) Noble Gas [1,2]											
Total Plume 1 Release Fraction	3.00E-03	4.00E-01	4.50E-01	9.00E-01	1.00E+00	1.00E+00	1.00E+00	5.00E-01	5.00E-01	8.30E-01	3.00E-01
Start of Plume 1 Release (hr)	2.00	95.00	41.00	95.00	41.00	26.00	0.20	2.00	3.40	2.70	26.00
End of Plume 1 Release (hr)	48.00	95.00	41.00	95.00	41.00	26.00	0.20	4.00	4.00	4.00	34.00
Total Plume 2 Release Fraction2		5.00E-01	7.00E-01					1.00E+00	7.00E-01		3.70E-01
Start of Plume 2 Release (hr)		95.00	41.00					4.00	4.00		34.00
End of Plume 2 Release (hr)		120.00	72.00					48.00	48.00		48.00
2) CsI [1,2]											
Total Plume 1 Release Fraction	1.50E-05	2.00E-04	2.00E-03	1.20E-04	2.00E-03	4.10E-01	9.60E-01	3.00E-02	1.90E-02	3.80E-01	3.70E-03
Start of Plume 1 Release (hr)	2.00	95.00	41.00	95.00	41.00	26.00	0.20	2.00	3.40	2.70	26.00
End of Plume 1 Release (hr)	48.00	95.00	41.00	120.00	45.00	30.00	0.20	4.00	4.00	48.00	34.00
otal Plume 2 Release Fraction2		3.00E-04	3.00E-03		3.00E-03			3.80E-02			
Start of Plume 2 Release (hr)		95.00	41.00		45.00			4.00			
End of Plume 2 Release (hr)		120.00	72.00		72.00			48.00			
3) TeO2 [1,2]											
Total Plume 1 Release Fraction	5.00E-06	1.00E-05	7.00E-05	1.50E-04	5.00E-05	4.00E-01	9.60E-01	5.50E-02	1.50E-02	1.00E-01	2.50E-03
Start of Plume 1 Release (hr)	2.00	20.00	41.00	95.00	41.00	26.00	0.20	2.00	3.40	2.70	26.00
End of Plume 1 Release (hr)	8.00	30.00	41.00	120.00	45.00	26.00	0.20	4.00	4.00	4.00	34.00
Total Plume 2 Release Fraction2			1.00E-04		8.00E-05						
Start of Plume 2 Release (hr)			41.00		45.00						
End of Plume 2 Release (hr)			72.00		72.00						

TABLE F.3.2
VEGP SOURCE TERM MAGNITUDE AND TIMING RESULTS

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-SGTR	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	SERF
4) SrO [1,2]											
Total Plume 1 Release Fraction	6.00E-06	2.50E-06	1.50E-06	3.00E-06	1.00E-06	5.00E-04	7.50E-02	1.00E-03	2.80E-02	8.00E-04	4.20E-03
Start of Plume 1 Release (hr)	2.00	25.00	5.00	25.00	5.00	26.00	0.20	2.00	3.40	2.70	26.00
End of Plume 1 Release (hr)	8.00	30.00	5.00	30.00	5.00	30.00	0.20	4.00	4.00	4.00	26.00
Total Plume 2 Release Fraction2											
Start of Plume 2 Release (hr)											
End of Plume 2 Release (hr)											
5) MoO2 [1,2]											
Total Plume 1 Release Fraction	6.00E-06	3.00E-06	2.00E-07	4.00E-06	3.00E-07	2.50E-03	6.00E-02	1.00E-03	2.50E-02	3.00E-02	3.20E-03
Start of Plume 1 Release (hr)	2.00	20.00	5.00	25.00	5.00	26.00	0.20	2.00	3.40	2.70	26.00
End of Plume 1 Release (hr)	8.00	30.00	5.00	30.00	5.00	30.00	0.20	4.00	4.00	4.00	26.00
Total Plume 2 Release Fraction2											
Start of Plume 2 Release (hr)											
End of Plume 2 Release (hr)											
6) CsOH [1,2]											
Total Plume 1 Release Fraction	4.50E-06	5.00E-06	2.00E-04	2.00E-04	3.00E-04	2.50E-01	9.60E-01	3.00E-02	8.00E-03	5.00E-02	1.00E-03
Start of Plume 1 Release (hr)	2.00	20.00	41.00	95.00	41.00	26.00	0.20	2.00	3.40	2.70	26.00
End of Plume 1 Release (hr)	8.00	30.00	41.00	120.00	45.00	26.00	0.20	4.00	4.00	4.00	26.00
Total Plume 2 Release Fraction2		5.00E-05	3.50E-04		4.00E-04					8.00E-02	
Start of Plume 2 Release (hr)		95.00	41.00		45.00					4.00	
End of Plume 2 Release (hr)		95.00	72.00		72.00					48.00	
7) BaO [1,2]											
Total Plume 1 Release Fraction	6.00E-06	2.00E-06	1.00E-06	3.00E-06	2.00E-06	3.00E-03	9.00E-02	1.00E-03	2.80E-02	8.50E-03	4.00E-03
Start of Plume 1 Release (hr)	2.00	20.00	5.00	25.00	41.00	26.00	0.20	2.00	3.40	2.70	26.00
End of Plume 1 Release (hr)	8.00	30.00	5.00	30.00	41.00	26.00	0.20	4.00	4.00	4.00	26.00
Total Plume 2 Release Fraction2											
Start of Plume 2 Release (hr)											
End of Plume 2 Release (hr)											

TABLE F.3.2
VEGP SOURCE TERM MAGNITUDE AND TIMING RESULTS

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-SGTR	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	SERF
8) La2O3 [1,2]											
Total Plume 1 Release Fraction	6.00E-06	3.00E-06	1.00E-07	3.00E-07	7.50E-08	8.50E-05	1.00E-03	9.00E-05	2.80E-02	4.00E-04	4.20E-03
Start of Plume 1 Release (hr)	2.00	95.00	5.00	25.00	5.00	26.00	0.20	2.00	3.40	4.00	26.00
End of Plume 1 Release (hr)	8.00	95.00	5.00	30.00	5.00	40.00	3.00	4.00	4.00	10.00	26.00
Total Plume 2 Release Fraction2											
Start of Plume 2 Release (hr)											
End of Plume 2 Release (hr)											
9) CeO2 [1,2]											
Total Plume 1 Release Fraction	6.00E-06	3.00E-06	2.50E-06	9.00E-07	2.00E-06	2.00E-04	1.50E-02	2.00E-03	2.80E-02	5.00E-04	4.20E-03
Start of Plume 1 Release (hr)	2.00	95.00	5.00	25.00	5.00	26.00	0.20	2.00	3.40	4.00	26.00
End of Plume 1 Release (hr)	8.00	95.00	5.00	30.00	5.00	30.00	3.00	4.00	4.00	10.00	26.00
Total Plume 2 Release Fraction2											
Start of Plume 2 Release (hr)											
End of Plume 2 Release (hr)											
10) Sb [1,2]											
Total Plume 1 Release Fraction	6.00E-05	1.50E-03	4.00E-03	6.00E-03	2.00E-02	9.00E-02	4.50E-01	2.20E-02	6.00E-02	2.00E-01	1.50E-02
Start of Plume 1 Release (hr)	2.00	95.00	41.00	95.00	41.00	26.00	0.20	2.00	3.40	2.70	26.00
End of Plume 1 Release (hr)	8.00	95.00	41.00	120.00	45.00	30.00	0.20	4.00	4.00	4.00	34.00
Total Plume 2 Release Fraction2			9.00E-03		3.00E-02			7.00E-02			
Start of Plume 2 Release (hr)			41.00		45.00			4.00			
End of Plume 2 Release (hr)			72.00		72.00			48.00			
11) Te2 [1,2]											
Total Plume 1 Release Fraction	5.00E-07	2.00E-06	1.00E-06	1.50E-04	3.00E-04	2.00E-05	5.00E-04	1.00E-04	3.00E-04	3.50E-06	1.00E-04
Start of Plume 1 Release (hr)	2.00	25.00	41.00	95.00	41.00	30.00	0.20	2.00	3.40	4.00	26.00
End of Plume 1 Release (hr)	8.00	50.00	41.00	120.00	45.00	40.00	3.00	4.00	4.00	10.00	34.00
Total Plume 2 Release Fraction2		8.00E-06			5.00E-04						
Start of Plume 2 Release (hr)		95.00			45.00						
End of Plume 2 Release (hr)		95.00			72.00						

TABLE F.3.2
VEGP SOURCE TERM MAGNITUDE AND TIMING RESULTS

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-SGTR	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	SERF
12) UO2 [1,2]											
Total Plume 1 Release Fraction	5.00E-09	3.00E-09	1.50E-08	9.00E-09	2.00E-08	2.00E-08	4.50E-05	8.50E-06	2.00E-06	1.00E-07	2.80E-07
Start of Plume 1 Release (hr)	2.00	95.00	5.00	95.00	41.00	30.00	0.20	2.00	3.40	4.00	26.00
End of Plume 1 Release (hr)	8.00	95.00	5.00	95.00	41.00	40.00	3.00	4.00	4.00	10.00	34.00
Total Plume 2 Release Fraction2											
Start of Plume 2 Release (hr)											
End of Plume 2 Release (hr)											

(1) Puff releases are denoted in the table by those entries with equivalent start and end times.

(2) Plume 2 release fraction is cumulative and includes the initial plume 1 release fraction.

(3) General emergency declaration based on time of core damage per Vogtle EALs.

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
LOSP	2.91E-02	3.302	LOSS OF OFFSITE POWER	The importance of the LOSP event provides limited information about plant risk given that the LOSP category is broad and includes several different contributors. These contributors are represented by other events in this importance list that better define specific failures that can be investigated to identify means of reducing plant risk. No credible means of reducing the VEGP grid-centered LOSP frequency have been identified. Implementation of the Maintenance Rule with risk informed maintenance planning is considered to address on-line risk management and equipment reliability issues such that no measurable improvement in the plant centered LOSP frequency is likely available based on enhancing maintenance practices. It may be possible to improve switchyard work planning and/or practices, but a reliable means of quantifying the impact of these types of changes is not available. No SAMAs suggested.
%SBO	1.00E+00	2.197	STATION BLACKOUT IE IDENTIFIER	The general importance of an SBO suggests that plant risk could be reduced by providing the reactor with a means of operating for an indefinite period of time without ac or dc power. For Vogtle, the most immediate problem is the ability to provide RCP seal cooling in an SBO. This would be followed by the need to maintain inventory in the Primary Coolant System (PCS) and provide secondary side cooling. Installation of a self-powered pump that could be automatically or rapidly aligned to the RCP seal cooling flow path (SAMA 1) in conjunction with the existing capability to operate the turbine driven AFW pump without dc power would allow for long term operation in an SBO. The existing procedures for operating the turbine driven AFW pump without dc power are currently credited in the VEGP PRA model. Changes to maintain credit for black start of the combustion turbines at all times and not just when in a 14-day EDG AOT would also reduce the risk of SBO scenarios (SAMA 2). Implementation of an alternate ac power source would also reduce the CDF risk contribution from this event (SAMA 8).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
WILSON-SWYD-LOSP	6.49E-01	1.78	PLANT WILSON SWYD FAILS GIVEN VEGP LOSP (GRID, SEV OR EXT. WEATHER)	The importance of this event is tied to the contribution of LOSP initiators that also fail the Plant Wilson Switchyard (i.e., all but plant-centered LOSP events). There would not be much to eliminate the loss of grid events from this occurrence, but enhanced structural protection of Plant Wilson Switchyard such that it would be more likely to survive in severe weather and extreme weather events would assist in reducing the failure probability of this event and as such its contribution to CDF risk (SAMA 3).
RCPSL-182GPM	1.98E-01	1.669	RCP SEAL LEAK 182 GPM/PUMP 13 MIN AFTER SBO	The largest contributors to seal LOCAs for Vogtle are sequences where an SBO leads to a loss of seal cooling. Installation of a self-powered pump that could be automatically or rapidly aligned to the RCP seal cooling flow path would provide a means of limiting the size of seal LOCAs after a loss of cooling in an SBO (SAMA 1). After 125V dc battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling. Changes to maintain credit for black start of the combustion turbines at all times and not just when in a 14-day EDG AOT would also reduce the risk of these scenarios (SAMA 2). Improvements to the existing RCP seal design that limited the likelihood that loss of cooling would lead to larger seal LOCAs would reduce the contribution to CDF risk from this and other events (SAMA 7). Additionally, since this event often occurs in combination in the cutsets with failure of the CT return valves, a bypass line around the 1668A and 1669A valves that could be manually opened given failure of the existing valves could greatly reduce the CDF risk from these scenarios (SAMA 6).
1AFPTP4001---X	3.82E-02	1.329	TDAFWP (P4-001) FAILS TO RUN	Installation of a dedicated generator for continued operation and control of a MD AFW pump would reduce the contribution to CDF risk from this event. This generator would need to have the capacity to operate a MD AFW pump and an associated battery charger required for dc power control of the AFW pump (SAMA 5).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
NACR4HR	2.31E-01	1.193	OFFISTE POWER NOT RECOVERED WITHIN 4 HRs AFTER LOSP	This event typically occurs in combination with the 182 gpm seal LOCA event described above. As such, the same SAMAs that would reduce its' importance would also reduce the importance of this event. Installation of a self-powered pump that could be automatically or rapidly aligned to the RCP seal cooling flow path would provide a means of limiting the size of seal LOCAs in an SBO (SAMA 1). Changes to maintain credit for black start of the combustion turbines at all times and not just when in a 14-day EDG AOT would also reduce the risk of these scenarios (SAMA 2). Implementation of an alternate ac power source would also reduce the CDF risk contribution from this event (SAMA 8).
%LOSP	1.00E+00	1.18	LOSS OF OFFSITE POWER IE IDENTIFIER	A large portion of this event's contribution occurs in conjunction with failure to cross-tie the emergency busses to the opposite unit EDG given the plant Wilson switchyard is also unavailable or failed. The current PRA human reliability assessment for this action is that the cross-tie action will not succeed (i.e., HEP failure probability = 1.0) prior to seven hours since procedures and training to perform this action have not been sufficiently developed. Improvement to the procedures and training for performing the cross-tie could reduce the CDF contribution for these scenarios (SAMA 4).
NACR1HR	5.28E-01	1.168	OFFSITE POWER NOT RESTORED WITHIN 1 HR AFTER LOSP	A large portion of this event's importance is linked to the SBO induced seal LOCA. Installation of a self-powered pump that could be automatically or rapidly aligned to the RCP seal cooling flow path would provide a means of limiting the size of seal LOCAs after a loss of cooling in an SBO (SAMA 1). After 125V dc battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling. Changes to maintain credit for black start of the combustion turbines at all times and not just when in a 14-day EDG AOT would also reduce the risk of these scenarios (SAMA 2). Implementation of an alternate ac power source would also reduce the CDF risk contribution from this event (SAMA 8).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
OA-XTIEDGS-4HR	1.00E+00	1.167	OPERATOR FAIL TO X-TIE A DG IN OPPOSITE UNIT WITHIN 4 HRS AFTER SBO	This event represents the failure to cross-tie an emergency bus to an opposite unit EDG given the plant Wilson switchyard is also unavailable or failed. The current PRA human reliability assessment for this action is that the cross-tie action will not succeed (i.e., HEP failure probability = 1.0) prior to seven hours since procedures and training to perform this action have not been sufficiently developed. Improvement to the procedures and training for performing the cross-tie could reduce the CDF contribution for these scenarios (SAMA 4).
NACR-G	1.00E-01	1.166	OFFSITE POWER NOT RECOVERED - NOT SBO, AT LEAST 1 DG INITIALLY RUN	A large portion of this event's contribution occurs in conjunction with failure to cross-tie the emergency busses to an opposite unit EDG given the plant Wilson switchyard is also unavailable or failed. The current PRA human reliability assessment for this action is that the cross-tie action will not succeed (i.e., HEP failure probability = 1.0) prior to seven hours since procedures and training to perform this action have not been sufficiently developed. Improvement to the procedures and training for performing the cross-tie could reduce the CDF contribution for these scenarios (SAMA 4).
PAV	1.00E+00	1.162	PLANT AVAILABILITY	This flag is included in all of the special initiator fault trees, and as such does not represent any unique contributions to risk. The importance of special initiating events is captured individually in this importance list review. No SAMAs suggested.
OA-XTIE-DGS-GH	1.00E+00	1.15	OP. FAILS TO X-TIE DGS GIVEN PLANT WILSON FAILED - GENERAL CASE, NO #SBO IE	This event represents the failure to cross-tie an emergency bus to an opposite unit EDG given the plant Wilson switchyard is also unavailable or failed. The current PRA human reliability assessment for this action is that the cross-tie action will not succeed (i.e., HEP failure probability = 1.0) prior to seven hours since procedures and training to perform this action have not been sufficiently developed. Improvement to the procedures and training for performing the cross-tie could reduce the CDF contribution for these scenarios (SAMA 4).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
OA-XTIEDGS-1HR	1.00E+00	1.147	OPERATOR FAIL TO X-TIE A DG IN OPPOSITE UNIT WITHIN 1 HR AFTER SBO	This event represents the failure to cross-tie the emergency busses to an opposite unit EDG given the plant Wilson switchyard is also unavailable or failed. The current PRA human reliability assessment for this action is that the cross-tie action will not succeed in the early time frame (i.e., HEP failure probability = 1.0) since procedures and training to perform this action have not been sufficiently developed. Improvement to the procedures and training for performing the cross-tie could reduce the CDF contribution for these relevant SBO scenarios with at least one EDG available from the other unit (SAMA 4).
1AC--ARUN-LS-FCC	1.84E-02	1.135	COMMON CAUSE FAILURE OF LS RELAYS ON HEAVILY LOADED TRAIN	The importance of this event occurs mostly in combination with failures of the TD AFW system or seal LOCAs larger than 21 gpm. Installation of a dedicated generator for continued operation and control of a MD AFW pump would reduce the contribution to CDF risk from this event (SAMA 5). Additionally, improvements to the existing RCP seal design that limited the likelihood that loss of cooling would lead to larger seal LOCAs would reduce the contribution to CDF risk from this and other events (SAMA 7).
1SWMV1668A69ADCC	2.66E-04	1.133	NSCW CT RETURN ISOLATION VALVE HV1668A & 69A FAILS TO OPEN DUE TO CCF	This event represents the common cause failure of the CT return valves. This results in an SBO with cooling water to the EDGs and other systems unavailable. A bypass line around the 1668A and 1669A valves that could be manually opened given failure of the existing valves could greatly reduce the CDF risk from these scenarios (SAMA 6).
RCPSL-GT21GPM	2.10E-01	1.132	RCP SEAL LEAK GREATER THAN 21 GPM/RCP AFTER TOTAL LOSS OF SEAL CLG.	The importance of this event is predominantly tied to loss of seal cooling initiators in which larger (> 21 gpm) seal LOCAs ensue. Improvements to the existing RCP seal design that limited the likelihood that loss of cooling would lead to larger seal LOCAs would reduce the contribution to CDF risk from this and other events (SAMA 7).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
RCPSL-21GPM	7.90E-01	1.129	RCP SEAL LEAK 21 GPM/PUMP AFTER 13 MIN. TOTAL LOSS OF SEAL COOLING	The largest contributors to seal LOCAs for Vogtle are sequences where an SBO leads to a loss of seal cooling. Installation of a self-powered pump that could be automatically or rapidly aligned to the RCP seal cooling flow path would provide a means of limiting the size of seal LOCAs after a loss of cooling in an SBO (SAMA 1). After 125V dc battery depletion, existing procedures would provide guidance on operating the turbine driven AFW pump to maintain secondary side cooling. Changes to maintain credit for black start of the combustion turbines at all times and not just when in a 14-day EDG AOT would also reduce the risk of these scenarios (SAMA 2).
%LONSCW	1.00E+00	1.124	LOSS OF NSCW IDENTIFIER	The importance of this initiator is predominantly tied to the likelihood that a subsequent seal LOCA larger than 21 gpm ensues. Improvements to the existing RCP seal design that limited the likelihood that loss of cooling would lead to larger seal LOCAs would reduce the contribution to CDF risk from this and other events (SAMA 7).
OAB_TR-------H	1.04E-01	1.115	OP. FAILS TO FEED AND BLEED - TRANSIENT, HEP=LD ON OA AFW OR MFW START	The importance of this event is tied directly to failures of both AFW trains. It is listed as a dependent HEP, but based on the recovery method utilized at VEGP (with reduction factors applied when it appears as an independent HEP failure), its' importance is more related to AFW hardware failures rather than AFW related HEP failures. As such, improvements to the existing AFW reliability such as that afforded by installation of a dedicated generator for continued operation and control of a MD AFW pump would reduce the contribution to CDF risk from this event (SAMA 5).
1DGDGG4002---X	7.54E-02	1.104	DG1B FAILS TO RUN BY RANDOM CAUSE (24 HR MISSION TIME)	The importance of this event occurs because of the dominant presence of LOOP and SBO events to the risk profile at VEGP. Several SAMAs (1, 2, 3, 4, 5, 7 and 8) have been identified that would reduce the CDF risk contribution from this event.
1AFPTP4001---A	1.41E-02	1.099	TDAFWP (P4-001) FAILS TO START	Installation of a dedicated generator for continued operation and control of a MD AFW pump would reduce the contribution to CDF risk from this event (SAMA 5).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
1DGDGG4001---X	7.54E-02	1.09	DG1A FAILS TO RUN BY RANDOM CAUSE (24 HR MISSION TIME)	The importance of this event occurs because of the dominant presence of LOOP and SBO events to the risk profile at VEGP. Several SAMAs (1, 2, 3, 4, 5, 7, and 8) have been identified that would reduce the CDF risk contribution from this event.
1SWMV1669A---D	6.26E-03	1.086	NSCW CT RETURN ISOLATION VALVE HV1669A FAILS TO OPEN ON DEMAND	This event represents the failure of the Loop "B" CT return valve. This results in failure of cooling water to one of the EDGs and other systems. A bypass line around the 1668A and 1669A valves that could be manually opened given failure of the existing valves could greatly reduce the CDF risk from this event (SAMA 6).
OA-OSW-------H	2.20E-02	1.073	NSCW PUMP 1, 2, 3, 4, 5, OR 6 INITIATOR AND OPERATOR FAILS TO ESTABLISH 1 NSCW PUMP	This event contributes to the loss of NSCW initiator given failure of the operating NSCW pumps via failure to manually establish cooling from at least 1 NSCW pump. Given the HEP for this action is relatively low, more reduction could occur if the associated events were reduced. Since the importance of this event occurs in combination with seal LOCAs > 21 gpm, the SAMAs related to reducing the seal LOCA potential (i.e., SAMA 1 and SAMA 7) would also reduce the risk contribution from this event.
1SWPM1234---&XCC	2.24E-04	1.071	NSCW PUMPS 1, 2, 3, & 4S PUMPS FAIL TO RUN (1 YEAR) - CCF	This event contributes to the Loss of NSCW initiator that results in core damage should a seal LOCA > 21 gpm ensue. Improvements to the existing RCP seal design that limited the likelihood that loss of cooling would lead to larger seal LOCAs would reduce the contribution to CDF risk from this and other events (SAMA 7), as would SAMA 1 which would provide an independent means of reducing the potential for seal LOCAs from occurring.
1DGDGG4002---M	9.79E-03	1.071	DG1B IN MAINTENANCE	The importance of this event occurs because of the dominant presence of LOOP and SBO events to the risk profile at VEGP. Several SAMAs (1, 2, 3, 4, 5, 7, and 8) have been identified that would reduce the CDF risk contribution from this event.

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
1SWMV1668A---D	6.26E-03	1.068	NSCW CT RETURN ISOLATION VALVE HV1668A FAILS TO OPEN ON DEMAND	This event represents the failure of the Loop "A" CT return valve. This results in failure of cooling water to one of the EDGs and other systems. A bypass line around the 1668A and 1669A valves that could be manually opened given failure of the existing valves could greatly reduce the CDF risk from this event (SAMA 6).
1OVDM-OABTR	5.47E-01	1.068	CORRECTION FACTOR FOR OAB_TR-------H IF INDENPENDENT - TRAN w/o MFW CREDIT CASE	Already covered by evaluation of event OAB_TR-------H above. No additional SAMAs suggested.
1DGDGG4001---M	9.79E-03	1.046	DG1A IN MAINTENANCE	The importance of this event occurs because of the dominant presence of LOOP and SBO events to the risk profile at VEGP. Several SAMAs (1, 2, 3, 4, 5, 7, and 8) have been identified that would reduce the CDF risk contribution from this event.
1DGDGG4002---A	4.91E-03	1.045	DG1B FAILS TO START BY RANDOM CAUSE	The importance of this event occurs because of the dominant presence of LOOP and SBO events to the risk profile at VEGP. Several SAMAs (1, 2, 3, 4, 5, 7, and 8) have been identified that would reduce the CDF risk contribution from this event.
1SWPMALL----&XCC	3.14E-06	1.044	CCF AFFECTING ALL NSCWPS REGARDLESS OF DIFFERENT OP. HISTORIES (1YR)	This event contributes to the Loss of NSCW initiator that results in core damage should a seal LOCA > 21 gpm ensue. Improvements to the existing RCP seal design that limited the likelihood that loss of cooling would lead to larger seal LOCAs would reduce the contribution to CDF risk from this and other events (SAMA 7), as would SAMA 1 which would provide an independent means of reducing the potential for seal LOCAs from occurring.

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
OA-START-AFW-H	4.80E-03	1.038	OPERATOR ACTION TO MANUALLY START AFWPUMPS IN MCR FAILS	Given the relatively low value of this event, it would not be that effective to reduce this event value, but rather it would be more effective to reduce the failure mode of the event that leads to the need for this action. That is, improvements to the ESFAS train reliability such that the common cause failure contribution of the A and B ESFAS trains were reduced would reduce the CDF contribution from this operator action failure. However, since the ESFAS modeling in the VEGP PRA model is very simplified (and as such leads to an artificially high ESFAS CCF probability), it is believed that the importance of this event is overstated. Sensitivity cases revealed that if the ESFAS CCF probability is reduced by a factor of 10, then the Risk Reduction Worth of this event is correspondingly reduced to 1.008 which is well below the threshold RRW value of 1.02 to identify SAMAs. Based on all of the considerations identified above, no SAMAs are suggested.
1SACC--SAFACTXCC	6.42E-04	1.037	ESFAS TRAINS A AND B UNAVAILABLE DUE TO COMMON CAUSE FAILURE	Improvements to the ESFAS train reliability such that the common cause failure contribution of the A and B ESFAS trains were reduced would reduce the CDF contribution from this failure mode. However, since the ESFAS modeling in the VEGP PRA model is very simplified (and as such leads to an artificially high ESFAS CCF probability), it is believed that the importance of this event is overstated. Sensitivity cases revealed that if the ESFAS CCF probability is reduced by a factor of 10, then the Risk Reduction Worth of this event is correspondingly reduced to 1.005 which is well below the threshold RRW value of 1.02 to identify SAMAs. Based on all of the considerations identified above, no SAMAs are suggested.

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
1SWFN4ORMORE-ACC	1.59E-04	1.033	4 OR MORE NSCW FANS FAIL TO START DUE TO COMMON CAUSE FAILURE	The failure of this event often occurs in combination with AFW failures and/or with the presence of seal LOCAs. As such, improvements to the existing AFW reliability such as that afforded by installation of a dedicated generator for continued operation and control of a MD AFW pump would reduce the contribution to CDF risk from this event (SAMA 5). Additionally, improvements to the existing RCP seal design that limited the likelihood that loss of cooling would lead to larger seal LOCAs would reduce the contribution to CDF risk from this and other events (SAMA 7), as would SAMA 1 which would provide an independent means of reducing the potential for seal LOCAs from occurring.
1DGDGG4001---A	4.91E-03	1.032	DG1A FAILS TO START BY RANDOM CAUSE	The importance of this event occurs because of the dominant presence of LOOP and SBO events to the risk profile at VEGP. Several SAMAs (1, 2, 3, 4, 5, 7, and 8) have been identified that would reduce the CDF risk contribution from this event.
1ACCB02050301DCC	2.19E-04	1.032	RAT A & B SUPPLY CIRCUIT BREAKERS FAIL TO OPEN BY COMMON CAUSE	The importance of this event is based on it typically appearing in cutsets when the plant Wilson switchyard is also unavailable or failed. Therefore, enhanced structural protection of Plant Wilson Switchyard such that it would be more likely to survive in severe weather and extreme weather events would also reduce the risk contribution from this failure mode (SAMA 3).
1DGDGU2DG----X	7.54E-02	1.031	OPPOSITE UNIT DG FAILS TO RUN (24 HR MISSION TIME)-RANDOM FAILURE	The need for this action to occur is contingent upon the Plant Wilson Switchyard being unavailable or failed. Changes to maintain credit for black start of the combustion turbines at all times and not just when in a 14-day EDG AOT would reduce the risk contribution from this failure mode (SAMA 2). Additionally, enhanced structural protection of Plant Wilson Switchyard such that it would be more likely to survive in severe weather and extreme weather events would also reduce the risk contribution from this failure mode (SAMA 3).

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
1ACREK158B--9F	3.35E-03	1.03	LOSP RELAY K158B FAILS TO OPERATE	The importance of this event is based on it typically appearing in cutsets with TD AFW pump failures and failure to align the emergency busses to the one available EDG given the plant Wilson switchyard is also unavailable or failed. Improvement to the procedures and training for performing the cross-tie could reduce the CDF contribution for scenarios with at least one EDG available (SAMA 4), as would installation of a dedicated generator for continued operation and control of a MD AFW pump reduce the contribution to CDF risk from this equipment failure (SAMA 5).
OAR_HISBOACR-H	2.70E-02	1.029	OPERATOR FAILS TO START HPI. AFTER AC RECOVERED IN SBO	The importance of this event is contingent upon the need for HPI following ac power recovery which means that a LOOP event with a sufficiently large seal LOCA that makeup is required has occurred. Several LOOP and SBO related SAMAs (1, 2, 3, and 7) have been identified that would reduce the CDF risk contribution from this event. Additionally, however, automatic initiation of HPI following ac power recovery would also reduce the importance of this event. Therefore, installation of an automatic initiation system for HPI on low RCS level following ac power recovery is identified as a potential area for plant improvement (SAMA 9).
OAF_MFW------H	5.10E-01	1.028	OP. FAILS TO ESTABLISH MFW TO SGs, DEP=HD ON OA-START-AFW-H	Already covered by evaluation of event OA-START-AFW-H above. No SAMAs suggested.

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
1ACCBBA0301--D	3.00E-03	1.027	RAT B SUPPLY CIRCUIT BREAKER FAILS TO OPEN BY RANDOM CAUSE	The importance of this event is based on it typically appearing in cutsets with TD AFW pump failures and failure to align the emergency busses to the one available EDG given the plant Wilson switchyard is also unavailable or failed. Improvement to the procedures and training for performing the cross-tie could reduce the CDF contribution for scenarios with at least one EDG available (SAMA 4), as would installation of a dedicated generator for continued operation and control of a MD AFW pump reduce the contribution to CDF risk from this equipment failure (SAMA 5).
RES-4160V	1.00E-01	1.027	FAILURE TO RESTORE 4160V BUS WITHIN 4 HRS	This event is based on generic analysis rather than on plant-specific insights, procedures, or examination of reliability data. As such there is not much that could be done to change this frequency. However, failure of this event is typically combined with TD AFW pump failures that lead to core damage. Therefore, installation of a dedicated generator at the 480V level for continued operation and control of a MD AFW pump would reduce the contribution to CDF risk from this event (SAMA 5).
1ACCBBA0319--K	2.91E-03	1.026	DG-B OUTPUT BREAKER BA0319 FAILS TO CLOSE RANDOMLY	The importance of this event occurs because of the dominant presence of LOOP and SBO events to the risk profile at VEGP. Several SAMAs (1, 2, 3, 4, 5, 7, and 8) have been identified that would reduce the CDF risk contribution from this event.
1ACBSAA02&---F	4.52E-03	1.025	4.16 KV BUS AA02 FAILURE - SPECIAL IE	This event represents the initiating event frequency for the Loss of 4.16 kV Bus AA02. Since this low frequency is determined from industry standard practices based on generic data, there is not much that could be done to change this frequency. However, failure of this event is typically combined with TD AFW pump failures that lead to core damage. Therefore, installation of a dedicated generator at the 480V level for continued operation and control of a MD AFW pump would reduce the contribution to CDF risk from this event (SAMA 5).
%LO4160VA	1.00E+00	1.025	LOSS OF 4.16KV BUS A SPECIAL IE IDENTIFIER	This is an initiating event flag that appears in tandem with the bus failure event (1ACBSAA02&---F) event described above. No additional SAMAs suggested.

TABLE F.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
1ACREK158A--9F	3.35E-03	1.022	LOSP RELAY K158A FAILS TO OPERATE	The importance of this event is based on it typically appearing in cutsets with TD AFW pump failures and failure to align the emergency busses to the one available EDG given the plant Wilson switchyard is also unavailable or failed. Improvement to the procedures and training for performing the cross-tie could reduce the CDF contribution for scenarios with at least one EDG available (SAMA 4), as would installation of a dedicated generator for continued operation and control of a MD AFW pump reduce the contribution to CDF risk from this equipment failure (SAMA 5).

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
NO_BYPASS	1.00E+00	50.484	CONTAINMENT NOT BYPASSED	This flag represents that the containment is not bypassed and as such does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
RCS_HIGH	1.00E+00	38.169	RCS PRESSURE HIGH - RISK OF INDUCED SGTR	This flag represents that the RCS is initially at high pressure and as such does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
LOSP	2.91E-02	4.284	LOSS OF OFFSITE POWER	Addressed in the Level 1 importance list.
WILSON-SWYD-LOSP	6.49E-01	3.409	PLANT WILSON SWYD FAILS GIVEN VEGP LOSP (GRID, SEV OR EXT. WEATHER)	Addressed in the Level 1 importance list.
%SBO	1.00E+00	2.16	STATION BLACKOUT IE IDENTIFIER	Addressed in the Level 1 importance list.
PDS_SBO	1.00E+00	2.157	LEVEL 2 PLANT DAMAGE STATE POWER UNAVAILABLE	The importance of this event occurs because of the dominant presence of SBO events to the risk profile at VEGP. Several SAMAs (1, 2, 3, 4, 5, 7, and 8) have been identified that would reduce the Level 2 risk contribution from this event.
NO_CFE1	1.00E+00	2.153	NO CONTAINMENT FAILURE EARLY	This flag represents that early containment failure does not occur and as such does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
VB_LOW	1.00E+00	2.145	CORE DAMAGE NOT ARRESTED BEFORE VESSEL BREACH	This flag represents the fact that no additional credit is taken for recovery of a damaged core in-vessel prior to vessel breach in SBO scenarios. Several SAMAs (1, 2, 3, 4, 5, 7, and 8) have been identified that would reduce the CDF and therefore the Level 2 risk contribution from this event.
NO_LATESGTR	1.00E+00	1.834	NOT A LATE SGTR SEQUENCE	This flag represents that the core damage event is not a late SGTR sequence and as such does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
PDS_NO_SBO	1.00E+00	1.834	LEVEL 2 PLANT DAMAGE STATE POWER AVAILABLE	This flag represents that the core damage event is not an SBO and as such does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
NO_CFE5	1.00E+00	1.77	NO CONTAINMENT FAILURE EARLY	This flag represents that early containment failure does not occur and as such does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
RCS_DEP_SUCCESS	9.10E-01	1.665	OPERATORS SUCCESSFULLY DEPRESSURIZE THE RCS EARLY	This event represents the success of early depressurization and as such does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
RCPSL-182GPM	1.98E-01	1.543	RCP SEAL LEAK 182 GPM /PUMP 13 MIN AFTER SBO	Addressed in the Level 1 importance list.
1AFPTP4001---X	3.82E-02	1.44	TDAFWP (P4-001) FAILS TO RUN	Addressed in the Level 1 importance list.
NACR4HR	2.31E-01	1.434	OFFISTE POWER NOT RECOVERED WITHIN 4 HRs AFTER LOSP	Addressed in the Level 1 importance list.

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
OA-XTIEDGS-4HR	1.00E+00	1.367	OPERATOR FAIL TO X-TIE A DG IN OPPOSITE UNIT WITHIN 4 HRS AFTER SBO	Addressed in the Level 1 importance list.
%LOSP	1.00E+00	1.298	LOSS OF OFFSITE POWER IE IDENTIFIER	Addressed in the Level 1 importance list.
NACR-G	1.00E-01	1.291	OFFSITE POWER NOT RECOVERED - NOT SBO, AT LEAST 1 DG INITIALLY RUN	Addressed in the Level 1 importance list.
NACR1HR	5.28E-01	1.291	OFFSITE POWER NOT RESTORED WITHIN 1 HR AFTER LOSP	Addressed in the Level 1 importance list.
NO_PI-SGTR_NOSBO	9.93E-01	1.288	NO PRESSURE INDUCED SGTR FOR POWER AVAILABLE SEQUENCES	This event represents that a pressure induced tube rupture does not occur and as such does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
NO_L2PI-SGTR_SBO	9.93E-01	1.274	NO PRESSURE INDUCED SGTR FOR SBO SEQUENCES	This event represents that a pressure induced tube rupture does not occur and as such does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
OA-XTIEDGS-1HR	1.00E+00	1.251	OPERATOR FAIL TO X-TIE A DG IN OPPSOITE UNIT WITHIN 1 HR AFTER SBO	Addressed in the Level 1 importance list.

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
OA-XTIE-DGS-GH	1.00E+00	1.246	OP. FAILS TO X-TIE DGS GIVEN PLANT WILSON FAILED - GENERAL CASE, no #SBO IE	Addressed in the Level 1 importance list.
RCPSL-GT21GPM	2.10E-01	1.231	RCP SEAL LEAK GREATER THAN 21 GPM/RCP AFTER TOTAL LOSS OF SEAL CLG.	Addressed in the Level 1 importance list.
PAV	1.00E+00	1.223	PLANT AVAILABILITY	Addressed in the Level 1 importance list.
%LONSCW	1.00E+00	1.216	LOSS OF NSCW IDENTIFIER	Addressed in the Level 1 importance list.
RCPSL-21GPM	7.90E-01	1.208	RCP SEAL LEAK 21 GPM/PUMP AFTER 13 MIN. TOTAL LOSS OF SEAL COOLING	Addressed in the Level 1 importance list.
1AC--ARUN-LS-FCC	1.84E-02	1.184	COMMON CAUSE FAILURE OF LS RELAYS ON HEAVILY LOADED TRAIN	Addressed in the Level 1 importance list.
1DGDGG4002---X	7.54E-02	1.176	DG1B FAILS TO RUN BY RANDOM CAUSE (24 HR MISSION TIME)	Addressed in the Level 1 importance list.

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
1DGDGG4001---X	7.54E-02	1.151	DG1A FAILS TO RUN BY RANDOM CAUSE (24 HR MISSION TIME)	Addressed in the Level 1 importance list.
1AFPTP4001---A	1.41E-02	1.125	TDAFWP (P4-001) FAILS TO START	Addressed in the Level 1 importance list.
OA-OSW-------H	2.20E-02	1.122	NSCW PUMP 1, 2, 3, 4, 5, OR 6 INITIATOR AND OPERATOR FAILS TO ESTABLISH 1 NSCW PUMP	Addressed in the Level 1 importance list.
1SWPM1234---&XCC	2.24E-04	1.12	NSCW PUMPS 1, 2, 3, & 4 PUMPS FAIL TO RUN (1 YEAR) - CCF	Addressed in the Level 1 importance list.
1DGDGG4002---M	9.79E-03	1.095	DG1B IN MAINTENANCE	Addressed in the Level 1 importance list.
1SWMV1669A---D	6.26E-03	1.077	NSCW CT RETURN ISOLATION VALVE HV1669A FAILS TO OPEN ON DEMAND	Addressed in the Level 1 importance list.
1SWPMALL----&XCC	3.14E-06	1.073	CCF AFFECTING ALL NSCWPS REGARDLESS OF DIFFERENT OP. HISTORIES (1YR)	Addressed in the Level 1 importance list.
1DGDGG4001---M	9.79E-03	1.061	DG1A IN MAINTENANCE	Addressed in the Level 1 importance list.

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
1DGDGG4002---A	4.91E-03	1.059	DG1B FAILS TO START BY RANDOM CAUSE	Addressed in the Level 1 importance list.
1SWMV1668A---D	6.26E-03	1.055	NSCW CT RETURN ISOLATION VALVE HV1668A FAILS TO OPEN ON DEMAND	Addressed in the Level 1 importance list.
1DGDGU2DG----X	7.54E-02	1.051	OPPOSITE UNIT DG FAILS TO RUN (24 HR MISSION TIME)-RANDOM FAILURE	Addressed in the Level 1 importance list.
1SWMV1668A69ADCC	2.66E-04	1.051	NSCW CT RETURN ISOLATION VALVE HV1668A & 69A FAILS TO OPEN DUE TO CCF	Addressed in the Level 1 importance list.
1SWFN4ORMORE-ACC	1.59E-04	1.047	4 OR MORE NSCW FANS FAIL TO START DUE TO COMMON CAUSE FAILURE	Addressed in the Level 1 importance list.
1DGDGG4001---A	4.91E-03	1.043	DG1A FAILS TO START BY RANDOM CAUSE	Addressed in the Level 1 importance list.
1ACCB02050301DCC	2.19E-04	1.041	RAT A & B SUPPLY CIRCUIT BREAKERS FAIL TO OPEN BY COMMON CAUSE	Addressed in the Level 1 importance list.
1ACREK158B--9F	3.35E-03	1.039	LOSP RELAY K158B FAILS TO OPERATE	Addressed in the Level 1 importance list.

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
RCS_DEP_HEP	9.00E-02	1.039	OPERATORS FAIL TO DEPRESSURIZE THE RCS EARLY	This event represents the failure to depressurize the RCS early and leaves the RCS susceptible to thermally induced steam generator tube ruptures. Improvements to existing procedures and training for implementing more timely RCS depressurization is identified as SAMA 10.
RCS_DEP2_SUCCESS	9.80E-01	1.037	OPERATORS SUCCESSFULLY DEPRESSURIZE THE RCS LATE	This event represents the success of RCS depressurization after initial failure and as such does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.
1ACCBBA0301--D	3.00E-03	1.035	RAT B SUPPLY CIRCUIT BREAKER FAILS TO OPEN BY RANDOM CAUSE	Addressed in the Level 1 importance list.
1ACCBBA0319--K	2.91E-03	1.034	DG-B OUTPUT BREAKER BA0319 FAILS TO CLOSE RANDOMLY	Addressed in the Level 1 importance list.
OA-ALIGNPW-G-H	9.20E-02	1.029	OPERATOR FAILS TO ALIGN PLANT WILSON - GENERAL CASE, NO #SBO IE	The importance of this event occurs mostly in combination with DG failures and failure to cross-tie the EDGs. Improvement to the procedures and training for performing the cross-tie could reduce the Level 2 contribution for scenarios that include this failure (SAMA 4).
1ACREK158A--9F	3.35E-03	1.029	LOSP RELAY K158A FAILS TO OPERATE	Addressed in the Level 1 importance list.

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
OA-ALIGNPW-1HR	9.20E-02	1.027	OPERTATOR FAIL TO ALIGN PLANT WILSON TO 4.16KV BUS WITHIN 1 HR AFTER SBO	The importance of this event is predominantly tied to loss of seal cooling initiators in which large (480 gpm) seal LOCAs ensue. Installation of a self-powered pump that could be automatically or rapidly aligned to the RCP seal cooling flow path would provide a means of limiting the size of seal LOCAs after a loss of cooling in an SBO (SAMA 1). Improvements to the existing RCP seal design that limited the likelihood that loss of cooling would lead to larger seal LOCAs would reduce the contribution to the Level 2 risk from this and other events (SAMA 7).
1ACCBAA0205--D	3.00E-03	1.026	RAT A SUPPLY CIRCUIT BREAKER FAILS TO OPEN BY RANDOM CAUSE	The importance of this event is based on it typically appearing in cutsets with TD AFW pump failures and failure to align the emergency busses to the one available EDG given the plant Wilson switchyard is also unavailable or failed. Improvement to the procedures and training for performing the cross-tie could reduce the Level 2 contribution for scenarios with at least one EDG available (SAMA 4), as would installation of a dedicated generator for continued operation and control of a MD AFW pump reduce the contribution to Level 2 risk from this equipment failure (SAMA 5).
1ACCBAA0219--K	2.91E-03	1.025	DG-A OUTPUT BREAKER AA0219 FAILS TO CLOSE RANDOMLY	The importance of this event occurs because of the dominant presence of LOOP and SBO events to the risk profile at VEGP. Several SAMAs (1, 2, 3, 4, 5, 7, and 8) have been identified that would reduce the Level 2 risk contribution from this event.
NO_TI-SGTR_NOSBO	9.63E-01	1.02	NO TEMPERATURE INDUCED SGTR FOR POWER AVAILABLE SEQUENCES	This flag represents that a temperature induced tube rupture does not occur and as such does not provide any insights related to potential means of reducing plant risk. No SAMAs suggested.

TABLE F.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	Red W	Description	Potential SAMAs
1AC--BPRUN-LSFCC	1.77E-03	1.02	COMMON CAUSE FAILURE OF LS RELAYS ON LIGHTLY LOADED TRAIN	The importance of this event occurs mostly in combination with DG failures and seal LOCAs larger than 21 gpm. Improvement to the procedures and training for performing the cross-tie could reduce the Level 2 contribution for scenarios that include this failure (SAMA 4). Additionally, improvements to the existing RCP seal design that limited the likelihood that loss of cooling would lead to larger seal LOCAs would reduce the contribution to Level 2 risk from this and other events (SAMA 7).

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase I Disposition
1	Permanent, self-powered pump to backup NCP	This SAMA provides a means of limiting the size of a seal LOCA that can be automatically or rapidly aligned to the RCP seals from the MCR. Long term secondary side cooling can be provided through the operation of the turbine driven AFW pump using existing VEGP procedures. This arrangement would make it possible to provide adequate core cooling in extended SBO evolutions.	VEGP Level 1 Importance List	The cost of this enhancement has been estimated to be $2.7M based on a conceptual design of the backup pump [SNC 2007a].	As the cost of implementation is greater than the MMACR, this SAMA would not normally be retained for Phase II analysis. However, this SAMA has been retained for Phase II analysis to determine the maximum averted cost should a lower cost alternative be identified.
2	Maintain full-time black start capability of the Wilson Switchyard combustion turbines	The combustion turbines (CTs) in the Plant Wilson Switchyard have black start diesel generators, but these are only verified to be operable prior to 14 day EDG AOTs. The use of the black start diesels would be necessary to start the CTs given unavailability of offsite power at Plant Wilson. This SAMA would add surveillance or maintenance activities to ensure that the black start capabilities would be available much more often than is currently credited in the PRA model.	VEGP Level 1 Importance List	The cost of this enhancement has been estimated to be $50,000 [SNC 2007b] based on an estimated cost of conducting additional training on the operation of Plant Wilson. The estimated cost is for both units since Plant Wilson is common to both. This equates to a $25,000 per unit cost for the performance of the cost benefit analysis.	As the cost of implementation less than the MMACR, this SAMA has been retained for Phase II analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase I Disposition
3	Provide enhanced structural protection of Plant Wilson Switchyard	This SAMA would provide enhanced structural protection of Plant Wilson Switchyard such that it would be more likely to survive in severe weather and extreme weather events.	VEGP Level 1 Importance List	The cost of this enhancement has been estimated to be greater than the MMACR since extensive structural changes would need to be made. The estimated cost is $8.228M or $4.114M per unit [SNC 2007c].	As the cost of implementation is greater than the MMACR, this SAMA has not been retained for Phase II analysis.
4	Opposite unit ac cross-tie capability	The current PRA human reliability assessment for this action is that the cross-tie action will not succeed (i.e., HEP failure probability = 1.0) until at least seven hours after event initiation. Providing the ability to perform a timely 4kV ac cross-tie using an available emergency diesel generator under emergency conditions would allow operators more flexibility to operate required equipment to protect the core.	VEGP Level 1 Importance List	The cost of this enhancement has been estimated to be $50,000 [SNC 2007d] for developing, implementing, and training on a new procedure. The estimated cost is for both units. This equates to a $25,000 per unit cost for the performance of the cost benefit analysis.	As the cost of implementation less than the MMACR, this SAMA has been retained for Phase II analysis.
5	Permanent, dedicated generator for one motor driven AFW pump and a battery charger	Installation of a dedicated generator for continued operation and control of a MD AFW pump would reduce the overall contribution to CDF risk. This generator would need to have the capacity to operate a MD AFW pump and an associated battery charger required for dc power control of the AFW pump (SAMA 5).	VEGP Level 1 Importance List	The cost of this enhancement has been estimated to be $3.52M based on a conceptual design of a shared diesel between the units [SNC 2007e]. This equates to a $1.76M per unit cost for the performance of the cost benefit analysis.	As the cost of implementation is greater than the MMACR, this SAMA has not been retained for Phase II analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase I Disposition
6	Add bypass line around CT return valves	Failure of the Loop CT return valves results in failure of cooling water to one of the EDGs and other systems. A bypass line around the 1668A (Loop "A") and 1669A (Loop "B") valves that could be remotely or manually opened given failure of the existing valves could greatly reduce the CDF risk from this failure mode.	VEGP Level 1 Importance List, PRA Group Insights	The cost of this enhancement has been estimated to be $525K per unit based on a conceptual design of a modification that would provide a 10" bypass line from the diesel generator cooler return line to downstream of the return isolation valve [SNC 2007f].	As the cost of implementation less than the MMACR, this SAMA has been retained for Phase II analysis.
7	Implement enhanced RCP seal design	For Vogtle, a dominant contributor to the current risk profile is that without RCP seal cooling, it is assumed (based on Westinghouse and NRC consensus modeling) that an RCP seal LOCA of sufficient magnitude to require RCS injection occurs within 13 minutes. This SAMA would implement enhanced RCP seal designs that virtually eliminate this failure mode.	VEGP Level 1 Importance List	The cost of installation of a new enhanced RCP seal which is currently in development by Westinghouse has been estimated to be $1.05M [SNC 2007g].	As the cost of implementation is greater than the MMACR, this SAMA would not normally be retained for Phase II analysis. However, since the estimated cost of implementation is very close to the MMACR, this SAMA has been retained for Phase II analysis to determine the maximum averted cost should a lower cost alternative be identified.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase I Disposition
8	Implement alternate ac power source	The implementation of an alternate ac power source would most likely take the form of an additional EDG. This SAMA would help mitigate LOOP events and would reduce the risk during time frames of on-line EDG maintenance. The benefit would be increased if the if the additional DG could 1) be substituted for any current diesel that is in maintenance, and 2) if the diesel was of a diverse design such that CCF dependence was minimized.	VEGP Level 1 Importance List	The cost of installing an additional EDG has been estimated to be greater than $20 million in the Calvert Cliffs Application for License Renewal [BGE 1998]. It was similarly estimated to be about $26.09M for both units at VEGP [SNC 2007h]. As the per unit cost of ~$13M is greater than the Vogtle modified MACR, it has been screened from further analysis.	As the cost of implementation is greater than the MMACR, this SAMA has not been retained for Phase II analysis.
9	Implement automatic initiation of HPI on low RCS level (after ac power recovery)	The implementation of an automatic HPI initiation system would reduce the potential for core damage from occurring following events where ac power is recovered, but where a seal LOCA has already occurred. In these cases, RCS level must be restored to avoid core damage from occurring.	VEGP Level 1 Importance List	The cost of this enhancement has been estimated to be $250K per unit based on a conceptual design to install isolated circuitry that would automatically start HPI if a SI signal is present when ac power is restored [SNC 2007i].	As the cost of implementation less than the MMACR, this SAMA has been retained for Phase II analysis.
10	Additional training and/or procedural enhancement to implement timely RCS depressurization	Enhanced training and/or procedure enhancements could reduce the potential for thermally induced steam generator tube ruptures, thereby reducing the overall Level 2 risk contribution.	VEGP Level 2 Importance List	The cost estimate of procedure changes is on the order of $50,000 [CPL 2004]. This is also alternatively assumed to be applicable to include enhanced training as well.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase II analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase I Disposition
11	Use the hydrostatic test pump as an alternate means of providing seal injection	For Vogtle, a dominant contributor to the current risk profile is that without RCP seal cooling, it is assumed (based on Westinghouse and NRC consensus modeling) that an RCP seal LOCA of sufficient magnitude to require RCS injection occurs within 13 minutes. This SAMA would implement enhanced RCP seal designs that virtually eliminate this failure mode.	Industry SAMA List Review (V.C. Summer, Farley)	The cost of implementation for this issue ranges from $150,000 [SCE 2002] to $580,000 [SNC 2003].	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase II analysis.
12	Ensure all ISLOCA releases are scrubbed	SAMA would scrub all ISLOCA releases. One example is to plug all drains in the break areas so that the break location would quickly be covered with water.	Industry SAMA List Review (V.C. Summer)	The cost of implementation of this SAMA has not been estimated in detail. A minimum value of $100K for a hardware change is assumed for screening purposes.	This SAMA has been retained for Phase II analysis to determine the maximum averted cost.
13	Completely automate swap over to recirculation on RWST depletion	SAMA would ensure that automatic swap over to recirculation would occur in cases where high pressure injection from the charging and SI pumps is required (compared to the current capability at VEGP that only automates the swap over for LPI).	Industry SAMA List Review (V.C. Summer, Wolf Creek)	The cost of implementation of this SAMA has not been estimated in detail. A minimum value of $100K for a hardware change is assumed for screening purposes.	This SAMA has been retained for Phase II analysis to determine the maximum averted cost.
14	Install additional instrumentation for ISLOCA detection	SAMA would provide additional confidence that detection and response to ISLOCAs could be implemented to reduce the risk from these types of events.	Industry SAMA List Review (Farley)	The cost of implementation for this SAMA was estimated to be $425,000 for Farley [SNC 2003]. A similar cost is assumed to be applicable for Vogtle.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase II analysis.

TABLE F.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	Cost Estimate	Phase I Disposition
15	Install permanent dedicated generator for NCP	SAMA provides a means of limiting the size of a seal LOCA that can be automatically or rapidly aligned to the RCP seals from the MCR. This is an alternative approach to SAMA 1 that provided for a backup NCP, but with similar impacts. Long term secondary side cooling can be provided through the operation of the turbine driven AFW pump using existing VEGP procedures. This arrangement would make it possible to provide adequate core cooling in extended SBO evolutions.	Industry SAMA List Review (Wolf Creek)	The cost of implementation for providing a dedicated diesel generator for the ABWR Feedwater or Condensate pumps was estimated to be $1.2 million in 1994 [GE 1994]. The capacity of the generator required for the ABWR application likely exceeds that required for the VEGP NCP. As a result, the ABWR cost has been reduced by 25%, but not inflated to 2007 dollars to estimate a cost of implementation for this SAMA ($900,000).	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase II analysis.
16	Enhance procedures for ISLOCA response	SAMA would provide additional confidence that the response to ISLOCAs could be implemented to reduce the risk from these types of events.	Industry SAMA List Review (Wolf Creek)	The cost estimate of procedure changes is on the order of $50,000 [CPL 2004]. This is also alternatively assumed to be applicable to include enhanced training as well.	As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase II analysis.

TABLE F.6-1
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE II BASELINE DISPOSITION	Cost Effective (Baseline Results)?
1	Permanent, self-powered pump to backup NCP	This SAMA provides a means of limiting the size of a seal LOCA that can be automatically or rapidly aligned to the RCP seals from the MCR. Long term secondary side cooling can be provided through the operation of the turbine driven AFW pump using existing VEGP procedures. This arrangement would make it possible to provide adequate core cooling in extended SBO evolutions.	VEGP Level 1 Importance List	The averted cost-risk associated with this SAMA is $426,172. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
2	Maintain full-time black start capability of the Wilson Switchyard combustion turbines	The combustion turbines (CTs) in the Plant Wilson Switchyard have black start diesel generators, but these are only verified to be operable prior to 14 day EDG AOTs. The use of the black start diesels would be necessary to start the CTs given unavailability of offsite power at Plant Wilson. This SAMA would add surveillance or maintenance activities to ensure that the black start capabilities would be available much more often than is currently credited in the PRA model.	VEGP Level 1 Importance List	The averted cost-risk associated with this SAMA is $417,096. As this is greater than the estimated cost of implementation, the SAMA is cost beneficial.	Yes

TABLE F.6-1
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE II BASELINE DISPOSITION	Cost Effective (Baseline Results)?
4	Opposite unit ac cross-tie capability	The current PRA human reliability assessment for this action is that the cross-tie action will not succeed (i.e., HEP failure probability = 1.0) until at least seven hours after event initiation. Providing the ability to perform a timely 4kV ac cross-tie using an available emergency diesel generator under emergency conditions would allow operators more flexibility to operate required equipment to protect the core.	VEGP Level 1 Importance List	The averted cost-risk associated with this SAMA is $211,496. As this is greater than the estimated cost of implementation, the SAMA is cost beneficial.	Yes
6	Add bypass line around CT return valves	Failure of the Loop CT return valves results in failure of cooling water to one of the EDGs and other systems. A bypass line around the 1668A (Loop "A") and 1669A (Loop "B") valves that could be remotely or manually opened given failure of the existing valves could greatly reduce the CDF risk from this failure mode.	VEGP Level 1 Importance List, PRA Group Insights	The averted cost-risk associated with this SAMA is $295,686. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No

TABLE F.6-1
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE II BASELINE DISPOSITION	Cost Effective (Baseline Results)?
7	Implement enhanced RCP seal design	For Vogtle, a dominant contributor to the current risk profile is that without RCP seal cooling, it is assumed (based on Westinghouse and NRC consensus modeling) that an RCP seal LOCA of sufficient magnitude to require RCS injection occurs within 13 minutes. This SAMA would implement enhanced RCP seal designs that virtually eliminate this failure mode.	VEGP Level 1 Importance List	The averted cost-risk associated with this SAMA is $471,296. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
9	Implement automatic initiation of HPI on low RCS level (after ac power recovery)	The implementation of an automatic HPI initiation system would reduce the potential for core damage from occurring following events where ac power is recovered, but where a seal LOCA has already occurred. In these cases, RCS level must be restored to avoid core damage from occurring.	VEGP Level 1 Importance List	The averted cost-risk associated with this SAMA is $25,460. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
10	Additional training and/or procedural enhancement to implement timely RCS depressurization	Enhanced training and/or procedure enhancements could reduce the potential for thermally induced steam generator tube ruptures, thereby reducing the overall Level 2 risk contribution.	VEGP Level 2 Importance List	The averted cost-risk associated with this SAMA is $6,464. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No

TABLE F.6-1
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE II BASELINE DISPOSITION	Cost Effective (Baseline Results)?
11	Use the hydrostatic test pump as an alternate means of providing seal injection	For Vogtle, a dominant contributor to the current risk profile is that without RCP seal cooling, it is assumed (based on Westinghouse and NRC consensus modeling) that an RCP seal LOCA of sufficient magnitude to require RCS injection occurs within 13 minutes. This SAMA would implement enhanced RCP seal designs that virtually eliminate this failure mode.	Industry SAMA List Review (V.C. Summer, Farley)	The averted cost-risk associated with this SAMA is $91,670. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
12	Ensure all ISLOCA releases are scrubbed	SAMA would scrub all ISLOCA releases. One example is to plug all drains in the break areas so that the break location would quickly be covered with water.	Industry SAMA List Review (V.C. Summer)	The averted cost-risk associated with this SAMA is $19,106. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
13	Completely automate swap over to recirculation on RWST depletion	SAMA would ensure that automatic swap over to recirculation would occur in cases where high pressure injection from the charging and SI pumps is required (compared to the current capability at VEGP that only automates the swap over for LPI).	Industry SAMA List Review (V.C. Summer, Wolf Creek)	The averted cost-risk associated with this SAMA is $17,728. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No

TABLE F.6-1
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE II BASELINE DISPOSITION	Cost Effective (Baseline Results)?
14	Install additional instrumentation for ISLOCA detection	SAMA would provide additional confidence that detection and response to ISLOCAs could be implemented to reduce the risk from these types of events.	Industry SAMA List Review (Farley)	The averted cost-risk associated with this SAMA is $19,106. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
15	Install permanent dedicated generator for NCP	SAMA provides a means of limiting the size of a seal LOCA that can be automatically or rapidly aligned to the RCP seals from the MCR. This is an alternative approach to SAMA 1 that provided for a backup NCP, but with similar impacts. Long term secondary side cooling can be provided through the operation of the turbine driven AFW pump using existing VEGP procedures. This arrangement would make it possible to provide adequate core cooling in extended SBO evolutions.	Industry SAMA List Review (Wolf Creek)	The averted cost-risk associated with this SAMA is $426,172. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No
16	Enhance procedures for ISLOCA response	SAMA would provide additional confidence that the response to ISLOCAs could be implemented to reduce the risk from these types of events.	Industry SAMA List Review (Wolf Creek)	The averted cost-risk associated with this SAMA is $19,106. As this is less than the estimated cost of implementation, the SAMA is not cost beneficial.	No

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ADDENDUM 1 TO F

SELECTED PREVIOUS INDUSTRY SAMAS

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to RCP Seal LOCAs (Loss of CC or SW)		
1	Cap downstream piping of normally closed component cooling water drain and vent valves.	SAMA would reduce the frequency of a loss of component cooling event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.
2	Enhance loss of component cooling procedure to facilitate stopping reactor coolant pumps.	SAMA would reduce the potential for reactor coolant pump (RCP) seal damage due to pump bearing failure.
3	Enhance loss of component cooling procedure to present desirability of cooling down reactor coolant system (RCS) prior to seal LOCA.	SAMA would reduce the potential for RCP seal failure.
4	Provide additional training on the loss of component cooling.	SAMA would potentially improve the success rate of operator actions after a loss of component cooling (to restore RCP seal damage).
5	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	SAMA would reduce effect of loss of component cooling by providing a means to maintain the centrifugal charging pump seal injection after a loss of component cooling.
6	Procedure changes to allow cross connection of motor cooling for residual heat removal service water (RHRSW) pumps.	SAMA would allow continued operation of both RHRSW pumps on a failure of one train of SW.
7	Proceduralize shedding component cooling water loads to extend component cooling heatup on loss of essential raw cooling water.	SAMA would increase time before the loss of component cooling (and reactor coolant pump seal failure) in the loss of essential raw cooling water sequences.
8	Increase charging pump lube oil capacity.	SAMA would lengthen the time before centrifugal charging pump failure due to lube oil overheating in loss of CC sequences.
9	Eliminate the RCP thermal barrier dependence on component cooling such that loss of component cooling does not result directly in core damage.	SAMA would prevent the loss of recirculation pump seal integrity after a loss of component cooling. Watts Bar Nuclear Plant IPE said that they could do this with essential raw cooling water connection to RCP seals.
10	Add redundant dc control power for SW pumps C & D.	SAMA would increase reliability of SW and decrease CDF due to a loss of SW.
11	Create an independent RCP seal injection system, with a dedicated diesel.	SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of component cooling or SW or from a SBO event.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
12	Use existing hydro-test pump for RCP seal injection.	SAMA would provide an independent seal injection source, without the cost of a new system.
13	Replace ECCS pump motor with air-cooled motors.	SAMA would eliminate ECCS dependency on component cooling system (but not on room cooling).
14	Install improved RCS pumps seals.	SAMA would reduce probability of RCP seal LOCA by installing RCP seal O-ring constructed of improved materials
15	Install additional component cooling water pump.	SAMA would reduce probability of loss of component cooling leading to RCP seal LOCA.
16	Prevent centrifugal charging pump flow diversion from the relief valves.	SAMA modification would reduce the frequency of the loss of RCP seal cooling if relief valve opening causes a flow diversion large enough to prevent RCP seal injection.
17	Change procedures to isolate RCP seal letdown flow on loss of component cooling, and guidance on loss of injection during seal LOCA.	SAMA would reduce CDF from loss of seal cooling.
18	Implement procedures to stagger high-pressure safety injection (HPSI) pump use after a loss of SW.	SAMA would allow HPSI to be extended after a loss of SW.
19	Use FPS pumps as a backup seal injection and high-pressure makeup.	SAMA would reduce the frequency of the RCP seal LOCA and the SBO CDF.
20	Enhance procedural guidance for use of cross-tied component cooling or SW pumps.	SAMA would reduce the frequency of the loss of component cooling water and SW.
21	Procedure enhancements and operator training in support system failure sequences, with emphasis on anticipating problems and coping.	SAMA would potentially improve the success rate of operator actions subsequent to support system failures.
22	Improved ability to cool the residual heat removal (RHR) heat exchangers.	SAMA would reduce the probability of a loss of decay heat removal by implementing procedure and hardware modifications to allow manual alignment of the FPS or by installing a component cooling water cross-tie.
23	Additional SW Pump	SAMA would conceivably reduce common cause dependencies from SW system and thus reduce plant risk through system reliability improvement.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
24	Create an independent RCP seal injection system, without dedicated diesel	This SAMA would add redundancy to RCP seal cooling alternatives, reducing the CDF from loss of CC or SW, but not SBO.
Improvements Related to Heating, Ventilation, and Air Conditioning		
25	Provide reliable power to control building fans.	SAMA would increase availability of CR ventilation on a loss of power.
26	Provide a redundant train of ventilation.	SAMA would increase the availability of components dependent on room cooling.
27	Procedures for actions on loss of HVAC.	SAMA would provide for improved credit to be taken for loss of HVAC sequences (improved affected electrical equipment reliability upon a loss of control building HVAC).
28	Add a diesel building switchgear room high temperature alarm.	SAMA would improve diagnosis of a loss of switchgear room HVAC. Option 1: Install high temp alarm. Option 2: Redundant louver and thermostat
29	Create ability to switch fan power supply to dc in an SBO event.	SAMA would allow continued operation in an SBO event. This SAMA was created for reactor core isolation cooling (RCIC) system room at Fitzpatrick Nuclear Power Plant.
30	Enhance procedure to instruct operators to trip unneeded RHR/CS pumps on loss of room ventilation.	SAMA increases availability of required RHR/CS pumps. Reduction in room heat load allows continued operation of required RHR/CS pumps, when room cooling is lost.
31	Stage backup fans in switchgear (SWGR) rooms	This SAMA would provide alternate ventilation in the event of a loss of SWGR Room ventilation
Improvements Related to Ex-Vessel Accident Mitigation/Containment Phenomena		
32	Delay containment spray actuation after large LOCA.	SAMA would lengthen time of refueling water storage tank (RWST) availability.
33	Install containment spray pump header automatic throttle valves.	SAMA would extend the time over which water remains in the RWST, when full CS flow is not needed
34	Install an independent method of suppression pool cooling.	SAMA would decrease the probability of loss of containment heat removal. For PWRs, a potential similar enhancement would be to install an independent cooling system for sump water.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
35	Develop an enhanced drywell spray system.	SAMA would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal.
36	Provide dedicated existing drywell spray system.	SAMA would provide a source of water to the containment to control containment pressure, when used in conjunction with containment heat removal. This would use an existing spray loop instead of developing a new spray system.
37	Install an unfiltered hardened containment vent.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products not being scrubbed.
38	Install a filtered containment vent to remove decay heat.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products being scrubbed. Option 1: Gravel Bed Filter Option 2: Multiple Venturi Scrubber
39	Install a containment vent large enough to remove ATWS decay heat.	Assuming that injection is available, this SAMA would provide alternate decay heat removal in an ATWS event.
40	Create/enhance hydrogen recombiners with independent power supply.	SAMA would reduce hydrogen detonation at lower cost, Use either 1) a new independent power supply 2) a nonsafety-grade portable generator 3) existing station batteries 4) existing AC/DC independent power supplies.
41	Install hydrogen recombiners.	SAMA would provide a means to reduce the chance of hydrogen detonation.
42	Create a passive design hydrogen ignition system.	SAMA would reduce hydrogen denotation system without requiring electric power.
43	Create a large concrete crucible with heat removal potential under the basemat to contain molten core debris.	SAMA would ensure that molten core debris escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through of the basemat.
44	Create a water-cooled rubble bed on the pedestal.	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.
45	Provide modification for flooding the drywell head.	SAMA would help mitigate accidents that result in the leakage through the drywell head seal.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
46	Enhance FPS and/or standby gas treatment system hardware and procedures.	SAMA would improve fission product scrubbing in severe accidents.
47	Create a reactor cavity flooding system.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
48	Create other options for reactor cavity flooding.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
49	Enhance air return fans (ice condenser plants).	SAMA would provide an independent power supply for the air return fans, reducing containment failure in SBO sequences.
50	Create a core melt source reduction system.	SAMA would provide cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal form the vitrified compound would be facilitated, and concrete attack would not occur
51	Provide a containment inerting capability.	SAMA would prevent combustion of hydrogen and carbon monoxide gases.
52	Use the FPS as a backup source for the containment spray system.	SAMA would provide redundant containment spray function without the cost of installing a new system.
53	Install a secondary containment filtered vent.	SAMA would filter fission products released from primary containment.
54	Install a passive containment spray system.	SAMA would provide redundant containment spray method without high cost.
55	Strengthen primary/secondary containment.	SAMA would reduce the probability of containment over-pressurization to failure.
56	Increase the depth of the concrete basemat or use an alternative concrete material to ensure melt-through does not occur.	SAMA would prevent basemat melt-through.
57	Provide a reactor vessel exterior cooling system.	SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head could be submerged in water.
58	Construct a building to be connected to primary/secondary containment that is maintained at a vacuum.	SAMA would provide a method to depressurize containment and reduce fission product release.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
59	Refill CST	SAMA would reduce the risk of core damage during events such as extended SBOs or LOCAs which render the suppression pool unavailable as an injection source due to heat up.
60	Maintain ECCS suction on CST	SAMA would maintain suction on the CST as long as possible to avoid pump failure as a result of high suppression pool temperature
61	Modify containment flooding procedure to restrict flooding to below TAF	SAMA would avoid forcing containment venting
62	Enhance containment venting procedures with respect to timing, path selection and technique.	SAMA would improve likelihood of successful venting strategies.
63	Severe Accident EPGs/AMGs	SAMA would lead to improved arrest of core melt progress and prevention of containment failure
64	Simulator Training for Severe Accident	SAMA would lead to improved arrest of core melt progress and prevention of containment failure
65	Dedicated Suppression Pool Cooling	SAMA would decrease the probability of loss of containment heat removal. While PWRs do not have suppression pools, a similar modification may be applied to the sump. Installation of a dedicated sump cooling system would provide an alternate method of cooling injection water.
66	Larger Volume Containment	SAMA increases time before containment failure and increases time for recovery
67	Increased Containment Pressure Capability (sufficient pressure to withstand severe accidents)	SAMA minimizes likelihood of large releases
68	Improved Vacuum Breakers (redundant valves in each line)	SAMA reduces the probability of a stuck open vacuum breaker.
69	Increased Temperature Margin for Seals	This SAMA would reduce containment failure due to drywell head seal failure caused by elevated temperature and pressure.
70	Improved Leak Detection	This SAMA would help prevent LOCA events by identifying pipes which have begun to leak. These pipes can be replaced before they break.
71	Suppression Pool Scrubbing	Directing releases through the suppression pool will reduce the radionuclides allowed to escape to the environment.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
72	Improved Bottom Penetration Design	SAMA reduces failure likelihood of RPV bottom head penetrations
73	Larger Volume Suppression Pool (double effective liquid volume)	SAMA would increase the size of the suppression pool so that heatup rate is reduced, allowing more time for recovery of a heat removal system
74	Unfiltered Vent	SAMA would provide an alternate decay heat removal method with the released fission products not being scrubbed.
75	Filtered Vent	SAMA would provide an alternate decay heat removal method with the released fission products being scrubbed.
76	Post Accident Inerting System	SAMA would reduce likelihood of gas combustion inside containment
77	Hydrogen Control by Venting	Prevents hydrogen detonation by venting the containment before combustible levels are reached.
78	Pre-inerting	SAMA would reduce likelihood of gas combustion inside containment
79	Ignition Systems	Burning combustible gases before they reach a level which could cause a harmful detonation is a method of preventing containment failure.
80	Fire Suppression System Inerting	Use of the FPS 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 Mark I).
81	Drywell Head Flooding	SAMA would provide intentional flooding of the upper drywell head such that if high drywell temperatures occurred, the drywell head seal would not fail.
82	Containment Spray Augmentation	This SAMA would provide additional means of providing flow to the containment spray system.
83	Integral Basemat	This SAMA would improve containment and system survivability for seismic events.
84	Reactor Building Sprays	This SAMA provides the capability to use firewater sprays in the reactor building to mitigate release of fission products into the reactor building following an accident.
85	Flooded Rubble Bed	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
86	Reactor Cavity Flooder	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
87	Basaltic Cements	SAMA minimizes carbon dioxide production during core concrete interaction.
88	Provide a core debris control system	(Intended for ice condenser plants): This SAMA would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and the containment shell.
89	Add ribbing to the containment shell	This SAMA would reduce the risk of buckling of containment under reverse pressure loading.
Improvements Related to Enhanced AC/DC Reliability/Availability		
90	Proceduralize alignment of spare diesel to shutdown board after LOOP and failure of the diesel normally supplying it.	SAMA would reduce the SBO frequency.
91	Provide an additional DF.	SAMA would increase the reliability and availability of onsite emergency AC power sources.
92	Provide additional dc battery capacity.	SAMA would ensure longer battery capability during an SBO, reducing the frequency of long-term SBO sequences.
93	Use fuel cells instead of lead-acid batteries.	SAMA would extend dc power availability in an SBO.
94	Procedure to cross-tie high-pressure core spray diesel.	SAMA would improve core injection availability by providing a more reliable power supply for the high-pressure core spray pumps.
95	Improve 4.16-kV bus cross-tie ability.	SAMA would improve ac power reliability.
96	Incorporate an alternate battery charging capability.	SAMA would improve dc power reliability by either cross-tying the ac busses, or installing a portable diesel-driven battery charger.
97	Increase/improve dc bus load shedding.	SAMA would extend battery life in an SBO event.
98	Replace existing batteries with more reliable ones.	SAMA would improve dc power reliability and thus increase available SBO recovery time.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
99	Mod for dc Bus A reliability.	SAMA would increase the reliability of ac power and injection capability. Loss of dc Bus A causes a loss of main condenser, prevents transfer from the main transformer to off-site power (OSP), and defeats one half of the low vessel pressure permissive for low pressure coolant injection (LPCI)/CS injection valves.
100	Create ac power cross-tie capability with other unit.	SAMA would improve ac power reliability.
101	Create a cross-tie for diesel fuel oil.	SAMA would increase diesel fuel oil supply and thus DG, reliability.
102	Develop procedures to repair or replace failed 4-kV breakers.	SAMA would offer a recovery path from a failure of the breakers that perform transfer of 4.16-kV non-emergency busses from unit station service transformers, leading to loss of emergency ac power.
103	Emphasize steps in recovery of OSP after an SBO.	SAMA would reduce HEP during OSP recovery.
104	Develop a severe weather conditions procedure.	For plants that do not already have one, this SAMA would reduce the CDF for external weather-related events.
105	Develop procedures for replenishing diesel fuel oil.	SAMA would allow for long-term diesel operation.
106	Install gas turbine generator.	SAMA would improve onsite ac power reliability by providing a redundant and diverse emergency power system.
107	Create a backup source for diesel cooling. (Not from existing system)	This SAMA would provide a redundant and diverse source of cooling for the DGs, which would contribute to enhanced diesel reliability.
108	Use FPS as a backup source for diesel cooling.	This SAMA would provide a redundant and diverse source of cooling for the DGs, which would contribute to enhanced diesel reliability.
109	Provide a connection to an alternate source of OSP.	SAMA would reduce the probability of a LOOP event.
110	Bury OSP lines.	SAMA could improve OSP reliability, particularly during severe weather.
111	Replace anchor bolts on DG oil cooler.	Millstone Nuclear Power Station found a high seismic SBO risk due to failure of the diesel oil cooler anchor bolts. For plants with a similar problem, this would reduce seismic risk. Note that these were Fairbanks Morse DGs.
112	Change undervoltage, AFW actuation signal block and high pressurizer pressure actuation signals to 3-out-of-4, instead of 2-out-of-4 logic.	SAMA would reduce risk of 2/4 inverter failure.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
113	Provide dc power to the 120/240V vital ac system from the Class 1E station service battery system instead of its own battery.	SAMA would increase the reliability of the 120V ac bus.
114	Bypass DG Trips	SAMA would allow D/Gs to operate for longer.
115	16 hour SBO Injection	SAMA includes improved capability to cope with longer SBO scenarios.
116	Steam Driven Turbine Generator	This SAMA would provide a steam driven turbine generator which uses reactor steam and exhausts to the suppression pool. If large enough, it could provide power to additional equipment.
117	Alternate Pump Power Source	This SAMA would provide a small dedicated power source such as a dedicated diesel or gas turbine for the feedwater or condensate pumps, so that they do not rely on OSP.
118	Additional DG	SAMA would reduce the SBO frequency.
119	Increased Electrical Divisions	SAMA would provide increased reliability of ac power system to reduce core damage and release frequencies.
120	Improved Uninterruptible Power Supplies	SAMA would provide increased reliability of power supplies supporting front-line equipment, thus reducing core damage and release frequencies.
121	Implement ac Bus cross-ties	SAMA would provide increased reliability of ac power system to reduce core damage and release frequencies.
122	Gas Turbine	SAMA would improve onsite ac power reliability by providing a redundant and diverse emergency power system.
123	Dedicated RHR (bunkered) Power Supply	SAMA would provide RHR with more reliable ac power.
124	Dedicated dc Power Supply	This SAMA addresses the use of a diverse dc power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).
125	Additional Batteries/Divisions	This SAMA addresses the use of a diverse dc power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).
126	Fuel Cells	SAMA would extend dc power availability in an SBO.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
127	Implement dc Cross-ties	This SAMA would improve dc power reliability.
128	Extended SBO Provisions	SAMA would provide reduction in SBO sequence frequencies.
129	Add an automatic bus transfer feature to allow the automatic transfer of the 120V vital ac bus from the on-line unit to the standby unit	Plants are typically sensitive to the loss of one or more 120V vital ac buses. Manual transfers to alternate power supplies could be enhanced to transfer automatically.
Improvements in Identifying and Mitigating Containment Bypass		
130	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture (SGTR).	SAMA would enhance depressurization during a SGTR.
131	Improve SGTR coping abilities.	SAMA would improve instrumentation to detect SGTR, or additional system to scrub fission product releases.
132	Add other SGTR coping abilities.	SAMA would decrease the consequences of an SGTR.
133	Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	SAMA would eliminate direct release pathway for SGTR sequences.
134	Replace steam generators (SG) with a new design.	SAMA would lower the frequency of an SGTR.
135	Revise emergency operating procedures to direct that a faulted SG be isolated.	SAMA would reduce the consequences of an SGTR.
136	Direct SG flooding after a SGTR, prior to core damage.	SAMA would provide for improved scrubbing of SGTR releases.
137	Implement a maintenance practice that inspects 100% of the tubes in a SF.	SAMA would reduce the potential for an SGTR.
138	Locate RHR inside of containment.	SAMA would prevent intersystem LOCA (ISLOCA) out the RHR pathway.
139	Install additional instrumentation for ISLOCAs.	SAMA would decrease ISLOCA frequency by installing pressure of leak monitoring instruments in between the first two pressure isolation valves on low-pressure inject lines, RHR suction lines, and HPSI lines.
140	Increase frequency for valve leak testing.	SAMA could reduce ISLOCA frequency.
141	Improve operator training on ISLOCA coping.	SAMA would decrease ISLOCA effects.
142	Install relief valves in the CC System.	SAMA would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
143	Provide leak testing of valves in ISLOCA paths.	SAMA would help reduce ISLOCA frequency. At Kewaunee Nuclear Power Plant, four MOVs isolating RHR from the RCS were not leak tested.
144	Revise EOPs to improve ISLOCA identification.	SAMA would ensure LOCA outside containment could be identified as such. Salem Nuclear Power Plant had a scenario where an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.
145	Ensure all ISLOCA releases are scrubbed.	SAMA would scrub all ISLOCA releases. One example is to plug drains in the break area so that the break point would be covered with water.
146	Add redundant and diverse limit switches to each containment isolation valve.	SAMA could reduce the frequency of containment isolation failure and ISLOCAs through enhanced isolation valve position indication.
147	Early detection and mitigation of ISLOCA	SAMA would limit the effects of ISLOCA accidents by early detection and isolation
148	Improved main steam isolation valve (MSIV) Design	This SAMA would improve isolation reliability and reduce spurious actuations that could be initiating events.
149	Proceduralize use of pressurizer vent valves during steam generator tube rupture (SGTR) sequences	Some plants may have procedures to direct the use of pressurizer sprays to reduce RCS pressure after an SGTR. Use of the vent valves would provide a back-up method.
150	Implement a maintenance practice that inspects 100% of the tubes in an SG	This SAMA would reduce the potential for a tube rupture.
151	Locate RHR inside of containment	This SAMA would prevent ISLOCA out the RHR pathway.
152	Install self-actuating containment isolation valves	For plants that do not have this, it would reduce the frequency of isolation failure.
Improvements in Reducing Internal Flooding Frequency		
153	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	SAMA would prevent flood propagation, for a plant where internal flooding from turbine building to safeguards areas is a concern.
154	Improve inspection of rubber expansion joints on main condenser.	SAMA would reduce the frequency of internal flooding, for a plant where internal flooding due to a failure of circulating water system expansion joints is a concern.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
155	Implement internal flood prevention and mitigation enhancements.	This SAMA would reduce the consequences of internal flooding.
156	Implement internal flooding improvements such as those implemented at Fort Calhoun.	This SAMA would reduce flooding risk by preventing or mitigating rupture in the RCP seal cooler of the component cooling system an ISLOCA in a shutdown cooling line, an AFW flood involving the need to remove a watertight door.
157	Shield electrical equipment from potential water spray	SAMA would decrease risk associated with seismically induced internal flooding
158	Reduction in Reactor Building Flooding	This SAMA reduces the Reactor Building Flood Scenarios contribution to core damage and release.
Improvements Related to Feedwater/Feed and Bleed Reliability/Availability		
159	Install a digital feedwater upgrade.	This SAMA would reduce the chance of a loss of main feedwater following a plant trip.
160	Perform surveillances on manual valves used for backup AFW pump suction.	This SAMA would improve success probability for providing alternative water supply to the AFW pumps.
161	Install manual isolation valves around AFW turbine-driven steam admission valves.	This SAMA would reduce the dual turbine-driven AFW pump maintenance unavailability.
162	Install accumulators for turbine-driven AFW pump flow control valves (CVs).	This SAMA would provide control air accumulators for the turbine-driven AFW flow control valves, the motor-driven AFW pressure control valves and SG power-operated relief valves (PORVs). This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOOP.
163	Install separate accumulators for the AFW cross-connect and block valves	This SAMA would enhance the operator's ability to operate the AFW cross-connect and block valves following loss of air support.
164	Install a new CST	Either replace the existing tank with a larger one, or install a back-up tank.
165	Provide cooling of the steam-driven AFW pump in an SBO event	This SAMA would improve success probability in an SBO by: (1) using the FP system to cool the pump, or (2) making the pump self cooled.
166	Proceduralize local manual operation of AFW when control power is lost.	This SAMA would lengthen AFW availability in an SBO. Also provides a success path should AFW control power be lost in non-SBO sequences.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
167	Provide portable generators to be hooked into the turbine driven AFW, after battery depletion.	This SAMA would extend AFW availability in an SBO (assuming the turbine driven AFW requires dc power)
168	Add a motor train of AFW to the Steam trains	For PWRs that do not have any motor trains of AFW, this would increase reliability in non-SBO sequences.
169	Create ability for emergency connections of existing or alternate water sources to feedwater/condensate	This SAMA would be a back-up water supply for the feedwater/condensate systems.
170	Use FP system as a back-up for SG inventory	This SAMA would create a back-up to main and AFW for SG water supply.
171	Procure a portable diesel pump for isolation condenser make-up	This SAMA would provide a back-up to the city water supply and diesel FP system pump for isolation condenser make-up.
172	Install an independent DG for the CST make-up pumps	This SAMA would allow continued inventory make-up to the CST during an SBO.
173	Change failure position of condenser make-up valve	This SAMA would allow greater inventory for the AFW pumps by preventing CST flow diversion to the condenser if the condenser make-up valve fails open on loss of air or power.
174	Create passive secondary side coolers.	This SAMA would reduce CDF from the loss of Feedwater by providing a passive heat removal loop with a condenser and heat sink.
175	Replace current PORVs with larger ones such that only one is required for successful feed and bleed.	This SAMA would reduce the dependencies required for successful feed and bleed.
176	Install motor-driven feedwater pump.	SAMA would increase the availability of injection subsequent to MSIV closure.
177	Use Main feedwater pumps for a Loss of Heat Sink Event	This SAMA involves a procedural change that would allow for a faster response to loss of the secondary heat sink. Use of only the feedwater booster pumps for injection to the SGs requires depressurization to about 350 psig; before the time this pressure is reached, conditions would be met for initiating feed and bleed. Using the available turbine driven feedwater pumps to inject water into the SGs at a high pressure rather than using the feedwater booster alone allows injection without the time consuming depressurization.
Improvements in Core Cooling Systems		

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
178	Provide the capability for diesel driven, low pressure vessel make-up	This SAMA would provide an extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., FP system)
179	Provide an additional HPSI pump with an independent diesel	This SAMA would reduce the frequency of core melt from small LOCA and SBO sequences
180	Install an independent ac HPSI system	This SAMA would allow make-up and feed and bleed capabilities during an SBO.
181	Create the ability to manually align ECCS recirculation	This SAMA would provide a back-up should automatic or remote operation fail.
182	Implement an RWT make-up procedure	This SAMA would decrease CDF from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR.
183	Stop LPSI pumps earlier in medium or large LOCAs.	This SAMA would provide more time to perform recirculation swap over.
184	Emphasize timely swap over in operator training.	This SAMA would reduce HEP of recirculation failure.
185	Upgrade Chemical and Volume Control System to mitigate small LOCAs.	For a plant like the AP600 where the Chemical and Volume Control System cannot mitigate a Small LOCA, an upgrade would decrease the Small LOCA CDF contribution.
186	Install an active HPSI system.	For a plant like the AP600 where an active HPSI system does not exist, this SAMA would add redundancy in HPSI.
187	Change "in-containment" RWST suction from 4 check valves to 2 check and 2 air operated valves.	This SAMA would remove common mode failure of all four injection paths.
188	Replace 2 of the 4 safety injection (SI) pumps with diesel-powered pumps.	This SAMA would reduce the SI system CCF probability. This SAMA was intended for the System 80+, which has four trains of SI.
189	Align low pressure core injection or core spray to the CST on loss of suppression pool cooling.	This SAMA would help to ensure low pressure ECCS can be maintained in loss of suppression pool cooling scenarios.
190	Raise high pressure core injection/RCIC backpressure trip setpoints	This SAMA would ensure high pressure core injection/RCIC availability when high suppression pool temperatures exist.
191	Improve the reliability of the ADS.	This SAMA would reduce the frequency of high pressure core damage sequences.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
192	Disallow automatic vessel depressurization in non-ATWS scenarios	This SAMA would improve operator control of the plant.
193	Create automatic swap over to recirculation on RWT depletion	This SAMA would reduce the human error contribution from recirculation failure.
194	Proceduralize intermittent operation of high pressure coolant injection (HPCI).	SAMA would allow for extended duration of HPCI availability.
195	Increase available net positive suction head (NPSH) for injection pumps.	SAMA increases the probability that these pumps will be available to inject coolant into the vessel by increasing the available NPSH for the injection pumps.
196	Modify Reactor Water Cleanup (RWCU) for use as a decay heat removal system and proceduralize use.	SAMA would provide an additional source of decay heat removal.
197	Control Rod Drive (CRD) Injection	SAMA would supply an additional method of level restoration by using a non-safety system.
198	Condensate Pumps for Injection	SAMA to provide an additional option for coolant injection when other systems are unavailable or inadequate
199	Align EDG to CRD for Injection	SAMA to provide power to an additional injection source during loss of power events
200	Re-open MSIVs	SAMA to regain the main condenser as a heat sink by re-opening the MSIVs.
201	Bypass RCIC Turbine Exhaust Pressure Trip	SAMA would allow RCIC to operate longer.
202	Passive High Pressure System	SAMA will improve prevention of core melt sequences by providing additional high pressure capability to remove decay heat through an isolation condenser type system
203	Suppression Pool Jockey Pump	SAMA will improve prevention of core melt sequences by providing a small makeup pump to provide low pressure decay heat removal from the RPV using the suppression pool as a source of water.
204	Improved High Pressure Systems	SAMA will improve prevention of core melt sequences by improving reliability of high pressure capability to remove decay heat.

TABLE A-1
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SAMA ID number	SAMA title	Result of potential enhancement
205	Additional Active High Pressure System	SAMA will improve reliability of high pressure decay heat removal by adding an additional system.
206	Improved Low Pressure System (Firepump)	SAMA would provide FPS pump(s) for use in low pressure scenarios.
207	CUW Decay Heat Removal	This SAMA provides a means for Alternate Decay Heat Removal.
208	High Flow Suppression Pool Cooling	SAMA would improve suppression pool cooling.
209	Diverse Injection System	SAMA will improve prevention of core melt sequences by providing additional injection capabilities.
210	Alternate Charging Pump Cooling	This SAMA will improve the high pressure core flooding capabilities by providing the SI pumps with alternate gear and oil cooling sources. Given a total loss of Chilled Water, abnormal operating procedures would direct alignment of preferred Demineralized Water or the Fire System to the Chilled Water System to provide cooling to the SI pumps' gear and oil box (and the other normal loads).
Instrument Air/Gas Improvements		
211	Modify EOPs for ability to align diesel power to more air compressors.	For plants that do not have diesel power to all normal and back-up air compressors, this change would increase the reliability of IA after a LOOP.
212	Replace old air compressors with more reliable ones	This SAMA would improve reliability and increase availability of the IA compressors.
213	Install nitrogen bottles as a back-up gas supply for safety relief valves (SRVs).	This SAMA would extend operation of SRVs during an SBO and loss of air events (BWRs).
214	Allow cross connection of uninterruptible compressed air supply to opposite unit.	SAMA would increase the ability to vent containment using the hardened vent.
ATWS Mitigation		
215	Install MG set trip breakers in CR	This SAMA would provide trip breakers for the MG sets in the CR. In some plants, MG set breaker trip requires action to be taken outside of the CR. Adding control capability to the CR would reduce the trip failure probability in sequences where immediate action is required (e.g., ATWS).

TABLE A-1
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SAMA ID number	SAMA title	Result of potential enhancement
216	Add capability to remove power from the bus powering the control rods	This SAMA would decrease the time to insert the control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has a rapid pressure excursion)
217	Create cross-connect ability for standby liquid control trains	This SAMA would improve reliability for boron injection during an ATWS event.
218	Create an alternate boron injection capability (back-up to standby liquid control)	This SAMA would improve reliability for boron injection during an ATWS event.
219	Remove or allow override of low pressure core injection during an ATWS	On failure on high pressure core injection and condensate, some plants direct reactor depressurization followed by 5 minutes of low pressure core injection. This SAMA would allow control of low pressure core injection immediately.
220	Install a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	This SAMA would improve equipment availability after an ATWS.
221	Create a boron injection system to back up the mechanical control rods.	This SAMA would provide a redundant means to shut down the reactor.
222	Provide an additional instrument system for ATWS mitigation (e.g., ATWS mitigation scram actuation circuitry).	This SAMA would improve instrument and control redundancy and reduce the ATWS frequency.
223	Increase the SRV reseat reliability.	SAMA addresses the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.
224	Use CRD for alternate boron injection.	SAMA provides an additional system to address ATWS with SLC failure or unavailability.
225	Bypass MSIV isolation in Turbine Trip ATWS scenarios	SAMA will afford operators more time to perform actions. The discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower human error probabilities
226	Enhance operator actions during ATWS	SAMA will reduce human error probabilities during ATWS
227	Guard against SLC dilution	SAMA to control vessel injection to prevent boron loss or dilution following SLC injection.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
228	ATWS Sized Vent	This SAMA would provide the ability to remove reactor heat from ATWS events.
229	Improved ATWS Capability	This SAMA includes items which reduce the contribution of ATWS to core damage and release frequencies.
Other Improvements		
230	Provide capability for remote operation of secondary side relief valves in an SBO	Manual operation of these valves is required in an SBO scenario. High area temperatures may be encountered in this case (no ventilation to main steam areas), and remote operation could improve success probability.
231	Create/enhance RCS depressurization ability	With either a new depressurization system, or with existing PORVs, head vents, and secondary side valve, RCS depressurization would allow earlier low pressure ECCS injection. Even if core damage occurs, low RCS pressure would alleviate some concerns about high pressure melt ejection (HPME).
232	Make procedural changes only for the RCS depressurization option	This SAMA would reduce RCS pressure without the cost of a new system
233	Defeat 100% load rejection capability.	This SAMA would eliminate the possibility of a stuck open PORV after a LOOP, since PORV opening would not be needed.
234	Change CRD flow control valve failure position	Change failure position to the "fail-safest" position.
235	Install secondary side guard pipes up to the MSIVs	This SAMA would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. This SAMA would also guard against or prevent consequential multiple SGTR following a Main Steam Line Break event.
236	Install digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (leak before break).
237	Increase seismic capacity of the plant to a high confidence, low pressure failure of twice the Safe Shutdown Earthquake.	This SAMA would reduce seismically -induced CDF.
238	Enhance the reliability of the demineralized water make-up system through the addition of diesel-backed power to one or both of the demineralized water make-up pumps.	Inventory loss due to normal leakage can result in the failure of the CC and the SW systems. Loss of CC could challenge the RCP seals. Loss of SW results in the loss of three EDGs and the containment air coolers.

TABLE A-1
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SAMA ID number	SAMA title	Result of potential enhancement
239	Increase the reliability of SRVs by adding signals to open them automatically.	SAMA reduces the probability of a certain type of medium break LOCA. Hatch evaluated medium LOCA initiated by an MSIV closure transient with a failure of SRVs to open. Reducing the likelihood of the failure for SRVs to open subsequently reduces the occurrence of this medium LOCA.
240	Reduce dc dependency between high-pressure injection system and ADS.	SAMA would ensure containment depressurization and high-pressure injection upon a dc failure.
241	Increase seismic ruggedness of plant components.	SAMA would increase the availability of necessary plant equipment during and after seismic events.
242	Enhance RPV depressurization capability	SAMA would decrease the likelihood of core damage in loss of HPCI scenarios
243	Enhance RPV depressurization procedures	SAMA would decrease the likelihood of core damage in loss of HPCI scenarios
244	Replace mercury switches on FPSs	SAMA would decrease probability of spurious fire suppression system actuation given a seismic event
245	Provide additional restraints for CO_2 tanks	SAMA would increase availability of FP given a seismic event.
246	Enhance control of transient combustibles	SAMA would minimize risk associated with important fire areas.
247	Enhance fire brigade awareness	SAMA would minimize risk associated with important fire areas.
248	Upgrade fire compartment barriers	SAMA would minimize risk associated with important fire areas.
249	Enhance procedures to allow specific operator actions	SAMA would minimize risk associated with important fire areas.
250	Develop procedures for transportation and nearby facility accidents	SAMA would minimize risk associated with transportation and nearby facility accidents.
251	Enhance procedures to mitigate Large LOCA	SAMA would minimize risk associated with Large LOCA
252	Computer Aided Instrumentation	SAMA will improve prevention of core melt sequences by making operator actions more reliable.
253	Improved Maintenance Procedures/Manuals	SAMA will improve prevention of core melt sequences by increasing reliability of important equipment
254	Improved Accident Management Instrumentation	SAMA will improve prevention of core melt sequences by making operator actions more reliable.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAS

SAMA ID number	SAMA title	Result of potential enhancement
255	Remote Shutdown Station	This SAMA would provide the capability to control the reactor in the event that evacuation of the MCR is required.
256	Security System	Improvements in the site's security system would decrease the potential for successful sabotage.
257	Improved Depressurization	SAMA will improve depressurization system to allow more reliable access to low pressure systems.
258	Safety Related CST	SAMA will improve availability of CST following a Seismic event
259	Passive Overpressure Relief	This SAMA would prevent vessel over-pressurization.
260	Improved Operating Response	Improved operator reliability would improve accident mitigation and prevention.
261	Operation Experience Feedback	This SAMA would identify areas requiring increased attention in plant operation through review of equipment performance.
262	Improved SRV Design	This SAMA would improve SRV reliability, thus increasing the likelihood that sequences could be mitigated using low pressure heat removal.
263	Increased Seismic Margins	This SAMA would reduce the risk of core damage and release during seismic events.
264	System Simplification	This SAMA is intended to address system simplification by the elimination of unnecessary interlocks, automatic initiation of manual actions or redundancy as a means to reduce overall plant risk.
265	Train operations crew for response to inadvertent actuation signals	This SAMA would improve chances of a successful response to the loss of two 120V ac buses, which may cause inadvertent signal generation.
266	Install tornado protection on gas turbine generators	This SAMA would improve onsite ac power reliability.

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