Applicant's Environmental Report – Operating License Renewal Stage Salem Nuclear Generating Station

Unit 1
Docket No. 50-272
License No. DPR-70

Unit 2
Docket No. 50-311
License No. DPR-75

PSEG Nuclear, LLC

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Acronyms and Abbreviations

AADT	Annual Average Daily Traffic
AEC	[U.S.] Atomic Energy Commission
AEI	Adverse Environmental Impact [analysis]
AIT	alternative intake technologies
AQCR	Air quality control region
bgs	below ground surface
BNE	NJDEP Bureau of Nuclear Engineering
BOD	biochemical oxygen demand
BTA	best technology available
BTU	British thermal unit
BWR	boiling water reactor
°C	degrees Celsius
CAIR	Clean Air Interstate Rule
CDS	Comprehensive Demonstration Study
CEEEP	Center for Energy, Economic & Environmental Policy
CEQ	Council on Environmental Quality
CFC	chlorofluorocarbon
CFR	Code of Federal Regulations
cm	centimeter
CO	carbon monoxide
CPUE	catch per unit effort
CVCS	Chemical and Volume Control System
CWA	Clean Water Act
CWIS	Circulating Water Intake Structure
CWS	Circulating Water System
DAW	Dry Active Waste
DDNREC	Delaware Department of Natural Resources and Environmental Control
DRBC	Delaware River Basin Commission
DSM	demand side management
EEP	Estuary Enhancement Program
EPA	[U.S.] Environmental Protection Agency
ESA	Endangered Species Act
°F	degrees Fahrenheit
FES	Final Environmental Statement
FHB	Fuel Handling Building
fps	feet per second
ft	feet
ft^2	square feet
ft^3	cubic feet

Acronyms and Abbreviations (Continued)

ft^3/sec	cubic feet per second
gal	gallon
GEIS	Generic Environmental Impact Statement [for License Renewal of Nuclear Plants]
gpd	gallons per day
gpm	gallons per minute
GWS	Gaseous Waste System
HCGS	Hope Creek Generating Station
in	inch(es)
IPA	integrated plant assessment
IPE	individual plant assessment
ISFSI	Independent Spent Fuel Storage Installation
ITS	Incidental Take Statement
km	kilometer(s)
km^2	square kilometer(s)
kV	kilovolt
kWh	kilowatt hour
lb	pound
LLC	Limited Liability Company
LLRSF	Low Level Radioactive [Waste] Storage Facility
LOS	level of service
LWS	Liquid Waste System
m	meter(s)
m^2	square meter(s)
m^3	cubic meter(s)
MGD	million gallons per day
mi	mile(s)
MOU	memorandum of understanding
msl	mean sea level
MUA	Municipal Utilities Authority
MWe	megawatts-electric
MWt	megawatts-thermal
NA	not applicable, not available, or not analyzed
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NESC	National Electrical Safety Code
NJBPU	New Jersey Board of Public Utilities
NJDEP	New Jersey Department of Environmental Protection
NJPDES	New Jersey Pollutant Discharge Elimination System

Acronyms and Abbreviations (Continued)

NMFS	National Marine Fisheries Service
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NRC	[U.S.] Nuclear Regulatory Commission
NRLWDS	Non-Radioactive Liquid Waste Disposal System
OTEC	Ocean Thermal Energy Conversion
OWS	oil-water separator
PCB	polychlorinated biphenyls
pCi/l	pico-curies per liter
PHI	Pepco Holdings, Inc.
PIT	passive integrated transponder
PJM	PJM Interconnection, LLC
$PM_{2.5}$	particulates with diameters less than 2.5 microns
PM_{10}	particulates with diameters less than 10 microns
ppt	parts per thousand
PRA	probabilistic risk assessment
PRM	Potomac-Raritan-Magothy
PSA	probabilistic safety assessment
PSEG	PSEG Nuclear, LLC, Public Service Electric and Gas (the operating company predecessor for PSEG Nuclear, LLC), Public Service Enterprise Group
PSE&G	Public Service Electric and Gas (the existing electricity transmission and distribution company)
psig	pounds per square inch gauge
PW	production well
PWR	pressurized water reactor
RCS	Reactor Coolant System
RGGI	Regional Greenhouse Gas Initiative
RGPP	Regional Groundwater Protection Program
RIR	Remedial Investigation Report
RIS	Representative Important Species
RLWS	Radioactive Liquid Waste System
RM	river mile
ROI	region of interest
RPS	Renewable Portfolio Standards
Salem	Salem Nuclear Generating Station
SAMA	Severe Accident Mitigation Alternatives
SAR	Safety Analysis Report
sec	second
SCR	selective catalytic reduction

Acronyms and Abbreviations (Continued)

SHPO	State Historic Preservation Officer
SIP	State Implementation Plan
SMITTR	surveillance, monitoring, inspections, testing, trending, and recordkeeping
SO_2	sulfur dioxide
SO_X	oxides of sulfur
SWS	Service Water System
TLD	thermoluminescent dosimeter
TSP	total suspended particulates
USCB	U.S. Census Bureau
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey

Conversion Factors

This table is derived from Thompson, A. and B. N. Taylor 2008. Guide for the Use of the International System of Units. NIST Special Publication 811, 2008 Edition. Gaithersburg, MD, US Department of Commerce, National Institute of Standards and Technology. Retrieved February 12, 2008 from http://physics.nist.gov/cuu/pdf/sp811.pdf.

To convert from	to	Multiply by
Area		
acre	hectare	4.047 E-01
square mile (mi^2)	kilometer (km^2)	2.589 E+00
Flow		
cubic foot per second (ft^3/sec)	cubic meter per second (m^3/sec)	2.831 E-02
Length		
foot (ft)	meter (m)	3.048 E-01
inch (in)	meter (m)	2.54 E-02
inch (in)	centimeter (cm)	2.54 E+00
mile (mi)	kilometer (km)	1.609 E+00
Mass		
pound	kilogram	4.535 E-01
ton (short ton)	metric ton	9.072 E-01
Temperature Interval		
°F (interval)	°C (interval)	5.55 E-01
Volume		
gallon (gal)	liter (l)	3.785 E+00
To convert from	**to**	**Use this formula**
degrees Fahrenheit (°F)	degrees Celsius (°C)	t°C = (t°F - 32°) / 1.8

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Chapter 1

Introduction

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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. PSEG Nuclear, LLC (PSEG) operates the Salem Nuclear Generating Station (Salem), pursuant to NRC Operating Licenses DPR-70 (Unit 1) and DPR-75 (Unit 2). The license for Unit 1 will expire on August 13, 2016. The license for Unit 2 will expire on April 18, 2020.

PSEG Nuclear, LLC, is seeking license renewal of the Salem operating licenses and has prepared this Environmental Report in conjunction with its application to NRC to renew the Salem 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)].

NRC has defined the purpose and need for the proposed action, the renewal of the operating license for nuclear power plants such as Salem, 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 Unit 1 to operate until August 13, 2036 and Unit 2 until April 18, 2040, an additional 20 years of operation beyond the current licensed operating period of 40 years for each Salem Unit.

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. 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 Salem Environmental Report, PSEG has relied on NRC regulations and the following supporting documents that provide additional insight into the regulatory requirements:

- Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996b and 1999a);
- NRC supplemental information in the Federal Register (NRC 1996a, 1996c, 1996d, and 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); and
- Supplement 1 to Regulatory Guide 4.2, Preparation of Supplemental Environmental Report for Applications to Renew Nuclear Power Plant Operating Licenses (NRC 2000).

PSEG has prepared Table 1.2-1 to verify conformance with regulatory requirements. Table 1.2-1 indicates the sections in the Salem Environmental Report that respond to each requirement of 10 CFR 51.53(c). In addition, each responsive section is prefaced by a boxed quote of the regulatory language and applicable supporting document language.

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
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	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)(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	Ground Water Use Conflicts (Plants Using Cooling Water Towers 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
10 CFR 51.53(c)(3)(ii)(B)	4.4	Heat Shock
10 CFR 51.53(c)(3)(ii)(C)	4.5	Ground-Water Use Conflicts (Plants Using >100 gpm of Ground Water)
10 CFR 51.53(c)(3)(ii)(C)	4.7	Ground-Water Use Conflicts (Plants Using Ranney Wells)
10 CFR 51.53(c)(3)(ii)(D)	4.8	Degradation of Ground-Water Quality

Table 1.2-1 Environmental Report Responses to License Renewal Environmental Regulatory Requirements (Continued)

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(3)(ii)(E)	4.9	Impacts of Refurbishment on Terrestrial Resources
	4.10	Threatened and Endangered Species
10 CFR 51.53(c)(3)(ii)(F)	4.11	Air Quality During Refurbishment (Non-Attainment or Maintenance 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 Water Supply
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 Archaeological Resources
10 CFR 51.53(c)(3)(ii)(L)	4.20	Severe Accident Mitigation Alternatives (SAMA)
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	Minority and Low-Income Populations

1.3 Salem Nuclear Generating Station Licensee and Ownership

Salem is owned 57.41 percent by PSEG Nuclear, LLC, which is a division of PSEG Power, LLC, the independent power production and energy marketing division of Public Service Enterprise Group, a corporation formed under the laws of the State of New Jersey in 1985 and headquartered in Newark, New Jersey. Exelon Generation, LLC, headquartered in Kennett Square, Pennsylvania, owns the remaining 42.59 percent. Exelon Generation, LLC is a wholly owned subsidiary of Exelon Corporation (Exelon).

In 2000, PSEG Nuclear, LLC obtained the nuclear generation assets from Public Service Electric and Gas (PSE&G), the operating predecessor to PSEG Nuclear, LLC, as required by the Electric Discount and Energy Competition Act and implementing New Jersey Board of Public Utilities orders. PSEG Nuclear, LLC holds both Salem licenses and is applying to renew those licenses.

Reference documents identified in this Environmental Report as being authored by PSE&G (the operating predecessor company for PSEG Nuclear), Public Service Enterprise Group, or PSEG Nuclear were developed during the different ownership periods of the generating station. Within this Environmental Report, these company designations may be interchangeably referred to as "PSEG."

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Chapter 2

Site and Environmental Interfaces

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2.1 Location and Features

Salem is at the southern end of Artificial Island in Lower Alloways Creek Township, Salem County, New Jersey. The Delaware River is about 4 kilometers (km; 2.5 miles [mi]) wide at this location. Salem is located at River Mile 50, 29 km (18 mi) south of the Delaware Memorial Bridge. Philadelphia is about 64 km (40 mi) northeast and the city of Salem, New Jersey, is 13 km (8 mi) northeast of the site (AEC 1973). The area adjacent to Salem is in the Delaware River's Estuary Transition Zone, as defined by the U.S. Environmental Protection Agency's (EPA) Delaware Estuary Program Scientific and Technical Advisory Committee and the Delaware River Basin Commission Zone 5 (PSEG 2006a, Section 4). Figures 2.1-1 and 2.1-2 are the 80-km (50-mi) and 10-km (6-mi) vicinity maps, respectively.

Artificial Island is a 607 hectare (1,500 acre) island that was created, beginning early in the twentieth century, when the U.S. Army Corps of Engineers began disposing of hydraulic dredge spoils within a progressively enlarged diked area established around a natural bar that projected into the river. Habitats on the low and flat 607-hectare (1,500-acre) island, which has an average elevation of about 2.7 meters (m; 9 feet [ft]) above mean sea level (msl) and a maximum elevation of about 5.5 m (18 ft) above msl, can best be characterized as tidal marsh and grassland. (AEC 1973)

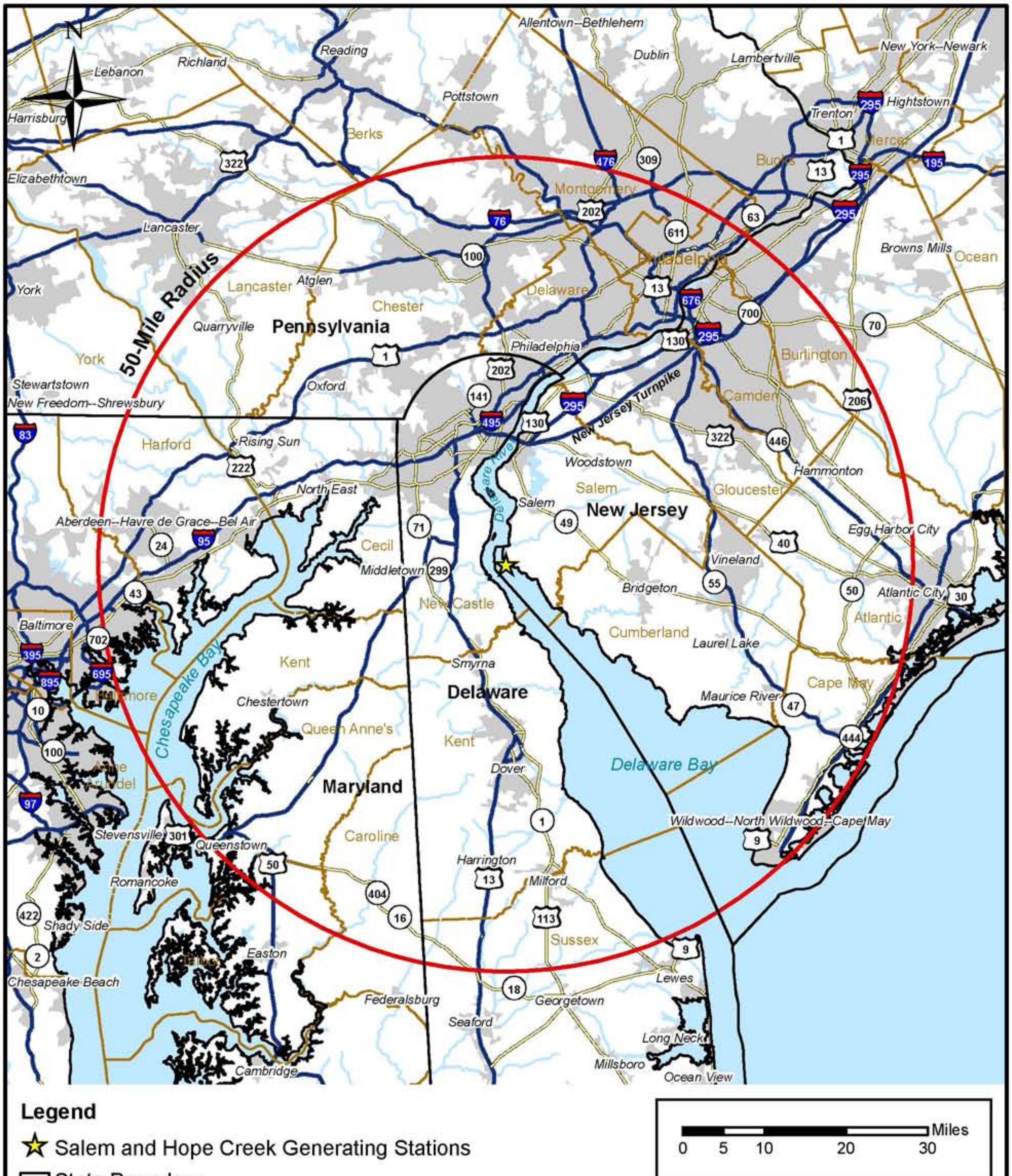
Salem occupies about 89 hectares (220 acres) of approximately 300 hectares (740 acres)[1] owned by PSEG on Artificial Island. The Hope Creek Generating Station (HCGS) is also located within the 300-hectare (740-acre) parcel owned by PSEG.[2] The remainder of Artificial Island is undeveloped. The northern portion of Artificial Island and a 1.6-km-wide (1-mi-wide) inland strip of land abutting the island are owned by the U.S. Government (AEC 1973). The State of New Jersey owns the remainder of Artificial Island as well as much nearby inland property. The northernmost tip of Artificial Island, which the U. S., Government owns, is within the State of Delaware boundary, which was established based on historical land grants related to the tide line at that time. Distance to the Salem site boundary from the Salem reactor buildings is approximately 1.3 km (4,200 ft). The nearest residence is approximately 5.5 km (3.4 mi) west of the Salem site in Bay View Beach, Delaware. Other nearby residences are located 5.6 km (3.5 mi) east-northeast and 5.6 km (3.5 mi) northwest of the Salem site. The population center distance (defined in 10 CFR 100 ["Reactor Site Criteria"] as the distance from the reactor to the nearest boundary of a densely populated center with 25,000 residents or more) is 25 km (15.5 mi). The area within 24 km (15 mi) of the site is primarily utilized for agriculture. Heavy industry exists more than 24 km (15 mi) north of the site (PSEG 2009c).

There are no major highways or railroads within about 11 km (7 mi) of the Salem site; the only land access is a road that PSEG constructed to connect its property with an existing secondary road about 5 km (3 mi) to the east. Barge traffic has access to the site by way of the Intracoastal Waterway channel maintained in the Delaware River. (AEC 1973)

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

[1] Throughout this report, the acreage of the PSEG-owned property on Artificial Island is reported as approximately 740 acres, which is consistent with the documentation for the original property conveyance. However, a recent survey indicates the PSEG-owned property size as 734 acres. The acreage change is likely the result of using improved technology that more accurately measures the boundaries of irregular surfaces in difficult physical environments, such as the riparian environment along the eastern boundary of the PSEG-owned property on Artificial Island. For the original conveyance, the meandering boundary line would have been approximated using straight lines.

[2] This Environmental Report is specific to Salem and includes all the information necessary for the NRC to prepare a Supplemental Environmental Impact Statement for Salem. PSEG has prepared a second Environmental Report that is specific to the HCGS.



Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 2.1-1 50-Mile Region

Legend

- Salem and Hope Creek Generating Stations
- Populated Place
- County Boundary
- Primary Highway with Limited Access
- Primary Highway
- Secondary Road
- Local Road
- Water

Miles
0 0.5 1 2 3 4

Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 2.1-2 6-Mile Vicinity

2.2 Aquatic Resources

The Delaware River rises on the western slope of the Catskill Mountains in south-central New York and flows south approximately 595 km (370 mi) to Liston Point, where it enters Delaware Bay (PSEG 1984). Delaware Bay extends another 80 km (50 mi) to the Atlantic Ocean. The Delaware River watershed encompasses parts of New York, Pennsylvania, Delaware, and New Jersey and drains an area of approximately 35,050 square kilometers (km^2) (13,533 square miles [mi^2]) (PSEG 2006a, Section 4). Major tributaries include the Lehigh River, which joins the Delaware at Easton, Pennsylvania, and the Schuykill River, which joins the Delaware at Philadelphia. The Delaware River has a total volume of about 450 billion cubic feet (ft^3)(PSEG 2006a, Section 4).

Near Trenton, New Jersey, the Delaware River crosses the Fall Line, the narrow zone that separates the rocky Piedmont physiographic region from the sandy Coastal Plain. At the Fall Line, the river descends through rapids ("falls") and then flows into the Delaware Estuary, which is defined as the tidally influenced portion of the Delaware River between Trenton, New Jersey, and the mouth of Delaware Bay, a distance of approximately 214 km (133 mi) (PSEG 2006a, Section 4).

The Delaware Estuary ranges in width from 0.3 km (0.2 mi) to 43 km (27 mi) and has a surface area of more than 2,590 km^2 (1,000 mi^2) (PSEG 2006a, Section 4). The Estuary has a mean depth of 5.8 m (19 ft) with a maximum depth of nearly 45 m (148 ft) in Delaware Bay. The surface area of the main stem of the Estuary is about 1878 km^2 (725 mi^2), with tidal creeks adding about another 85 km^2 (33 mi^2). Approximately 798 km^2 (308 mi^2) of tidal marshes surround the Estuary, playing an important role in water and nutrient exchange and influencing its water chemistry and biological communities (PSEG 1984). Salem is located adjacent to the Delaware Estuary. However, the documents referenced in this Environmental Report refer inconsistently to the water body adjacent to Salem as either "the river" or "the estuary." Because the affected water body is an estuary, this Environmental Report refers to it as "the Estuary" or "the Delaware Estuary." An estuary is the tidally influenced interface between fresh water and salt water. As such it supports a variety of habitats, and species common to both fresh water and marine environments.

The freshwater flow into the Delaware Estuary averages 645 cubic meters per second (m^3/sec; 22,783 cubic feet per second [ft^3/sec]), approximately half of which is contributed by the Delaware River at Trenton (PSEG 1984). The balance of the flow is contributed by the Schuylkill River and all other tributaries below Trenton. By contrast, tidal flow (or "flux") near the site (at River Km 80 [River Mile 50]) has been estimated to be 11,324 m^3/sec (400,000 ft^3/sec) which equates to 3.6 x 10^{11} m^3/year (1.3 x 10^{13} ft^3/year) (PSEG 1984). As a consequence, current speed and direction throughout the Estuary are determined primarily by tides. However, circulation patterns in the Delaware Estuary are influenced by river discharge. In general, as Delaware River discharge increases, there is a tendency for the Estuary to shift from well-mixed or partially-mixed to a stratified or two-layered circulation pattern in which less-dense fresh (river) water overlies more-dense sea water, creating a salt wedge.

The Delaware River, Estuary, and Bay system is a continuum of environments: fresh water, tidal fresh water, tidal brackish water, and marine. Salinity in the Delaware River, Estuary, and Bay varies from fresh water at Trenton to typical ocean water concentrations of about 34 parts per thousand on the continental shelf off the mouth of the Bay. Variables such as freshwater discharge, tidal phase, basin morphology, and meteorological conditions affect salinity. In the vicinity of Salem, salinity ranges seasonally from about 0.5 to 20 parts per thousand (PSEG 2007a).

Water circulation within the Delaware Estuary affects the occurrence, distribution, and abundance of organisms both directly (as a result of net water transport, turbulent mixing, and exchange of water among the system's components) and indirectly (as a result of its influence on biologically important water quality parameters such as salinity, temperature, dissolved oxygen, and turbidity). Tidal circulation, freshwater discharge from the drainage basin and upstream impoundments, wind-induced flushing, and salinity-induced density gradients are major forces that influence the water circulation patterns in the system and result in its highly dynamic physical and chemical environment (PSEG 2007a).

The distribution and abundance of aquatic organisms in the Delaware River, Estuary, and Bay system is determined primarily by salinity, but is also influenced by other water quality parameters, especially temperature and dissolved oxygen. Salinity gradients move up and down the Estuary in response to changes in freshwater inflow, which varies twice daily with the tides, and seasonally and annually with precipitation in the watershed. Water temperatures likewise vary seasonally, but changes are moderated by the large volume of ocean water entering the Bay with each tidal cycle, and river inflow. The buffering effect of the ocean water is most noticeable in the lower Bay and least noticeable in the upper Bay. The waters of the Delaware Estuary are generally well-oxygenated, with dissolved oxygen levels varying inversely with temperature. (PSEG 1984)

The major contributions to the food base of the Delaware Estuary are detritus from marsh plant production, material washed in from the tributaries, and phytoplankton production in the middle and lower bay. The area of the Estuary in the vicinity of Salem and HCGS supports very low levels of phytoplanktonic photosynthesis because high sediment loads and associated turbidity limit light penetration. Also, there are low concentrations of immature planktonic stages of commercially important shellfish, no commercially important species of zooplankton, and no threatened or endangered species of zooplankton. (PSEG 1999a, Appendix E)

The value of the Delaware River ecosystem, and its need to be protected, has been recognized for more than 40 years. In 1961, President John F. Kennedy, representing the United States, and the governors of New Jersey, New York, Pennsylvania, and Delaware signed the Delaware River Basin Compact, which created the Delaware River Basin Commission. The Commission is responsible for administering a comprehensive multipurpose plan to provide effective flood control; conserve and develop ground and surface water supplies; develop recreational facilities; propagate fish and wildlife; promote related forestry, soil conservation, and watershed projects; protect and aid fisheries dependent on the water resources; develop hydroelectric potential; improve navigation; control the movement of saltwater; control stream pollution; and regulate stream flow (DRBC 1961).

2.2.1 PSEG BIOLOGICAL MONITORING PROGRAM

Trawl surveys have been conducted from the mouth of the Bay to the upper Estuary at Trenton, (referred to as “bay wide” in some reports) using both bottom trawls and pelagic trawls. In addition, ichthyoplankton was collected for several years. Sampling began in 1968 for the then-planned Salem Nuclear Generating Station and has been conducted continuously since that time. PSEG has changed the program scope or gear deployment as the survey purposes changed in response to evolving regulatory requirements.

The PSEG bay-wide monitoring area was initially divided into eight sampling zones with six additional freshwater zones added later (Figure 2.2-1): Zones 1, 2, and 3 (lower Bay) are near the mouth of the Bay. Zones 4, 5, and 6 are located in the middle Bay. Zones 7 and 8 (upper Bay) are in the lower Delaware River. Zones 9 through 14 are in the freshwater portion of the Estuary, extending to the falls at Trenton. These sampling zones, the EPA's Delaware Estuary Program zones, the Delaware River Basin Commission (DRBC) zones, and the New Jersey Surface Water Quality Standards zones are independent of each other. As a point of reference when reviewing the various reports on the Delaware River, Estuary, and Bay system, the EPA's Delaware Estuary Program locates Salem in its Estuary Transition Zone, the New Jersey beach seine sampling program locates Salem in Region 1, the DRBC water quality zone is 5, and the PSEG monitoring program locates Salem in its Zone 7.

Primarily two data sources have been used to describe the fishery in the vicinity of Salem. The New Jersey Pollutant Discharge Elimination System (NJPDES) renewal application for Salem submitted by PSEG in 2006 (PSEG 2006a) includes a Comprehensive Demonstration Study (CDS; Section 4) and an Adverse Environmental Impact (AEI) analysis (Section 5). These studies summarize data from a recent (2002-2004) three-year period of intensive sampling on distribution and abundance of fish in the vicinity of the Station. The CDS discussion is focused on Zone 7, an approximately ten-mile-long reach of the Estuary (Figure 2.2-1) that includes the Station. Each year PSEG produces an annual report of sampling results. The 2007 report is most frequently referenced here because it provides the most recent snapshot. However, annual reports have been produced since 1995, and taken together, the data indicate a typical fishery with some species common every year, and some species common to uncommon in different years. Fish were sampled using a variety of gear types (otter [bottom] trawl, pelagic frame trawl, plankton net, beach seine) to ensure that a range of habitats and life stages were adequately characterized. The 1999 Salem NJPDES renewal application also contains extensive analyses and data compilations (PSEG 1999a).

Recent monitoring has focused on the following target species: blue crabs (*Callinectes sapidus*), blueback herring (*Alosa aestivalis*), alewife (*A. pseudoharengus*), American shad (*A. sapidissima*), bay anchovy (*Anchoa mitchilli*), white perch (*Morone americana*), striped bass (*M. saxatilis*), weakfish (*Cynoscion regalis*), spot (*Leiostomus xanthurus*), Atlantic croaker (*Micropogonias undulates*), Atlantic menhaden (*Brevoortia tyrannus*), Atlantic silverside (*Menidia menidia*), and bluefish (*Pomatomus saltatrix*).

2.2.1.1 Bottom Trawl Sampling

PSEG has conducted a daytime bottom trawl program since 1968. During each year of sampling, samples were collected beginning in the spring and ending in the fall. Sampling protocols have changed over the years. For example, until 1978 the tows were taken with a fixed-length towline. Since 1979, the trawls have been collected with a variable-length towline. In 1995, the direction of the trawl changed from towing with the current to towing into the current. Since 1995, daytime bottom trawls have been conducted monthly from April through November at randomly selected stations in the monitoring area which extends from the mouth of the Delaware Bay (River Mile 0) to just north of the Delaware Memorial Bridge (River Mile 70).

Data collected from bottom-trawl studies included the number of specimens per finfish species, individual lengths, and sex. All blue crabs were enumerated. Other data collected included tide, air and water temperature, salinity, dissolved oxygen, pH, secchi depth (visibility), and water depth.

Three species dominated bottom-trawl collections from Zone 7 over the 2002-2004 period: Atlantic croaker, hogchoker (*Trinectes maculatus*), a non-target species, and white perch (PSEG 2006a, Section 4). These three species made up 81 to 88 percent, per annum, of all fish in bottom-trawl samples and were present in relatively high numbers in all three years. In 2002, 69.7 percent of fish collected in Zone 7 bottom trawl samples were Atlantic croaker; with hogchoker and bay anchovy making up 13.1 and 5.7 percent, respectively of fish collected. In 2003, hogchoker (35.7 percent), Atlantic croaker (30.7 percent), and white perch (17.0 percent) were first, second, and third in abundance in samples. In 2004, Atlantic croaker again dominated Zone 7 bottom-trawl collections (47.2 percent of fish collected), with hogchoker (24.4 percent), white perch (2 percent), and weakfish (14.7 percent) also appearing frequently in samples.

Abundance of other fish species was more variable. Weakfish, for example, were uncommon in bottom-trawl samples in 2002 and 2003, but were third in abundance in 2004, when 826 weakfish were collected (nearly 15 percent of the total). Striped bass, on the other hand, were uncommon in 2002 and 2004, but ranked fourth in the number of fish captured (123 total; 6.2 percent) in bottom trawls in 2003. Bay anchovy made up 6 percent of fish in bottom-trawl collections in 2002, but were relatively uncommon in 2003 and 2004 (less than 1 percent in each year).

In the 2007 bay-wide bottom trawl survey, 29,966 finfish from 55 species and 2,354 blue crabs were collected in 320 trawl samples. Approximately 78 percent (23,243 individuals) of the total finfish catch comprised the target species. Atlantic croaker (38 percent) and bay anchovy (24 percent) dominated the total catch. The remaining 10 target finfish species collectively represented 15.5 percent of the total finfish catch. No Atlantic silverside was caught (PSEG 2007a).

Since 1995, the Atlantic croaker has generally been the dominant or co-dominant species in bottom trawl catches, representing more than 20 percent, of the catch during each year since 2001 (PSEG 2001, 2002, 2003, 2004a, 2005, 2006b, 2007a). Atlantic croaker comprised 71 percent of the catch in 2002, 47 percent in 2004 (PSEG 2006a), and 38 percent in 2007 (PSEG 2007a). Approximately 8 percent of the total Atlantic croaker catch was from Zone 7 during the most recent sampling year (PSEG 2007a). No other finfish species routinely comprises more than 10 percent of the annual bay-wide bottom-trawl samples, although occasional high abundances have been reported. Some examples include white perch in 2003 (20 percent; PSEG 2003), weakfish in 1997 (17 percent; PSEG 1997), and hogchoker in 2000 (28 percent; PSEG 2000). In 2007, the most abundant fish caught in the area of the estuary nearest Salem was the hogchoker (32 percent of total catch); Atlantic croaker (30 percent) was second most abundant (PSEG 2007a).

In Zone 7, catch per unit effort (CPUE) was reported by species since 2002. During those years CPUE for Atlantic croaker showed high variability, ranging from 100.28 (in 2002) to 18.94 (in 2003). Variability was also high for other finfish (PSEG 2002, 2003, 2004a, 2005, 2006b, 2007a).

2.2.1.2 Pelagic Trawl Sampling

Pelagic trawl sampling provides data on the relative abundance of juvenile organisms. PSEG conducted a pelagic trawl sampling program from 1979 through 1982, from 1988 through 1998, and then from 2002 through 2004. As was the case with the bottom trawls, sampling protocols changed during the course of the monitoring program.

From 2002 to 2004, pelagic trawls were conducted throughout the monitoring area at randomly selected stations in Zones 1 through 8, in the same manner as for bottom trawls; in addition, Zones 9 through 14 were established up-river in the Delaware Estuary. During the 2004 pelagic trawl effort, 191,672 finfish from 46 species and 277 blue crabs were collected (PSEG 2004a). In 2004, in Zone 7, the month with the highest mean density (341.8 organisms per 1000 m^3) was October.

More than 90 percent of fish collected annually in Zone 7 pelagic trawls in 2002, 2003, and 2004 were bay anchovy and Atlantic croaker (PSEG 2006a, Section 4). Approximately 99 percent of the total finfish catch during 2004 was of target species. Bay anchovy (88 percent) and Atlantic croaker (10 percent) dominated the total catch. Catches in 2002 and 2003 were consistent with the 2004 relative abundance (PSEG 2002, 2003). Weakfish and Atlantic menhaden appeared less consistently in pelagic-trawl samples, but were relatively abundant in at least one year of the three. Weakfish, for example, were uncommon in pelagic-trawl samples in 2002 and 2004 but were the species third most often collected in 2003 (433 fish; 5.3 percent of total). Atlantic menhaden were third in abundance in 2002 (346 fish; 4.4 percent of total), but were collected in very small numbers in 2003 and 2004, less than one percent of the total in each year.

The total abundance of target finfish species in the lower Zones (1 through 6, downstream of Salem) was similar for 2002, 2003, and 2004 with bay anchovy, Atlantic menhaden, and weakfish dominating the catches in all three years. In the fresh water sampling zones (7 through 14, near to and upstream of Salem), the total abundance of target finfish species differed in 2003. White perch was dominant in 2002 and 2004. However in 2003, the clupeid group (unidentifiable clupeids, alewives, and American shad) was more dominant in the upper zones (PSEG 2004a).

2.2.1.3 Ichthyoplankton Sampling

PSEG conducted ichthyoplankton sampling from 1968 through 1982, in 1996 and 1998, and from 2002 through 2004. The PSEG ichthyoplankton field program was designed to provide relative density, standing crop, spatial distribution, and length frequency data on early life stages of target species of finfish within the Delaware River, Estuary, and Bay system. Samples were collected with a 1.0-m diameter, 500-micron mesh conical plankton net.

PSEG conducted an ichthyoplankton sampling program in all trawl zones from 2002 through 2004 with sampling twice per month, at night, from April through July, for a total of eight sampling events per year. Three species dominated Zone 7 ichthyoplankton collections in 2002, 2003, and 2004: striped bass, bay anchovy, and *Morone* spp (PSEG 2006a, Section 4). In each year, striped bass ranked first, bay anchovy second, and *Morone* spp. third in abundance. (*Morone* larvae were either striped bass or white perch; the early larval stages of the two species are difficult to tell apart.) Weakfish larvae were present in small numbers in 2002 and 2003 ichthyoplankton samples, but made up 10 percent of all ichthyoplankton collected in 2004. Small numbers of Atlantic croaker larvae were collected in 2002, but none were collected in 2003 and 2004. The scarcity of Atlantic croaker eggs and larvae in the area of the Station was not surprising, given the species' spawning habits. Atlantic croaker spawn in late fall and winter over the nearshore Continental Shelf, in depths up to 54 meters (Diaz and Onuf 1985; Creswell et al. 2007). Eggs are pelagic, and upon hatching, early-stage larvae are primarily planktonic. Post-larvae move or are carried by flood tides into estuaries. Actual mechanisms for larval transport into estuarine nursery grounds are unclear and may involve passive transport or directed movement (Diaz and Onuf 1985).

In 2004, the last year of ichthyoplankton sampling, 3,815,437 fish eggs and larvae from the 12 target species were collected from all zones. Bay anchovy (90 percent) dominated the total catch. Weakfish was the second most abundant species (7 percent), and white perch accounted for 1 percent of the total finfish catch (PSEG 2002, 2003, 2004a).

2.2.1.4 Beach Seine Surveys

The bay-wide beach seine surveys were initiated in 1995 to complement the New Jersey Department of Environmental Protection (NJDEP) Bureau of Marine Fisheries' Delaware River Seine Survey (initiated in 1980), providing sampling beyond the geographic boundaries of the NJDEP's monitoring area. The intent of the combined studies was to more fully characterize target species abundance and distribution patterns within the shallow-water habitats of the Estuary. In 2002 the sampling gear and deployment procedures for the PSEG bay-wide beach seine survey were revised to provide data equivalent to the data collected in the NJDEP program as closely as possible. The PSEG bay-wide beach seine survey targets the same 12 important finfish species identified in Section 2.2.1. Blue crab catches are also reported.

Beginning in 1995, PSEG collected samples at 32 selected locations from the mouth of the Bay to the Chesapeake & Delaware Canal (6 km [4 mi] north of Salem) semi-monthly in November through July and monthly from August through October. In 2002, the program added 16 upriver stations. Additionally, the sampling frequency was changed to once per month in June and November and semi-monthly from July through October. As with the NJDEP Delaware River Seine Survey, samples are collected with a bagged 30.5-m by 1.8-m (100-ft by 6-ft) beach seine of 0.95-cm (3/8-in) bar mesh netting. Beach seine samples were collected during daylight at high slack tide.

Beach seine samples from Zone 7 over the 2002-2004 period were dominated by juvenile and adult representatives of small, schooling species and young gamefish (PSEG 2006a, Section 4). Atlantic silverside was the species collected most often, making up 35.8, 50.8, and 64.2 percent, respectively, of fish collected in 2002, 2003, and 2004. Bay anchovy was second in abundance every year, making up 23.6, 23.7, and 17.9 percent of fish collected. Substantial numbers of young weakfish, Atlantic croaker, and striped bass were also collected. Weakfish represented 4.0, 4.2, and 5.0 percent of seine collections in 2002, 2003, and 2004. Atlantic croaker and striped bass were also regularly collected, but in generally smaller numbers than weakfish.

In the most recent seine samples available from the PSEG bay-wide beach seine survey, 13,187 specimens of 44 finfish species and 296 blue crabs were collected (PSEG 2007a). Atlantic silverside was the most abundant species taken in the seine catch, composing 41 percent of the annual sample. Historically, Atlantic silverside has been predominant in the shore zone of the lower Delaware River and Bay (PSEG 1995, 1996, 1997, 1998, 1999b, 2000, 2001, 2002, 2003, 2004a, 2005, 2006b, and 2007a), composing more than 50 percent of the annual seine catch in 8 of the 13 years. Generally, bay anchovy ranked second in total catch, ranging from 47 percent in 1995 to 18 percent in 2004. In both 2006 and 2007, bay anchovy composed about 24 percent of the catch. Atlantic croaker and white perch each represented less than 5 percent of the annual catch (PSEG 2007a). Only four species were collected during all sampling periods, in all zones and at all beach types: Atlantic silverside, bay anchovy, striped bass, and American shad. These species may be characterized as the ubiquitous core of the shore zone community (PSEG 2007a).

Relatively small catches of blueback herring and alewife have been consistently reported in the PSEG bay-wide beach seine surveys since 1995 (with the exception of one anomalous year, 2001). These results, together with long-term data provided by the NJDEP Delaware River Seine Survey which is conducted further upriver, indicate that the summer nursery grounds for alosids of interest (blueback herring and alewife) are restricted to fresh water and brackish portions of the river (PSEG 2005)

2.2.1.5 Impingement Abundance Monitoring

PSEG has conducted impingement studies since August 1977, the first year of commercial operation for Salem Unit 1. PSEG collects impingement abundance samples at the fish counting pools adjacent to the discharge troughs at the northern and southern ends of the Cooling Water System (CWS) intake structure. Ten samples per day, three days per week, are taken. Individual samples are collected by diverting flow from the fish return system for 1 to 8 minutes each sampling period, depending on fish abundance and detritus, into the fish sampling pool. To collect a sample, the water level in the fish sampling pool is lowered and organisms are removed with a dip net and placed in buckets. Organisms are sorted by species and condition, then counted, measured, and weighed. PSEG records the following environmental/operating conditions for each sample: the amount of detritus, the salinity and temperature of the water, number of pumps and screens in operation, screen speeds, tidal stage and elevation, sky condition, wind direction, wave height, and air temperature. Additional, special studies have included impingement survival, impingement collection efficiency, and screen selectivity evaluations to improve data collection and analysis.

An enhanced biological monitoring program has been conducted since 1995 in accordance with the 1994 NJPDES permit in order to estimate the occurrence and abundance of species impinged at Salem, and to estimate the initial survival of impinged individuals. Nine target finfish species and blue crab (*Callinectes sapidus*) were included in the 1995 through 1999 monitoring: blueback herring (*Alosa aestivalis*), alewife (*Alosa pseudoharengus*), American shad (*Alosa sapidissima*), bay anchovy (*Anchoa mitchilli*), white perch (*Morone americana*), striped bass (*Morone saxatilis*), weakfish (*Cynoscion regalis*), spot (*Leiostomus xanthurus*), and Atlantic croaker (*Micropogonias undulates*). In 2000, Atlantic menhaden (*Brevoortia tyrannus*), Atlantic silverside *(Menidia menidia*), and bluefish (*Pomatomus saltatrix*) were added as target species. In 2007, 62,399 finfish, of 58 species and 36 families, and 15,409 blue crabs were taken in 1,570 samples (2,602 minutes sampled) at the Salem CWS intake structure. All target species were collected (PSEG 2007a). Atlantic croaker was the most abundant fish in impingement samples, representing 29.4 percent of the total catch; it was present in about 43 percent of the samples. Other frequently impinged species in 2007 included white perch (13 percent) and weakfish (12 percent). In recent years (since 2000), the percentage of weakfish in the impingement sample has ranged as high as 27 percent, and the percentage of white perch as high as 59 percent. All 12 of the target species are represented to some extent in impingement samples, although for some species, such as spot and bluefish, the numbers are generally low.

In 2007, 67 percent of the impinged bluefish sampled were classified as “live” (defined as “swimming vigorously, no apparent orientation problems, behavior normal”), 28 percent were dead and 5 percent were damaged. Of all the species collected, this was the lowest percent survival. The other targeted finfish species had a live capture rate of 83 percent or higher. Many fish had a 100 percent live capture rate. (PSEG 2007a)

2.2.1.6 Entrainment Abundance Monitoring

PSEG has conducted entrainment studies since August 1977, the first year of commercial operation for Salem Unit 1. PSEG conducts year-round sampling for the entrainment abundance monitoring program. During 2002, eight samples per day were collected three days per week from January through March. This frequency was increased to 12 samples per day collected 5 days per week from April through July. After 2003, the sampling frequency was revised to conform to an optimal allocation scheme. During January through March and August through December, seven samples were collected per day three days per week. During April through July this was increased to 14 samples per day, 4 days per week.

Entrainment monitoring tracks the same finfish species as the impingement monitoring. Totals of 125,590 fish eggs, 86,950 larvae, 9,059 juveniles, and 206 adults representing at least 36 species were collected in 1,658 entrainment abundance samples, with 83,956 m^3 (2,964,878 ft^3) of sample water filtered during 2007 (PSEG 2007a). Ten of the 12 target species were collected (blueback herring, alewife, Atlantic menhaden, bay anchovy, Atlantic silverside, white perch, striped bass, weakfish, spot, and Atlantic croaker). The dominant species in annual collections was bay anchovy, representing 66 percent of the total sample (PSEG 2007a). In fact, bay anchovy has dominated the entrainment samples since 1995, comprising close to 75 percent of the total catch in 1999 and 2004 (PSEG 1995, 1996, 1997, 1998, 1999b, 2000, 2001, 2002, 2003, 2004a, 2005, 2006b, and 2007a). Occasionally, striped bass have been collected in substantial numbers in entrainment samples, notably in 2000 and 2001. In 2007, striped bass comprised 16 percent of the total entrainment sample and unidentified *Morone* spp. comprised another 4 percent of the total (PSEG 2007b).

2.2.2 POTENTIAL IMPACT OF SALEM OPERATIONS ON AQUATIC RESOURCES

In 2006, in conjunction with the Salem NJPDES permit renewal, PSEG prepared a comprehensive evaluation of the long-term trends in population and community characteristics of the Delaware Estuary that included an assessment of impacts of Salem's CWS intake on fisheries and other aquatic life. With regard to potential impacts of cooling system operation, three benchmarks were evaluated: (1) whether adverse changes in the balance of the biotic community had occurred, (2) whether continuing declines in the abundance of aquatic species potentially attributable to Salem operations had occurred, and (3) whether the levels of mortality caused by plant operations were sufficient to jeopardize the long-term sustainability of fish stocks. Based on an examination of the three benchmarks, the report concluded that "…operation of Salem has had no adverse impacts on populations and communities inhabiting the Delaware Estuary" (PSEG 2006a, Section 5). These conclusions are consistent with the results of similar analyses performed in 1999 (PSEG 1999a) and earlier studies.

PSEG examined three indicators of community health to determine if station operations had adversely affected the balance of the aquatic community: species richness/species density, species abundance, and the presence (or absence) of nuisance aquatic species (PSEG 2006a, Section 5). The analysis showed that fish species richness in the vicinity of Salem had not changed since the startup of Salem, and fish species density had increased. (PSEG 2006a, Section 5). The analysis suggested that most species had either increased in abundance since 1998 or that mortality associated with Station operations over the 1999-2004 period was much too low to have reduced abundance. With respect to nuisance species, the only outbreak of consequence in the Delaware Estuary took place in 2000 when a harmful algal bloom caused a fish kill in two creeks in Delaware more than 50 miles down-estuary and cross-estuary from the Station. Nuisance algal blooms are not anticipated near the station due to the high turbidity and low light penetration affect algal growth. (PSEG 1999a, Appendix E).

Trends in the relative abundance of the target species were analyzed using data from three long-term monitoring programs: the NJDEP Delaware River Seine Survey, the Delaware Department of Natural Resources and Environmental Control (DDNREC) Juvenile Trawl Survey, and the PSEG bottom trawl sampling. Trends over time were evaluated to determine whether the relative abundance of each target species had increased, decreased, or remained stable since the 1980s. Alewife, American shad, Atlantic croaker, striped bass, weakfish, white perch, and blue crab showed either a statistically significant increase in abundance or no significant change in abundance (PSEG 2006a, Section 5). Spot was the only species for which a statistically significant decline was detected (PSEG 2006a, Section 5). This decline could not be attributed to anything occurring specifically within the Delaware River or Estuary because abundance of spot had declined throughout the region, including in the Chesapeake Bay. The Delaware Estuary is at the northern limit of the range of this species, and the numbers entering the Delaware Estuary are highly variable from year to year (PSEG 2006a, Section 5). The fact that most populations have increased during the period of Station operation suggests that there has been no continuing decline in abundance of aquatic populations.

The effect of Salem operations on the long-term sustainability of fish stocks was assessed using widely accepted stock assessment models. The object of this assessment was to determine whether the future impact of station operations could jeopardize the sustainability of any of these stocks. The analysis showed that incremental effects of Salem operation on five important fish species (weakfish, striped bass, white perch, spot, and American shad) were small compared to the effects of fishing. The analysis indicated that reducing or eliminating impingement and entrainment at Salem would not measurably increase the reproductive potential (spawning stock biomass per recruit) or spawning stock biomass of any of the five species.

2.2.3 STATUS OF AQUATIC RESOURCES

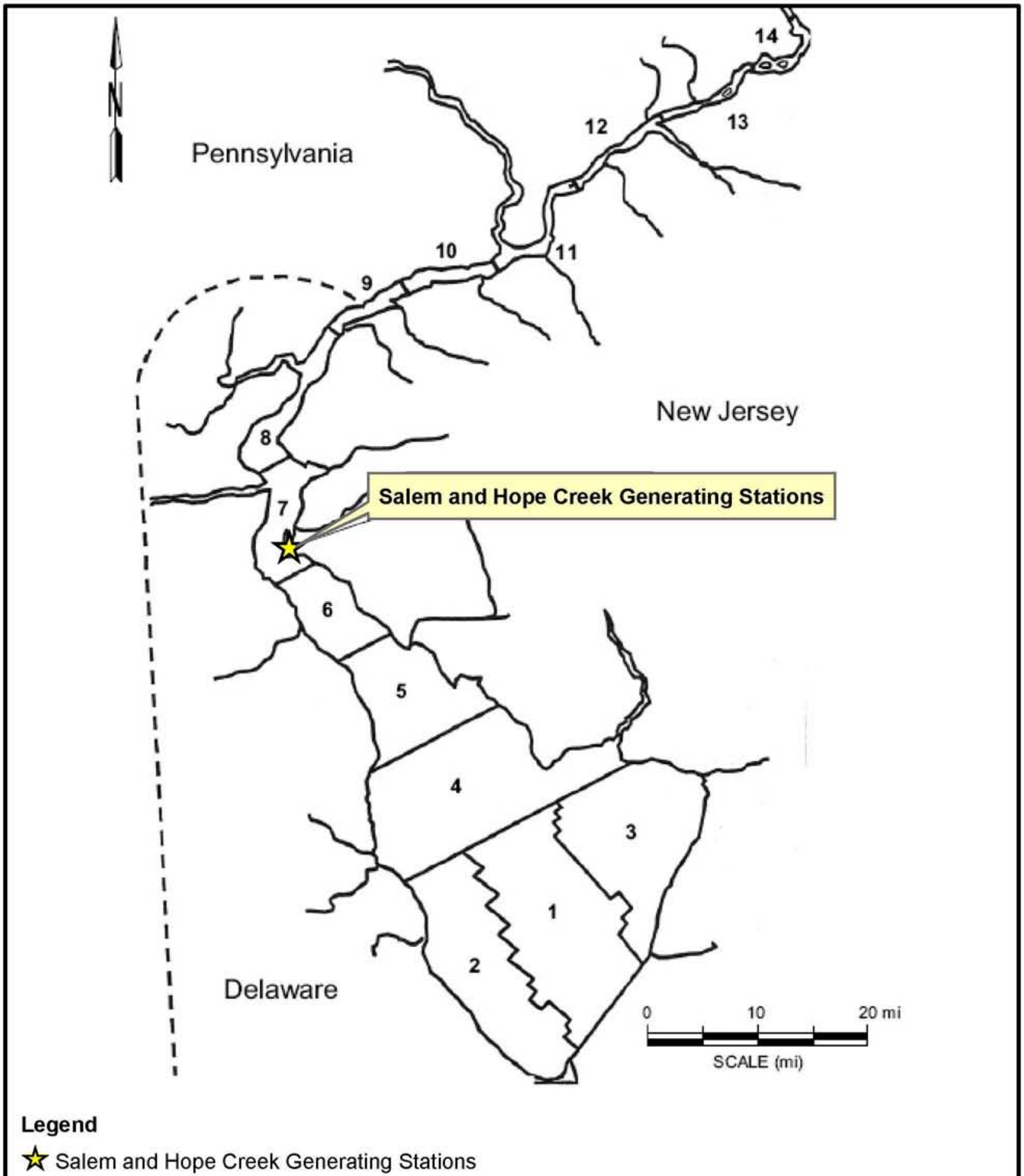
PSEG has periodically assessed population and community characteristics of the fishery in the Delaware Estuary such as species composition and population abundance (see, e.g. PSEG 1999a, PSEG 2006a). Three benchmarks historically have been examined: (1) whether adverse changes in the balance of the biotic community have occurred; (2) whether continuing declines in the abundance of aquatic species potentially attributable to nuclear power plant operations have occurred; and (3) whether the mortality attributable to plant operations is sufficient to jeopardize the sustainability of fish stocks. Evaluations of all three benchmarks identified no adverse impacts on populations or communities in the Delaware Estuary.

In 2006, data on the composition of the finfish community in the vicinity the Station from 1970 through 2004 were analyzed using widely accepted techniques for measuring species richness (defined as the average number of species present in a community), and species density (defined as the average number of species per unit area or volume). Results indicate that finfish species richness has not changed since the startup of Salem, and that finfish species density has increased. During trawl surveys conducted from 1999 through 2004, 27 finfish species were collected that had not been collected during PSEG's earlier field surveys. Annual fluctuations in the abundance of individual fish species since 1998 were compared to the changes expected to occur as a result of documented changes in habitat quality, fisheries management practices, coast-wide environmental changes, increases in predator abundance, and to changes expected to occur if Salem was adversely affecting fish populations. Most species have increased in abundance since 1998. Rates of mortality due to station operations during this period are too low to have caused measurable reductions in abundance. No estimates of mortality due to station operations are available for blue crab or Atlantic silverside. However, other data indicate that the apparent declines in abundance of these species are attributable to local environmental fluctuations (blue crab) or regional environmental changes (Atlantic silverside). (PSEG 2006a, Section 4)

Trends in the relative abundance of monitored species were analyzed for evidence of population decline. Data from three long-term monitoring programs were examined: the NJDEP Beach Seine Survey; the DDNREC Juvenile Trawl Survey; and the PSEG Nearfield Bottom Trawl Survey. Statistically significant increases in abundance were found for alewife, American shad, Atlantic croaker, striped bass, weakfish, white perch, and blue crab. Spot had a statistically significant decline over the same time period. The Delaware Estuary is at the northern limit of the range of spot, and the number of individuals entering the Delaware Estuary are highly variable from year to year. A similar decline has been observed in the Chesapeake Bay.

The impact on the long-term sustainability of fish stocks was assessed models that are commonly used in fisheries science and management. The objective of this assessment was to determine whether, compared to known effects of fishing on fish populations, the future impact of station operations could jeopardize the sustainability of any of these stocks. The stock jeopardy analyses show that, for all of the harvested species for which conditional mortality rates are available, the incremental effects of Salem are negligibly small compared to the effects of fishing. (PSEG 2006a, Section 5)

Analyses of the fish community indicate that a balanced indigenous community has been maintained in the Delaware River, Estuary, and Bay system (PSEG 2006a, Section 5). Salem Unit 1 and Unit 2 have operated for more than 26 years and 22 years, respectively. During this time, the abundance of aquatic species has fluctuated in response to natural environmental factors and human use, but for most monitored species have generally increased or remained stable. Also, improvements in the aquatic community, principally attributable to advances in wastewater management and fisheries resource management, have been observed in the Delaware River system during this time.



Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 2.2-1 PSEG Biological Sampling Zones

2.3 Ground-Water Resources

Salem is adjacent to HCGS in the New Jersey Coastal Plain, approximately 29 km (18 mi) south of the Fall Line (PSEG 2009c). The Salem site is on the eastern shore of the Delaware River at approximately River Mile 50. The Delaware Estuary borders the PSEG-owned property on Artificial Island that contains the Salem and HCGS sites to the west and south, and extensive marshlands border it on the east and north (ARCADIS 2006). The Coastal Plain is underlain by an interbedded sequence of sands and silts that compose a series of aquifers, aquitards, and aquicludes of Quaternary, Tertiary, and Cretaceous ages (PSEG 2009c). The beds generally thicken seaward and dip gently to the southeast between 2 and 11 m per km (10 and 60 ft per mi) (ARCADIS 2006).

There are four primary water-bearing zones underlying the Salem and HCGS sites. Starting with the shallowest, they are the shallow water-bearing zone and three aquifers: 1) the Vincentown aquifer, 2) the Mount Laurel-Wenonah aquifer, and 3) the Potomac-Raritan-Magothy aquifer. The shallow water-bearing zone consists of dredge spoils, engineered fill, tidal marsh deposits and the discontinuous Quaternary riverbed sand and gravel deposits that make up Artificial Island. This zone occurs between 3 and 12 m (10 and 40 ft) below ground surface (bgs). In general, the dredge spoils, engineered fill, and tidal marsh deposits are characterized by high porosity and low permeability. Lenses of sand occur within the dredge spoils and may contain perched water within a few feet of ground surface. Ground water in the zone is generally brackish, and flow is toward the southwest at a gradient of 0.007 meters/meter (0.007 feet/foot) (PSEG 2007b). Recharge to the unit at the site is primarily through direct infiltration at an outcrop area (PSEG 2009a).

The Kirkwood Formation is approximately 12 m (40 ft) bgs in the vicinity of Salem/HCGS. At the site, the Kirkwood Formation consists of Miocene clays and acts as a confining unit, separating the shallow water-bearing zone from the underlying Vincentown aquifer. The Vincentown aquifer at the site occurs from approximately 17 to 41 m (55 to 135 ft) bgs and is a semi-confined-to-confined aquifer. Flow within this unit at the site is from north to south with a gradient of approximately 0.003 meters/meter (0.003 feet/foot). The Vincentown aquifer supplies potable water to domestic wells up-gradient of Artificial Island, in eastern Salem County, where ground water in this unit is moderately hard and has high iron content. Saltwater intrusion into the Vincentown aquifer occurs along the Delaware River in western Salem County, making that water brackish and non-potable (PSEG 2007b). Recharge to the Vincentown aquifer occurs primarily from overlying units. Discharge under normal conditions is toward the southwest (PSEG 2006c).

The Hornerstown and Navesink confining units separate the Vincentown aquifer from the underlying Mount Laurel-Wenonah aquifer. The Hornerstown and Navesink confining units occur from approximately 41 to 52 m (135 to 170 ft) bgs (PSEG 2007b). The Mount Laurel-Wenonah aquifer consists of clayey sand with some gravel. In the vicinity of the site, the formation is approximately 30 m (100 ft) thick and occurs from 52 to 82 m (170 to 270 ft) bgs. (PSEG 2006c) Recharge to the Mount Laurel-Wenonah aquifer at the site is by leakage of overlying aquifers (PSEG 2006c).

At the site, the Mount Laurel-Wenonah aquifer overlies the Marshalltown Formation. The Marshalltown Formation consists generally of 12 to 13 m (38 to 44 ft) of clayey silt with minor amounts of quartz and glauconite. The formation throughout the region generally consists of fine sand and sandy clay and is 3 to 5 m (10 to 15 ft) thick. The Marshalltown Formation acts as a leaky confining layer. Water quality is generally fair to poor for human consumption due to high iron content, turbidity, and an objectionable odor. (PSEG 2006c)

Underlying the Marshalltown Formation are the Englishtown Formation, which consists of fine sand; the Woodbury Clay; the Merchantville Formation clay; the Magothy Formation, a coarse to fine silt with little fine sand; and the Raritan and Potomac Formations consisting of interbedded sand, gravelly sand, and clay. The Magothy, Raritan, and Potomac Formations form the Potomac-Raritan-Magothy aquifer (ARCADIS 2006). Recharge to the aquifer is through precipitation at an outcrop area up-gradient of the site and leakage from under- and overlying aquicludes. (PSEG 2006c)

In 1986, New Jersey designated two Critical Water-Supply Management Areas in the New Jersey Coastal Plain in response to long-term declines in ground-water levels where ground water is the primary water supply (USGS 2007). Critical Water-Supply Management Area 1 includes portions of Middlesex, Monmouth, and Ocean counties along the Atlantic Ocean shore. Critical Water-Supply Management Area 2, the nearer Critical Water-Supply Management Area, is northeast of the site in portions of Ocean, Burlington, Camden, Atlantic, Gloucester, and Cumberland counties, and a small portion of eastern Salem County (USGS 2007). In Critical Water-Supply Management Area 2, ground-water withdrawals were reduced and new allocations are limited from the Potomac-Raritan-Magothy Aquifer (USGS 2007). The Salem and HCGS sites are southwest of the management area, along the Delaware River, not in a Critical Water-Supply Management Area, and are not subject to the ground-water withdrawal restrictions.

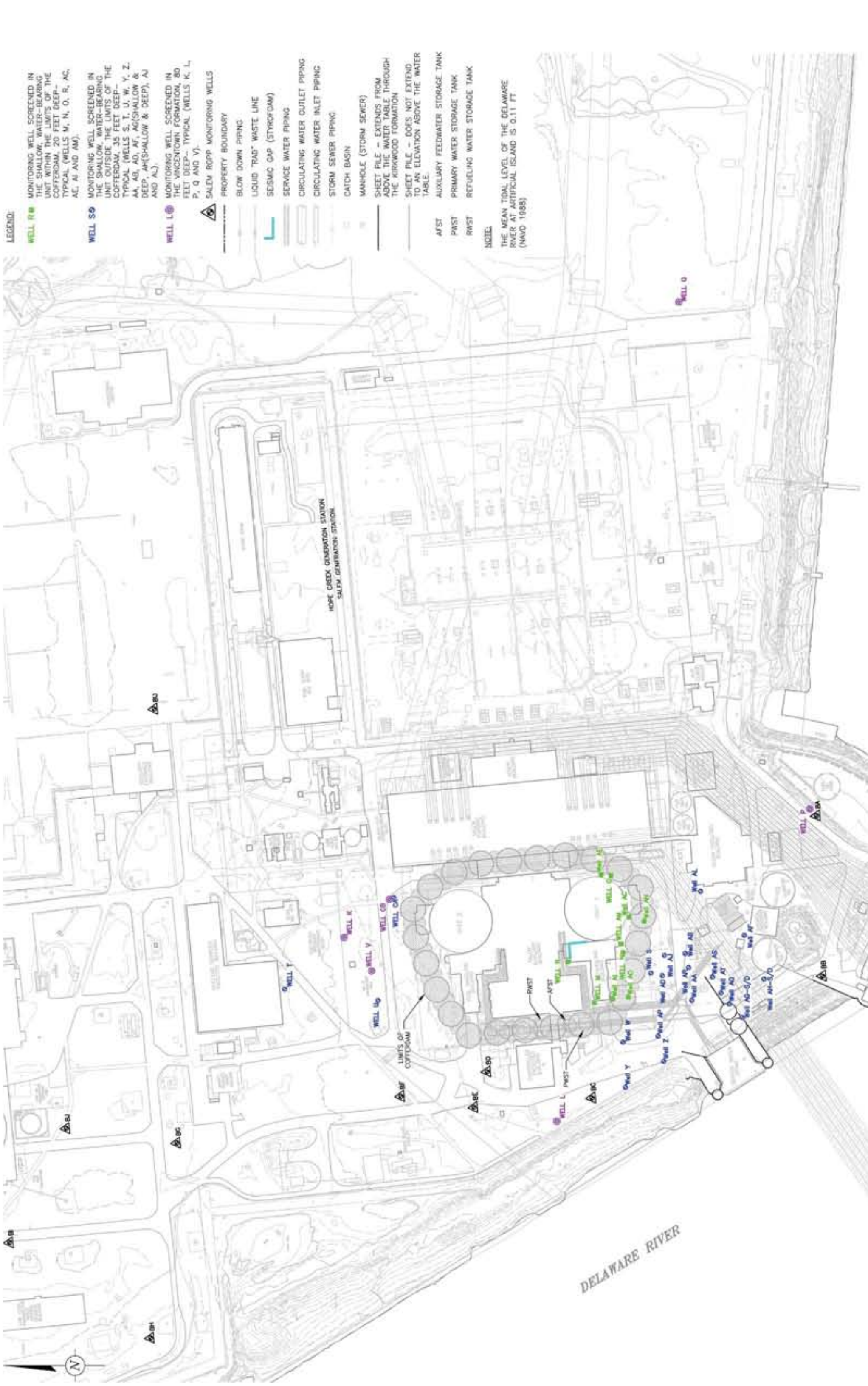
There are no off-site public water supply wells or private wells within 1.6 km (1 mi) of the Salem and HCGS sites. The nearest off-site potable supply well is located more than 5.6 km (3. 5 mi) west of the site, across the Delaware River, in Delaware (ARCADIS 2006). For a discussion of Salem ground-water usage, refer to Section 3.1.4.

Ground-Water Tritium

In 2003, PSEG identified tritium in ground water from onsite sampling wells near the Salem Unit 1 Fuel Handling Building (FHB). The sampling locations were within the Salem protected area (i.e., the access-controlled site area encompassed by physical barriers). Other locations of tritium contamination in the general vicinity of the Unit 1 FHB and within the protected area were also identified. In April 2004, a Remedial Investigation Report (RIR) was submitted to the NJDEP Bureau of Nuclear Engineering (NJDEP-BNE) presenting details and results of ground-water investigation activities (PSEG 2004b). The RIR indicated that the source of tritium detected in ground water was the Salem Unit 1 Spent Fuel Pool, the tritium release to the environment had been stopped, and tritium concentrations above the New Jersey Ground Water Quality Criterion had not migrated to the property boundary. Neither strontium nor plant-related gamma emitters were detected in any ground-water well. These results were used to develop a remedial action strategy designed to hydraulically contain further migration of tritium in the ground water and to remove tritium from the ground water in accordance with a Remedial Action Work Plan (PSEG 2004c). The NJDEP-BNE approved the strategy in November 2004, and by September 2005 a full-scale ground-water recovery system (GRS) had been installed and was operational to contain the elevated tritium concentrations in the ground water directly under the Salem units. The ground-water recovery system reverses the ground-water flow gradient so that ground water in the recovery system's radius of influence is pulled toward the recovery system and away from the site boundary, thus ensuring that any tritium is contained and will not leave the Salem site. A total of 36 wells are included in the GRS monitoring and recovery network (Figure 2.3-1). All tritium removed from the ground water is processed in accordance with NRC requirements and station procedures.

Additionally, drains were installed in the Salem Auxiliary Buildings adjacent to the seismic gap, which provide continuous draining of the seismic gap and prevent contaminated water from the Spent Fuel Pool from migrating into the environment. Ongoing ground-water monitoring results are reported quarterly to the NJDEP-BNE, and thus far they indicate that, in addition to containing tritium migration, the ground-water recovery system is accomplishing significant decreases in ground-water tritium concentrations (PSEG 2007b). Figure 2.3-2 shows the extent and concentrations of tritium in the initial tritium plume as of March 2004. Figure 2.3-3 shows the extent and concentrations of tritium in the plume as of December 2008. Together, these figures demonstrate the success of the GRS at maintaining hydraulic containment of tritium, preventing off-site release, and reducing the concentration of tritium in the shallow ground water. The Spent Fuel Pool leakage was reported to the NRC and is the subject of NRC Information Notice 2004-05, "Spent Fuel Pool Leakage to Onsite Groundwater."

The Quarterly Remedial Action Progress Report for Salem for the fourth Quarter of 2007 indicates that the concentrations of tritium in ground water has continued to drop since the initiation of remediation and termination of the release to the environment. All tritium concentrations have been reduced to below 100,000 picoCuries per liter (pCi/L) from an initial maximum of approximately 15,000,000 pCi/L. Most of the ground-water concentrations are below 20,000 pCi/L (PSEG 2007b). No station-related gamma emitting radionuclides or strontium has been detected in ground-water samples. Tritium concentrations exceeding NJDEP Ground Water Quality Criterion have not migrated to the property boundary or to geologic formations deeper than the shallow water-bearing unit beneath Salem. There is no complete exposure pathway to humans or biota resulting from the release (ARCADIS 2006).



Salem Nuclear Generating Station
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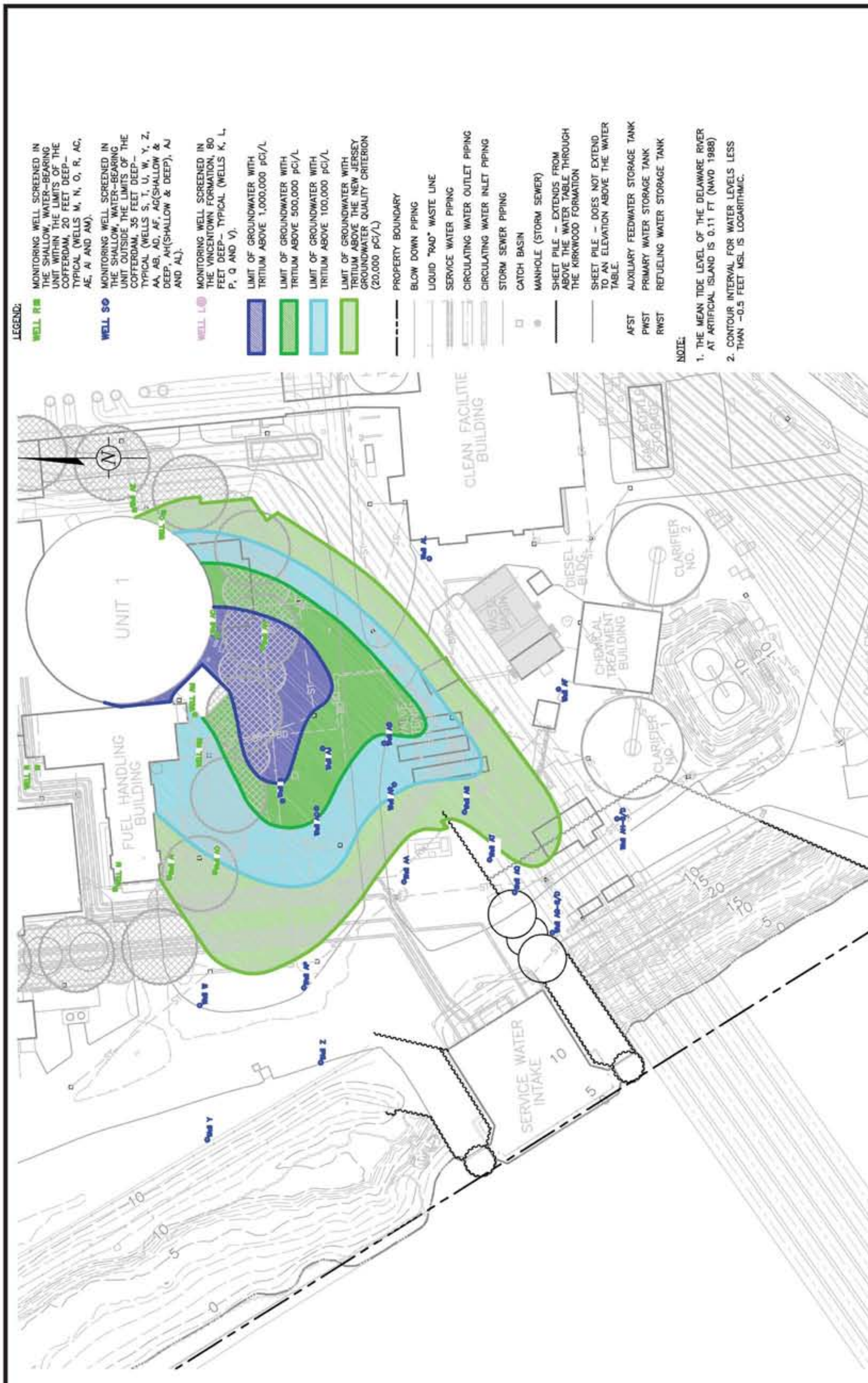
Figure 2.3-1 Salem GRS Well Network



Salem Nuclear Generating Station
PSEG
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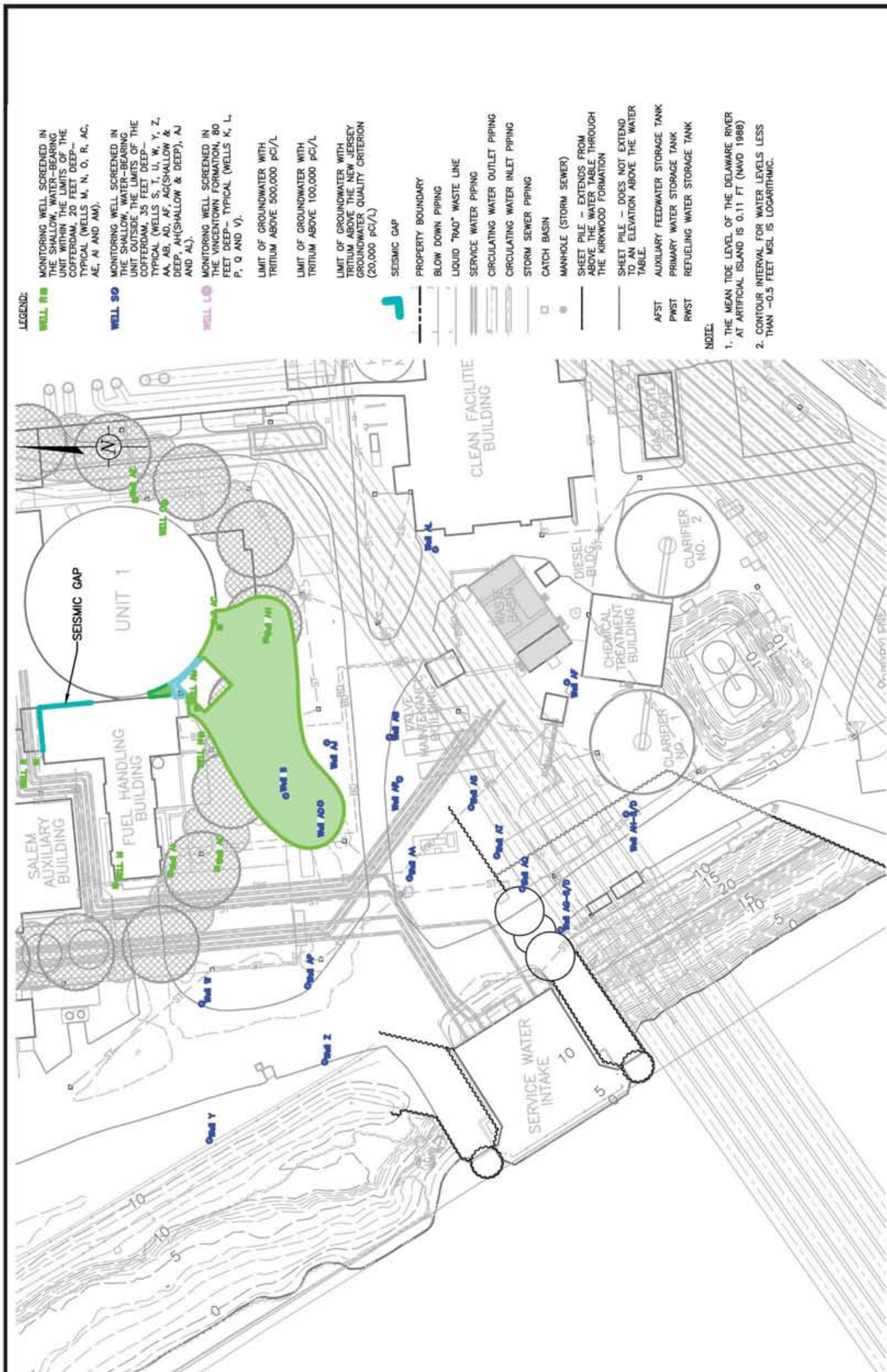
Figure 2.3-2 Tritium Plume 2004



Salem Nuclear Generating Station
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Figure 2.3-3 Tritium Plume 2008

2.4 Critical and Important Terrestrial Habitats

Salem occupies about 89 hectares (220 acres) at the southern portion of Artificial Island on the east bank of the Delaware River in Salem County, New Jersey. The 607-hectare (1,500-acre) Artificial Island was created and has been maintained since the early 1900s through the 1950s by deposition of hydraulic dredge spoils. It is connected to the New Jersey mainland by a strip of tideland also formed by fill from dredging operations in the River. PSEG owns approximately 300 hectare (740 acres) on Artificial Island. Salem was constructed on a portion of this property between 1968 and 1975. Salem is immediately adjacent to the approximately 62-hectare (153-acre) HCGS nuclear facility, which is also owned by PSEG (see Figure 3.1-1), thus ecological surveys for each facility provide information relevant to both. The remainder of the island consists of marshes, impounded areas, and open pools.

Artificial Island, actually an artificial peninsula, projects from the New Jersey shore into the Delaware River. The average elevation of the site is 2.7 m (9 ft) above sea level. Construction of Salem resulted in the permanent loss of 89 hectares (220 acres) of land previously occupied by dense stands of giant reed (*Phragmites australis*). Giant reed, a strongly invasive plant (NJ Category 1; Ling 2003) common to disturbed soils and tolerant of varying levels of soil moisture and salinity, is considered a pest due to its ability to out-compete native marsh plants such as the cordgrasses (*Spartina* spp.), often producing a thick monoculture stand of little value to wildlife or fish. Notwithstanding, Artificial Island provides critical foraging habitat for bald eagles, which were de-listed from the federal list of endangered and threatened wildlife in 2007 (USFWS 2007), but remain federally protected under the Bald and Golden Eagle Protection Act and remain on the New Jersey list of endangered species (NJDEP 2006).

As a dredge spoil island with poor quality soils, Artificial Island has few trees and is dominated primarily by giant reed. Other plants in the marshes surrounding the PSEG property include big cordgrass (*Spartina cynosuroides*), salt marsh cordgrass (*S. alterniflora*), saltmeadow cordgrass (*S. patens*), and saltmarsh bulrush (*Scirpus robustus*).

The wildlife species on Artificial Island and in the surrounding areas are those typically found in similar habitats within the Delaware River Estuary. Avian species observed on the Salem site during construction included marsh hawk (now northern harrier, *Circus cyaneus*), red-winged blackbird (*Agelaius phoeniceus*), common grackle (*Quiscalus quiscala*), yellowthroat (*Geothlypis trichas*), and song sparrow (*Melospiza melodia*) (AEC 1973). Ospreys (*Pandion haliaetus*) nested within the local marshes. Forty-four avian species were observed within 6 km (4 mi) of Salem during pre-construction surveys, which included some upland/farmland areas (AEC 1973). Approximately half of these species were water birds (wading birds, waterfowl, seabirds, shorebirds, etc.), likely associated with nearby open water and tidal habitats. A study done for the HCGS construction project has indicated the occurrence of at least 178 avian species within 16 km (10 mi) of HCGS; 25 percent were considered year-round resident species (PSEG 1983). Other observations made at the Alloways Creek Estuary Enhancement Program restoration site, located just north of Artificial Island, included many species of water birds, common marsh birds such as red-winged blackbirds and marsh wrens (*Cistrothorus palustris*), and migrant songbirds such as palm warblers (*Dendroica palmarum*) and swamp sparrow (*Melospiza georgiana*) (PSEG 2004d). Overall avian community composition and relative abundance are largely a function of migration.

Common mammals observed during wildlife surveys associated with Salem construction included white-tail deer (*Odocoileus virginiana*), eastern cottontail (*Silvilagus floridanus*), house mouse (*Mus musculus*), and Norway rat (*Rattus norvegicus*) (AEC 1973). Other mammals thought to be common in the surrounding areas were raccoon (*Procyon lotor*), opossum (*Didelphis virginianus*), and muskrat (*Ondatra zibethica*). An additional 39 mammal species are expected to occur within 16 km (10 mi) of Salem (NRC 1984). The only herpetological species found at Salem during the construction period was the diamondback terrapin (*Malaclemys terrapin*). An additional eight turtle species, four snakes, and one skink species were observed within 10 km (6 mi) of Salem during early surveys (AEC 1971).

Other surveys of the area surrounding both facilities suggest that up to 26 species of reptiles, including five species of sea turtles may occur on or near the site (PSEG 1983). Of the three most common sea turtles in vicinity of the station, the loggerhead (*Caretta caretta*) and Atlantic green turtle (*Chelonia midas*) are classified as federally threatened and the Kemp's ridley sea turtle (*Lepidochelys kempi*) is classified as federally endangered. Both the hawksbill (*Eretmochelys imbricata*) and leatherback sea turtle (*Dermochelys coriacea*) are classified as federally endangered, but are not typically observed near the plant site.

Section 3.1.6 describes the transmission lines built to deliver electricity generated at the Salem and HCGS sites to the transmission grid. The approximately 171 km (106 mi) of corridors associated with Salem and HCGS exit through three corridors routed to two primary substations (Figure 3.1-3). Two corridors, containing three lines, run roughly parallel to each other (1.6 to 3.2 km [1 to 2 mi] apart) and extend east-northeast toward the New Freedom Substation. The more northern corridor contains the Salem-New Freedom (North) line and the HCGS-New Freedom line, and the more southern corridor contains the Salem-New Freedom (South) line. A third corridor exits the site north for a distance and then turns west and crosses the Delaware River into Delaware. It contains the Salem-Keeney line.

All three corridors cross land identified as critical bald eagle foraging habitat (NJDEP 2006). Both east-northeast running corridors traverse approximately two miles of marsh habitat east of the PSEG property, then a combination of forested and agricultural lands, and for approximately the last one-quarter of their distance to the New Freedom substation, both corridors cross the New Jersey Pinelands National Reserve, which has been designated a biosphere reserve. A biosphere reserve is a representative ecological area with three mutually reinforcing functions: conservation, sustainable development and logistic support for scientific research and education. Biospheres are recognized by the United Nations Educational, Scientific and Cultural Organization (UNESCO) under its Programme on Man and the Biosphere. (UNESCO 2009)

The New Jersey Pinelands Commission implements the Pinelands Comprehensive Management Plan, the purpose of which is to preserve, protect, and enhance the natural and cultural resources of the Pinelands National Reserve, and to encourage compatible economic and other human activities. Electric transmission corridor maintenance in the New Pinelands is regulated by the New Jersey Pinelands Commission (New Jersey Pinelands Commission 2009).

In the Pinelands National Reserve, the two corridors extending east-northeast from the Salem and HCGS sites also cross the Great Egg Harbor River, a National Scenic and Recreational River.

Each transmission corridor is 107 m (350 ft) wide, and the corridors in New Jersey are currently maintained by PSE&G. PHI maintains the corridor segment extending into Delaware. PSE&G performs ground inspections annually and aerial inspections once every 5 years. PHI performs aerial inspections twice annually and ground inspections once every 3 years. Both companies maintain vegetation (primarily the removal of fast-growing trees, trimming, and herbicides or mechanical cutting if herbicides are prohibited) as needed to ensure continued and safe distribution of electricity throughout the system (PJM 2005).

2.5 Threatened or Endangered Species

Table 2.5-1 lists protected animal and plant species recorded in counties in which Salem and its associated transmission lines are located. The species are those that are state- or federally listed as endangered or threatened, and those that are candidates or proposed for federal listing. The HCGS-New Freedom and Salem-New Freedom South corridors cross portions of Salem, Gloucester, and Camden counties in New Jersey (Figure 3.1-3). The HCGS to Red Lion segment of the Salem-Keeney line (which was originally built for Salem; see Section 3.1.6) crosses the counties of Salem (in New Jersey) and New Castle (in Delaware). The species shown in Table 2.5-1 as occurring in these counties were taken from county records maintained by the U.S. Fish and Wildlife Service (USFWS undated), the New Jersey Department of Environmental Protection (NJDEP 2001, NJDEP 2008a) and the Delaware Department of Natural Resources and Environmental Control (DDNREC 2008), except shortnose sturgeon and five species of sea turtles which are not included on county lists, but are listed by the USFWS in 50 CFR 17.11 and are known to occur in the Delaware River (see below).

As shown in Table 2.5-1, numerous special-status animal and plant species have been recorded in Salem, Gloucester, Camden, and New Castle counties. Most of these species have not been observed on the Salem site. Some endangered or threatened bird species could move through the site during seasonal migrations. Federally listed species recorded in Salem, Gloucester, Camden (New Jersey), and New Castle (Delaware) Counties, and state-listed species that have been observed on the Salem site or along the transmission lines, are discussed below.

The bog turtle (*Clemmys muhlenbergii*) and American burying beetle (*Nicrophorus americanus*) are the only terrestrial animals in Table 2.5-1 that are federally listed as endangered or threatened. The bog turtle, which is federally listed as threatened, inhabits calcareous (limestone) fens, sphagnum bogs, and wet, grassy pastures that are characterized by soft, muddy substrates (bottoms) and perennial ground-water seepage (NJDEP 2008b). These habitats are not found on the Salem site but could occur along the transmission corridors. Bog turtles have been observed within 0.8 km (0.5 mi) of the transmission corridor in New Castle County (DDNREC 2008). The federally and state-listed endangered American burying beetle, although recorded in Camden and Gloucester counties, is now believed to have been extirpated from New Jersey (NJDEP 2008a, USFWS undated).

The Pine Barrens tree frog (*Hyla andersoni*), which is state-listed as endangered, has not been found within any transmission corridor associated with Salem, but is known from other transmission corridors in the Pine Barrens (NJDEP 2008a, DDNREC 2008).

Five federally listed plant species have been recorded in Salem, Gloucester, Camden, and New Castle Counties: chaffseed, sensitive joint vetch, swamp pink, Knieskern's beaked-rush, and small-whorled begonia. Chaffseed (*Schwalbea americana*), which is federally listed as endangered, and sensitive joint vetch (*Aeschynomene virginica*), which is federally listed as threatened, are known only from historic records and no current populations are known to exist in these counties (USFWS undated). Swamp pink (*Helonias bullata*), which is federally listed as threatened, is restricted to forested wetlands that are perennially water-saturated (NatureServe 2008). Transmission corridors in Salem County cross habitats known to support swamp pink (NJDEP 2008c), and PSEG is aware of one occurrence of the species along a transmission corridor in Salem County.

Knieskern's beaked-rush (*Rhynchospora knieskernii*), which is federally listed as threatened, is restricted to early successional habitats in pitch pine lowland forests, typically in areas with fluctuating water regimes. The species is usually found in bare or sparsely vegetated areas within pine barrens where open conditions are maintained through natural disturbances such as fire or flood scouring, or through human-caused disturbances such as roadside, railroad, or transmission line right-of-way maintenance, or in inactive sand or clay pits (NatureServe 2008). Within New Jersey, Knieskern's beaked-rush is known to occur in Camden County but is not known to occur in Salem or Gloucester counties (NJDEP 2008c, USFWS undated).

Small-whorled begonia (*Isotria medeoloides*), which is federally listed as threatened, is typically found on forested sites with an open understory canopy and sparse to moderate groundcover. The species is usually located close to long-persisting breaks in the forest canopy, such as occurs along streams and established roads. Within Delaware, this orchid is known to occur in New Castle County, but is not documented within 0.8 km (0.5 mi) of the transmission corridor (DDNREC 2008). The species is not known or listed in the New Jersey counties (NJDEP 2008c, USFWS undated).

Bald eagles (*Haliaeetus leucocephalus*) and peregrine falcons (*Falco peregrinus*) are occasionally seen in the vicinity of Salem (NRC 1984) but are not known to nest at the site or within the transmission corridors (NJDEP 2008d, NJDEP 2008e), however elevated structures and open fields near these areas could support nesting. Bald eagles were removed from the federal list of endangered and threatened wildlife in 2007 (USFWS 2007), but the species remains federally protected under the Bald and Golden Eagle Protection Act and is on the New Jersey list of endangered species (NJDEP 2006). New Jersey reported 64 eagle pairs in 2007; 37 of those were in Salem, Cumberland, or Gloucester counties (NJDEP 2007a). The nearest bald eagle nest is approximately 8 km (5 mi) from the Salem site (NJDEP 2008d).

Peregrine falcons were removed from the federal list of endangered and threatened wildlife in 1999 (USFWS 1999), but the species remains on the New Jersey list of endangered species (Table 2.5-1). Peregrine falcons continue to do well throughout New Jersey (NJDEP 2008e).

Ospreys (*Pandion haliaetus*), which are state-listed as threatened, nest on transmission towers near the Salem site and in areas along the Delaware Estuary (NJDEP 2008f). PSEG has erected nesting platforms for ospreys within the Estuary Enhancement Program properties; birds are currently using the platforms (TNC 2008).

The Cooper's hawk (*Accipiter cooperii*), bobolink (*Dolichonyx oryzivorus*), and grasshopper sparrow (*Ammodramus savannarum*) had been observed within 10 km (6 mi) of Salem (AEC 1973). None of these birds is federally listed. The Cooper's hawk and bobolink are state-listed as threatened. NJDEP classifies the breeding population of grasshopper sparrows as threatened, and the migratory or winter population of grasshopper sparrows as stable in number (NJDEP 2001a).

Five federally listed species of sea turtle may occur in Delaware Bay: the threatened loggerhead sea turtle (*Caretta caretta*), threatened Atlantic green turtle (*Chelonia mydas*), endangered Kemp's ridley sea turtle *(Lepidochelys kempi*), endangered hawksbill turtle (*Eretmochelys imbricata*), and endangered leatherback turtle (*Dermochelys coriacea*). The NJDEP classifies these turtle species as endangered, except the Atlantic green turtle, which is state-listed as threatened. Young sea turtles move from the open waters of the Atlantic Ocean into near-shore coastal areas, where they forage and mature into adults. The young turtles make occasional forays into the shallow waters of mid-Atlantic estuaries in late summer to feed and rest. While no nesting occurs along Delaware Bay beaches, all five sea turtle species move into the Bay and may travel up the Estuary as far as Artificial Island (Delaware Estuary Program 1996). Most of the sea turtles found in Delaware Bay are sub-adults that were hatched on beaches in the Caribbean, Florida, and the Carolinas and have migrated north to nursery grounds in the mid-Atlantic region. The vast majority of the sea turtles observed in Delaware Bay are loggerheads, with smaller numbers of Kemp's ridley and Atlantic green turtles occasionally observed.

Between 1979 and 1991, a total of 53 sea turtles were observed, captured, or recovered by biologists conducting pre-operational and operational monitoring studies in the vicinity of Salem. In 1991, 23 loggerhead sea turtles were recovered from the Salem cooling water intake area, which was by far the highest one-year total recorded up to that time (NMFS 1999a). Twenty-two of the recovered turtles were relocated and released; one was recovered dead. In 1992, after two Kemp's ridley sea turtles were found dead in the Salem cooling water intake area (the Incidental Take Statement in place at that time allowed one fatal Kemp's ridley taking per year), NRC re-initiated consultation with the National Marine Fisheries Service (NMFS) (NMFS 1993). This resulted in the issuance of a revised Incidental Take Statement requiring more frequent inspections of the cooling water intake area and trash racks and sonic and satellite tracking of movements of loggerhead sea turtles incidentally taken at Salem. Over the next several years the tracking studies revealed that released turtles moved throughout the Estuary, showing no particular affinity for the Salem intake (NMFS 1999a).

In late 1992, PSEG removed the ice barriers that were designed to keep the cooling water intakes free of winter ice and that had been left in place in the "off seasons" (summer and fall) of 1991 and 1992 (NMFS 1999a). The ice barriers were assumed to have reduced the sea turtles' ability to escape the intake area and increased their susceptibility to impingement at the cooling water intake. Beginning in 1993, the ice barriers were removed in the spring, and the number of sea turtle strandings was dramatically reduced (NMFS 1999a). Since 1993, only six sea turtles, all loggerheads, have been stranded at Salem. None has been stranded since 2001.

One federally listed fish, the shortnose sturgeon (*Acipenser brevirostrum*), occurs in Delaware Bay. In the Delaware River system, adult shortnose sturgeons spend most of their lives in the upper tidal fresh water portion of the river (the most heavily used portion of the river is that between River Mile 118 and River Mile 137). However, shortnose sturgeon often move further upstream to spawn (O'Herron, Able, and Hastings 1993). After spawning, some adults move downstream into low-salinity reaches of the river (including Delaware Bay), primarily in spring and summer (O'Herron, Able, and Hastings 1993; NMFS 1998a). This is in sharp contrast to sturgeon in southeastern rivers, which spend most of the year in the lower Estuary and move upstream in spring into the middle and upper reaches of natal rivers to spawn. Based on surveys conducted in the 1980s, the Delaware River shortnose sturgeon population is one of the largest along the eastern seaboard, with population estimates ranging from 6,408 to 14,080 individuals (NMFS 1998a).

Small numbers of shortnose sturgeon, mostly dead or dying, have been found in the vicinity of the Salem cooling water intake structure in pre-operational and operational monitoring periods. Since 1978, 21 individuals (an average of 0.6 sturgeon per year) have been captured in the vicinity of Salem.

A revised Incidental Take Statement issued by NMFS on January 21, 1999, allows PSEG to take (impingement at the intake screens being the primary "take" mechanism) 5 Kemp's ridley turtles, 5 Atlantic green turtles, 30 loggerhead sea turtles, and 5 shortnose sturgeon per year

(NMFS 1999a). Lethal take limits are 1 Kemp's ridley turtle, 1 Atlantic green turtle, 5 loggerhead sea turtles, and 5 shortnose sturgeon annually. The Incidental Take Statement includes the following "reasonable and prudent measures" to minimize takings of sea turtles and sturgeon:

- Removal of ice barriers by May 1 and replacement of ice barriers after October 24
- Three-times-per-week cleaning of intake trash racks between May 1 and November 15; daily cleaning of intake trash racks from June 1 to October 15
- Inspection of trash racks every two hours from June 1 through October 15
- Monitoring of trash racks hourly if a lethal take occurs during the June 1 through October 15 period

The Incidental Take Statement also contains a list of "non-discretionary" terms and conditions that include requirements for resuscitating sea turtles, handling and treating injured sea turtles, necropsying dead sea turtles and reporting results, inspecting dead shortnose sturgeon for external tags and passive integrated transponder (PIT) tags, collecting shortnose sturgeon tissue samples and carcasses for shipment to research institutions, and submitting documentation of incidental takes to NMFS's Protected Resources Division.

Atlantic sturgeon (Acipenser oxyrinchus oxyrinchus) occur in the Delaware River. In 2006, NMFS initiated a status review for Atlantic sturgeon to determine if listing as threatened or endangered under the Endangered Species Act (ESA) is warranted. The Status Review Report was published on February 23, 2007 (NMFS 2007). NMFS is currently considering the information presented in the Status Review Report to determine if any listing action pursuant to the ESA is warranted at this time. If it is determined that listing is warranted, a final rule listing the species could be published. As a candidate species, Atlantic sturgeon receive no substantive or procedural protection under the ESA; however, NMFS recommends that project proponents consider implementing conservation actions to limit the potential for adverse effects on Atlantic sturgeon from any proposed project. The Atlantic sturgeon is a member of the Acipenseridae family as is the short-nosed sturgeon, and sturgeon are among the oldest fish species in the world. Its range extends from New Brunswick, Canada, to the eastern coast of Florida. Atlantic sturgeon have not been recorded in the 2002 through 2004 PSEG biological monitoring program in the bottom trawl, pelagic trawl, ichthyoplankton and macrozooplankton sampling, or impingement sampling, nor as eggs, larvae, juveniles, or adults in the entrainment sampling (described in Section 2.2.1). A single Atlantic sturgeon was reported in the 2003 beach seine sampling. These data indicate that a robust population of Atlantic sturgeon that would be of particular concern is not present in the vicinity of the station.

Winter flounder (NMFS 1998b), windowpane flounder (NMFS 1998c), and butterfish (NMFS 1999b) essential fish habitat (as defined by the Magnuson-Stevens Fishery Conservation and Management Act [P.L. 94-25]) has been identified in the Delaware Bay in the area of Salem. Winter flounder essential fish habitat ranges from Passamaquoddy Bay in Maine to Chincoteague Bay in Maryland (NMFS 1998b). Windowpane flounder essential fish habitat ranges from Passamaquoddy Bay in Maine to Chesapeake Bay in Maryland (NMFS 1998c). Butterfish essential fish habitat ranges from Newfoundland to Cape Hatteras in North Carolina (NMFS 1999b).

Table 2.5-1 Threatened or Endangered Species Recorded in Salem County and Counties Crossed by Transmission Lines

Scientific Name	Common Name	Status		County[c]
		Federal[a]	State[a,b]	
Mammals				
Lynx rufus	Bobcat	-	E	Salem
Birds				
Accipiter cooperii	Cooper's hawk	-	T/T	Gloucester, Salem
Ammodramus henslowii	Henslow's sparrow	-	E	Gloucester
A. savannarum	Grasshopper sparrow	-	T/S	Salem
Bartramia longicauda	Upland sandpiper	-	E	Gloucester, Salem
Buteo lineatus	Red-shouldered hawk	-	E/T	Gloucester
Circus cyaneus	Northern harrier	-	E/U	Salem
Cistothorus platensis	Sedge wren	-	E	Salem
Dolichonyx oryzivorus	Bobolink	-	T/T	Salem
Falco peregrinus	Peregrine falcon	-	E	Camden, Gloucester, Salem
Haliaeetus leucocephalus	Bald eagle	-	E	Gloucester, Salem
Lanius ludovicianus	Loggerhead shrike	-	E	New Castle[d]
Melanerpes erythrocephalus	Red-headed woodpecker	-	T/T	Camden, Gloucester, Salem
Pandion haliaetus	Osprey	-	T/T	Gloucester, Salem
Passerculus sandwichensis	Savannah sparrow	-	T/T	Salem
Podilymbus podiceps	Pied-billed grebe	-	E/S	Salem
Pooecetes gramineus	Vesper sparrow	-	E	Gloucester, Salem
Strix varia	Barred owl	-	T/T	Gloucester, Salem
Reptiles and Amphibians				
Ambystoma tigrinum tigrinum	Eastern tiger salamander	-	E	Gloucester, Salem
Clemmys insculpta	Wood turtle	-	E	Gloucester
C. muhlenbergii	Bog turtle	T	E	Camden, Gloucester, Salem, New Castle[d]
Crotalus horridus horridus	Timber rattlesnake	-	E	Camden
Hyla andersoni	Pine barrens treefrog	-	E	Camden, Gloucester, Salem
Pituophis melanoleucus	Northern pine snake	-	T	Camden, Gloucester, Salem
Caretta caretta	Loggerhead sea turtle	T	E	Delaware River[e]
Lepidochelys kempi	Kemp's ridley	E	E	Delaware River[e]
Dermochelys coriacea	Leatherback turtle	E	E	Delaware River[e]
Eretmochelys imbricata	Hawksbill turtle	E	E	Delaware River[e]
Chelonia mydas	Atlantic green turtle	T	T	Delaware River[e]
Fish				
Acipenser brevirostrum	Shortnose sturgeon	E	E	Delaware River[e]
A. oxyrinchus oxyrinchus	Atlantic sturgeon	C	-	Delaware River[e]
Insects				
Nicrophorus americanus	American burying beetle	E	E	Camden, Gloucester

Table 2.5-1 Threatened or Endangered Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status		County[c]
		Federal[a]	State[a,b]	
Plants				
Aeschynomene virginica	Sensitive joint vetch	T	E	Camden, Gloucester, Salem
Aplectrum hyemale	Putty root	-	E	Gloucester
Aristida lanosa	Wooly three-awn grass	-	E	Camden, Salem
Asimina triloba	Pawpaw	-	E	Gloucester
Aster radula	Low rough aster	-	E	Camden, Gloucester, Salem
Bouteloua curtipendula	Side oats grama grass	-	E	Gloucester
Cacalia atriplicifolia	Pale Indian plantain	-	E	Camden, Gloucester
Calystegia spithamaea	Erect bindweed	-	E	Camden, Salem
Cardamine longii	Long's bittercress	-	E	Gloucester
Carex aquatilis	Water sedge	-	E	Camden
C. bushii	Bush's sedge	-	E	Camden
C. cumulata	Clustered sedge	-	E	Camden
C. limosa	Mud sedge	-	E	Gloucester
C. polymorpha	Variable sedge	-	E	Gloucester
Castanea pumila	Chinquapin	-	E	Gloucester, Salem
Cercis canadensis	Redbud	-	E	Camden
Chenopodium rubrum	Red goosefoot	-	E	Camden
Commelina erecta	Slender dayflower	-	E	Camden
Cyperus lancastriensis	Lancaster flat sedge	-	E	Camden, Gloucester
C. polystachyos	Coast flat sedge	-	E	Salem
C. pseudovegetus	Marsh flat sedge	-	E	Salem
C. retrofractus	Rough flat sedge	-	E	Camden, Gloucester
Dalibarda repens	Robin-run-away	-	E	Gloucester
Diodia virginiana	Larger buttonweed	-	E	Camden
Draba reptans	Carolina Whitlow-grass	-	E	Camden, Gloucester
Eleocharis melanocarpa	Black-fruit spike-rush	-	E	Salem
E. equisetoides	Knotted spike-rush	-	E	Gloucester
E. tortilis	Twisted spike-rush	-	E	Gloucester
Elephantopus carolinianus	Carolina elephant-foot	-	E	Gloucester, Salem
Eriophorum gracile	Slender cotton-grass	-	E	Gloucester
E. tenellum	Rough cotton-grass	-	E	Camden, Gloucester
Eupatorium capillifolium	Dog fennel thoroughwort	-	E	Camden
E. resinosum	Pine barren boneset	-	E	Camden, Gloucester
Euphorbia purpurea	Darlington's glade spurge	-	E	Salem

Table 2.5-1 Threatened or Endangered Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status		County[c]
		Federal[a]	State[a,b]	
Glyceria grandis	American manna grass	-	E	Camden
Gnaphalium helleri	Small everlasting	-	E	Camden
Gymnopogon brevifolius	Short-leaf skeleton grass	-	E	Gloucester
Helonias bullata	Swamp-pink	T	E	Camden, Gloucester, Salem, New Castle[d]
Hemicarpha micrantha	Small-flower halfchaff sedge	-	E	Camden
Hottonia inflata	Featherfoil	-	E	Salem
Hydrastis canadensis	Golden seal	-	E	Camden
Hydrocotyle ranunculoides	Floating marsh-pennywort	-	E	Salem
Hypericum adpressum	Barton's St. John's-wort	-	E	Salem
Isotria meleoloides	Small-whorled begonia	T	-	New Castle[d]
Juncus caesariensis	New Jersey rush	-	E	Camden
J. torreyi	Torrey's rush	-	E	Camden
Kuhnia eupatorioides	False boneset	-	E	Camden
Lemna perpusilla	Minute duckweed	-	E	Camden, Salem
Limosella subulata	Awl-leaf mudwort	-	E	Camden
Linum intercursum	Sandplain flax	-	E	Camden, Salem
Luzula acuminate	Hairy wood-rush	-	E	Gloucester, Salem
Melanthium virginicum	Virginia bunchflower	-	E	Camden, Gloucester, Salem
Micranthemum micranthemoides	Nuttall's mudwort	-	E	Camden, Gloucester
Muhlenbergia capillaris	Long-awn smoke grass	-	E	Gloucester
Myriophyllum tenellum	Slender water-milfoil	-	E	Camden
M. pinnatum	Cut-leaf water-milfoil	-	E	Salem
Nelumbo lutea	American lotus	-	E	Camden, Salem
Nuphar microphyllum	Small yellow pond-lily	-	E	Camden
Onosmodium virginianum	Virginia false-gromwell	-	E	Camden, Gloucester, Salem
Ophioglossum vulgatum pycnostichum	Southern adder's tongue	-	E	Salem
Panicum aciculare	Bristling panic grass	-	E	Gloucester
Penstemon laevigatus	Smooth beardtongue	-	E	Gloucester
Plantago pusilla	Dwarf plantain	-	E	Camden
Platanthera flava flava	Southern rein orchid	-	E	Camden
Pluchea foetida	Stinking fleabane	-	E	Camden
Polemonium reptans	Greek-valerian	-	E	Salem
Polygala incarnata	Pink milkwort	-	E	Camden, Gloucester

Table 2.5-1 Threatened or Endangered Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status		County[c]
		Federal[a]	State[a,b]	
Prunus angustifolia	Chickasaw plum	-	E	Camden, Gloucester, Salem
Pycnanthemum clinopodioides	Basil mountain mint	-	E	Camden
P. torrei	Torrey's mountain mint	-	E	Gloucester
Quercus imbricaria	Shingle oak	-	E	Gloucester
Q. lyrata	Overcup oak	-	E	Salem
Rhododendron atlanticum	Dwarf azalea	-	E	Salem
Rhynchospora globularis	Coarse grass-like beaked-rush	-	E	Camden, Gloucester, Salem
R. knieskernii	Knieskern's beaked-rush	T	E	Camden
Sagittaria teres	Slender arrowhead	-	E	Camden
Scheuchzeria palustris	Arrow-grass	-	E	Camden, Gloucester
Schwalbea americana	Chaffseed	E	E	Camden
Scirpus longii	Long's woolgrass	-	E	Camden
S. maritimus	Saltmarsh bulrush	-	E	Camden
Scutellaria leonardii	Small skullcap	-	E	Salem
Spiranthes laciniata	Lace-lip ladies' tresses	-	E	Gloucester
Stellaria pubera	Star chickweed	-	E	Camden
Triadenum walteri	Walter's St. John's wort	-	E	Camden
Utricularia biflora	Two-flower bladderwort	-	E	Gloucester, Salem
Valerianella radiata	Beaked cornsalad	-	E	Gloucester
Verbena simplex	Narrow-leaf vervain	-	E	Camden, Gloucester
Vernonia glauca	Broad-leaf ironweed	-	E	Gloucester, Salem
Vulpia elliotea	Squirrel-tail six-weeks grass	-	E	Camden, Gloucester, Salem
Wolffiella floridana	Sword bogmat	-	E	Salem
Xyris fimbriarta	Fringed yellow-eyed grass	-	E	Camden

[a] E = Endangered; T = Threatened; C = Candidate; - = Not listed.

[b] State status for birds separated by a slash (/) indicates a dual status. First status refers to the state breeding population, and the second status refers to the migratory or winter population. S = Stable species (a species whose population is not undergoing any long-term increase/decrease within its natural cycle); U = Undetermined (a species about which there is not enough information available to determine the status) (NJDEP 2008a).

[c] Camden, Gloucester, and Salem Counties are in New Jersey. New Castle County is in Delaware. Source of county occurrence: USFWS undated; NJDEP 2008a; DDNREC 2008.

[d] Delaware does not maintain T&E species lists by county. Upon request, Delaware provided PSEG the locations of protected species that occurred within 0.8 km (0.5 mi) of the transmission corridor (DDNREC 2008).

[e] Sea turtles and sturgeon were not included in county lists maintained by USFWS (undated) and NJDEP (2008a), but were included in DDNREC (2008) and are known by PSEG to occur in the Delaware River (see text).

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 1996b). "Sparseness" measures population density and city size within 32 km (20 mi) of a site and categorizes the demographic information as follows:

Demographic Categories Based on Sparseness

		Category
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
Least sparse	4.	Greater than or equal to 120 persons per square mile within 20 miles

Source: NRC 1996b

"Proximity" measures population density and city size within 80 km (50 mi) and categorizes the demographic information as follows:

Demographic Categories Based on Proximity

		Category
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 1996b

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

GEIS Sparseness and Proximity Matrix

		Proximity			
		1	**2**	**3**	**4**
Sparseness	**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 1996b

PSEG used 2000 census data from the U.S. Census Bureau (USCB) and geographic information system software (ArcGIS®) to determine most demographic characteristics in the Salem vicinity. Approximately 501,820 people live within 32 km (20 mi) of Salem, at a population density of 450 persons per square mile. The GEIS sparseness matrix identifies this density as in the least sparse category, Category 4 (greater than or equal to 120 persons per square mile within 20 miles).

PSEG determined that 5,201,842 people live within 80 km (50 mi) of Salem, at a population density of 771 persons per square mile. Based on the GEIS proximity matrix, the population density is classified as Category 4 (greater than or equal to 190 persons per square mile within 50 miles). Therefore, according to the GEIS sparseness and proximity matrix, the Salem regional population ranks of sparseness Category 4 and proximity Category 4 result in the conclusion that Salem is in a high population area.

All or parts of 21 counties and a number of Metropolitan Statistical Areas (MSAs) are located within 80 km (50 mi) of Salem (Figure 2.1-1). The MSAs nearest Salem are (1) Wilmington, Delaware, (2) Dover, Delaware, (3) Philadelphia, Pennsylvania, (4) Camden, New Jersey, (5) Baltimore-Towson, Maryland, (6) Atlantic City, New Jersey, and (7) Vineland-Millville-Bridgeton, New Jersey (USCB 2003). The nearest major city is Wilmington, Delaware (32 km [20 mi] north), with a 2000 population of 72,664 (USCB 2000a). The municipality nearest Salem is the city of Salem (13 km [8 mi] northeast) with a 2000 population of 5,857 (USCB 2000a).

From 1990 to 2007, the population of the Wilmington, Delaware MSA increased from approximately 579,000 to approximately 694,000, an increase of 20 percent. In the same time period, the population of the Dover Delaware MSA increased from approximately 111,000 to approximately152,000 an increase of 37 percent. The population of the Philadelphia, Pennsylvania MSA increased from approximately 3,700,000 to approximately 3,900,000 an increase of five percent. The population of the Camden, New Jersey MSA increased from approximately 1,100,000 to approximately 1,200,000, an increase of nine percent. The population of the Baltimore-Towson, Maryland MSA increased from approximately 2,400,000 to approximately 2,700,000, an increase of 12 percent. The population of the Atlantic City, New

Jersey MSA increased from approximately 220,000 to approximately 271,000, an increase of 23 percent. The population of the Vineland-Millville-Bridgeton, New Jersey MSA increased from approximately 138000 to 156,000, an increase of 13 percent (Table 2.6-1).

Because approximately 83 percent of Salem employees reside in Cumberland, Gloucester, or Salem counties, New Jersey, or New Castle County, Delaware (Table 2.6-2), and because most property taxes from the station are paid to municipalities in Salem County, they are the counties with the greatest potential to be socioeconomically affected by license renewal at Salem, and are collectively referred to as the socioeconomic region of interest in this report. Table 2.6-3 shows population counts and annual growth rates for the four counties in which most Salem employees reside. The table also provides these statistics for the states of New Jersey and Delaware for comparison.

From 1990 to 2000 the growth rates of Cumberland and Salem counties were less than that of New Jersey, and Gloucester County's was slightly higher. Salem County's population decreased between 1990 and 2000, although its population increased from 2000 to 2006. Between 1990 and 2000 the growth rate of New Castle County, Delaware, was less than that of Delaware overall. Gloucester County has experienced the highest percentage of growth of any county of interest (Table 2.6-3).

Because the city of Salem and Lower Alloways Creek Township, New Jersey, receive property taxes from the Salem Nuclear Generating Station, population in these municipalities is also reviewed. The population in the city of Salem has steadily declined from 1970 to 2000. Lower Alloways Creek Township population increased from 1970 to 2000, however, it is a smaller municipality than Salem. From 1990 to 2000, the population of the city of Salem decreased from 6,883 to 5,857, a decrease of 14.9 percent, although since 2006 the population has increased slightly. The population of Lower Alloways Creek Township has increased by approximately one percent in the same timeframe (Table 2.6-4).

2.6.2 MINORITY AND LOW INCOME POPULATIONS

The NRC performed environmental justice analyses for previous license renewal applications and concluded that an 80-km (50-mi) radius (Figure 2.1-1) could reasonably be expected to contain potential environmental impact sites and that the state was appropriate as the geographic area for comparative analysis. PSEG has adopted these parameters for quantifying the minority and low-income populations that may be affected by Salem operations.

PSEG used 2000 census data from the USCB with geographic information system software (ArcGIS®) to determine the minority characteristics by block group. If any part of a block group was located within 80 km (50 mi) of Salem, then PSEG included that entire block group in the analysis. The 80-km (50-mi) radius includes 4,585 block groups (Table 2.6-5).

2.6.2.1 Minority Populations

The NRC's 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). Additionally, NRC's guidance requires that (1) all other single minorities are to be treated as one population and analyzed, (2) multi-racial populations are to be analyzed, and (3) the aggregate of all minority populations is to be treated as one population and analyzed. The guidance indicates that a minority population exists if either of the following two conditions exists:

- The minority population in the census block group or environmental impact site exceeds 50 percent.
- 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 4,585 block groups within the 80-km (50-mi) radius, PSEG 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. PSEG selected Delaware, Maryland, New Jersey, and Pennsylvania, depending on which state the block groups fell within, as the geographic area for comparative analysis for block groups located within the 80-km (50-mi) radius, and calculated the percentages of each minority category within each state (Table 2.6-5). If any block group percentage exceeded the corresponding state percentage by more than 20 percent, then a minority population was determined to exist.

Table 2.6-5 presents the numbers of block groups in each county in the 80-km (50-mi) radius that exceed the threshold for minority populations. Figures 2.6-1 through 2.6-6 display the minority block groups within the 80-km (50-mi) radius.

For all categories but the Aggregate of Minorities in Maryland, the "more than 20 percent greater than the state average" was the limiting criterion. For the Aggregate category in Maryland, 50 percent was the limiting criterion. Within the 80-km (50-mile) radius, one-thousand three hundred twenty census block groups have significant Black races populations. Sixty-seven census block groups within the 80-km (50-mi) radius have significant Asian populations. One hundred eighty-five census block groups within the 80-km (50-mi) radius have significant All Other Single Minority populations. One census block group within the 80-km (50-mi) radius is Multi-Racial. One thousand five hundred eighty-two census block groups within the 80-km (50-mi) radius have significant Aggregate Minority populations. Two hundred seventy-three census block groups within the 80-km (50-mi) radius have significant Hispanic Ethnicity populations. None of the census block groups within the 80-km (50-mi) radius has significant American Indian or Alaskan Native, or Native Hawaiian or Other Pacific Islander populations.

2.6.2.2 Low-Income Populations

NRC guidance defines low-income population based on statistical poverty thresholds (NRC 2001) if either of the following two conditions is met:

- The low-income population in the census block group or the environmental impact site exceeds 50 percent.
- 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 population percentage in the geographic area chosen for comparative analysis.

PSEG divided the number of 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. Table 2.6-5 and Figure 2.6-7 illustrate the low-income block groups in the 80-km (50-mi) radius, based on NRC's criteria. Six hundred sixty-seven census block groups within the 80-km (50-mi) radius have significant low-income households.

Table 2.6-1 Population and Growth Rates for Surrounding Metropolitan Statistical Areas

MSA	Year	Population	Annual Percent Growth
Wilmington, DE	1990[a]	578,587	NA
	2000[a]	650,501	1.2
	2007[b]	693,929	0.9
Dover, DE	1990[a]	110,993	NA
	2000[a]	126,697	1.4
	2007[b]	152,255	2.0
Baltimore-Towson, MD	1990[a]	2,382,172	NA
	2000[a]	2,552,994	0.7
	2007[b]	2,668,056	0.6
Philadelphia, PA	1990[a]	3,728,909	NA
	2000[a]	3,849,647	0.3
	2007[b]	3,887,694	0.1
Camden, NJ	1990[a]	1,127,927	NA
	2000[a]	1,186,999	0.5
	2007[b]	1,246,339	0.7
Atlantic City, NJ	1990[a]	224,327	NA
	2000[a]	252,552	1.2
	2007[b]	270,644	1.0
Vineland-Millville-Bridgton, NJ	1990[a]	138,053	NA
	2000[a]	146,438	0.6
	2007[b]	155,544	0.9

NA = Not applicable
[a] USCB 2003
[b] USCB 2008a

Table 2.6-2 Residential Distribution of Salem Employees

County and State of Residence	Number of Employees	Percent of Total
Appling, GA	2	0.2
Atlantic, NJ	2	0.2
Baltimore, MD	1	0.1
Beaver, PA	1	0.1
Berks, PA	4	0.4
Burlington, NJ	21	2.1
Calvert, MD	1	0.1
Cambria, PA	1	0.1
Camden, NJ	43	4.2
Cape May, NJ	2	0.2
Cecil, MD	21	2.1
Chester, PA	37	3.6
Columbia, PA	1	0.1
Cumberland, NJ	107	10.5
Delaware, PA	18	1.8
Gloucester, NJ	153	15.0
Hamilton, TN	1	0.1
Hartford, MD	2	0.2
Howard, MD	1	0.1
Kent, DE	2	0.2
Lancaster, PA	4	0.4
Luzerne, PA	1	0.1
Montgomery, PA	3	0.3
New Castle, DE	163	16.0
Norfolk City, VA	1	0.1
Northumberland, PA	1	0.1
Salem, NJ	426	41.7
Tarrant, TX	1	0.1
Total	**1021**	**100**

Shading indicates a county within the socioeconomic region of interest

Table 2.6-3 Decennial Populations and Growth Rates

	Cumberland		Gloucester		Salem		New Jersey		New Castle		Delaware	
	Population	Annual Percent Growth	Population	Annual Percent Growth	Population	Annual Percent Growth	Population	Annual Percent Growth	Population	Annual Percent Growth	Population	Annual Percent Growth
1970[a]	121,374	NA	172,681	NA	60,346	NA	7,168,164	NA	385,856	NA	548,104	NA
1980[a]	132,866	0.9	199,917	1.5	64,676	0.7	7,364,823	-0.5	398,115	0.3	594,338	0.8
1990[a]	138,053	0.4	230,082	1.4	65,294	0. 1	7,730,188	0.5	441,946	1.0	666,168	1.1
2000[b]	146,438	0.6	254,673	1.0	64,258	-0.2	8,414,350	0.9	500,265	1.2	783,600	1.6
2006[c]	154,823	0.9	282,031	1.7	66,595	0.6	8,724,560	0.6	525,587	0.8	853,476	1.4

[a] USCB 1995
[b] USCB 2000b
[c] USCB 2006
NA = Not Applicable

Table 2.6-4 Population and Growth Rates for the City of Salem and Lower Alloways Creek Township

	City of Salem [a,b]		Lower Alloways Creek Twp [a,b]	
	Population	Decennial Percent Growth	Population	Decennial Percent Growth
1970	7648	NA	1400	NA
1980	6959	-9.0	1547	10.5
1990	6883	-1.1	1858	20.1
2000	5857	-14.9	1851	-0.4
2007	5678	-3.1	1883	1.7

[a] USCB 1982
[b] USCB 2008b
NA = Not Applicable

Table 2.6-5 Environmental Justice Summary[a,b]

State Name	County Name	Number of Block Groups	Black	American Indian or Alaskan Native	Asian	Native Hawaiian or Other Pacific Islander	Some Other Race	Multi-Racial	Aggregate	Hispanic	Low-Income Households
Delaware	Kent	68	7	0	0	0	0	0	9	0	1
Delaware	New Castle	349	66	0	0	0	6	0	72	15	21
Delaware	Sussex	23	1	0	0	0	1	0	2	1	0
Maryland	Baltimore	68	4	0	0	0	0	0	6	0	1
Maryland	Caroline	18	1	0	0	0	0	0	1	0	0
Maryland	Cecil	55	0	0	0	0	0	0	0	0	1
Maryland	Harford	138	3	0	0	0	0	0	6	0	2
Maryland	Kent	19	0	0	0	0	0	0	0	0	0
Maryland	Queen Anne's	16	0	0	0	0	0	0	0	0	0
Maryland	Talbot	2	0	0	0	0	0	0	0	0	0
New Jersey	Atlantic	53	2	0	0	0	0	0	3	2	0
New Jersey	Burlington	133	3	0	0	0	0	0	4	0	0
New Jersey	Camden	407	91	0	0	0	30	0	107	38	47
New Jersey	Cape May	59	3	0	0	0	0	0	3	0	1
New Jersey	Cumberland	101	11	0	0	0	9	0	23	14	9
New Jersey	Gloucester	196	16	0	0	0	0	0	11	0	4
New Jersey	Salem	49	7	0	0	0	0	0	5	0	2
Pennsylvania	Berks	2	0	0	0	0	0	0	0	0	0
Pennsylvania	Chester	243	15	0	0	0	1	0	17	11	6
Pennsylvania	Delaware	462	82	0	8	0	0	0	95	0	13
Pennsylvania	Lancaster	44	0	0	0	0	0	0	0	0	0
Pennsylvania	Montgomery	311	33	0	0	0	0	0	41	2	3
Pennsylvania	Philadelphia	1762	975	0	59	0	138	1	1177	190	556
Pennsylvania	York	7	0	0	0	0	0	0	0	0	0
	TOTALS:	4585	1320	0	67	0	185	1	1582	273	667

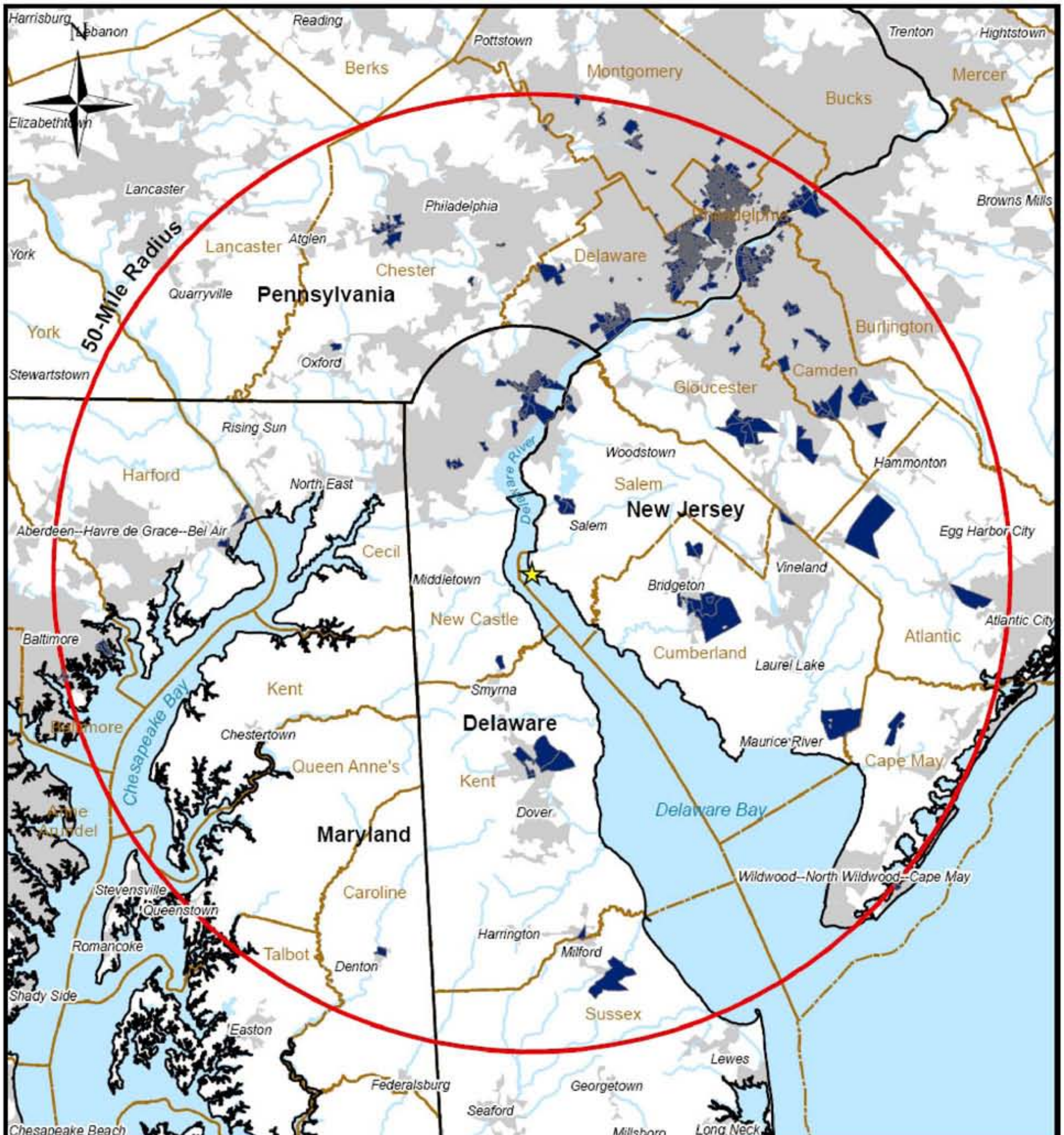
Table 2.6-5 Environmental Justice Summary (Continued)

	Black	American Indian or Alaskan Native	Asian	Native Hawaiian or Other Pacific Islander	Some Other Race	Multi-Racial	Aggregate	Hispanic	Low-Income Households
Delaware Percentages	19.23	0.35	2.07	0.04	2.02	1.66	25.37	4.76	8.75
Maryland Percentages	27.89	0.29	3.98	0.04	1.80	1.96	35.97	4.30	8.32
New Jersey Percentages	13.57	0.23	5.71	0.04	5.36	2.54	27.45	13.28	8.29
Pennsylvania Percentages	9.97	0.15	1.79	0.03	1.53	1.16	14.63	3.21	10.99

Highlighted counties are completely contained within the 50-mile radius.

[a] USCB 2000a

[b] Table entries denote number of census block groups, except on lines indicated as “percentages.”

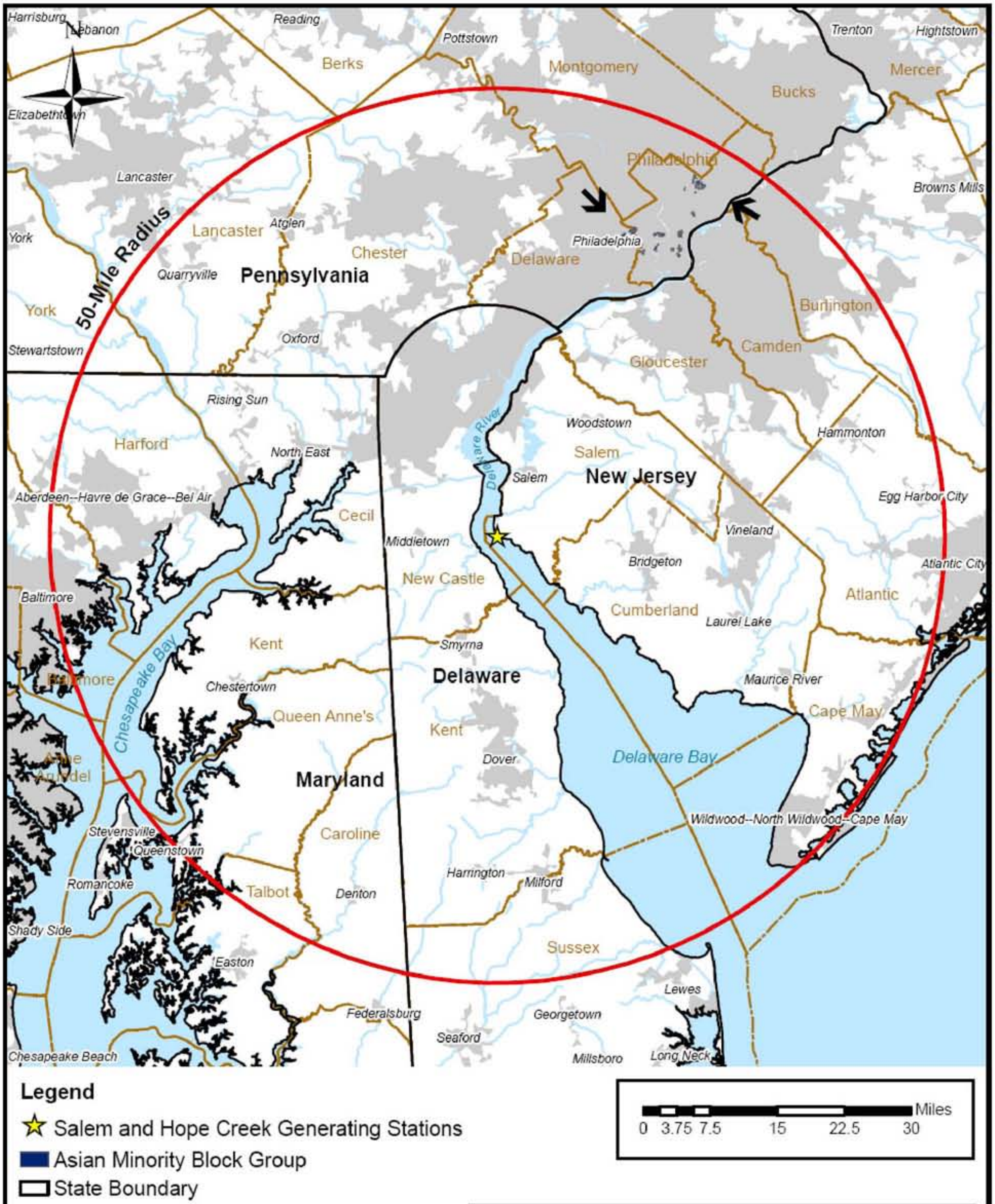


Legend

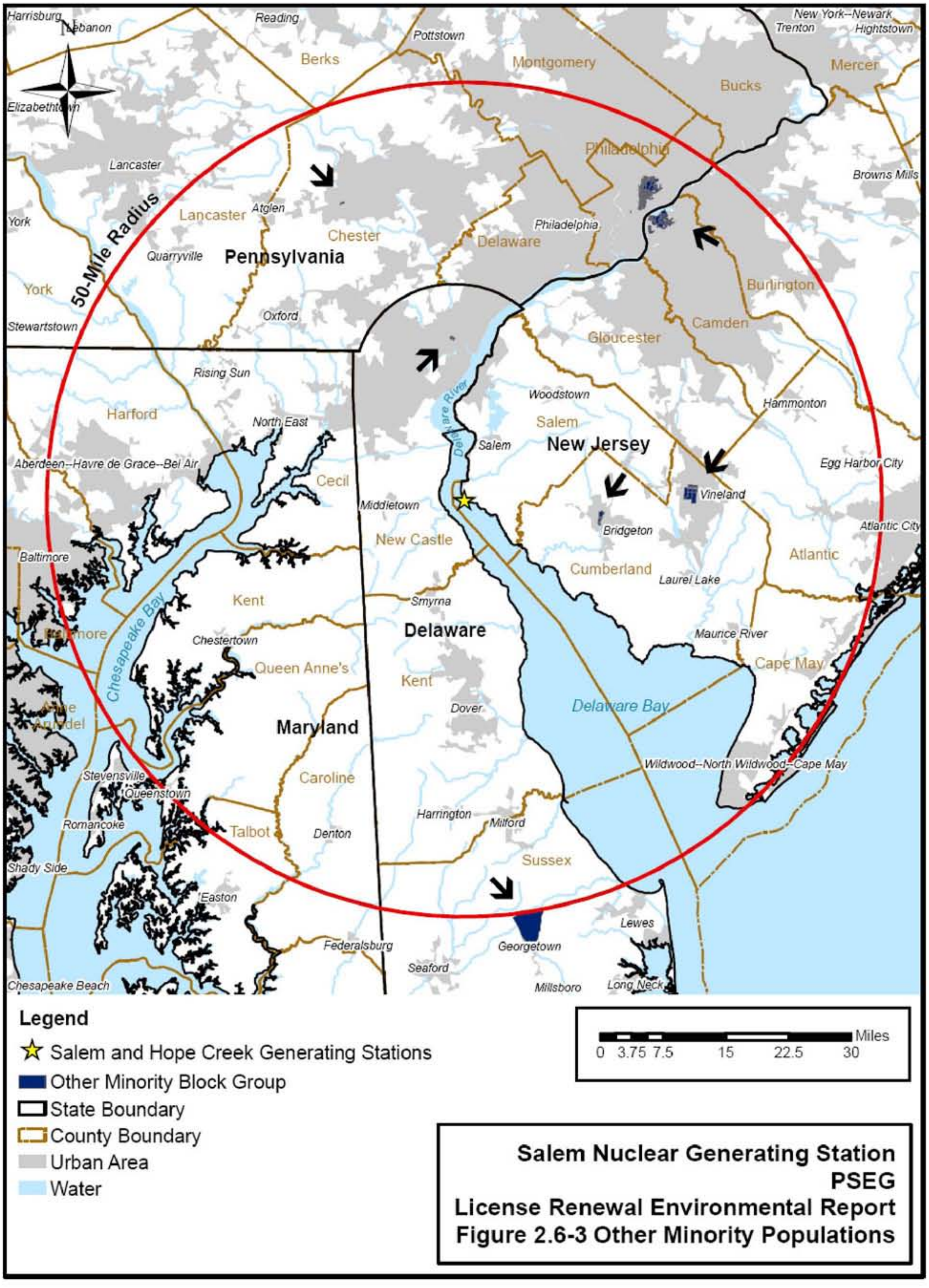
- ☆ Salem and Hope Creek Generating Stations
- Black Minority Block Group
- State Boundary
- County Boundary
- Urban Area
- Water

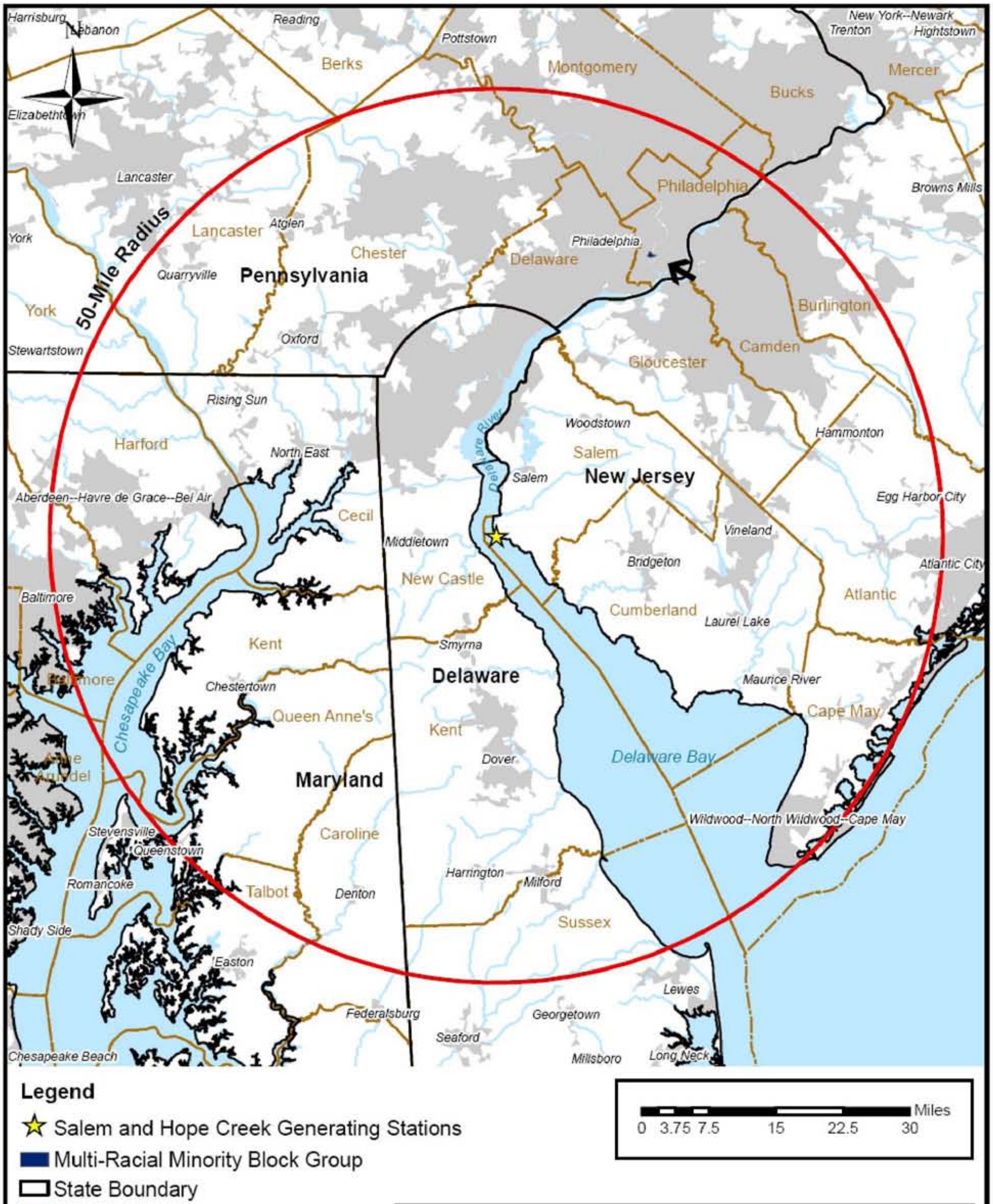
Miles
0 3.75 7.5 15 22.5 30

Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 2.6-1 Black Minority Populations



Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 2.6-2 Asian Minority Populations


Harrisburg
Lebanon
Reading
Pottstown
New York--Newark
Trenton
Hightstown
Berks
Montgomery
Mercer
Bucks
Elizabethtown
Philadelphia
Lancaster
Browns Mills
York
Lancaster
Atglen
Chester
Philadelphia
Delaware
50-Mile Radius
Quarryville
Pennsylvania
York
Burlington
Oxford
Camden
Stewartstown
Gloucester
Rising Sun
Woodstown
Hammonton
Harford
Delaware River
Salem
North East
Salem
New Jersey
Aberdeen--Havre de Grace--Bel Air
Egg Harbor City
Cecil
Vineland
Middletown
Bridgeton
Atlantic City
New Castle
Baltimore
Atlantic
Cumberland
Laurel Lake
Kent
Smyrna
Chesapeake Bay
Delaware
Maurice River
Chestertown
Queen Anne's
Cape May
Kent
Dover
Delaware Bay
Maryland
Wildwood--North Wildwood--Cape May
Stevensville
Caroline
Queenstown
Harrington
Milford
Romancoke
Talbot
Denton
Sussex
Shady Side
Easton
Lewes
Federalsburg
Georgetown
Seaford
Chesapeake Beach
Millsboro
Long Neck
Legend
Salem and Hope Creek Generating Stations
Other Minority Block Group
State Boundary
County Boundary
Urban Area
Water
Miles
0 3.75 7.5 15 22.5 30
Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 2.6-3 Other Minority Populations



Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 2.6-4 Multi-Racial Minority Populations

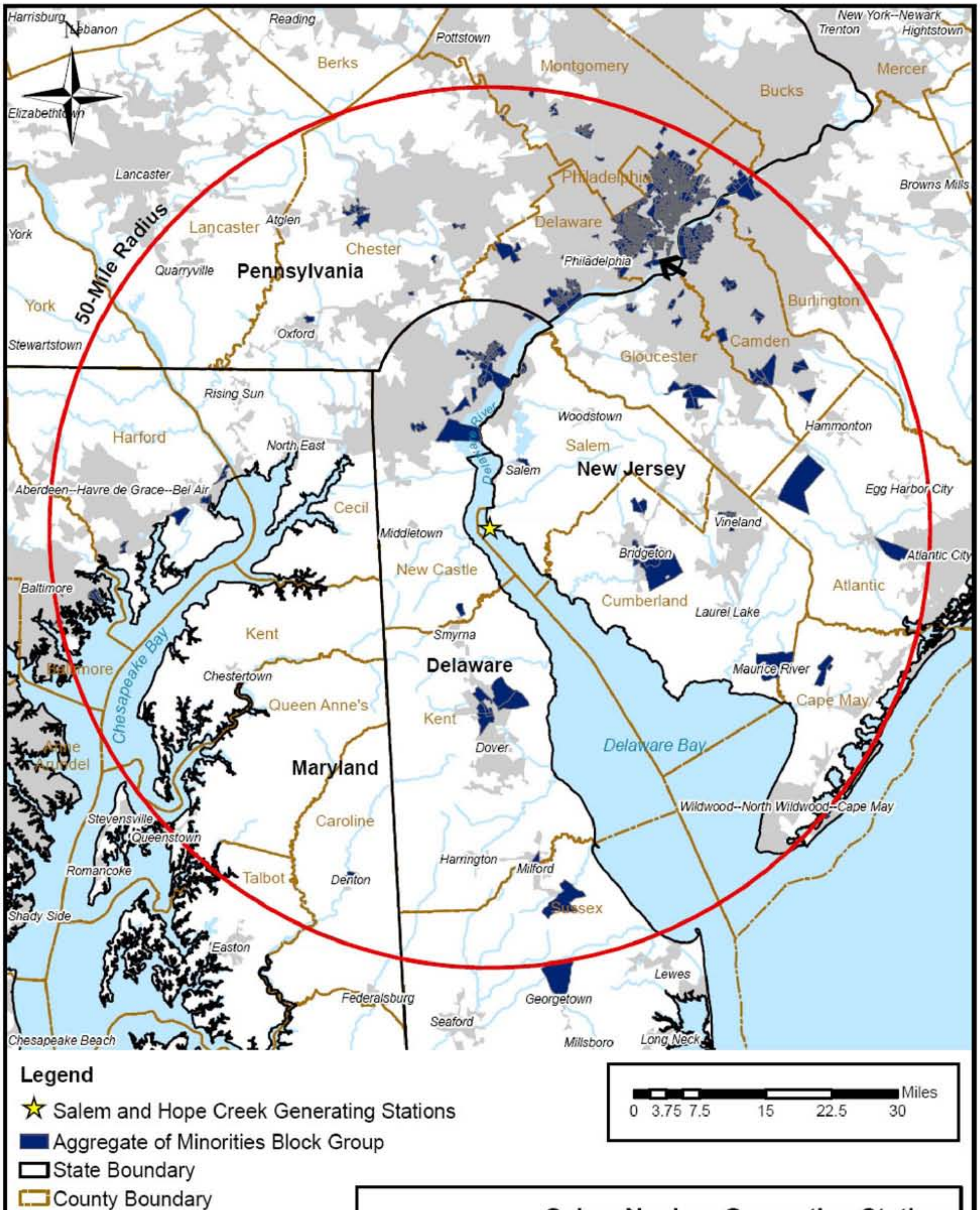


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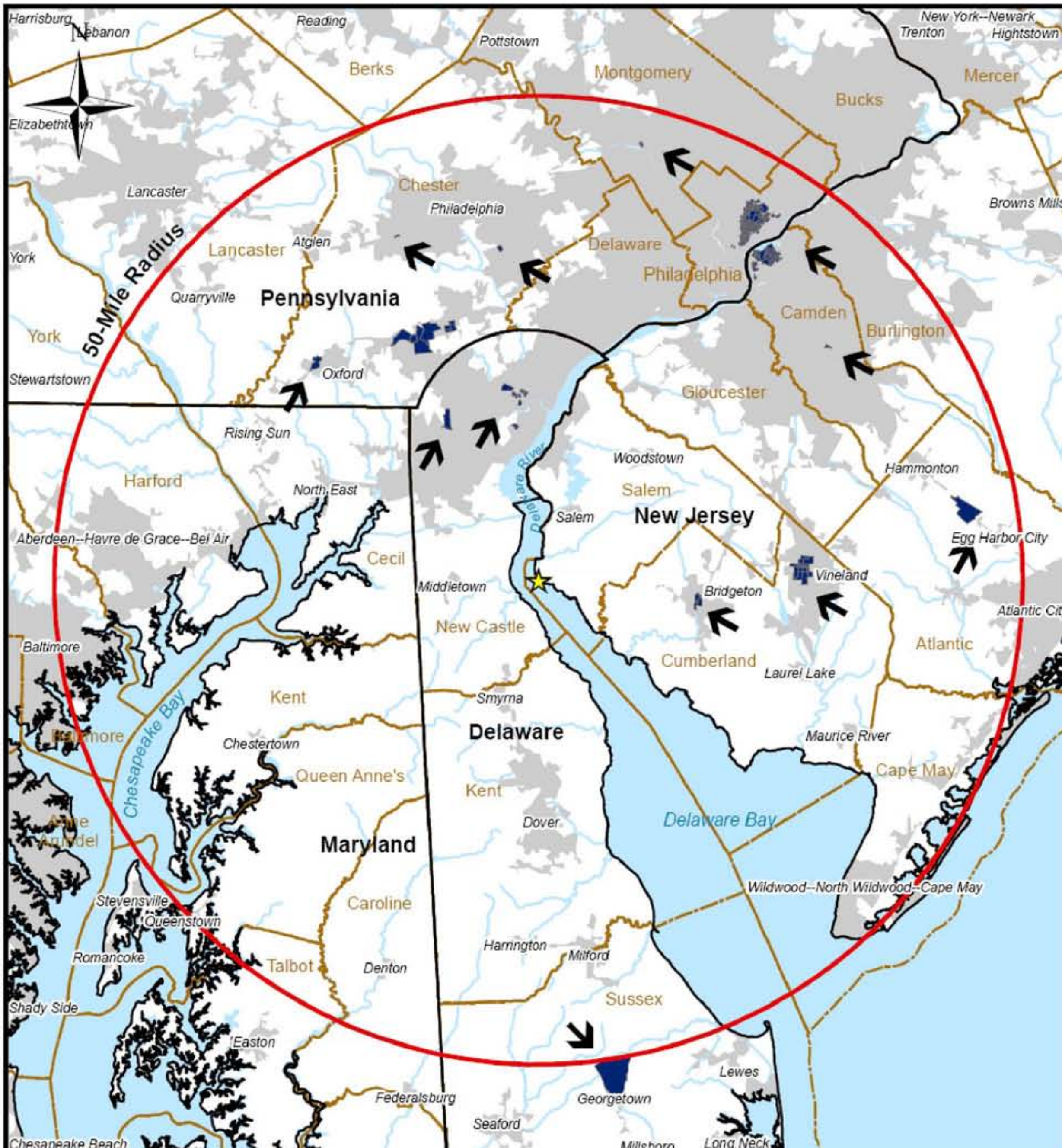
Figure 2.6-5 Aggregate of Minorities Populations

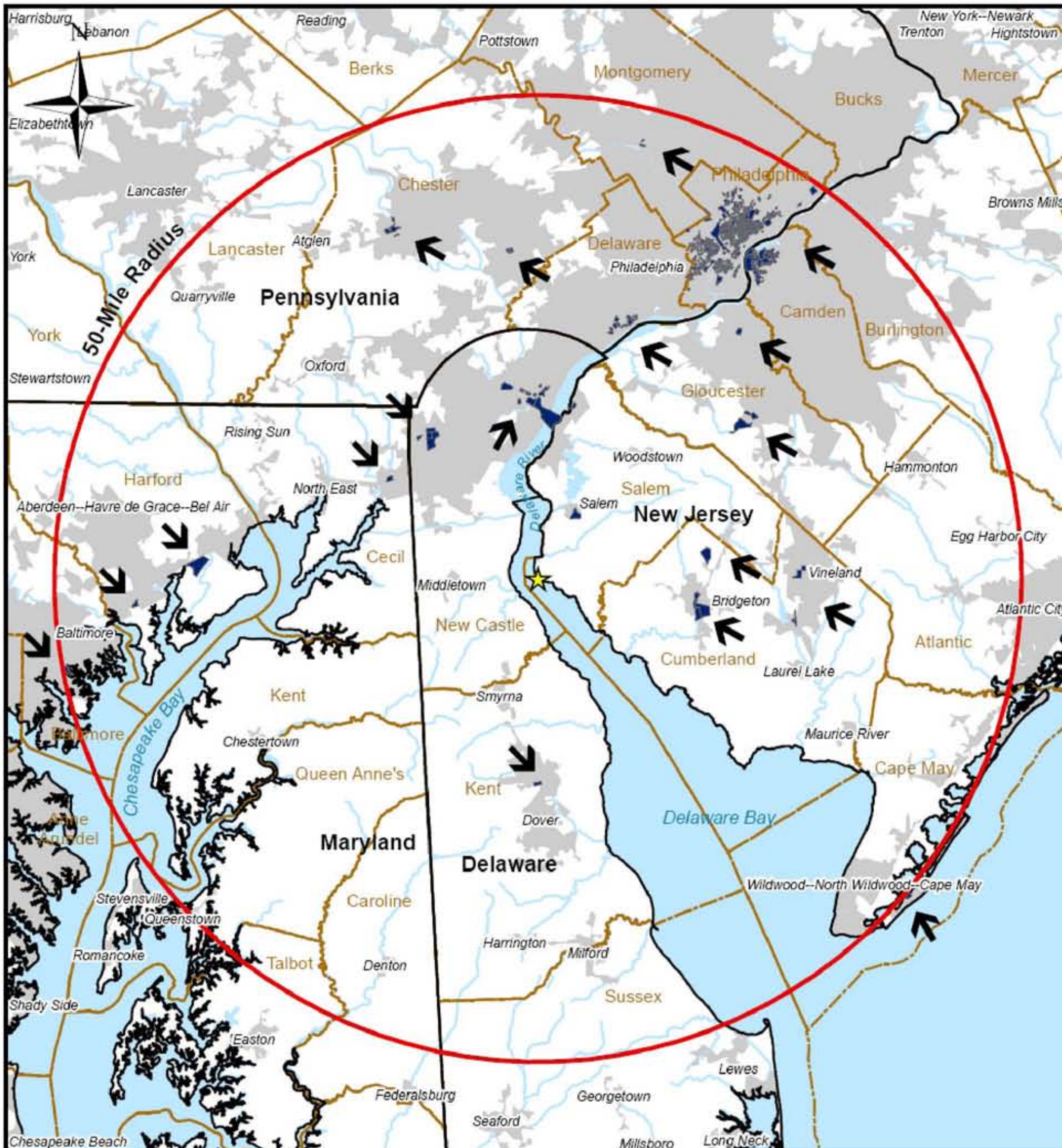


Legend

- ☆ Salem and Hope Creek Generating Stations
- Hispanic Ethnicity Block Group
- State Boundary
- County Boundary
- Urban Area
- Water

Miles: 0 3.75 7.5 15 22.5 30

Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 2.6-6 Hispanic Ethnicity Minority Populations



Legend

- Salem and Hope Creek Generating Stations
- Low-Income Household Block Group
- State Boundary
- County Boundary
- Urban Area
- Water

Miles: 0, 3.75, 7.5, 15, 22.5, 30

Salem Nuclear Generating Station
PSEG
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Figure 2.6-7 Low-Income Households

2.7 Taxes

New Jersey is one of a few states that initiate the budget process at a local, rather than county, level. In addition, local governments in New Jersey use the calendar year as opposed to a July-June fiscal year. Property taxes collected in Lower Alloways Creek Township are not retained by the township but are provided to Salem County, which provides most services to residents of Lower Alloways Creek Township.

PSEG pays property taxes to Lower Alloways Creek Township for the Salem Nuclear Generating Station. Over the last 5 years, the taxes paid to Lower Alloways Creek Township for the Salem Nuclear Generating Station ranged from $429,735 in 2003 to $443,517 in 2007 (Table 2.7-1). PSEG also pays taxes to the City of Salem for the Energy and Environmental Resource Center which is located in the City of Salem and is shared by the Salem and Hope Creek Generating Stations. Table 2.7-1 summarizes PSEG's property tax payments to Lower Alloways Creek and the City of Salem for 2003 to 2007.

In addition to property tax on Salem Nuclear Generating Station and the Energy and Environmental Resource Center, PSEG pays property taxes to various townships for the Estuary Enhancement Program sites (EEP; see Appendix F of this document). Table 2.7-2 provides a summary of the tax payments for the EEP from 2003 to 2007. However, the EEP tax payments are independent of the operation of Salem and will not be analyzed further.

From 2003 through 2007, Lower Alloways Creek Township collected between $2,099,185 and $2,325,378 (in 2005) annually in total commercial property tax revenues (Table 2.7-1). From 2003 to 2007, Salem Nuclear Generating Station's property tax payments represented 19.2 to 20.5 percent of Lower Alloways Creek Township's total property tax revenues. PSEG's property tax payment to Lower Alloways Creek Township is large enough to relieve the Lower Alloways Creek residents of the burden of paying local municipal property taxes on residences, local school taxes, and open space municipal taxes (a local option). The Lower Alloways Creek residents only pay Salem County taxes and county open space taxes. The PSEG property tax payments represent 0.95 to 1.24 percent of Salem County's total property tax revenues during the same time period (Table 2.7-1).

From 2003 through 2007, the City of Salem collected between $5,092,527 and $7,389,319 annually in total property tax revenues (see Table 2.7-1). The City of Salem's property tax revenues are allocated to county services, schools, open space, and municipal services. From 2003 to 2007, PSEG's property tax payments for the Energy and Environmental Resource Center represented 2.6 to 3.2 percent of the City of Salem's total property tax revenues. The City of Salem's property tax revenues are allocated to county services, schools, open space, and municipal services.

Table 2.7-1 Tax Information for Salem Nuclear Generating Station and the Energy and Environmental Resource Center, 2003-2007

PSEG's Property Taxes for the Salem Nuclear Generating Station	2003	2004	2005	2006	2007
Amount PSEG Paid in Property Tax	$429,735	$438,830	$449,890	$421,872	$443,517
Lower Alloways Creek Total Property Tax Revenue[a]	$2,099,185	$2,251,474	$2,325,378	$2,195,746	$2,310,262
Percent of Lower Alloways Creek Total Property Tax Revenues	20.5	19.5	19.3	19.2	19.2
Salem County Total Property Tax Revenue[a]	$34,697,781	$36,320,365	$40,562,971	$43,382,037	$46,667,551
Percent of Salem County Total Property Tax Revenues	1.24	1.21	1.11	0.97	0.95

PSEG's Property Taxes for the Energy and Environmental Resource Center in Salem, New Jersey[b]	2003	2004	2005	2006	2007
Amount PSEG Paid in Property Tax	$131,477	$156,974	$163,695	$169,381	$236,408
City of Salem Total Property Tax Revenues[a]	$5,092,527	$6,049,675	$6,294,613	$6,485,947	$7,389,319
Percent of City of Salem Total Property Tax Revenues	2.6	2.6	2.6	2.6	3.2

a. Source: State of New Jersey 2008
b. Property taxes for the Energy and Environmental Resource Center is provided for information only. The Resource Center would not be affected by any license renewal decision.

Table 2.7-2 Salem Nuclear Generating Station EEP Tax Information, 2003-2007

Township	County	2003	2004	2005	2006	2007
Dennis	Cape May	$6716	$7048	$7563	$8160	$8632
Commercial	Cumberland	$58,726	$61,631	$66,137	$71,354	$75,482
Fairfield	Cumberland	$15,674	$16,449	$17,652	$19,044	$20,146
Greenwich	Cumberland	$90,926	$95,423	$102,400	$110,477	$116,869
Hopewell	Cumberland	$4038	$4238	$4547	$4906	$5190
Maurice River	Cumberland	$10,174	$10,677	$11,458	$12,362	$13,077
Elsinboro	Salem	$27,178	$28,522	$30,607	$33,021	$34,932
Lower Alloways Creek	Salem	$7334	$7696	$8259	$8910	$9426
	Total	$220,765	$231,685	$248,624	$268,234	$283,754
Total Property Tax Revenues for all of the Townships		$30,411,957	$30,411,957	$32,802,086	$35,362,778	$39,091,744
EEP Tax Percent of Total Municipal Property Tax Revenues		0.73	0.73	0.71	0.70	0.69

Source: State of New Jersey 2008

2.8 Land Use Planning

This section focuses on Salem County because the property taxes paid by PSEG for the Salem Nuclear Generating Station and the Energy and Environmental Resource Center are paid to the municipalities in Salem County. Land use in the City of Salem and in Lower Alloways Creek Township is analyzed because the PSEG pays property taxes to these municipalities which host the Energy and Environmental Resource Center and the Salem Nuclear Generating Station, respectively. Regional and local planning officials have shared goals of encouraging expansion and development in areas where public facilities, such as water and sewer systems, have been planned, and discouraging incompatible land use mixes in agricultural or open spaces (Rukenstein and Associates 2004).

2.8.1 SALEM COUNTY

Salem County occupies roughly 875 km^2 (338 mi^2) of land area (USCB 2008b) in the southwestern corner of New Jersey and is bordered by Gloucester County to the north, Cumberland County to the east and south, and the Delaware River to the west. Salem County's Smart Growth Plan, submitted for final adoption in January 2004 (Rukenstein and Associates 2004), focuses on directing future growth toward the western side of the county, where infrastructure and major roadways already exist, and containing growth in the eastern and central portions to protect the traditional agrarian economy of the area. The Smart Growth Plan sets forth a strategic plan for a western economic growth and development corridor. Only 10 percent of Salem County is developed for residential, commercial, or industrial use. Over half the county's land comprises tidal and freshwater wetlands, lakes, ponds, and forests, and the remainder (over one-third of the total area) is farmland. Salem County would like to provide sustainable economic development while protecting its rural character. Salem County has no measures to limit growth (Rukenstein and Associates 2004).

2.8.2 CITY OF SALEM

The City of Salem is the county seat of Salem County, and had a population of approximately 5,700 in 2007. As noted in Section 2.6, in general, the City of Salem's population has been declining for decades. In 1999, "Salem Main Street" was formed to stimulate business opportunities, historic preservation, and community growth. Salem Main Street created the Main Street Revitalization Master Plan which acts as a "road map" for future land use for the City of Salem. The Master Plan focuses on creating a cohesive town core and coordinating with Salem County to reduce competition between the city and the county. (Salem Main Street 2003)

2.8.3 LOWER ALLOWAYS CREEK TOWNSHIP

Lower Alloways Creek Township occupies approximately 122 km^2 (47 mi^2) in the southwest corner of Salem County (Lower Alloways Creek Township 1992) and had a population of approximately 1900 in 2007. Lower Alloways Creek's land use plan focuses on preserving farmland and open spaces and directing growth toward areas of the community most capable of providing necessary services. (Lower Alloways Creek Township 1992)

The 2005 Master Plan Reexamination Report for Lower Alloways Creek Township states that there has been little change in the Township's land use patterns since the last Master Plan review in 1999 (Alaimo Group 2005). The Master Plan describes the following land use: (Lower Alloways Creek Township 1992):

- Residential – 7 percent
- Commercial – <1 percent
- Industrial – 3 percent (the industrial district is entirely composed of the nuclear generating facilities on Artificial Island)
- Public/Quasi-public – 37.5 percent
- Agriculture – 52 percent

The Master Plan designates the area immediately adjacent to Artificial Island as appropriate for additional industrial development.

2.9 Social Services and Public Facilities

2.9.1 PUBLIC WATER SUPPLY

Because the Salem Nuclear Generating Station is in Salem County and most of the Salem employees reside in Salem, Cumberland, or Gloucester counties (in New Jersey) or New Castle County (in Delaware) the discussion of public water supply systems will be limited to these counties.

2.9.1.1 Salem County

Salem County is served by 15 public water systems. In addition to the large public systems, there are some small private systems that serve individual communities such as mobile home parks. Public water systems serve approximately 41,700 persons (EPA 2008a). Water systems serving the largest populations are Penns Grove Water Supply (approximately 14,400 persons served in Salem and Gloucester Counties) and the Pennsville Water Department (approximately 13,500 persons served) (EPA 2008a). The sources for these systems are primarily ground water. Table 2.9-1 lists the largest municipal water suppliers (serving more than 5,000 people) in Salem, Gloucester and Cumberland counties, and indicates their daily peak demands, total capacities and excess capacities.

The Penns Grove Water Supply is at 80 percent of capacity. In order to provide additional storage capacity, Carneys Point Township, which receives water from Penns Grove Water Supply, has secured federal and state grants for the Penns Grove Water Supply to construct an additional 500,000-gallon storage tank. The Penns Grove Water Supply Company has requested additional permitted capacity from NJDEP to meet the projected demand. (Rukenstein and Associates 2004)

2.9.1.2 Cumberland County

Cumberland County is served by 15 public water systems. In addition to the large public systems, there are some small private systems that serve individual communities such as mobile home parks. Public water systems serve approximately 83,300 persons. Water systems serving the largest populations are Vineland Water & Sewer Utility (approximately 33,000 persons served), the Millville Water Department (approximately 27,500 persons), and the Bridgeton Water Department (approximately 23,000 persons). The sources for these systems are primarily ground water. (EPA 2008a)

2.9.1.3 Gloucester County

Gloucester County has 32 public water systems. In addition to the large public systems, there are some small private systems that serve individual communities such as mobile home parks and campgrounds. Public water systems serve approximately 220,000 persons (EPA 2008a). Water systems serving the largest populations are Washington Municipal Utilities Authority (MUA) (approximately 48,000 persons served), the Monroe MUA (approximately 26,000 persons served), the Deptford MUA (approximately 26,000 persons), and the West Deptford Water Department (approximately 20,000 persons) (EPA 2008a). The sources for these systems are primarily ground water, with the exception of the Deptford MUA, which uses purchased surface water (EPA 2008a).

2.9.1.4 New Castle County, Delaware

Seventy-five percent of drinking water in New Castle County comes from surface water sources, and 25 percent is from ground water (New Castle County 2007). New Castle County is served by three privately-owned water utilities and four city-owned water utilities. Public and private water systems serve approximately 334,000 persons (EPA 2008a). The sources for these systems are ground and surface water. Table 2.9-2 lists the daily demand, total capacity and excess capacity for those water systems for which information was available.

2.9.2 TRANSPORTATION

Salem County is traversed by two major highways, one interstate highway (I-295), and the New Jersey Turnpike. Road access to Salem is via Alloways Creek Neck Road, a small two-lane road, to Nuclear Station Access Road. The combined Salem and HCGS workforces use the Nuclear Station Access Road entrance. Approximately 11 km (7 mi) east of Salem, Alloways Creek Neck Road intersects with County Route 658, which has a north-south orientation (Figure 2.9-1). Employees traveling to Salem from locations to the north, northeast, or northwest could use a variety of interstate, state, and secondary roads to access State Route 49, which intersects County Route 658 at the western edge of the city of Salem. These employees could then reach Salem by traveling south on County Route 658 to Alloways Creek Neck Road. Employees traveling to Salem from Greenwich could use County Route 623, which intersects Alloways Creek Neck Road about one mile east of the intersection of Alloways Creek Neck Road and County Route 658. From County Route 623, these employees could reach Salem by traveling west on Alloways Creek Neck Road. Employees from farther south than Greenwich or from the southeast could reach Salem by using a variety of state highways and secondary roads to access State Route 49. From State Route 49, these employees could reach Salem by traveling northwest to County Route 667, then west to County Route 623, and from there, south to Alloways Creek Neck Road.

Table 2.9-3 provides annual average daily traffic counts (AADTs) for roads in the vicinity of Salem for which traffic counts were available. Figure 2.9-1 shows the locations at which such AADTs are collected and the major roadways in the area. New Jersey does not collect data for highway Levels of Service.

Table 2.9-1 Major Water Suppliers (serving 5,000 or more people) in Salem, Cumberland, and Gloucester Counties, New Jersey.

Water System Name	County	Population Served[a]	Primary Water Source	Peak Daily Demand plus additional Committed Peak (MGD)	Total Capacity (MGD)	Excess Capacity (MGD)
Bridgeton Water Department	Cumberland	22,770	Ground water	3.083	5.616	2.533
Millville Water Department	Cumberland	27,500	Ground water	7.232	7.82	0.588
Vineland Water & Sewer Utility	Cumberland	33,000	Ground water	14.91	16.392	1.482
Clayton Water Department	Gloucester	7,155	Ground water	1.42	1.944	0.524
Deptford MUA	Gloucester	26,000	Purchased surface water	4.628	8.6	3.972
Glassboro Water Department	Gloucester	19,238	Ground water	3.829	6.036	2.207
Greenwich Water Department	Gloucester	4,900	Ground water	1.427	1.972	0.545
Mantua MUA	Gloucester	11,713	Ground water	2.172	2.376	0.204
Monroe MUA	Gloucester	26,145	Ground water	4.789	6.54	1.751
NJ American Water Company	Gloucester	5,967	Ground water	1.518	2.146	0.628
Paulsboro Water Department	Gloucester	6,200	Ground water	1.248	1.8	0.552
Penns Grove Water Supply Company	Gloucester/Salem	14,406	Ground water	2.377	3.055	0.678
Pitman Water Department	Gloucester	9,445	Ground water	0.85	1.67	0.82
South Jersey Water Supply	Gloucester	9,181	Ground water	2.635	3.398	0.763
Washington MUA	Gloucester	48,000	Ground water	7.992	11.7	3.708
West Deptford Water Department	Gloucester	20,000	Ground water	3.265	6.884	3.619
Westville Water Department	Gloucester	6,000	Ground water	0.696	1.728	1.032
Woodbury Water Department	Gloucester	11,000	Purchased surface water	1.857	5.76	3.903
Pennsville Water Department	Salem	13,500	Ground water	1.445	3.376	1.931
Salem Water Department	Salem	6,199	Surface water	1.655	4.274	2.619
Total Excess Capacity						**34.1**

Source: NJDEP 2007b; EPA 2008a
MUA = Municipal Utility Authority
[a] Population served may include more or less persons than previously specified within the geopolitical boundaries

Table 2.9-2 Major Water Suppliers (serving 5,000 or more people) in New Castle County, Delaware.

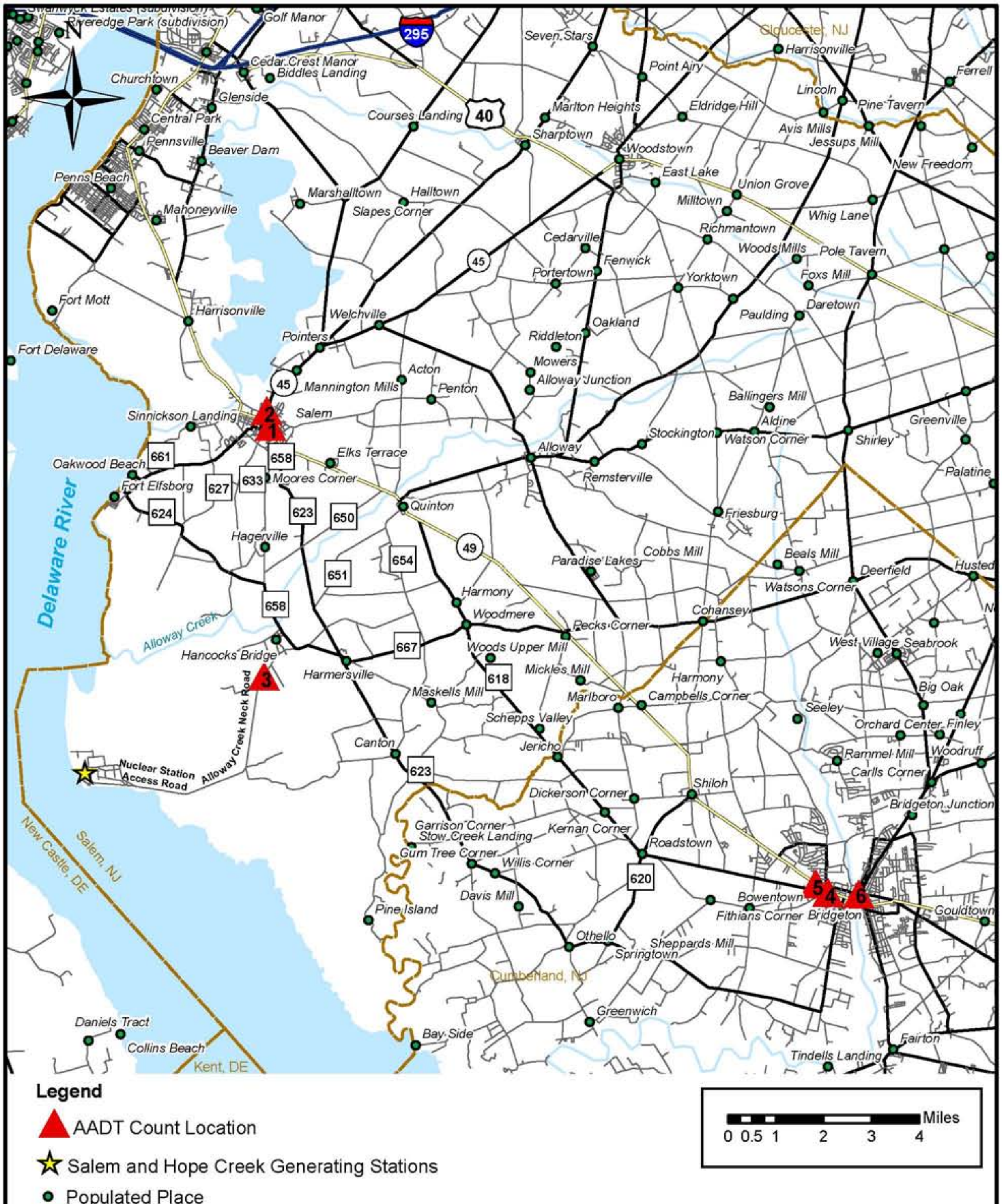
Water System Name	Population Served[a]	Primary Water Source Type	Average Daily Production (MGD)	Maximum Capacity (MGD)
Artesian Water Company, Inc.	6,483	Purchased surface water	NA	NA
City of Wilmington Water	140,000	Surface water	29	61
Tidewater Utilities, Inc.	30,000	Ground water	NA	NA
United Water Delaware	105,270	Surface water	NA	NA
New Castle Water Department	6,000	Ground water	0.5	1.3
Middletown Water Department	9,900	Ground water	NA	NA
Newark Water Department	36,130	Surface water	4	6
Total Production/ Capacity			33.5	68.3
Total Excess Capacity				**34.8**

Source: EPA 2008a; TetraTech 2008
MGD = million gallons per day
NA = Not Available
[a] Population served may include more or less persons than previously specified within the geopolitical boundaries

Table 2.9-3 Annual Average Daily Traffic Counts on Roads in the Vicinity of Salem Nuclear Generating Station

	Roadway and Location	Annual Average Daily Traffic (AADT)
1[a]	NJ 49, between NJ 45 and York Street	12,920
2	NJ 45, between CR 657 and Howell Street	11,246
3	Alloways Creek Neck Road, between Grosscup Road and Pancoast Road	3,175
4	NJ 49, between CR 607 and Lawrence Street	12,340
5	NJ 49, between CR 607 and Commerce Street	8,490
6	NJ 49, between Laurel Street and NJ 77	20,590

Source: NJDOT 2007
[a] Numbers refer to locations on Figure 2.9-1



Salem Nuclear Generating Station
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Figure 2.9-1 Transportation Routes to HCGS

2.10 Meteorology and Air Quality

Salem is located in Salem County, New Jersey. New Jersey, while small in total land area (20,295 km^2 [7,836 mi^2]), has five distinct climatic zones: Northern, Central, Pine Barrens, Southwest, and Coastal. The diversity of climatic conditions is attributed to the regional geology, close proximity to the Atlantic Ocean, and the prevailing atmospheric flow pattern impacting the state. The Northern Zone is dominated by mountainous climate that is unlike other zones in the state. This area receives more precipitation and thunderstorms. The Central Zone is comprised of heavily urbanized areas, which affect local temperatures. The boundary of freezing and non-freezing precipitation is located near the northern portion of this zone. The climate of the Pine Barrens Zone is affected by the dense forests and sandy soils, which allow for drier conditions and a wider range of maximum and minimum daily temperatures. The Coastal Zone is heavily influenced by continental and oceanic conditions. The climatic conditions of this zone are affected by ocean breezes, which buffer extreme seasonal temperature fluctuations compared to the inland portions of the state. Coastal storms also influence this zone, resulting in higher winds and larger cumulative effects from precipitation. The Southwest Zone is close to the Delaware Bay, and its climate is influenced to some degree by maritime weather conditions. High humidity and moderate temperatures produced by prevailing winds from the south or east and early spring conditions provide the longest growing season in New Jersey. (NCDC 2008a)

Salem County is in the Southwest climate zone, and the local climate can be described as humid continental and humid sub-tropical (PSEG 2009c). Based on data from the National Oceanic and Atmospheric Administration's weather station in Salem County, New Jersey (Woodstown Pittsgrove Station), winter temperatures average 1.78 degrees Celsius (°C; 35.2 degrees Fahrenheit [°F]) and summer temperatures average 23.78°C (74.8°F). Average annual precipitation is 112 cm (44 in), with the most precipitation in July and August. The average seasonal snowfall is 39 cm (15 in), with the largest percentage falling during the month of January (NCDC 2008b).

Under the Clean Air Act, the U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS), which specify maximum concentrations for carbon monoxide (CO), particulate matter with aerodynamic diameters of 10 microns or less (PM_{10}), particulate matter with aerodynamic diameters of 2.5 microns or less ($PM_{2.5}$), ozone, sulfur dioxide (SO_2), lead, and nitrogen dioxide (NO_2). Areas of the United States having air quality as good as or better than the NAAQS are designated by EPA as "attainment areas". Areas having air quality that is worse than the NAAQS are designated by EPA as "non-attainment areas." Those areas that were previously designated non-attainment and subsequently re-designated as attainment due to meeting the NAAQS are termed "maintenance areas". States with maintenance areas are required to develop an air quality maintenance plan as an element of the State Implementation Plan.

Salem County, New Jersey is part of the Metropolitan Philadelphia Interstate Air Quality Control Region (AQCR) (40 CFR 81.15). Salem County is in attainment for CO, SO_2, and NO_2. However, several neighboring counties are designated non-attainment or maintenance areas (NJDEP 2008g).

Salem County is designated as non-attainment for 8-hour ozone (40 CFR 81.331). On March 12, 2008, EPA significantly strengthened its national air quality standards for ground-level ozone. As the regulations require, NJDEP provided recommendations to EPA regarding areas to be designated as attainment, non-attainment or unclassifiable (NJDEP 2009). EPA will issue final designations by 2010 or 2011 (EPA 2008b). Salem County's non-attainment designation would not be expected to change following the issuance of new EPA standards.

Salem County is in attainment for $PM_{2.5}$; however, New Castle County, Delaware, which is across the Delaware River from Salem, is non-attainment for $PM_{2.5}$ (40 CFR 81.331). In October 2006, the EPA issued a final rule that revised the 24-hour $PM_{2.5}$ standard and revoked the annual PM_{10} standard (EPA 2006a). Non-attainment designations for PM_{10} are not affected by the new rule, but additional non-attainment areas could be designated under the new $PM_{2.5}$ standard (EPA 2008c). Salem County is in attainment for PM_{10}. On December 18, 2007, the NJDEP submitted recommendations to the EPA that identified many areas surrounding Salem County as not in attainment with the 2006 24-hour $PM_{2.5}$ NAAQS. Under the final rule, Salem County, including the Salem site, is in attainment (NJDEP 2008g).

The Clean Air Act, as amended, established 156 Mandatory Class I Federal Areas where visibility is an important issue. The Brigantine Wilderness (a portion of the Edwin B. Forsythe National Wildlife Refuge) is approximately 93 km (58 mi) southeast of Salem, and is the only Class I area located within 161 km (100 mi) of Salem (40 CFR 81.420).

2.11 Historic and Archaeological Resources

2.11.1 REGIONAL HISTORY IN BRIEF

Aboriginal people migrated to New Jersey approximately 15,000 years ago. Three major cultural traditions dominated the prehistory of New Jersey and the Middle Atlantic Coastal Plain: the Paleo-Indian Tradition (15,000 to 10,000 years ago); the Archaic Tradition (10,000 to 3,000 years ago); and the Woodland Tradition (3,000 years ago to European contact). Artifacts from the Paleo-Indians are the earliest documented evidence of early populations inhabiting the area now known as New Jersey. When the first European explorers and settlers came to the area, they found the Late Woodland period people (BBNEP 2001).

When the European immigrants arrived in the mid-1600s and early 1700s, they settled first along the coastal bays and inlets of the Hudson, Hackensack, Passaic, and Raritan River valleys in northern New Jersey, and the Delaware River valley and inner Coastal Plain south of Trenton. The area between the Delaware River and the Atlantic Ocean in the southern part of the outer Coastal Plain was still "unsettled" in 1765. This vast area, eventually called the "Pine Barrens," was used by the earliest European settlers largely for harvesting lumber and hunting, and later it supplied resources for the colonial industries. From the 17th through the 20th centuries, European settlers engaged in a number of vocations and avocations in the New Jersey Pine Barrens, such as hunting, fishing, lumber harvesting, shipbuilding, bog iron manufacture, charcoal manufacture, cranberry and blueberry cultivation, salt hay and eelgrass harvesting, sphagnum moss harvesting, mineral (silica) extraction, salt harvesting, and tourism. A number of these industries no longer exist for various reasons, including resource depletion (BBNEP 2001).

2.11.2 PRE-OPERATIONAL AND OPERATIONAL HISTORIC AND ARCHAEOLOGICAL ANALYSIS

Salem is on the southern portion of Artificial Island. Beginning in the early 1900s, Artificial Island was created by disposing of hydraulic dredge spoil within a progressively larger diked area on a natural peninsula that projected into the river. The completed island is approximately 607 hectares (1500 acres) with an average elevation of 3 m (9 ft) above msl (AEC 1973). The Final Environmental Statement for the construction and operation of Salem identified 25 historic sites and landmarks in New Jersey and 7 sites in Delaware within a 16-km (10-mi) radius of the station (AEC 1973). The majority of the sites were identified as local and state sites of historical interest; however, four of the sites were listed on the National Register of Historic Places (AEC 1973). The Final Environmental Statement for the operation of HCGS identified 57 properties listed on the National Register of Historic Places within a 16-km (10-mi) radius of the two sites (NRC 1984), reflecting additions to the National Register between the publication dates of the Salem and Hope Creek Final Environmental Statements. Due to the disturbed and artificial nature of the PSEG property, no archaeological resources have ever been identified.

2.11.3 CURRENT HISTORIC AND ARCHAEOLOGICAL ANALYSIS

As of 2008, 21 properties in Salem County, New Jersey and 387 properties in New Castle County, Delaware, have been listed on the National Register of Historic Places. Of these 408 properties, 6 locations in Salem County, New Jersey (NPS 2008a) and 17 locations in New Castle County, Delaware (NPS 2008b), fall within a 10-km (6-mi) radius of the Salem Nuclear Generating Station (Table 2.11-1).

Table 2.11-1 Sites Listed on the National Register of Historic Places within a 10-km (6-mi) Radius of Salem Nuclear Generating Station

Resource Name	Address	City	Distance (km [mi]) from Station
Salem County, New Jersey			
Alloways Creek Friends Meetinghouse	Buttonwood Avenue, 150 ft. West of Main Street	Hancock’s Bridge	8 (5)
Hancock House	3 Front Street	Hancock’s Bridge	8 (5)
Holmes, Benjamin, House	West of Salem on Fort Elfsborg-Hancock’s Bridge Road	Salem	10 (6)
Nicholson, Abel and Mary, House	Junction of Hancocks Branch and Fort Elfsborg Road, Elsinsboro Township	Salem	8 (5)
Nicholson, Sarah and Samuel, House	2 miles South of Salem on Amwellbury Road	Salem	10 (6)
Ware, Joseph, House	134 Poplar Street	Hancock’s Bridge	6 (4)
New Castle County, Delaware			
Ashton Historic District	North of Port Penn on Thornton Road	Port Penn	8 (5)
Augustine Beach Hotel	South of Port Penn on DE 9	Port Penn	6 (4)
Cleaver House	Off Biddle’s Corner Road	Port Penn	10 (6)
Dilworth House	Off DE 9	Port Penn	8 (5)
Gordon, J.M., House	Route 44	Odessa	8 (5)
Green Meadow	Thomas Landing Road (DE 440), Appoquinimink Hundred	Odessa	6 (4)
Grose, Robert, House	1000 Port Penn Road	Port Penn	8 (5)
Hart House	East of Taylors Bridge on DE 453	Taylor’s Bridge	5 (3)
Hazel Glen	West of Port Penn on DE 420	Port Penn	8 (5)
Higgins, S., Farm	Route 423	Odessa	8 (5)
Johnson Home Farm	Co. Road 453 East of Junction with DE 9, Blackbird Hundred	Taylor’s Bridge	6 (4)
Liston House	East of Taylors Bridge on DE 453	Taylor’s Bridge	6 (4)
Misty Vale	Route 423	Odessa	10 (6)
Port Penn Historic District	DE 9	Port Penn	6 (4)
Reedy Island Range Rear Light	Junction of DE 9 and Road 453	Taylor’s Bridge	8 (5)
Thomas, David W., House	326 Thomas Landing Road, Appoquinimink Hundred	Odessa	8 (5)
Vandegrift, J., House	Route 44	Odessa	8 (5)

2.12 Known or Reasonably Foreseeable Projects in Site Vicinity

As indicated on Figure 2.1-2, there is no urban area within the 10-km (6-mi) radius of Salem, nor is there any industrial development. The immediate vicinity consists of extensive tidal marshlands and low-lying meadowlands.

2.12.1 WATER USERS IN THE DELAWARE RIVER BASIN IN THE VICINITY OF SALEM

In its "Envirofacts Data Warehouse" online database access tool, EPA provides information about environmental activities that may affect air, land, and water. A search of the Envirorfacts "water" database for facilities that hold permits to discharge to waters of the United States in the vicinity of Salem identified heavy industries, electric generation, and manufacturing, among others. These industries represent the types of industrial facilities that could be permitted near Salem in the future. Additional information concerning these facilities may be accessed through EPA's "Envirofacts Warehouse" (http://oaspub.epa.gov/enviro/).

2.12.2 ELECTRIC CAPACITY IN THE IMMEDIATE VICINITY OF SALEM

2.12.2.1 Hope Creek Generating Station

The Hope Creek Generating Station (HCGS) is co-located adjacent to Salem on Artificial Island. HCGS is a one-unit station utilizing a boiling water reactor (BWR) designed by General Electric, and has a current licensed thermal power at 100 percent power of 3,840 MWt. Full commercial operation began December 20, 1986 (PSEG 2006c).

HCGS has a closed-cycle cooling system consisting of a natural draft cooling tower and associated withdrawal, circulation, and discharge facilities. The HCGS closed-cycle cooling system withdraws water from the Delaware Estuary for the Circulating Water System (CWS) and the Service Water System (SWS) through a single intake. Cooling tower blowdown and other station effluents discharge through an underwater conduit located 457 m (1,500 ft) upriver of the intake, into the Delaware River (PSEG 2006c). PSEG has a current NJPDES permit (No. NJ0025411) for HCGS surface water withdrawals and discharges.

PSEG has a contract with the Delaware River Basin Commission (DRBC) for HCGS consumptive and non-consumptive use of river water. The DRBC does not limit withdrawals by HCGS except to note that if the flow at Trenton, New Jersey is less than 3,000 cubic feet per second, withdrawals may be curtailed (DRBC 1984).

PSEG has a single ground-water allocation permit from NJDEP for the diversion by both Salem and HCGS of up to 164 billion liters (43.2 billion gallons) of ground water per month (NJDEP 2004).

As a result of operations, both Salem and HCGS release liquid and gaseous radiological effluents into the environment. The releases are controlled and monitored to ensure that regulatory limits on the radioactivity discharged to the environment are not exceeded. Doses from these releases represent a fraction of the allowable doses specified in the facility operating license and NRC regulations. Results presented in the Radiological Environmental Monitoring

Report, which evaluates the combined contributions from both Salem and HCGS, indicate that there has been no significant impact on the radiological characteristics of the environs of the area (PSEG 2007b).

2.12.2.2 Potential New Generating Unit(s)

PSEG currently plans to submit an Early Site Permit (ESP) application to the NRC during the second quarter of 2010 to address the possibility that new nuclear generating capacity could be located on Artificial Island (PSEG 2008a). The decision to pursue an ESP does not represent a commitment by PSEG to build a new nuclear power plant. If the decision were made later to build new nuclear generation, then PSEG would develop and submit a Combined License Application (COLA).

2.12.2.3 Mid-Atlantic Power Pathway

PJM has identified a 500-kV transmission line to be constructed from Possum Point in Virginia to Salem as necessary to increase grid stability and to get additional power into the Mid-Atlantic states (PJM 2009).

Chapter 3

The Proposed Action

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3.1 General Plant Information

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)**

PSEG proposes that the NRC extend the terms of the operating license for each Salem unit for 20 years beyond its current term of 40 years. License renewal would give PSEG and the State of New Jersey the option of relying on Salem units to meet future electricity needs. Section 3.1 discusses the station in general. Sections 3.2 through 3.4 address potential changes that could occur as a result of license renewal.

General information regarding Salem Units 1 and 2 is available in several documents. In 1973, the U.S. Atomic Energy Commission published the Final Environmental Statement (FES) related to the operation of Salem (AEC 1973). The Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS; NRC 1996b) describes Salem features. Finally, in accordance with NRC requirements, PSEG routinely revises the updated Final Safety Analysis Report for Salem to reflect current plant design and operating features (PSEG 2009c). PSEG has referred to each of these and additional documents while preparing this Environmental Report for license renewal.

Figure 3.1-1 illustrates the PSEG property boundary and the spatial relationship of HCGS and Salem on the south end of Artificial Island. The major structures and facilities located on and adjacent to the Salem site are shown in Figure 3.1-2. Major buildings include:

- Unit 1 and Unit 2 containment buildings, which house the nuclear steam supply systems including the reactors, steam generators, reactor coolant pumps, and related equipment
- The auxiliary building, which houses major components of the primary component cooling water system, boric acid storage tanks and pumps, and other safety-related equipment
- The turbine building, where the turbine generators, main condensers, turbine plant heat exchangers, and related equipment are housed
- The adjacent Hope Creek Generating Station (HCGS)
- Other structures and facilities of interest such as Salem Unit 3 (an air-cooled combustion turbine peaking unit rated at approximately 40 MWe), intake and discharge structures, switchyard, and the nuclear operations support facility.

3.1.1 REACTOR AND CONTAINMENT SYSTEMS

The Salem units are pressurized water reactors (PWR) with once-through steam generator systems. The units were designed and fabricated by Westinghouse Electric Corporation. United Engineers and Constructors were the original plant construction contractors, and PSEG served as the architect-engineer (AEC 1973). Salem Units 1 and 2 entered commercial service on June 30, 1977 and October 31, 1981, respectively (NRC 1996b). Each unit is licensed for 3,459 MWt. At 100 percent reactor power, the currently anticipated net electrical output is approximately 1,195 MWe for Unit 1 and 1,196 for Unit 2 (PSEG 2009c).

The nuclear steam supply system for each Unit includes a pressurized water reactor, reactor coolant system (RCS), and associated auxiliary fluid systems. The RCS is arranged as four closed reactor coolant loops connected in parallel to the reactor vessel, each with a reactor coolant pump and a steam generator. The reactor vessel and reactor internals contain and support the fuel and control rods. The reactor vessel is cylindrical with hemispherical heads and is clad with stainless steel. A pressurizer is connected to one of the coolant loops. It is cylindrical with hemispherical heads and is equipped with electrical heaters and spray nozzles for system pressure control. (PSEG 2009c)

The steam generators are vertical U-tube units utilizing Inconel tubes. Integral moisture separating equipment reduces the moisture content of the steam at the turbine throttle to 0.25 percent or less. The Salem Unit 1 steam generators were replaced in 1997, and the Salem Unit 2 steam generators were replaced in 2008. The reactor coolant pumps are vertical single-stage centrifugal pumps equipped with controlled-leakage shaft seals. (PSEG 2009c)

Auxiliary systems are provided to charge the RCS, add makeup water, purify reactor coolant water, provide chemicals for corrosion inhibition, cool system components, remove residual heat when the reactor is shut down, cool the spent fuel storage pool, sample reactor coolant water, provide for emergency safety injection, and vent and drain the RCS. (PSEG 2009c)

The reactor containment structure is a reinforced concrete vertical cylinder with a flat base and a hemispherical dome. A welded steel liner with a minimum thickness of 0.635 cm (0.25 in) is attached to the inside face of the concrete shell to ensure a high degree of leak tightness. The design objective of the containment structure is to contain all radioactive material that might be released from the core following a loss-of-coolant accident. The structure serves as both a biological shield and a pressure container. (PSEG 2009c)

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 FUEL ENRICHMENT AND BURN-UP

Both Salem units are licensed for low-enriched uranium-dioxide fuel with enrichment to a nominal 5.0 percent by weight of uranium-235 and an allowable fuel burn-up of 60,000 megawatt-days per metric ton uranium. The uranium-dioxide fuel is in the form of high-density ceramic pellets. The reactor core is composed of uranium dioxide pellets enclosed in Zircaloy-based tubing with welded end plugs (PSEG 2009c).

The 1994 spent fuel pool reracking project increased the fuel storage capacity for each unit from 1,170 fuel assemblies to 1,632 fuel assemblies and provided an additional 10 years of storage capacity, which is expected to be sufficient up to the year 2011 for Unit 1 and 2015 for Unit 2. (NRC 2004)

The NRC issued a general license to PSEG authorizing an Independent Spent Fuel Storage Installation (ISFSI) at the PSEG site. The general license allows PSEG, as a reactor licensee under 10 CFR 50, to store spent fuel from both HCGS and Salem at the ISFSI, provided that such storage occurs in pre-approved casks in accordance with the requirements of 10 CFR 72, subpart K (General License for Storage of Spent Fuel at Power Reactor Sites). Currently, only Hope Creek spent fuel is being stored at the ISFSI. Spent fuel transfers to the ISFSI from each Salem unit are expected to begin approximately one year before the capability of a complete offload to the spent fuel pool is lost (NRC 2004).

3.1.3 COOLING AND AUXILIARY WATER SYSTEMS

The Salem units have once-through circulating water systems for condenser cooling that withdraws brackish water from the Delaware Estuary through one intake structure located at the shoreline on the south end of the site (Figure 3.1-1). Each bay of the cooling water system (CWS) intake structure is outfitted with the following equipment (NJDEP 2000):

- Removable ice barriers;
- Trash racks;
- Traveling screens;
- Circulating Water Pumps; and
- Fish return system.

Through a separate intake structure located approximately 122 m (400 ft) north of the CWS intake, Salem also withdraws brackish water from the Delaware Estuary for use in its service water system (SWS). Like the CWS intake, the SWS intake has trash racks, traveling screens, and fish-return troughs. Both the CWS and the SWS discharge to the river through a common return system located between the CWS and SWS intake structures, with discharge piping extending 152 m (500 ft) into the Delaware Estuary (PSEG 2006a, Section 5).

Two onsite ground-water wells provide fresh water for domestic/potable, industrial, and fire protection needs (in addition to the two main ground-water wells, two additional wells are permitted as stand-by wells). The following subsections describe the water systems at Salem in greater detail.

3.1.3.1 <u>Surface Water</u>

PSEG has a current NJPDES permit from the New Jersey Department of Environmental Protection (NJDEP 2001b; No. NJ005622) for Salem that limits use of Delaware Estuary water to a 30-day average of 11,447 million liters or 3,024 million gallons per day (MGD) of circulating water.

PSEG is authorized by the Delaware River Basin Commission (DRBC) to withdraw surface water from the Delaware Estuary for consumptive and non-consumptive use as cooling water not to exceed 367,000 million liters (97,000 million gallons) in a single 30-day period. (DRBC 1977, DRBC 2001)

Circulating Water System

The CWS provides approximately 3,974,670 liters per minute (1,050,000 gallons per minute [gpm]) to each unit. The CWS intake consists of 12 circulating water pumps (6 for each unit), each in a separate bay of a pumphouse on the shoreline of the site (PSEG 2006a, Section 5). The CWS circulates water from the Estuary, through the main condenser, and back to the Estuary. Each pump's design rating is 700,299 liters per minute (185,000 gpm), for a total design flow of 4,201,794 liters per minute (1,110,000 gpm) through each unit. For each unit, all six circulating water pumps are normally in service. The velocity at the intake screens is approximately 0.3 meters per second (1 ft per second [fps]) at mean low tide, a rate that is compatible with the protection of aquatic species (EPA 2001).

Twelve traveling screens of a modified Ristroph design extend the full height of each of the 12 bays in the intake structure. The traveling screens have been extensively upgraded over time. The most significant upgrades occurred in 1995 to improve performance and reliability and increase the survival rates of impinged fish. (NJDEP 2000)

Each screen panel has a 3-m (10-ft) long composite material fish bucket attached to its bottom support member. As the Ristroph bucket travels over the head sprocket of the traveling screen, organisms slide onto the screen face and are flushed by the low-pressure spray system. As the panel rotates to the fish-removal position, the spray wash water helps to slide fish on the screen surface over a flap seal into a bidirectional fish trough. As the panels continue to travel, debris is removed into a bidirectional debris trough using high-pressure spray. The fish and debris troughs are joined after the troughs leave the building. Fish and debris washed from the screens are returned to the Estuary on either the north or south side of the intake, depending on the direction of tidal flow. The troughs are bidirectional in that they are emptied in the direction of the tide, so that fish and debris will move away from the circulating water intake structure, in an effort to minimize the likelihood of re-impingement. (NJDEP 2000)

A full-depth heavy duty trash rack is located at the entrance to each pump bay to protect the circulating pumps and traveling screens from damage by large debris. The trash racks are constructed of 1.27-cm (0.5-in.) wide steel bars on 8.9-cm (3.5-in.) centers; the size of the clear slot opening is 7.6 cm (3 in.). PSEG employees inspect the trash racks and, if required, remove any debris using a mobile clamshell-type mechanical rake. The trash rakes are self-contained and traverse the entire width of the intake. Refuse pits with removable bins are provided at each end of the intake structure for collecting the debris raked off the trash rack for offsite disposal. (NJDEP 2000)

No biocides are required in the circulating water system. The initial design included a sodium hypochlorite addition system. However, the system was removed after operational experience demonstrated chemical biocides were not required.

Service-Water System

The SWS supplies cooling water to the reactor safeguard and auxiliary systems. Each of the 12 service-water pumps (6 for each unit) is rated at 41,166 liters per minutes (10,875 gpm; PSEG 2006a, Section 5). The average velocity throughout the SWS intake is less than 0.3 m per second (1 fps) at the design flow rate. The pumps for both units are in an enclosed intake structure with four independent pump compartments containing three pumps each (PSEG

2006a, Section 5). The SWS is equipped with trash racks, traveling screens, and filters to remove debris from the incoming water (PSEG 2009c). Service water enters the bays through mechanically cleaned trash racks constructed of 1.27-cm (0.5-inch) wide steel bars on 8.9-cm (3.5-inch) centers. After passing through the trash racks, water is drawn under a curtain wall to prevent liquids that could compromise the safety of the system from entering the SWS. Water is then drawn through conventional vertical traveling screens. To dislodge debris, the screens are backwashed with service water. The backwash water and debris are discharged into a trough and directed through trash baskets to the Estuary. Debris collected in the baskets is transported for disposal at a landfill (PSEG 2006a, Section 5).

The primary method of preventing organic buildup and biofouling organisms in the heat exchangers and piping of the SWS is by injecting sodium hypochlorite into the suction of each service water pump (PSEG 2009c). Service water combines with the CWS water prior to discharge and effluent residual chlorine limitations are met in accord with the NJPDES Permit.

3.1.3.2 Ground Water

PSEG has authorization from the NJDEP (NJDEP 2004) and DRBC (DRBC 2000) for consumptive use of up to 163 million liters (43.2 million gallons) of ground water per month at the Salem and HCGS sites combined. The discussion of ground water in this section includes use at both the Salem and HCGS sites for the following reasons.

- NJDEP issued a single permit for both sites combined. Although each site uses its own wells and there are individual pumping limits for each well, the permit limits are for both sites combined. The current permit allows a combined maximum diversion rate for Salem and HCGS of 11,000 liters per minute (2,900 gpm) and limits actual water diverted to 163 million liters (43.2 million gallons) per month or 1.1 billion liters (300 million gallons) per year (NJDEP 2004). The ground-water pumping limit per well, based on the January 1, 2005, permit (NJDEP 2004), is indicated in Table 3.1-1. This limit is consistent with the docket authorization issued by DRBC for ground-water withdrawal. (DRBC 2000)

- The ground-water distribution systems for Salem and HCGS are interconnected in order to transfer water between the stations, if needed.

Ground water is the only source of fresh water at the Salem and HCGS sites. Both sites use fresh water for potable, industrial process make-up, fire protection, and sanitary purposes (PSEG 2009c, PSEG 2006c).

Ground water at Salem is withdrawn primarily from two production wells, PW-5 and PW-6, which are installed to depths of 256 m (840 ft) and 347 m (1,140 ft), respectively, in the Upper and Middle Raritan Formations of the Potomac-Raritan-Magothy Aquifer (DRBC 2000). Salem also has the capability of using two shallower wells, PW-2 and PW-3, currently classified as stand-by wells by NJDEP (NJDEP 2004). These wells are installed to depths of 87 m (286 ft) and 89 (293 ft), respectively, in the Mt Laurel-Wenonah Aquifer (DRBC 2000). The wells supply two 1.3 million-liter (350,000-gallon) storage tanks. Of the total volume, 2.27 million liters (600,000 gallons) of water are reserved for fire protection; the remainder is for potable, sanitary, and industrial purposes, including makeup water to those plant systems requiring demineralized water (PSEG 2009c). The Demineralized Water Makeup system uses reverse osmosis to provide the ultrapure water required.

HCGS derives ground water from two production wells (HC-1 and HC-2) installed to a depth of 249 m (816 ft) in the Upper Raritan Formation of the Potomac-Raritan-Magothy Aquifer (DRBC 2000). The wells supply two 1.3 million-liter (350,000-gallon) storage tanks (for a total of four storage tanks, two for each station). Of the total volume, approximately 2.5 million liters (656,000 gallons) of water are reserved for fire protection; the remainder is for potable, sanitary, and industrial purposes, including demineralized makeup water. The Demineralized Water Makeup system uses ion-exchange resin to provide the ultrapure water required.

Ground-Water Usage

PSEG has authorization from the NJDEP (NJDEP 2004) and DRBC (DRBC 2000) for consumptive use of up to 163 million liters (43.2 million gallons) of ground water per month at the Salem and HCGS sites combined.

Between 2002 and 2008 the Salem wells pumped an average of 821 liters per minute (217 gpm) with a production low for the period of 640 liters per minute (169 gpm) during 2002 and a high of 1,007 liters per minute (266 gpm) during 2008. During the same period, the HCGS wells pumped an average of 609 liters per minute (161 gpm) with a production low for the period of 518 liters per minute (137 gpm) during 2002 and a high of 749 liters per minute (198 gpm) during 2004. (Table 3.1-1; TetraTech 2009)

Ground-water elevations were measured during a ground-water study in 1987 by Dames & Moore (Dames & Moore 1988) in the River Sand and Gravel Aquifer, the Vincentown Aquifer, the Mt. Laurel-Wenonah Aquifer, and the Upper and Middle Raritan Formations of the Potomac-Raritan-Magothy (PRM) Aquifer. The ground-water elevation ranges measured for these aquifers are indicated in Table 3.1-2. Ground-water elevation ranges were more recently monitored in the Salem/HCGS wells, as indicated in Table 3.1-3. Of the four primary Salem/HCGS wells, three (PW-5, HC-1, and HC-2) are installed in the Upper Raritan Formation. The fourth (PW-6) is installed in the Middle Raritan Formation.

The ground-water elevation ranges (Table 3.1-3) measured in PW-6 (in the Middle Raritan Formation) in 2002, 2003, 2005, 2006, 2007, and 2008 are higher than the elevation recorded in 1987; the ranges of elevations recorded from PW-6 in 2000, 2001 and 2004 bracket the elevation recorded in 1987. For the last 3 years, elevations in PW-6 have been fairly constant at about -45 to -48 feet.

The data for wells PW-5, HC-1 and HC-2 in the Upper Raritan Formation are more difficult to interpret. In eight of nine years from 2000 to 2008, the ranges of elevations monitored in these three wells in the Upper Raritan Formation bracketed the 1987 data. That is, in eight of nine years, elevations measured in the Upper Raritan Formation were both higher and lower than those measured in 1987. In 2005, the range was lower than was measured in 1987. Elevation ranges in individual wells and between wells are highly variable. Taken as a whole, the ranges exhibit a consistent pattern of high variability. One explanation of the difference in ground-water elevations observed among and within the wells is that the ground-water elevations in the wells were measured before the water level had stabilized during the monitoring events.

Because the PRM is an important aquifer extending from as far north as Mercer and Middlesex Counties, New Jersey, southward into and beyond Delaware, it is subject to numerous pumping influences (NJGS 1965). The ground-water demand placed on the PRM has resulted in a decrease in the elevation of the piezometric surface that has been historically observed in the counties of Camden, Middlesex, and Monmouth (USGS 1983). The development of these piezometric surface reductions was observed in wells completed in the middle and lower aquifers between 1973 and 1978. The declines may have been a result of an increase in the amount of extraction from the lower aquifer which began in approximately 1973. Coincident cones of depression in the upper and middle/lower PRM suggest that significant communication occurs between these aquifers (USGS 1983). Furthermore PRM aquifer withdrawals in Camden County have been previously shown to influence water levels at significant lateral distances resulting in water level reductions in Salem and Gloucester counties (USGS 1983).

Ground-water withdrawals in central and southern New Jersey increased from 1904 to a peak in the mid/late 1970s. They then dropped off precipitously in the mid 1980s (USGS 1983, USGS 2001a). A slower rate of declining withdrawals continued until 1995 (USGS 2001a). Water levels in lower PRM observation wells located in New Jersey and Delaware generally increased during the period from the mid-1980s to the late 1990s, as documented by the USGS (2001b). Decreased consumptive use and greater controls on water withdrawals by the state of New Jersey [in favor of surface water withdrawals (NJDEP 1985) as referenced by USGS 2001a)] allowed water levels in the PRM to recover in central New Jersey from the over-pumping of the 1970s.

Station pumping wells completed in the PRM have exhibited relatively stable to slightly decreasing water levels during the period 2000–2008. A study by the USGS (2001b) clearly shows that the pumping centers north of the Chesapeake and Delaware canal influence water levels in the lower PRM in the Artificial Island vicinity. The interconnected nature of the lower and middle units of the PRM in conjunction with this study (USGS 2001b) suggest that water levels in the middle PRM are influenced by/related to water levels in the lower PRM. A more recent USGS study (USGS 2009) indicates that Delaware withdrawals from the middle and lower PRM had increased as of 2003. This appears to have resulted in reduced regional water levels in this area of the lower PRM. These effects continued to influence water levels at Artificial Island in both the lower and middle units of the PRM. Water level monitoring at the station is consistent with the regional water level changes resulting from the increased withdrawals in Delaware (USGS 2009).

The information described above suggests that the observed decrease in water levels in observation wells located at Artificial Island are part of a larger regional trend rather than a result of station-related withdrawals. This is supported by data documenting increased water withdrawals (both location and quantity) in Lower New Castle County, Delaware and water level maps prepared by the USGS as part of a long-term ground-water monitoring program.

Artificial Island is not included in either the Southeastern Pennsylvania Ground Water Protected Area, or a New Jersey Critical Area, and the Delaware River Basin Commission (DRBC) monitors these regional ground-water sources (DRBC 2008). PSEG withdraws less than half of the allocation authorized by DRBC and NJDEP.

Ground-Water Monitoring for Tritium and Other Radionuclides

In March of 2006, PSEG implemented a program to proactively review the environmental status of its nuclear power generating stations, specifically to identify the potential for releases of tritium, strontium, or station-related gamma-emitting radionuclides from all systems, structures, and components at the stations that are not designed for such a release. The PSEG program was designed as part of an industry-wide initiative, consistent with the guidance provided by the Nuclear Energy Institute (NEI 2007).

To more thoroughly quantify the potential for unmonitored releases of tritium, strontium, or station-related radionuclides to the environment from various systems, engineers performed an internal review of systems, structures, and components to determine which have the greatest potential for impacting shallow ground-water quality, should a release of radionuclides occur. Based upon the results of those reviews, a ground-water monitoring well network was designed and installed to include wells located: (1) in the vicinity and downgradient of station systems that "screened in" as a result of the analysis; (2) at downgradient locations around the perimeter of the Station; and, (3) at upgradient locations, to verify that any radionuclides that may be found in ground water are not migrating offsite above applicable New Jersey Ground Water Quality Criteria. Thirteen wells were identified at Salem, five existing wells and eight newly installed wells (Figure 3.1-4). Thirteen new wells were installed at HCGS (Figure 3.1-5). Following installation, each well was developed and sampled by trained technicians using low-flow ground-water sampling techniques, and the samples were analyzed by a laboratory qualified to perform the requested analyses. No plant-related gamma emitter or strontium was detected in those ground-water samples.

Monitoring has been conducted at least semi-annually since installation of the Radiological Groundwater Protection Program (RGPP) wells. No plan-related gamma emitters have been detected in the 26 RGPP wells. No analytical results for tritium have exceeded the EPA Drinking Water Standard or triggered voluntary communication or reporting under the Nuclear Energy Institute (NEI) guidance (NEI 2007). Some variability in the tritium concentrations has been observed but there is no identifiable trend. Results of the monitoring program, including trending data, program modifications, reporting protocols, and other information are included as an appendix to the annual Radiological Environmental Operating Report. (PSEG 2007b, PSEG 2008b).

3.1.4 RADIOACTIVE WASTE MANAGEMENT SYSTEMS

3.1.4.1 Liquid Radioactive Waste Systems

The Radioactive Liquid Waste System (RLWS) provides controlled handling and disposal of small quantities of low-activity liquid radioactive wastes generated during station operation. The system is designed to minimize exposure to station personnel and the general public, in accord with NRC regulations. Radioactive fluids entering the RLWS are collected in tanks, sampled, and analyzed to determine the quantity of radioactivity with an isotopic breakdown, if necessary. Based on the results of the analysis, the waste is processed and released to the Delaware Estuary via the circulating water system under controlled conditions as required by regulation. Discharge streams are appropriately monitored, and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20. (PSEG 2009c)

The bulk of the radioactive liquids discharged from the RCS is processed and retained inside the plant by the Chemical and Volume Control System (CVCS) recycle train. This minimizes liquid input to the RLWS. Processed water from which most of the radioactive material has been removed to meet discharge limits is discharged to the Delaware Estuary via the circulating water discharge system. (PSEG 2009c)

Where possible, liquid wastes drain to the waste holdup tanks by gravity flow. Liquid wastes that drain to the Auxiliary Building sump tank are pumped from there to the waste holdup tanks. (PSEG 2009c)

With the exception of the shared pumps and tanks of the Laundry and Hot Shower Drains, the Chemical Drains, Portable Filter, and the Portable Demineralizer, each unit has its own Liquid Waste Disposal System. The Laundry and Hot Shower Drain Tanks and the Chemical Drain Tank are pumped to one of the Waste Hold-up Tanks or the Waste Monitor Hold-up Tank of either unit. (PSEG 2009c)

Wastes requiring processing before release are batched through a portable filter and portable demineralizer. The effluent of the portable system is returned to the Waste Monitor Hold-up Tanks or the CVCS Monitor Tanks to be sampled, analyzed, and either reprocessed or pumped through a flow meter and a radiation monitor to the SWS for release through the circulating water discharge system. The radioactivity removed from the liquid wastes is concentrated in the filter media and ion exchange resins, which are managed as solid radioactive wastes. (PSEG 2009c)

3.1.4.2 Gaseous Radioactive Waste Systems

The Gaseous Waste System (GWS) provides controlled handling and disposal of gaseous wastes generated during station operation. The system is designed and operated to minimize exposure to station personnel and the general public, in accordance with NRC regulations. (PSEG 2009c)

Radioactive gases entering the GWS are collected in tanks to allow for decay and isotopic analysis. Discharge streams are monitored and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20. (PSEG 2009c)

Cover gases in the Nitrogen Blanketing System can be reused to minimize gaseous waste. During normal operation, decayed gases are discharged intermittently at a controlled rate through the plant vent. All system equipment is located in the Auxiliary Building. (PSEG 2009c)

3.1.4.3 Solid Radioactive Waste Systems

The Solid Radioactive Waste System collects, processes, packages, and provides temporary storage for radioactive solid waste until offsite shipment, volume reduction, and disposal at a licensed disposal facility. New Jersey is a member of the Atlantic Interstate Low Level Radioactive Waste Management Compact and thus is not affected by the closing of the Barnwell Low Level Radioactive Waste facility (Barnwell) to non-compact members, effective July 1, 2008.

Spent resins from the demineralizers and filter cartridges are packaged and stored onsite until shipment offsite for disposal in a licensed low-level radioactive waste disposal facility. All radioactive resin waste and cartridge waste are shipped to Barnwell. Packaging is done within the Auxiliary Building to control releases to the environment. Radioactivity levels of the contents are monitored to maintain doses within regulatory limits. (PSEG 2009c)

Dry Active Waste (DAW) consisting of compactable trash is placed in Sea-van containers and shipped to a licensed off-site vendor for volume reduction. Contaminated metals are also processed by an offsite vendor. The volume-reduced DAW is repackaged at the vendor and shipped for disposal at a licensed low-level waste disposal facility (PSEG 2009c). Class A non-resin waste is typically shipped to the EnergySolutions Class A disposal facility in Clive, Utah. All other radioactive waste normally is shipped to Barnwell.

The PSEG Low Level Radwaste Storage Facility (LLRSF) is on the HCGS site. The LLRSF can support normal radioactive material handling activities for HCGS and Salem (excluding wet waste processing). Examples of these activities are pre-staging waste packages awaiting shipment, using handling equipment and shielding capabilities to prepare and load radioactive materials for shipment, performing radiography, storing and working on contaminated equipment and supplies, as well as other activities that require appropriate radiation protection controls. The NRC has approved a Process Control Program for the LLRSF. The Process Control Program outlines the in-plant measures and controls to assure the suitability of solid radioactive waste for transportation and/or disposal at a licensed low-level radioactive waste disposal facility. All packaging meets U.S. Department of Transportation and NRC standards as well as the waste acceptance criteria of any offsite burial facility to which it is destined. (PSEG 2006c)

The LLRSF is intended to serve as an interim storage facility for Salem and HCGS low-level radioactive waste until the waste can be shipped to a radioactive waste disposal facility. It is sized to store the volume of waste that typically would be generated from both Salem and HCGS over a 5-year period, and has a maximum capacity of 1,918.5 m^3 (67,750 ft^3). The LLRSF was designed in accordance with the guidelines provided in Generic Letter 81-38 (Storage of Low Level Radioactive Wastes at Power Reactor Sites [NRC 1981]). (PSEG 2009c)

PSEG expects Barnwell and the LLSRF will provide adequate low-level radioactive waste management capacity through the license renewal terms of both Salem units.

Salem currently does not have processes that result in the generation of mixed waste (i.e., waste having both a hazardous component that is subject to the requirements of the Resource Conservation and Recovery Act and a radioactive component that is subject to the requirements of the Atomic Energy Act). In the past, most mixed wastes generated at Salem resulted from the contamination of oils (hydraulic and lubricating) used in plant systems. All oils currently used in plant systems are non-hazardous and would not result in mixed waste if they became radiologically contaminated. There are currently no mixed wastes stored at Salem.

3.1.5 NONRADIOACTIVE WASTE MANAGEMENT SYSTEMS

A common sewage treatment system located at HCGS and operated by HGGS staff treats domestic wastewater from both Salem and HCGS. Wastewater and activated sludge are introduced into the single-channel oxidation ditch where extended aeration, a modification of the activated sludge process, oxidizes the organic constituents of the wastewater. This process lowers Biochemical Oxygen Demand (BOD), reduces suspended solids, nitrifies, and partially denitrifies the wastewater. Rotor aerators mix air into the contents of the basin and keep the contents moving through the oxidation ditch. Following aeration, mechanical settling in the biological clarifiers separates suspended solids from the liquid flow. The settled solids (i.e., sludge) are either returned to the oxidation ditch or removed to a sludge-holding tank, based upon process requirements. Sludge directed to the sludge-holding tank is aerated and dewatered before being trucked offsite to a licensed disposal facility, or to an NRC-licensed facility if the residuals contain low levels of radioactivity. The sewage treatment system waste stream is a facility internal outfall monitored in accordance with the current Hope Creek NJPDES Permit. The sewage treatment system effluent discharges through the Hope Creek cooling tower blowdown outfall to the Delaware Estuary. Residual cooling tower blowdown de-chlorination chemical, ammonium bisulfite, de-chlorinates the sewage treatment effluent. (NJDEP 2002, Tab DSN 462B – Sewage Treatment System (Explanation of Summary Notes)).

A common chemical waste treatment system, known as the Non Radioactive Liquid Waste Disposal System (NRLWDS), is located at Salem and operated by Salem staff. The NRLWDS collects and treats secondary plant wastewater from Salem and HCGS which may contain chemicals, especially acidic and caustic wastewater, prior to discharge. The NRLWDS processes and treats the non-radioactive low volume wastes from various Station processes, such as demineralizer regenerations, steam generator blowdown, chemical handling operations, and reverse osmosis reject waste. The NRLWDS discharge commingles with the non-contact cooling water prior to discharge to the environment. Treatment processes include thorough mixing in an equalization-mixing basin to provide homogeneity and some self-neutralization of acid and caustic wastes, solids removal by settling, chlorination, and pH adjustment to induce precipitation of any remaining metals prior to commingling with cooling water for ultimate discharge to the Delaware Estuary. (PSEG 2009c)

At Salem, the Oil Water Separator (OWS) removes solids and floating oil from the influent water, primarily precipitation runoff, transformer sumps, and turbine building sumps. The solids are collected at the bottom of the OWS and oil is pumped from the surface of the OWS and removed when necessary.

PSEG currently is a conditionally exempt small-quantity hazardous waste generator, generating less than 100 kilograms/month (220 pounds/month). Because of episodic generation of hazardous wastes, during outages for example, PSEG maintains the program required of a small-quantity generator and monitors the amount of hazardous waste generated each month to determine the correct status. Hazardous waste is disposed of through a licensed broker. Universal waste, such as paint waste, lead-acid batteries, used lamps, and mercury-containing switches, is segregated and disposed of through a licensed broker.

Normal station waste (e.g., paper, plastic, glass, river vegetation) is segregated and, as much as possible, processed for recycling. Approximately 55 percent of the normal station waste is transferred to recycling vendors, and the remaining 45 percent is disposed in the local landfill.

3.1.6 TRANSMISSION SYSTEM

The transmission lines of interest in this Environmental Report are indicated in Table 3.1-4 and shown in Figure 3.1-3.

The FES (AEC 1973) for Salem identifies three 500-kilovolt (kV) transmission lines that were to be built to deliver electricity generated at the Salem site to the transmission system. Two of these lines were built to connect the station with the New Freedom substation near Williamstown, New Jersey. Due to reliability considerations, these lines were constructed to transverse separate rights-of-way and are identified as “Salem-New Freedom North” and “Salem-New Freedom South”. The third line was constructed to extend north, across the Delaware River, and to terminate at Keeney substation in Delaware. This line is identified as the “Salem-Keeney.”

When HCGS was constructed, several changes in transmission line connections with Salem were made (NRC 1984). The existing Salem-New Freedom North and Salem-Keeney lines were disconnected from Salem and reconnected to HCGS. Also, a new substation (known as Red Lion) was built along the Salem-Keeney transmission line. Hence, the Salem-Keeney transmission line is now comprised of two segments: one from HCGS to Red Lion and the other from Red Lion to Keeney

Because the Salem-New Freedom North line was re-routed to HCGS, it was necessary to build a new transmission line to connect Salem to the New Freedom substation. This line is known as the “HCGS-New Freedom” transmission line.

Because the Salem-New Freedom North, Salem-New Freedom South, and Salem-Keeney lines were originally built to connect Salem to the grid, they are further considered for analysis in this Environmental Report. The HCGS-New Freedom line, having been constructed for HCGS, is not part of the analysis in this Environmental Report. The HCGS-Salem tie line does not pass beyond the site boundary, and therefore, is also not evaluated in this Environmental Report. Nevertheless, for completeness, all lines are described below:

- *Salem-New Freedom North*—This 500-kV line, which is operated by PSE&G, runs northeast from HCGS for 63 km (39 mi) in a 107-m (350-ft) wide corridor to the New Freedom Switching Station north of Williamstown, New Jersey. This line shares the corridor with the 500-kV HCGS-New Freedom line.

- Salem-Red Lion segment of Salem-Keeney—This 500-kV line extends north from HCGS for 21 km (13 mi) and then crosses over the New Jersey-Delaware state line. It then continues west over the Delaware River about 6 km (4 mi) to the Red Lion substation. In New Jersey the line is operated by PSE&G, and in Delaware it is operated by PHI. Two thirds of the 27-km (17-mi) corridor is 61 m (200 ft) wide, and the remainder is 107 m (350 ft) wide.

- Red Lion-Keeney segment of Salem-Keeney—This 500-kV line, which is operated by PHI, extends from the Red Lion substation 13 km (eight mi) northwest to the Keeney switch station. Two thirds of the corridor is 70 m (200 ft) wide, and the remainder is 107 m (350 ft) wide.

- Salem-New Freedom South—This 500-kV line, operated by PSE&G, extends northeast from Salem for 68 km (42 mi) in a 107-m (350-ft wide corridor from Salem to the New Freedom substation north of Williamstown, New Jersey.

- HCGS-New Freedom—This 500-kV line, which is operated by PSE&G, extends northeast from Salem for 69 km (43 mi) in a 107-m (350-ft) wide corridor to the New Freedom switching station north of Williamstown, New Jersey. This line shares the corridor with the 500-kV Salem-New Freedom North line. During 2008, a new substation (Orchard) was installed along this line, dividing it into two segments.

- HCGS-Salem—This 500-kV tie line connects the HCGS and Salem switchyards. It consists of two towers and spans about 610 m (2,000 ft). This line does not pass beyond the site boundary, and is not discussed further or included in Table 3.1-4.

In total, the transmission lines of interest (Figure 3.1-3) are contained in 171 km (106 mi) of corridor that occupy about 1,720 hectares (4,250 acres). These corridors pass through the marshes and wetlands north and east of Salem. The remaining corridor distances traverse primarily agricultural or forested land, and some residential and urban areas. The developed areas are mostly remote with low population densities. Corridors that pass through pastures generally continue to be used as pastures. The lines cross several roads including state highway 55, U.S. highway 40, and the Atlantic City Expressway to the east and U.S. Highway 13 to the northwest.

PSE&G and PHI (for the Delaware portion of the Salem-Keeney line) own and operate the Salem-New Freedom North, Salem-New Freedom South, and Salem-Keeney transmission lines, which connect to the PJM interconnection. PJM is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. These transmission lines would remain under PSE&G and PHI ownership and would stay in service even if the operating licenses of the two Salem units were not renewed and the units were decommissioned.

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

Table 3.1-1 Salem and HCGS's Annual Ground-Water Pumpage (MG), 2002-2008

		2002	2003	2004	2005	2006	2007	2008
Salem								
Water Supply Well	**Pump Limit**	**Pumpage**	**Pumpage**	**Pumpage**	**Pumpage**	**Pumpage**	**Pumpage**	**Pumpage**
PW-2	300 gpm	0.0	0.0	0.0	0.1	0.0	0.0	0.0
PW-3	600 gpm	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PW-5	800 gpm	87.2	98.5	107.9	133.8	108	104	127.3
PW-6	600 gpm	1.7	1.6	4.2	3.7	1	8	13.2
Total Salem Ground-water Pumpage per Year		89 MG (169 gpm)	100 MG (190 gpm)	112 MG (213 gpm)	138 MG (263 gpm)	109 MG (207 gpm)	112 MG (213 gpm)	140 MG (266 gpm)
HCGS								
Water Supply Well	**Pump Limit**	**Pumpage**	**Pumpage**	**Pumpage**	**Pumpage**	**Pumpage**	**Pumpage**	**Pumpage**
HC-1	750 gpm	36.5	38.5	49.7	36.7	39.7	49.6	40.8
HC-2	750 gpm	35.5	34.9	53.9	44.8	41.7	47.5	42.7
Total HCGS Ground-Water Pumpage per Year		72 MG (137 gpm)	73 MG (139 gpm)	104 MG (198 gpm)	81 MG (154 gpm)	81 MG (154 gpm)	97 MG (184 gpm)	83 MG (158 gpm)
Salem and HCGS Combined								
		Pumpage	**Pumpage**	**Pumpage**	**Pumpage**	**Pumpage**	**Pumpage**	**Pumpage**
Total Salem and HCGS Ground-Water Pumpage per Year		161 MG (306 gpm)	173 MG (329 gpm)	216 MG (411 gpm)	219 MG (417 gpm)	190 MG (361 gpm)	209 MG (398 gpm)	223 MG (424 gpm)

Source: TetraTech 2009
MG = million gallons
gpm = gallons per minute

Table 3.1-2 Ground-Water Elevations 1987

Aquifer	Ground-Water Elevation (ft bgs)
River Sand and Gravel Aquifer	+3 to +7
Vincentown Aquifer	0 to +4
Mt. Laurel-Wenonah Aquifer	-2 to -8
Upper Raritan Formation	-57 to -62
Middle Raritan Formation	-49

Source: Dames & Moore 1988

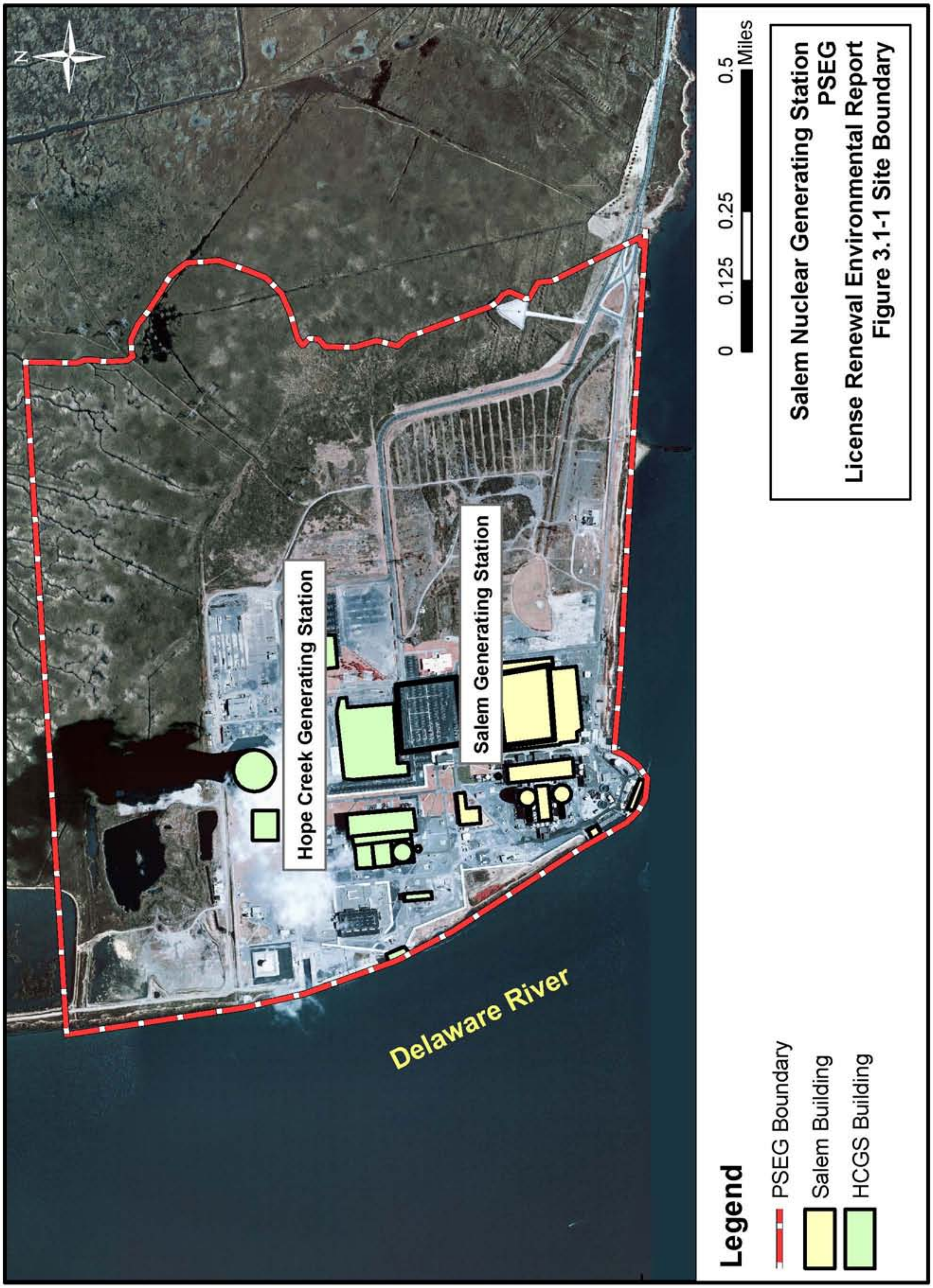
Table 3.1-3 Ground-Water Elevation Data Range (in feet) for Salem and HCGS Ground-Water Wells, 2000 – 2008. (The aquifer range includes data from all production wells monitored in that aquifer.)

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Mount Laurel/Wenonah	**3.08 to -3.12**	**3.68 to -1.12**	**4.08 to 0.16**	**3.28 to 0.86**	**3.48 to -7.82**	**13.78 to 0.68**	**3.58 to 1.08**	**3.56 to 0.96**	**3.88 to 1.58**
Salem Wells									
PW-2	2.36 to -1.64	2.26 to -0.14	2.96 to 0.16	2.66 to 0.86	2.96 to -0.14	10.06 to 1.36	2.66 to 1.56	3.56 to 0.96	2.76 to 1.66
PW-3	3.08 to -3.12	3.68 to -1.12	4.08 to 0.28	3.28 to 0.88	3.48 to -7.82	13.78 to 0.68	3.58 to 1.08	2.98 to 0.98	3.88 to 1.58
Middle Raritan	**-35.85 to -64.75**	**-42.45 to -54.15**	**-42.45 to -45.15**	**-40.45 to -45.65**	**-41.55 to -52.65**	**-35.75 to -45.45**	**-44.75 to -46.25**	**-45.35 to -48.35**	**-45.35 to -51.35**
Salem Well (PW-6)	-35.85 to -64.75	-42.45 to -54.15	-42.45 to -45.15	-40.45 to -45.65	-41.55 to -52.65	-35.75 to -45.45	-44.75 to -46.25	-45.35 to -48.35	-45.35 to -51.35
Upper Raritan	**-28.93 to -68.35**	**-41.53 to -72.13**	**-54.33 to -74.94**	**-55.73 to -74.35**	**-57.94 to - 84.35**	**-60.94 to -86.35**	**-53.94 to -81.35**	**-55.94 to -83.35**	**-53.93 to -88.35**
Salem Well									
PW-5	-28.93 to -67.73	-41.53 to -72.13	-54.33 to -66.23	-55.73 to -70.73	-58.23 to -78.13	-64.33 to -80.73	-59.33 to -75.33	-63.03 to -79.63	-54.63 to -74.33
Hope Creek Wells									
HC-1	-59.94 to -67.94	-58.94 to -65.94	-57.94 to -74.94	-60.94 to -71.94	-57.94 to -83.94	-60.94 to -74.94	-53.94 to -73.94	-55.94 to -65.94	-53.94 to -71.94
HC-2	-61.35 to -68.35	-60.35 to -70.35	-58.35 to -74.35	-61.35 to -74.35	-69.35 to -84.35	-73.35 to -86.35	-69.35 to -81.35	-70.35 to -83.35	-63.35 to -88.35

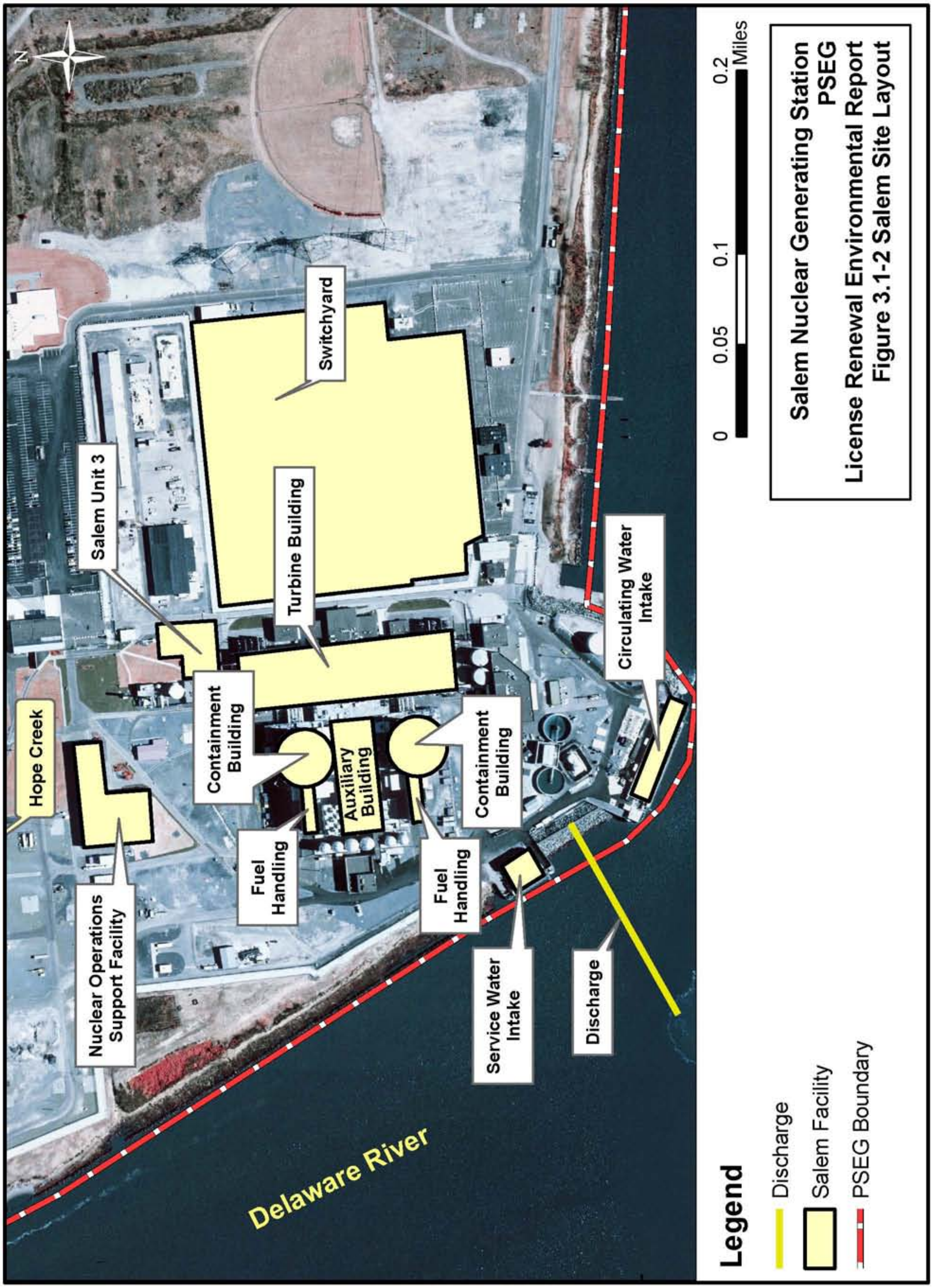
Source: TetraTech 2009

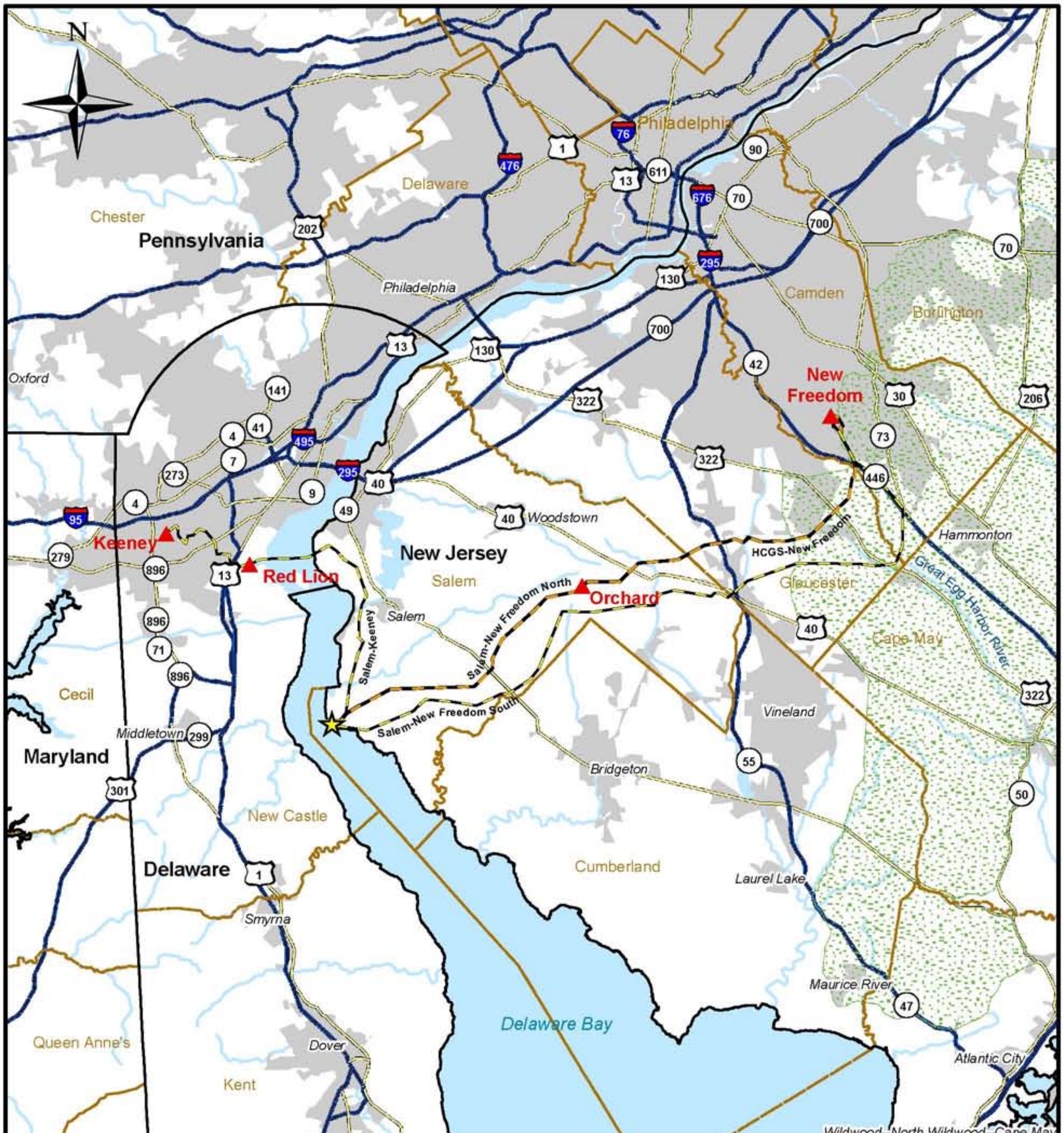
Table 3.1-4 Transmission Lines Associated with Salem Nuclear Generating Station and HCGS.

Present Name	Built during construction of	Segments	Presently Connected to	Analyzed in LR report for
Salem-New Freedom South	Salem	None	Salem	Salem
Salem-New Freedom North	Salem	None	HCGS	Salem
Salem-Keeney	Salem	HCGS to Red Lion; Red Lion to Keeney	HCGS	Salem
HCGS-New Freedom	HCGS	Salem to Orchard; Orchard to New Freedom	Salem	HCGS



Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 3.1-1 Site Boundary


Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 3.1-2 Salem Site Layout
0 0.05 0.1 0.2 Miles
Switchyard
Salem Unit 3
Turbine Building
Hope Creek
Containment Building
Auxiliary Building
Containment Building
Circulating Water Intake
Nuclear Operations Support Facility
Fuel Handling
Fuel Handling
Service Water Intake
Discharge
Delaware River
Legend
Discharge
Salem Facility
PSEG Boundary

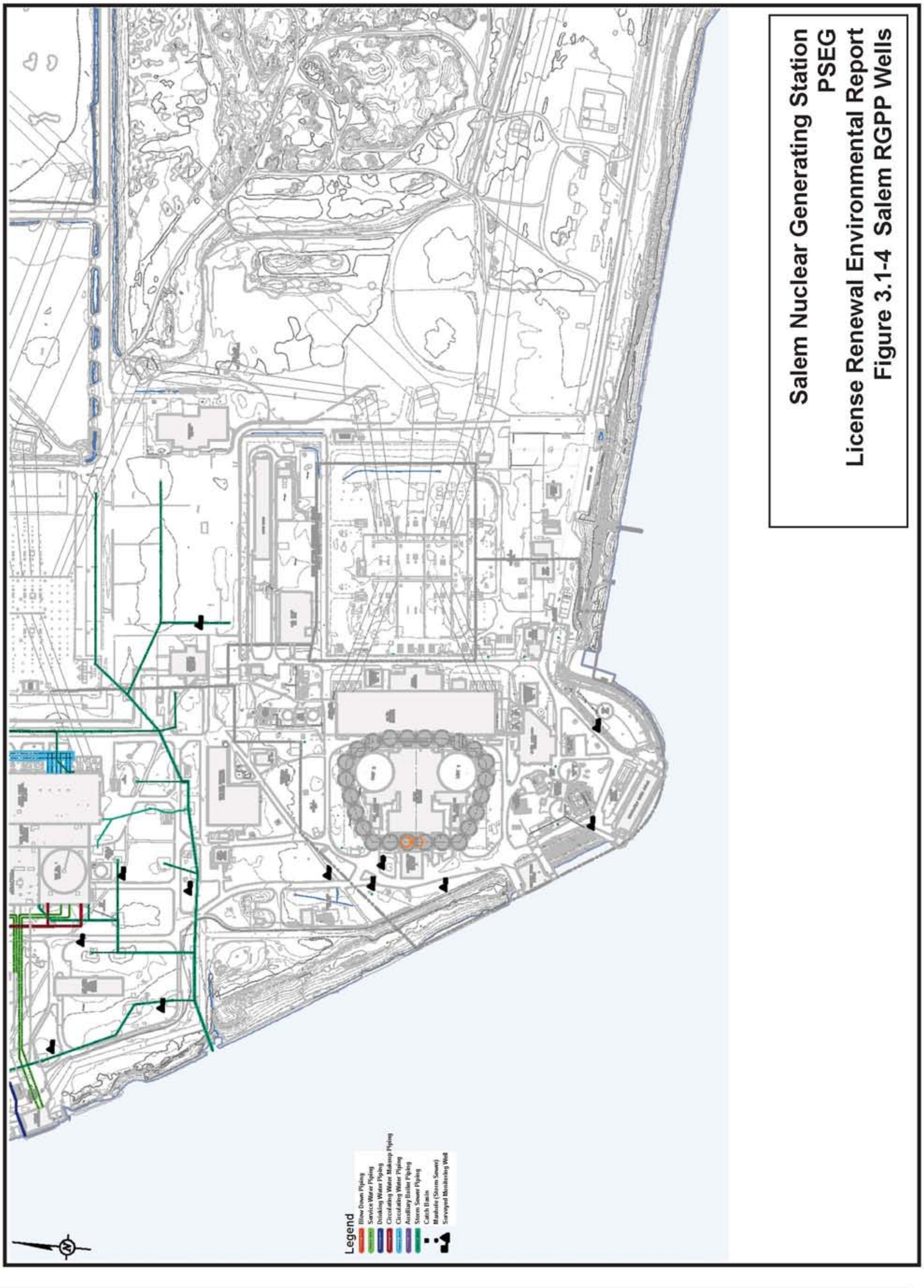


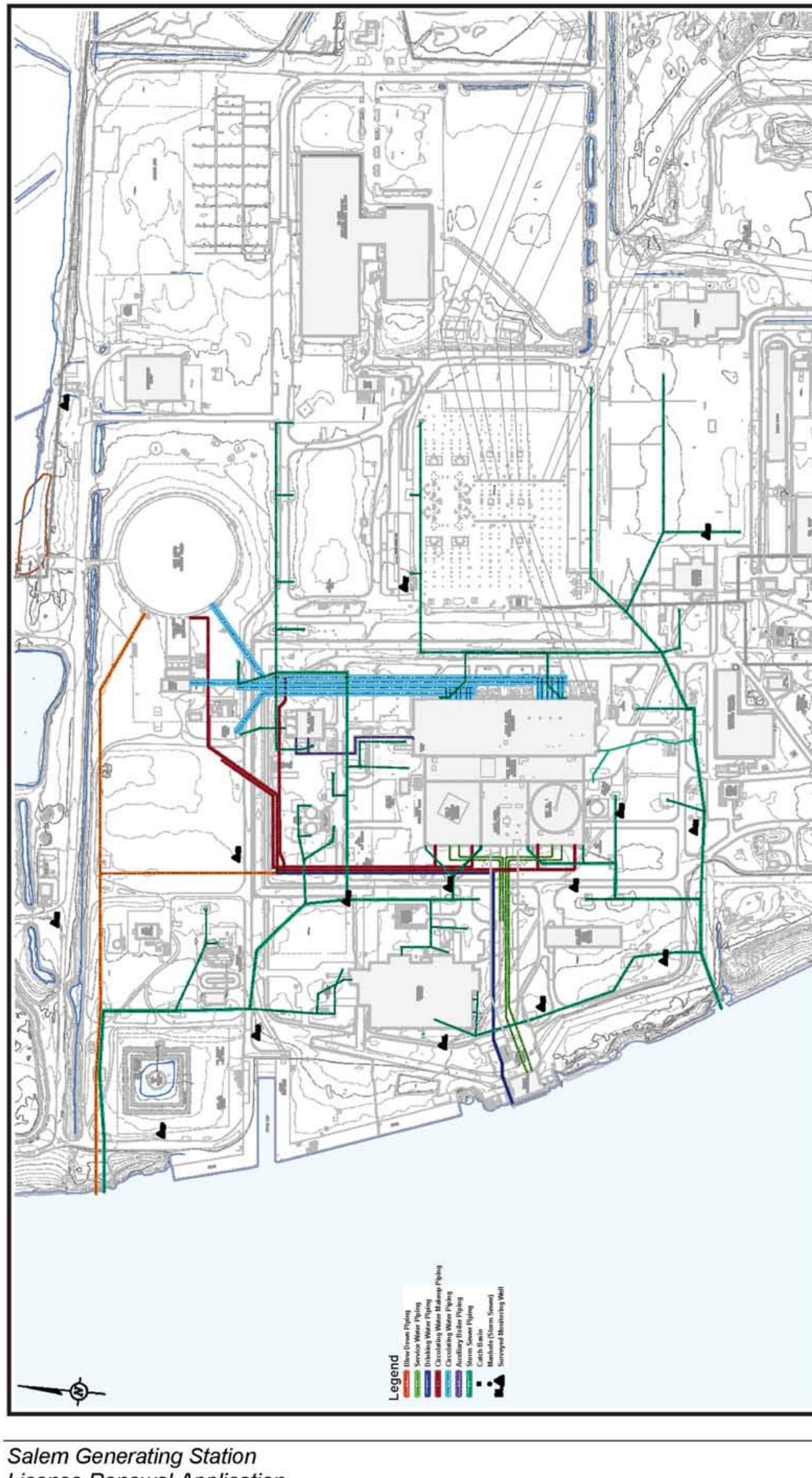
Legend

- Salem and Hope Creek Generating Stations
- Substation
- Transmission Line analyzed in Hope Creek ER
- Transmission Line analyzed in Salem ER
- State Boundary
- County Boundary
- Primary Highway with Limited Access
- Primary Highway
- Urban Area
- Pinelands
- Water

Miles: 0 2.5 5 10 15

Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 3.1-3 Transmission Lines


Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 3.1-4 Salem RGPP Wells
Legend
Blow Down Piping
Service Water Piping
Drinking Water Piping
Circulating Water Makeup Piping
Circulating Water Piping
Auxiliary Boiler Piping
Storm Sewer Piping
Catch Basin
Manhole (Storm Sewer)
Surveyed Monitoring Well



Salem Nuclear Generating Station
PSEG
License Renewal Environmental Report
Figure 3.1-5 HCGS RGPP Wells

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 as described in accordance with § 54.21...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 environmental report must contain analyses of …refurbishment activities, if any, associated with license renewal…" 10CFR51.53 (c)(3)(ii)**
>
> **"…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…(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 1996b, Section 2.6.3.1, pg.2-41)**

PSEG has no plans for refurbishment or replacement activities at Salem. PSEG has addressed refurbishment activities in this Environmental Report in accordance with NRC regulations and complementary information in the NRC GEIS for license renewal (NRC 1996b). 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, the reactor vessel piping, supports, and pump casings (see 10 CFR 54.21 for details), as well as items that are not subject to periodic replacement.

The Salem IPA that PSEG conducted under 10 CFR 54 has not identified the need to undertake any major refurbishment or replacement actions to maintain the functionality of important systems, structures, and components during the Salem renewed license period. PSEG has included the IPA as Section 2 of this Salem license renewal application.

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 1996b, Section 2.6.3.1. pg/2-41 (SMITTR is defined in NRC 1996b as surveillance, on-line monitoring, inspections, testing, trending, and recordkeeping.)**

The IPA required by 10 CFR 54.21 identifies the programs and inspections for managing aging effects at Salem. These programs are described in the Salem Nuclear Generating Station License Renewal Application, Section 2, Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results. Other than implementation of the programs and inspections identified in the IPA, there are no planned modifications of Salem administrative control procedures associated with license renewal.

3.4 Employment

3.4.1 CURRENT WORK FORCE

Salem currently employs a workforce of approximately 665 regular, full-time employees and shares up to an additional 270 PSEG corporate and 86 matrixed employees with HCGS. To ensure conservatism, the analyses in this Environmental Report include the total complement of corporate and matrixed employees as part of the Salem workforce. Approximately 83 percent of the workforce lives in Cumberland, Gloucester, and Salem counties, New Jersey, and New Castle County, Delaware. Addresses for permanent residences of the remaining employees are distributed across 24 counties in Georgia, Maryland, New Jersey, Pennsylvania, Texas, and Virginia, with numbers ranging from 1 to 43 employees per county. Less than 3 percent of the workforce has permanent residences someplace other than New Jersey, Pennsylvania, or Delaware (see Table 2.6-2).

Salem is on an 18-month refueling cycle. During refueling outages, site employment increases above the regular, shared, and matrixed work force by as many as 600 workers for approximately 23 days of temporary duty. This number of outage workers falls within of the range (200 to 900 workers per reactor unit) reported in the GEIS for additional maintenance workers (NRC 1996b).

3.4.2 LICENSE RENEWAL INCREMENT

Performing the programs and activities for managing the effects of aging that are described in Section 3.3 would necessitate increasing the Salem staff workload by some increment. The size of this increment would be a function of the schedule within which PSEG must accomplish the work and the amount of work involved. The analysis of license renewal employment increment focuses on programs and activities for managing the effects of aging.

The GEIS assumes that NRC would renew a nuclear power plant license for a 20-year period beyond the term of its initial license, and that NRC would issue the renewal approximately 10 years before the initial license expires. In other words, the renewed license would be in effect for approximately 30 years. 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 1996b)

PSEG has determined that the GEIS scheduling assumptions are reasonably representative of Salem incremental license-renewal, workload scheduling. Many Salem license-renewal SMITTR activities would have to be performed during outages. Although some Salem 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 in order to "...provide a realistic upper bound to potential population-driven impacts…." (NRC 1996b)

PSEG expects that its existing capability for temporarily supplementing the workforce for routine activities such as outages will enable PSEG to perform the increased SMITTR workload without adding workers to the Salem staff. However, for purposes of analysis in this Environmental Report, PSEG conservatively assumes that Salem would require 60 additional permanent workers to perform all license-renewal SMITTR activities and that all 60 employees would migrate into the 80-km (50-mi) radius. Adding 60 full-time employees to the station work force for the period of extended operation would create additional indirect jobs. Considering the population in the 80-km (50-mi) radius and the fact that most indirect jobs would be service-related, PSEG assumes that all indirect workers would already reside within the 80-km (50-mi) radius.

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Chapter 4

Environmental Consequences of the Proposed Action and Mitigating Actions

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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 must 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 Salem 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 NA (not applicable). 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)

- mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that 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.

Finally, NRC designated two issues as 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 Code of Federal Regulations [CFR] 51) as described in the Generic Environmental

Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996b). An applicant may reference the generic findings or GEIS analyses for Category 1 issues.

NRC requires plant-specific analyses for Category 2 issues. For the two issues designated as NA, applicants are not required to submit information to the NRC.

Of the 92 total issues, in addition to the two issues designated as NA, NRC designated 69 as Category 1 and 21 as Category 2. Appendix A of this report lists the 92 issues and identifies the Environmental Report section that addresses each issue.

Category 1 and NA License Renewal Issues

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 1996a, pg. 28483)**

Category 1 License Renewal Issues

PSEG has determined that 11 of the 69 Category 1 issues do not apply to Salem because they are specific to design or operational features that are not found at the facility. Because Salem is not planning any refurbishment activities, seven additional Category 1 issues related to refurbishment do not apply. Appendix A, Table A-1 lists the 69 Category 1 issues, indicates whether or not each issue is applicable to Salem, and if inapplicable provides PSEG's basis for this determination. Appendix A, Table A-1 also includes references to supporting analyses in the GEIS where appropriate.

PSEG has reviewed the NRC findings at Table B-1 in Appendix B to 10 CFR 51 and has not identified any new and significant information that would make the NRC findings, with respect to Category 1 issues, inapplicable to Salem. Therefore, PSEG 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, PSEG included these issues in 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). PSEG 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 2 issues) address the Category 2 issues, beginning with a statement of the issue. Nine Category 2 issues apply to operational features that Salem does not have or to an activity, refurbishment, which Salem is not planning to undertake. If the issue does not apply to Salem, the section explains the basis for inapplicability.

For the 12 Category 2 issues that PSEG has determined to be applicable to Salem, 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 Salem and, if applicable, discuss potential mitigative alternatives to the extent required. PSEG 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 practice, PSEG 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 makeup 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…." 10 CFR 51.53(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.**

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 (Limerick and Palo Verde) 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 1996b).

NRC has determined that Salem withdraws from and discharges to an estuary (NRC 1996b; Table 5.13). As discussed in Section 3.1.3, Salem uses an open-cycle condenser cooling system. Therefore, this issue does not apply because Salem does not use cooling ponds or cooling tower technology and withdraw water from a small river.

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 can not 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 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 on fish and shellfish resources resulting from entrainment a Category 2 issue, because it could not assign a single significance level to the issue. The impacts of entrainment are small at many plants, but they may be moderate or large at others. Also, ongoing restoration efforts may increase the number of fish susceptible to intake effects during the license renewal period (NRC 1996b, Section 4.2.2.1.2). Information needing to be ascertained includes: (1) type of cooling system (whether once-through or closed cycle), and (2) status of Clean Water Act (CWA) Section 316(b) determination or equivalent state documentation.

As Section 3.1 describes, Salem employs pressurized water reactors with once-through condenser cooling systems. Cooling water is withdrawn from the Delaware Estuary through two separate intake facilities, the CWS intake structure and the SWS intake structure, and returned to the Estuary through a common return (discharge) system (AEC 1973).

Section 316(b) of the CWA requires that any standard established pursuant to Sections 301 or 306 of the CWA shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts (33 USC 1326). Entrainment through the condenser cooling system of fish and shellfish in early life stages is a potential adverse environmental impact that can be minimized by the BTA.

In 1978, the US Environmental Protection Agency (EPA) recommended a multiyear Section 316(b) study for the Salem CWS and SWS intakes. During the following 5 years, PSE&G collected and analyzed data for Salem's 316(b) demonstration study in which 40 alternatives to intake design and practices were analyzed to determine the BTA (PSEG 1984). This 5-year study focused on potential impacts to target fish species. Of the 40 alternatives, 30 were eliminated after an initial review for being impractical or technically infeasible. Ten alternatives were considered further in the demonstration report. In 1984, the original 316(b) demonstration report for Salem was submitted naming the Ristroph traveling screen and fish return system as the BTA for the CWS and SWS intakes (PSEG 1984). EPA delegated NPDES authority to New Jersey in 1984 (NJDEP 2001b).

In 1990, NJDEP issued a draft permit proposing closed-cycle cooling as BTA for Salem, but in 1993 NJDEP reconsidered the proposal based on new information submitted by PSEG and issued a new draft (PSEG 1999a, Appendix A).

In 1994, NJDEP issued a renewed NJPDES permit. NJDEP determined that BTA consisted of the existing cooling water intake structure, in conjunction with the following: (1) modifications to the intake screens and an improved fish bucket design; (2) a restriction on cooling water intake flow rate; and (3) a sound deterrent study. Special conditions were also imposed by the permit, including (1) study and modification of the CWS intake structure, (2) restoration of wetlands to increase fish production, and (3) implementation of a comprehensive bay-wide biological monitoring program. To settle a legal challenge by the State of Delaware and a non-governmental organization, PSEG agreed to restore a minimum of 1,214 hectares (3,000 acres) of degraded wetlands and acquire up to 809 hectares (2,000 acres) of upland buffers in addition to the acreage required in the permit, and fund construction of artificial reefs on the Delaware side of the Delaware Estuary. (NJDEP 2001b).

In fulfillment of requirements of the 1994 NJPDES permit, PSEG developed and implemented an intensive biological monitoring program for the Delaware River, Estuary and Bay system, which has been followed, with modification and improvement, since 1995. PSEG applied for renewal of its Salem NJPDES permit in March 1999. The application included an updated demonstration pursuant to Section 316(b) relative to Salem's CWS and SWS intake structures, as well as detailed information demonstrating compliance with the special conditions of the 1994 permit (PSEG 1999a). NJDEP reviewed the permit application, including contracting with a third-party expert to review the 316(b) data and analyses in the application (ESSA 2000). In 2001, NJDEP renewed the permit, acknowledging that the CWS and SWS intakes represented BTA, and that the special conditions of the 1994 permit had been met.

The 2001 NJPDES permit contained several special conditions of its own, including continuation of the wetlands restoration and enhancement, continued monitoring of the fish ladders, improved biological monitoring, further study and analysis of entrainment and impingement, and estimates of restored marsh productivity (NJDEP 2001b).

The Fact Sheet for the 2001 NJPDES permit (NJDEP 2001b) notes that:

> The Department [NJDEP] has determined that the Station's existing once-through cooling system in conjunction with an intake flow limitation, an enhanced fish return system and the study and potential implementation of a multi-sensory hybrid system constitutes best technology available.

The 2001 NJPDES permit contained other special conditions describing information that would be required if PSEG wanted to renew the NJDEP's Section 316(b) determination. In particular, Custom Requirement G.12a.ii states:

> With respect to Section 316(b), the Department's determination shall include, but not be limited to, an evaluation of whether technologies, their costs and benefits, and potential for application at Salem have changed. This shall include, at a minimum, revised outages and seasonal flow reductions (NJDEP 2001b).

In 2006 PSEG submitted an application for renewal of the 2001 NJPDES permit including the Section 316(b) determination. This paragraph summarizes the entrainment discussion included as part of the 2006 NJPDES application. A relatively small number of fish species were predominant in entrainment samples between 2002 and 2004. Most eggs collected were those of the bay anchovy. Bay anchovy eggs made up 98.2, 96.2, and 99.8 percent of all eggs in entrainment samples in 2002, 2003, and 2004 (PSEG 2006a, Section 4). Larvae of three species were numerically dominant: naked goby, bay anchovy, and striped bass. In 2002, naked goby (60.7 percent of larvae collected), bay anchovy (21.7 percent), and striped bass (10.6 percent) ranked first, second, and third in abundance. In 2003, the percent composition of larvae in samples was essentially the same as in 2002, with 64 percent naked goby, 21.4 percent bay anchovy, and 9.2 percent striped bass. In 2004, there were more bay anchovy (47.2 percent) than naked goby (43.0 percent) larvae, with striped bass making up a relatively small percentage (3.4) of the total. Although most organisms in entrainment samples were (planktonic) eggs and larvae, substantial numbers of juveniles and small numbers of adults were also present. Eggs and larvae made up 82, 89, and 94 percent of organisms in entrainment samples in 2002, 2003, and 2004. The species most often entrained as a juvenile was the Atlantic croaker. Atlantic croaker juveniles represented 13.4 percent, 4.7 percent, and 3.6 percent, respectively, of all organisms in entrainment samples in 2002, 2003, and in 2004.

The 2006 renewal application addressed the provisions in Custom Requirement G.12.a.ii of the 2001 permit by presenting the information required by the EPA's Phase II Rule (69 FR 41576, July 9, 2004 [establishing location, design, construction and capacity standards for cooling water intake structures at large power stations]) to support a new Section 316(b) determination by NJDEP. Specifically, PSEG submitted an extensive assessment of alternative intake technologies (AIT) (PSEG 2006a, Section 5). In addition to evaluating the costs and benefits of the revised refueling outage and seasonal flow reduction alternatives, the AIT assessment examined several other fish protection alternatives that might be applicable at Salem, which were selected based on a screening process implemented by Alden Research Laboratory, Inc. The AIT report also calculated net fishery benefits of the wetlands restoration (one of the custom requirements in the 2001 NJPDES permit), and compared existing benefits to estimated benefits that would accrue under alternative intake scenarios. Finally, the AIT report calculated costs and benefits of the wetland restoration; the report concluded that the restoration sites passed a cost-benefit test (PSEG 2006a, Section 5). In fact, an estimated 725,000 kilograms (1.6 million pounds) of striped bass, weakfish, and white perch in 2008 were directly attributed to the enhancement of the salt hay farm (PSEG 2006a, Section 5).

In the AIT assessment completed in 2006, historical entrainment and impingement data were used to populate quantitative predictive models of total pounds of important species lost to the fishery due to entrainment and impingement at Salem (PSEG 2006b). Data were analyzed from 1995 through 2006 for 12 target species. These baseline data were used as the point of comparison for proposed alternative technologies and operating schedules. The AIT study, which calculated differential net benefits to fisheries under multiple alternative scenarios, including cooling towers, concluded that the present system represents BTA with respect to maximizing net benefits to important fisheries resources. Based on the calculations of entrained organisms, restoring the salt hay farms alone, which is 1,619 hectares (4,000 acres) of the 9,094 hectares (20,000-acre) wetland restoration program, provides approximately twice the biomass estimated to be entrained.

To further evaluate the potential impact of Salem on the long-term sustainability of fish stocks, known entrainment and impingement rates at Salem were compared with known effects of fishing on fish populations, using stock jeopardy analyses. For all of the harvested species for which conditional mortality rates are known, the incremental increases in mortality caused by Salem are negligibly small compared to the effects of fishing. In other words, reducing or eliminating entrainment and impingement at Salem would not measurably increase the reproductive potential or spawning stock biomass of any of these species. In summary, field data collected since Salem began operating, and especially since the NJPDES permit renewal application in 1999, show that continued operation of Salem has caused no substantial harm to any fish populations or communities inhabiting the Delaware Estuary (PSEG 2006a, Section 5).

Thus the current NJPDES permit (No. NJ0005622) for Salem, which was issued June 29, 2001 (included as Appendix B to this document) and administratively continued by NJDEP on July 31, 2006, constitutes the current CWA Section 316(b) determination that the intakes are BTA. For this reason, and because of the demonstrated success of the wetland restorations, PSEG concludes that impacts of entrainment on important fish and shellfish at Salem are SMALL and warrant no additional mitigation.

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 can not 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 on fish and shellfish resources resulting from impingement a Category 2 issue because it could not assign a single significance level to the issue. The impact of impingement is small at many plants, but it may be moderate or large at others (NRC 1996b, Section 4.2.2.1.3). Information needing to be ascertained includes: (1) type of cooling system (whether once-through or closed cycle), and (2) status of CWA Section 316(b) determination or equivalent state documentation.

As Section 3.1.1 describes, Salem employs pressurized water reactors with once-through condenser cooling systems. Cooling water is withdrawn from the Delaware Estuary through two separate intake facilities, the CWS intake structure and the SWS intake structure, and returned to the river through a common return (discharge) system (AEC 1973).

Section 316(b) of the CWA requires that any standard established pursuant to Sections 301 or 306 of the CWA shall require that the location, design, construction, and capacity of cooling water intake structures reflect the BTA for minimizing adverse environmental impacts (33 USC 1326). Impingement of fish and shellfish on screens that protect the condenser cooling system is a potential adverse environmental impact that can be minimized by the BTA.

In 1978, EPA recommended a multiyear Section 316(b) study for the Salem CWS and SWS intakes. During the following 5 years, PSEG collected and analyzed data for Salem's 316(b) demonstration in which 40 alternatives to intake design and practices were analyzed to determine the BTA (PSEG 1984). This 5-year study focused on potential impacts to 9 target fish species (PSEG 1984, PSEG 1985). Based on results of the demonstration study at Unit 1, PSEG made design changes to Unit 2 prior to its 1981 start-up to reduce impingement at Unit 2. In 1984, the 316(b) demonstration report was submitted naming the Ristroph traveling screens and fish return system as the BTA.

In 1990, NJDEP issued a draft permit proposing closed-cycle cooling as BTA for Salem, but in 1993 reconsidered the proposal based on new information submitted by PSEG. NJDEP then issued a new draft permit (PSEG 1999a, Appendix A).

In 1994, NJDEP issued a renewed NJPDES permit. NJDEP determined that BTA consisted of the existing cooling water intake structure, in conjunction with the following: (1) modifications to the intake screens and an improved fish bucket design; (2) a restriction on cooling water intake flow rate; and (3) a sound deterrent study. Special conditions were also imposed by the permit, including (1) study and modification of the intake structure, (2) restoration of wetlands to increase fish production, and (3) implementation of a comprehensive bay-wide biological monitoring program. To settle a legal challenge by the State of Delaware and a non-governmental organization, PSEG agreed to additional restoration and mitigation projects, as described in Section 4.2. (NJDEP 1994)

Impingement monitoring to estimate the occurrence and abundance of target species impinged at Salem, and to estimate the initial survival of impinged individuals has been conducted since the station started operating. Most years, Atlantic croaker, weakfish, and white perch are the most common finfish species impinged (PSEG 1995, 1996, 1997; 1998, 1999b, 2000, 2001a, 2002, 2003, 2004a, 2005, 2006b, 2007b).

PSEG applied for renewal of its NJPDES permit in March 1999 (PSEG 1999a). The application included an updated demonstration pursuant to Section 316(b) relative to the Station's CWS and SWS intake structures, and detailed information demonstrating compliance with the special conditions of the 1994 permit (PSEG 1999a, Appendices F and G).

NJDEP reviewed the permit renewal application and, in 2001, issued a new permit acknowledging that the CWS and SWS intake systems represented BTA, and that the special conditions in the 1994 NJPDES permit had been met. The 2001 NJPDES permit contained several special conditions of its own, including continuation of the wetlands restoration and enhancement; continued monitoring of the fish ladders; improved biological monitoring; further study and analysis of entrainment and impingement; and estimates of restored marsh productivity (NJDEP 2001b). The Fact Sheet for the 2001 NJPDES permit (NJDEP 2001b) notes that:

> The Department [NJDEP] has determined that the Station's existing once-through cooling system in conjunction with an intake flow limitation, an enhanced fish return system and the study and potential implementation of a multi-sensory hybrid system constitutes best technology available.

The 2001 NJPDES permit contained other special conditions describing information that would be required as part of any subsequent NJPDES permit renewal application, if PSEG wanted to renew the NJDEP's Section 316(b) determination. In particular, Custom Requirement G.12.a.ii states:

> With respect to Section 316(b), the Department's determination shall include, but not be limited to, an evaluation of whether technologies, their costs and benefits, and potential for application at Salem have changed. This shall include, at a minimum, revised outages and seasonal flow reductions (NJDEP 2001b).

Over the years, PSEG has incorporated a number of modifications at Salem designed to minimize impingement. In 1979, Unit 1's screen assembly was modified to incorporate Ristroph vertical traveling screens with the capability for continuous operation and fish handling. In 1995, additional alterations to the traveling screen system were made to improve performance and reliability and to increase the survival rates for impinged fish. These new traveling water screens are a modified Ristroph design. PSEG has extensively upgraded the screens to improve fish survival. In addition, the Ristroph screens incorporate water-filled fish lifting buckets and low-pressure fish removal sprays, and the screens are continuously rotated to minimize the duration of impingement. A bi-directional fish return system with separate fish and debris troughs is also installed at the units. (NJDEP 2001b)

In 2006 PSEG submitted an application for renewal of the 2001 NJPDES permit, including the Section 316(b) determination. The following paragraphs summarize the impingement information provided in the 2006 application.

The Comprehensive Demonstration Study (CDS; PSEG 2006a, Section 4) that PSEG submitted in 2006 as part of the NJPDES renewal application for Salem summarizes impingement monitoring at Salem over a recent three-year period (2002-2004). In 2002, two-thirds (66.5 percent) of all finfish in impingement samples were Atlantic croaker (PSEG 2006a, Section 4). Smaller numbers of spotted hake (11.9 percent), white perch (7.4 percent), hogchoker (3.1 percent), and weakfish (3.0 percent) appeared in samples. Two species, white perch (59.3 percent) and weakfish (17.8 percent), were numerically dominant in 2003. Striped bass (5.4 percent), hogchoker (3.4 percent), and Atlantic croaker (3.4 percent) also appeared regularly in impingement samples. In 2004, impingement samples were dominated by three species: white perch (48.8 percent), weakfish (16.7 percent), and Atlantic croaker (14.5 percent). Smaller numbers of spotted hake (3.7 percent) and blueback herring (3.6 percent) were also present.

In 2002, a year in which ages of impinged fish were noted, the vast majority of fish were Age 0 (young of the year) (PSEG 2002). For example, 100 percent of (3,047) weakfish and 100 percent of (139) bluefish in impingement samples were young of the year. Atlantic croaker in impingement samples were “predominantly” young of the year, as were striped bass.

In addition to age, PSEG biologists noted the condition of all fish washed from traveling screens and into holding pools. In 2002, 95 percent of Atlantic croaker (N=67,300), 97 percent of white perch (N=7,534), 98 percent of weakfish (N=3,047), 81 percent of Atlantic menhaden (N=1,566), and 81 percent of bay anchovy (N=1,305) were categorized as “live,” meaning they were behaving normally and were apparently unharmed (PSEG 2002). These fish would most likely survive being returned to the Estuary via the fish return system rather than diverted to the holding pools for observation. In 2003, 97 percent of white perch (N=31,131), 94 percent of weakfish (N=9,328), 97 percent of striped bass (N=2,811), and 84 percent of bay anchovy (N=1,573) were alive (PSEG 2003). In 2004, survival rates were somewhat lower. Approximately 75 percent of white perch (N=30,251), 85 percent of weakfish (N=10,389), 96 percent of Atlantic croaker (N=8,972), and 92 percent of blueback herring (N=2,241) in impingement samples were alive (PSEG 2004a). As a general rule, survival rates of recreationally important species (e.g., weakfish, striped bass, and white perch) were higher than survival rates of small, schooling fish species such as Atlantic menhaden and bay anchovy.

The 2006 renewal application addressed the provisions in Custom Requirement G.12.a.ii of the 2001 permit by presenting the information required by the EPA’s Phase II Rule (69 FR 41576; July 9, 2004 [establishing location, design, construction and capacity standards for cooling water intake structures at large power stations]) to support a renewed Section 316(b) determination by the NJDEP. Specifically, PSEG submitted an extensive assessment of AIT (PSEG 2006a, Section 5). In addition to evaluating the costs and benefits of the revised refueling outage and seasonal flow reduction alternatives, the AIT assessment examined several other fish protection alternatives that might be applicable at Salem, which were selected based on a screening process implemented by Alden Research Laboratory, Inc. (PSEG 2006a, Section 5).

In the AIT evaluation entrainment and impingement data were used to populate quantitative predictive models of total pounds of important species lost to the fishery due to entrainment and impingement at Salem (PSEG 2006a, Section 5). Data were analyzed from 1995 through 2004 for 12 target species. Losses due to entrainment and impingement combined were highly variable from year to year. All of the target species are represented in impingement samples to some extent, although for some species, such as spot and bluefish, the numbers are generally low. Commonly impinged species include Atlantic croaker, weakfish, and white perch (PSEG 1995, 1996, 1997, 1998, 1999b, 2000, 2000a, 2002, 2003, 2004a, 2005, 2006b, 2007b).

The 2006 AIT study, which calculated differential net benefits to fisheries under multiple alternative scenarios, including cooling towers, concluded that the present system represents BTA with respect to maximizing net benefits to important fisheries resources (PSEG 2006a, Section 5). To further evaluate the potential impact of Salem on the long-term sustainability of fish stocks, known entrainment and impingement rates at Salem were compared with known effects of fishing on fish populations, using stock jeopardy analyses. For all of the harvested species for which conditional mortality rates are known, the incremental increases in mortality caused by Salem are negligibly small compared to the effects of fishing. In other words, reducing or eliminating entrainment and impingement at Salem would not measurably increase the reproductive potential or spawning stock biomass of any of these species. In summary, field data collected since Salem began operating, and especially since the NJPDES permit renewal application was filed in 1999, show that continued operation of Salem has caused no substantial harm to any fish populations or communities inhabiting the Delaware Estuary (PSEG 2006a, Section 5).

Thus the current NJPDES permit (No. NJ0005622) for Salem, which was issued June 29, 2001 (included as Appendix B of this document) and administratively continued by NJDEP on July 31 2006, constitutes the current CWA Section 316(b) determination that the intakes are BTA. For this reason, and because of the demonstrated success of the wetland restorations, PSEG concludes that impacts of impingement on important fish and shellfish at Salem are SMALL and warrant no additional mitigation.

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 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 on fish and shellfish resources resulting from heat shock a Category 2 issue, because of continuing concerns about thermal discharge effects and the possible need to modify thermal discharges in the future in response to changing environmental conditions (NRC 1996b). Information to be ascertained includes: (1) type of cooling system (whether once-through or cooling tower), and (2) evidence of a CWA Section 316(a) variance or equivalent state documentation.

As Section 3.1.1 describes, Salem employs pressurized water reactors with once-through condenser cooling systems. Cooling water is withdrawn from the Delaware Estuary through two separate intake facilities, the CWS intake structure and the SWS intake structure, and returned to the river through a common return (discharge) system (AEC 1973; PSEG 2006a, Section 5). Effluent heat and temperature are limited and monitored, but the low effluent temperature and high flow rate of the Delaware Estuary preclude heat shock and cold shock.

Section 316(a) of the CWA establishes a process whereby a thermal effluent discharger can demonstrate that thermal discharge limitations are more stringent than necessary to assure the protection and propagation of balanced, indigenous populations of fish and wildlife in and on the receiving waters and can obtain facility-specific thermal discharge limits (33 USC 1326). PSEG submitted a comprehensive 316(a) study in 1974, filed three supplements through 1979, and provided review and analysis of the study in 1991 and 1993, and, at that time, requested facility-specific thermal discharge limits for Salem, as allowed under Section 316(a). The NJDEP granted the variance request in the NJPDES permit issued on July 24, 1994, which contained thermal limits that would allow the continued operation of the existing once-through cooling system. NJDEP noted that the adverse impacts from the thermal discharges were small and localized (NJDEP 1994). PSEG subsequently provided comprehensive 316(a) studies in the 1999 and 2006 NJPDES Permit renewal applications. NJDEP reissued the Section 316(a) variance in the 2001 NJPDES Permit (NJDEP 2001b).

The fact sheet for the draft of the 1994 NJPDES permit (NJDEP 2001b) stated that thermal discharges from Salem, which do not exceed a maximum of 46.1°C (115°F), are expected to ensure the protection and propagation of the balanced indigenous populations. The total thermal discharge for the facility is limited to 30,600 million BTU per hour as a monthly average. In the 1994 permit, NJDEP also required PSEG to perform comprehensive monitoring of Salem's thermal plume and prepare an updated assessment of its biological effects.

In 1999 PSEG submitted a comprehensive 316(a) demonstration to satisfy all decision criteria for a Type III demonstration, as described in the EPA's 1977 Draft *Interagency 316(a) Technical Guidance Manual and Guide for Thermal Effects Sections of Nuclear Facilities Environmental Impact Statements*. The demonstration included an extensive hydrothermal analysis of Salem's thermal plume to characterize potential thermal exposures of organisms in the river, a predictive biothermal analysis using all available data on thermal requirements of aquatic species designated as representative and important (RIS), and a retrospective analysis of population abundance of RIS in the river from pre-operation to the time of the demonstration. It included a description of hydrothermal monitoring programs, a discussion of prior characterizations of the Salem thermal plume, a description of the hydrothermal modeling methods, and the results of those modeling efforts. The biothermal assessment included the following components: a history of past biothermal assessments of Salem's plume; a discussion of biothermal assessment methodology; a discussion of temperature-related factors affecting aquatic communities; and a discussion of the assessment approach, including decision criteria based on EPA draft guidance. It also discussed the continuing applicability of Salem's prior Section 316(a) variance to the thermal discharge and the nature of the aquatic community, the application of current best scientific methods for impact assessment, and the latest knowledge about biothermal effects of Salem's discharge. The biothermal assessment concludes that the thermal plume is protective of a balanced, indigenous population or community of the Delaware River. Furthermore, Salem's discharge does not result in excessive heat shock, growth of nuisance organisms, impairment of zones of passage or reproduction, adverse impact on threatened or endangered species, or destruction of unique habitat. The extensive additional evidence developed for this demonstration showed that the premises underlying the 1994 NJDEP determination to grant a 316(a) variance for Salem were essentially unchanged. (PSEG 1999a)

In the fact sheet accompanying the draft 2001 permit, NJDEP concurred with PSEG's Type III demonstration that Salem operations and the resulting thermal plume have not significantly changed since the onset of operations. NJDEP characterized the plume as a very small area of more elevated temperatures in the immediate vicinity of the discharge that cools rapidly as the discharge surfaces and spreads, and a larger area of mildly elevated temperatures (NJDEP 2000). Population trends of most important species appear to be increasing in the area. High velocities associated with the zone of initial mixing make it unlikely that target species could reside in this area of biological significance for very long. Based on a review of the data and modeling pertaining to the thermal plume and the biothermal assessment, in 2001 NJDEP renewed the variance under Section 316(a) in Salem's NJPDES permit.

Since the 2001 permit was issued, PSEG has conducted additional biothermal monitoring. There have been no changes in the nature of the thermal discharge, the nature of the aquatic community, or the scientific methods or technical knowledge of thermal stresses that would materially alter the conclusions of the 1999 hydrothermal and biothermal assessments (PSEG 2006a, Section 3). Careful evaluation of the NJDEP's considerations for granting a Section 316(a) variance renewal indicates that the conclusions of the 1999 Section 316(a) demonstration remain valid (PSEG 2006a, Section 4).

The findings of the 2006 evaluation, the margins of safety included in forming the conclusions of the 1999 Section 316(a) demonstration, and the direct evidence from field monitoring that a balanced indigenous community is present after more than 25 years of Salem's operation conclusively demonstrate that Salem's thermal discharge meets all of the established criteria for granting a Section 316(a) variance, including those provided by NJDEP in the 2001 Salem Permit (PSEG 2006a, Section 3).

Based on the fact that PSEG was granted a thermal variance for Salem in accordance with Section 316(a) of the Clean Water Act in 1994 and this variance remains a part of the current NJPDES permit, issued to PSEG in 2001 (see Appendix B), PSEG concludes that impacts to fish and shellfish from heat shock at Salem are SMALL and warrant no additional mitigation.

4.5 Ground-Water Use Conflicts (Plants Using >100 gpm of Ground Water)

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 ground-water use conflicts a Category 2 issue because, at a withdrawal rate of more than 100 gpm, a cone of depression could extend offsite which could deplete the ground-water supply available to offsite users, an impact that could warrant mitigation. Information to be ascertained includes: (1) Salem ground-water withdrawal rate (whether greater than 100 gpm), (2) drawdown at offsite locations, and (3) impact on neighboring wells.

Based on information presented in Section 3.1.4, Salem used average rates of 640 to 1,007 liters per minute (169 to 266 gpm) of ground water from the four facility wells from 2002 through 2008 to supply domestic/potable, industrial, and fire protection water. Therefore, the issue of ground-water use conflicts does apply at Salem because withdrawal rates exceed 100 gpm.

As discussed in Section 3.1.4, the two primary Salem ground-water production wells (PW-5 and PW-6) are installed in the Upper Raritan and Middle Raritan Formation of the Potomac-Raritan-Magothy Aquifer, respectively. The two HCGS ground-water production wells (HC-1 and HC-2) are installed in the Upper Raritan Formation of the Potomac-Raritan-Magothy Aquifer. Table 3.1-1 presents ground-water withdrawals for production wells at Salem during 2002 through 2008. Table 3.1-3 presents water level elevation data for production wells at Salem during 2000 to 2008.

Ground-water use in the Upper Raritan Formation has not been adversely impacted by Salem withdrawals because, as Section 2.3 indicates, there are no off-site wells within 1.6 km (1 mi) of the Salem site. Also, the nearest potable supply well is located more than 5.6 km (3.5 mi) from the site, across the Delaware River. PSEG utilizes less than half of the allocation authorized by DRBC and NJDEP for both Salem and HCGS. PSEG further concludes that impacts from the use of ground water at the current rates would be SMALL and would not warrant mitigation.

4.6 Ground-Water 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 ground-water use conflict a Category 2 issue because consumptive use of water withdrawn from small rivers could adversely impact aquatic life, downstream users, and ground-water-aquifer recharge. This is a particular concern during low-flow conditions and could create an adverse cumulative impact if there were additional large consumptive users withdrawing water from the same river. Cooling towers and cooling ponds lose water through evaporation, which is necessary to cool the heated water before it is discharged to the environment.

NRC has determined that Salem does not use cooling towers and that surface water withdrawals and discharges are from and to an estuary (NRC 1996b; Table 5.13). Therefore, this issue does not apply because Salem does not use cooling towers and does not withdraw water from a small river.

4.7 Ground-Water 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 ground-water use conflict a Category 2 issue because large quantities of ground water withdrawn from Ranney wells could degrade ground-water quality at river sites by induced infiltration of poor-quality river water into an aquifer.

NRC has determined that Salem surface water withdrawals and discharges are from and to an estuary (NRC 1996b; Table 5.13). As Section 3.1 describes, Salem withdraws its cooling water and service water from surface water. Ground water is only withdrawn for potable and other uses. Therefore, this issue does not apply because Salem does not use Ranney wells.

4.8 Degradation of Ground-Water 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 ground-water 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 ground-water quality.

Salem is not at an inland site and does not use cooling ponds. Therefore, this issue does not apply.

4.9 Impacts of Refurbishment on Terrestrial Resources

NRC

The environmental report must contain an assessment of "…the impact 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 resource 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 1996b, Section 3.6, pg. 3-6)

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 1996b). 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.

As Section 3.2 describes, PSEG has no plans for refurbishment activities at Salem. Therefore, this issue does not apply.

4.10 Threatened or 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 site-specific assessment is required to determine whether any identified species could be affected by refurbishment activities or continued station operations through the renewal period. In addition, compliance with the Endangered Species Act requires consultation with the appropriate federal agency (NRC 1996b).

Section 2.2 of this Environmental Report describes the aquatic communities of the Delaware Estuary in the vicinity of Salem. Section 2.4 describes important terrestrial habitats at Salem and along the associated transmission corridors (Salem-New Freedom North, Salem-Keeney, and Salem-New Freedom South). Section 2.5 discusses threatened or endangered species that occur or may occur in the vicinity of Salem and along associated transmission corridors.

As discussed in Section 3.2, no refurbishment activities at Salem are planned during the license renewal term and thus no further analysis of refurbishment-related impacts is applicable.

With the exception of the species identified in Section 2.5, PSEG is not aware of any species that are listed as threatened or endangered, or have been nominated for listing, that could occur at Salem or along its associated transmission corridors. Except for the potential impacts to aquatic species described below, current operations of Salem are not believed to affect any listed terrestrial or aquatic species or their habitats. Similarly, PSE&G or PHI vegetation management practices along the transmission corridors are developed and implemented in conjunction with appropriate regulatory agencies to minimize potential impacts on threatened or endangered species. 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 terrestrial or aquatic species from current or future operations beyond those previously identified are anticipated.

Three listed sea turtle species and the shortnose sturgeon have been incidentally captured at Salem since Salem began operating. In 1993, the National Marine Fisheries Service (NMFS) issued a biological opinion and incidental take statement that determined that the continued operation of Salem and HCGS would not jeopardize threatened or endangered species, including sea turtles and shortnose sturgeon (NMFS 1993). The 1993 incidental take statement was reviewed and revised in 1999 (NMFS 1999a). NRC incorporated the requirements of the incidental take statements into Appendix B of the Salem Technical Specifications.

Furthermore, station operations and transmission line maintenance practices are not expected to change significantly during the license renewal terms. Therefore, no adverse impacts to threatened or endangered terrestrial or aquatic species from current or future operations beyond those previously identified are anticipated. Since 1999 two dead loggerhead sea turtles have been collected at the Salem CWS intake and one live loggerhead turtle was found in the Delaware estuary near Stow Creek.

One plant species federally listed as threatened is known from one transmission corridor associated with Salem. Also, one reptile federally listed as threatened and state listed as endangered, and one amphibian state listed as endangered occur in the vicinity of the transmission lines associated with Salem (see Section 2.5). PSE&G works cooperatively with the Pinelands Commission to ensure that best management maintenance practices for the protection of these species are implemented, including limiting maintenance and vegetation control during specific times of the year.

PSEG has initiated contacts with the NJDEP, Delaware Department of Natural Resources and Environmental Control, USFWS, and NMFS requesting information on any listed species or critical habitats that might occur on the Salem site or along the associated transmission corridors, with particular emphasis on species that might be adversely affected by continued operation over the license extension term. All species and habitats identified have been considered. Contact letters and responses received are provided in Appendix C.

Renewal of the Salem licenses is not expected to jeopardize the continued existence of any threatened or endangered species or result in the destruction or adverse modification of any critical habitat. Because current operational practices that could affect the environment will not be modified by license renewal, PSEG concludes that impacts to threatened or endangered species from license renewal would be SMALL and do not warrant additional mitigation.

4.11 Air Quality During Refurbishment (Non-Attainment or Maintenance 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 at each site and the number of workers expected to be employed during an outage (NRC 1996b). Information needed would include: (1) the attainment status of the area, and (2) the number of additional vehicles as a result of refurbishment activities.

As Section 3.2 describes, PSEG has no plans for refurbishment activities at Salem. Therefore, this issue does not apply.

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 flowrate 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

NRC designated impacts to public health from thermophilic organisms a Category 2 issue, requiring plant-specific analysis, because the magnitude of the potential public health impacts associated with thermal enhancement of such organisms, particularly *Naegleria fowleri*, could not be determined generically. NRC noted in the GEIS that impacts of nuclear power plant cooling towers and thermal discharges are considered to be of small significance if they do not enhance the presence of microorganisms that are detrimental to water quality and public health (NRC 1996b).

NRC requires [10 CFR 51.53(c)(3)(ii)(G)] an assessment of the potential impact of thermophilic organisms in receiving waters on public health if a nuclear power plant uses cooling ponds, cooling lakes, or cooling canals or discharges to a river with an average annual flow rate less than 9×10^{10} cubic meters per year (3.15×10^{12} cubic feet per year).

NRC has determined that Salem discharges to an estuary (NRC 1996b; Table 5.13). As discussed in Section 3.1.2, the Salem units have open-cycle circulating water systems for condenser cooling. As described in Section 3.1.3, Salem withdraws surface water from an estuary for condenser cooling and discharges to the same estuary. Salem does not use cooling ponds, cooling lakes, cooling canals, or discharge to a small river. Therefore, this issue does not apply.

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 currents…" 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, 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) criteria (IEEE 2006), NRC could not determine the significance of the electric shock potential. This section provides an analysis of the Salem transmission lines' conformance to the NESC standard.

Production of Induced Currents

Objects located near transmission lines can become electrically charged due to their immersion in the lines' electric fields. 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, the NESC adopted a provision that describes how to establish minimum vertical clearances to the ground for electric lines having voltages exceeding 98-kilovolt alternating current to ground. The clearance must limit the induced current 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.

Salem Transmission Lines

As described in Section 3.1.6, there were three 500-kilovolt lines that were constructed to connect Salem to the transmission system. These lines are the following:

- Salem-New Freedom South
- Salem-New Freedom North (subsequently rearranged to connect HCGS to the transmission system)
- Salem-Keeney (via Red Lion substation) (subsequently rearranged to connect HCGS to the transmission system)

In addition, the transmission line rearrangements that occurred as a result of HCGS construction necessitated building one more 500-kilovolt transmission line connected to Salem, HCGS-New Freedom. For the purpose of license renewal, the HCGS-New Freedom line is treated as being constructed to connect HCGS to the transmission system. Hence, it is not part of this report's scope of analysis. Even so, results from the analysis in the HCGS license renewal Environmental Report (PSEG 2009b) are provided in Table 4.13-1:

- HCGS-New Freedom (via Orchard substation)

Induced Current Analysis

This analysis of the Salem transmission lines is based on computer modeling of induced current under the line. The initial step of the analysis was identification of the line/road crossings to be analyzed. Only paved roads and highways were considered in the analysis; minor roads, i.e., "dirt" or service road crossings, were not included. The electric field strength and subsequently the induced current were then calculated for the transmission line at each location.

The electric field strength and induced current were calculated using the computer code ACDCLINE, produced by the Electric Power Research Institute. The results of this analysis have been field-verified through actual electric field measurements by several utilities. The input parameters included design features of the limiting-case scenario and were taken from plan-and-profile drawings for each line. NESC requires that line sag measurements be determined at a minimum conductor temperature of 49°C (120°F). For analysis purposes, the maximum vehicle size under the lines is considered to be a tractor-trailer of 2.6 m (8.5 ft) wide, 3.7 m (12 ft) average height, and 20 m (65 ft) long.

Analysis Results

The induced current calculated at a conductor temperature of 49°C (120°F) resulted in a maximum current of 4.2 milliamperes (on Salem-New Freedom South line) (Table 4.13-1).

PSE&G and PHI, operators of the transmission lines, conduct regular aerial and ground surveillance, and maintenance to ensure that design ground clearances do not change. The aerial patrols of all corridors include checks for encroachments, broken conductors, broken or leaning structures, and signs of burnt trees, any of which would be evidence of clearance problems. Ground inspections include examination for clearance at questionable locations, examination of integrity of structures, and surveillance for dead or diseased trees that might fall on the transmission line. Problems noted during any inspection are brought to the attention of the appropriate organizations for corrective action.

PSEG concludes that electric shock is of SMALL significance for the Salem transmission lines because the NESC standard is not exceeded at any location.

Table 4.13-1 Maximum Induced Current from Salem and HCGS Transmission Lines

Line Name	Maximum induced current (milliamperes)
Salem-New Freedom South	4.2
Salem-New Freedom North	4.1
Salem to Red Lion segment of Salem-Keeney	2.2
Red Lion to Keeney segment of Salem-Keeney	2.7
HCGS-New Freedom (via Orchard)	4.0

HCGS-New Freedom was not constructed to connect Salem to the grid and is therefore not analyzed in this environmental report. It is analyzed in the HCGS License Renewal Environmental Report (PSEG 2009b).

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 1996b, Section 4.7.1.1, pg. 4-101)**

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 1996b). Local conditions that need to be ascertained are: (1) population categorization as small, medium, or high and (2) applicability of growth control measures.

Refurbishment activities and continued operations could result in housing impacts as a result of increased staffing. As described in Section 3.2, PSEG has no plans for refurbishment therefore, no refurbishment-related increase in staff will occur and no refurbishment-related impacts to area housing will occur.

The following discussion focuses on impacts of continued operations on local housing availability and the assumption that PSEG would need to add up to 60 additional employees to support both Salem units during the period of extended operations.

In 10 CFR 51, Subpart A, Appendix B, Table B-1, NRC concluded that impacts to housing are expected to be of small significance at stations located in high population areas where growth control measures are not in effect.

The maximum impact to area housing was calculated using the following assumptions: (1) all direct jobs would be filled by in-migrating residents and any indirect jobs created by 60 additional employees would be filled by people already residing within the 80- km (50-mi) radius; (2) the residential distribution of new residents would be similar to current operations worker distribution; and (3) each new direct job created would represent one housing unit. PSEG's estimate of 60 license renewal employees (Section 3.4) could generate the demand for 60 housing units.

As described in Section 2.6.1, Salem is located in a high population area and 83 percent of the operations workforce lives in Salem, Cumberland or Gloucester counties (in New Jersey) or

New Castle County (in Delaware). Salem County, which receives the tax revenues from Salem Nuclear Generating Station, is not subject to growth control measures that limit housing development (Rukenstein and Associates 2004). Gloucester, Cumberland, and New Castle counties also are not subject to growth control measures (Gloucester County 2007, Orth-Rogers 2002, New Castle County 2007). The area within an 80-km (50-mi) radius of Salem has a population of approximately 5,201,842 people. Delaware averages 2.54 persons per household. Maryland averages 2.61, New Jersey averages 2.68, and Pennsylvania averages 2.48 persons per household (USCB 2000b), suggesting the existence of approximately 2 million housing units in the 80-km (50-mi) radius. It is reasonable to conclude that 60 additional employees at Salem would not create a discernible change in housing availability, rental rates, or housing values, or spur housing construction or conversion. PSEG concludes that impacts to housing availability resulting from station-related population growth would be SMALL and would not warrant mitigation.

4.15 Public Water Supply

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 1996b, Section 3.7.4.5, pg. 3-19 as referenced by Section 4.7.3)**

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 station demand and station-related population growth (NRC 1996b). Local information needed would include: (1) a description of water shortages experienced in the area, and (2) an assessment of the public water supply system's available capacity.

NRC's analysis of impacts to the public water supply system considered both station demand and station-related population growth demands on local water resources. As stated in Section 2.3, the station does not use water from an offsite public water system, there are no offsite wells within 1.6 km (1 mi) of the site, and the nearest potable supply well is more than 5.6 km (3.5 mi) from the site. Therefore, there would be no station demand-related impacts to the public water supply or private potable water wells. As discussed in Section 3.2, PSEG plans no refurbishment activities for Salem. Therefore, there would be no refurbishment-related impacts on local public water supplies.

The following discussion focuses on impacts of the increased demand on local public water supplies from 60 additional employees needed to support operations at Salem during the period of extended operation. As Section 3.4 indicates, PSEG analyzed a hypothetical 60-person increase in Salem employment attributable to license renewal. Section 2.6 describes the Salem regional demography. Section 2.9 describes the public water supply systems in the area, their permitted capacities, and current demands.

The maximum impact to local public water supply systems was assessed using the following assumptions: (1) all 60 direct jobs would be filled by in-migrating residents; (2) no indirect jobs would be filled by in-migrating residents, and (3) the residential distribution of the workers would resemble that of the current operations workforce. Impacts were determined by estimating the amount of water that would be required by the 60 new Salem employees and their families, which is 54,850 liters per day (14,490 gallons per day [gpd]). This estimate was calculated by:

- Multiplying the estimated number of new jobs during the period of continued operation (60) by the average number of persons per household in New Jersey (2.68) (USCB 2000b) to determine the increase in population caused by license renewal (161 persons); and

- Multiplying the increase in population (161 persons) by the average American's daily water consumption for personal use (341 liters per day [90 gpd]) (EPA 2003).

It was then assumed that the resulting estimated license-renewal related water demand of 54,850 liters per day (14,490 gpd) or (161 persons x 341 liters per day [90 gpd] per person) would be geographically distributed, in the same manner as the existing Salem work force. That is, the increased demand would be imposed primarily on public water supply systems located in Salem, Gloucester, and Cumberland counties (in New Jersey) and New Castle County (in Delaware). These counties currently have excess public water supply capacity of approximately 129 million liters (34 million gallons) per day for Cumberland, Gloucester, and Salem counties (see Table 2.9-1) and more than 132 million liters (35 million gallons) per day for New Castle County (see Table 2.9-2). Any increase in water demand resulting from renewal of the Salem operating licenses would not create shortages in capacity for the existing public water supply systems. PSEG concludes that impacts resulting from station-related population growth to public water supply systems would be SMALL, requiring no additional capacity and warranting no mitigation.

4.16 Education Impacts from Refurbishment

NRC

The environmental report must contain "…[a]n 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, 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 generally associated with 4 to 8 percent increases in enrollment. Impacts are considered moderate 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 project-related enrollment increases above 8 percent…." (NRC 1996b, Section 3.7.4.1, pg. 3-15)

NRC made refurbishment-related impacts to education a Category 2 issue because site- and project-specific factors determine the significance of impacts (NRC 1996b). Local factors to be ascertained include (1) project-related enrollment increases and (2) status of the student/teacher ratio.

As Section 3.2 describes, PSEG has no plans for refurbishment activities at Salem. Therefore, this issue does not apply.

4.17 Offsite Land Use

4.17.1 OFFSITE LAND USE - REFURBISHMENT

NRC

> **The environmental report must contain "…[a]n 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)**
>
> **"…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 1996b)**

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 (1) plant-related population growth, (2) patterns of residential and commercial development, and (3) proximity to an urban area with a population of at least 100,000.

As Section 3.2 describes, PSEG has no plans for refurbishment activities at Salem. Therefore, this issue does not apply.

4.17.2 OFFSITE LAND USE - LICENSE RENEWAL TERM

NRC

> **The environmental report must contain "…[a]n assessment of the impact of the proposed action on…land-use…." 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 1996b, Section 3.7.5, pg. 3-21)**
>
> **"…[I]f the plant's tax payments are projected to be small relative to the community's total revenue, new tax-driven land-use changes during the plant's license renewal term would be small, especially where the community has preestablished patterns of development and has provided adequate public services to support and guide development." (NRC 1996b, Section 4.7.4.1, pg. 4-108)**

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 1996b). Site-specific factors to consider in an assessment of land-use impacts include: (1) the size of plant-related population growth compared to the area's total population, (2) the size of the plant's tax payments relative to the community's total revenue, (3) the nature of the community's existing land-use pattern, and (4) 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 1996b).

<u>Population-Related Impacts</u>

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 resulting from the initial population growth that occurred at the start of operations (NRC 1996b).

<u>Tax-Revenue-Related Impacts</u>

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.

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 1996b).

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

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.

NRC further determined that, "…[I]f the plant's tax payments are projected to be medium to large relative to the community's total revenue, new tax-driven land-use changes would be moderate. This is most likely to be true where the community has no pre-established patterns of development (i.e., land use plans or controls) or has not provided adequate public services to support and guide development in the past, especially infrastructure that would allow industrial development (NRC 1996b).

Tax Impacts

Table 2.7-1 provides a comparison of the 2003 to 2007 tax payments made by PSEG to Lower Alloways Creek Township for Salem Nuclear Generating Station and to the City of Salem for the Energy and Environmental Resource Center. Because PSEG's property tax payments to Lower Alloways Creek Township is so substantial (approximately 20 percent of the total property taxes collected), the residents of Lower Alloways Creek Township are relieved of local municipal, school, and optional open space municipal taxes. Therefore, the significance of PSEG's property tax payments to Lower Alloways Creek Township is MODERATE to LARGE. However, while PSEG's property taxes are a large portion of Lower Alloways Creek Township taxes, the town forwards all of its tax revenues to Salem County in return for services Salem County provides to the township. PSEG's property tax payments are of SMALL significance for Salem County (less than 10 percent) and the City of Salem (less than 10 percent).

Land Use Impacts

As described in Section 2.6, Salem County has experienced an annual population growth rate of less than 1 percent for the last 30 years. Salem County has a recently updated comprehensive plan which recognizes the value of open space, and continues to identify the goals of directing infrastructure development and planning to support smart growth, providing housing for all residents, and developing economic engines to ensure continued growth (Runkenstein and Associates 2004). Because no new construction activities would occur as a result of license renewal, there would be no change in Salem's tax basis and, consequently, no changes to land use based on renewal of the two Salem licenses.

From 1990 to 2000, the population in Lower Alloways Creek Township remained almost constant. As described in Section 2.8, there has been little change in the township's land-use patterns since the last Master Plan review in 1999. With no new construction activities planned as a result of license renewal, there would be no change in Lower Alloways Creek's tax basis, and consequently, no changes to land use based on renewal of the license.

The City of Salem has experienced a significant decline in population over the past several decades (Salem Main Street 2003). There is room for growth, however, PSEG's property tax payment is only a small portion of the City of Salem's total property tax revenues. With no new construction activities planned as a result of license renewal, there would be no change in Salem's tax basis, and consequently, no changes to land use based on renewal of the license.

Conclusion

As described in Section 3.2, PSEG has no plans for refurbishment activities at Salem. Therefore, PSEG anticipates neither an increase in the assessed value of Salem Nuclear Generating Station due to refurbishment-related improvements, or any related tax-increase-driven changes to offsite land-use and development patterns. The Salem Nuclear Generating Station property tax payments are of LARGE significance to Lower Alloways Creek Township residents because they eliminate the need for most other taxes, but the magnitude of the tax revenues from Salem Nuclear Generating Station has not affected land-use patterns. The Salem Nuclear Generating Station's property tax payments are of SMALL significance to Salem County, which provides services to Lower Alloways Creek Township, and land-use changes in the county have been minimal. PSEG's property tax payments to the City of Salem for the Energy and Environmental Resource Center are of SMALL significance and land-use changes in the city have been minimal. Hence, PSEG concludes that the impacts of license renewal for the Salem units on both tax revenue and land use in Salem County would be SMALL.

<u>Property Values</u>

The City of Salem has experienced significant decline in population over the past several decades (Salem Main Street 2003). There is room for growth; however, PSEG's property tax is only a small portion of the City of Salem and Salem County's total property tax revenues. With no new construction activities as a result of license renewal, there would be no change in the tax basis, and consequently, no changes to land use based on renewal of the license.

PSEG considered whether the presence of Salem has a depressing effect on property values that would be continued during the license renewal term. NRC considered this question for seven nuclear plants in its GEIS and found no depressed property values resulting from construction and operation or license renewal of these plants (NRC 1996b). Published literature on the subject comes to varying conclusions. Of the studies claiming to show a depressing effect, the geographic extent of the claimed effect ranges from less than 3.2 km (2 mi) to as many as 96.5 km (60 mi; Blomquist 1974, Clark and Nieves 1994, Folland and Hough 2000, Sheppard 2007). Some studies demonstrate no effects (Gamble and Downing 1982, Nelson 1981, Rephann undated). The Nuclear Energy Institute (NEI) has studied economic benefits of several nuclear plants, including Salem (NEI 2006a), and found that property (housing) values are enhanced by the presence of nuclear plants, a conclusion that aligns with NRC 1996b and other studies (Bezdek and Wendling 2006; Clark et al. 1997; Farrell and Hall 2004; Metz et al. 1997; NEI 2003, NEI 2004a NEI 2004b, NEI 2004c, NEI 2004d, NEI 2005a, NEI 2005b, and NEI 2006b).

Sheppard (2007), which concludes that property values are depressed within 3.2 km (2 mi) of a nuclear plant, is based on the Blomquist (1974) study of a single fossil-fueled plant located in a residential area. Blomquist (1974) noted that "[T]he findings of this study are based on a rather special instance…where the community is composed of primarily single-family residences…." The Blomquist proposition does not apply to Salem because there are no residential properties within 3.2 km (2 mi) of Salem. The area within 3.2 km (2 mi) of the Salem site is water

(Delaware River), dredged spoil disposal sites (owned by the U. S. government), and open space (marsh; owned by the U.S. government and State of New Jersey). Hence, given the ownership and New Jersey wetlands protection requirements, further development of these offsite areas for residential use is unlikely.

PSEG also notes that the plant that Blomquist (1974) studied was small, about 27 megawatts, burned oil and coal, and began commercial operation in 1949 (EIA 1996). The workforce at such a facility would likely be much smaller than one at a large nuclear plant such as Salem. Accordingly, the multiplier effect of the Salem workforce would be larger for tax contributions than the comparable multiplier effect for a 27-MW fossil-fueled facility. This could demonstrably increase, rather than decrease, property values. For this reason, PSEG believes the Blomquist (1974) methodology should not be applied to evaluate impacts of nuclear plants such as Salem, on property values as was done in Sheppard (2007).

Conclusion

Because the Sheppard (2007) assumptions do not apply to Salem, PSEG concludes, consistent with the GEIS (NRC 1996b), NEI (2006a), and the other studies cited above, that impacts on property values from Salem, if any, are positive, and that license renewal would not alter this status.

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 1996b, Section 3.7.4.2, pg. 3-18)**

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 1996b). Local road conditions to be ascertained are: (1) level of service conditions and (2) 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 anticipated. Accordingly, the following discussion focuses on impacts of continued operations on transportation and the assumption that Salem would add 60 additional employees during the period of extended operations. PSEG's Salem workforce includes 665 employees and shares up to an additional 270 PSEG corporate and 86 matrixed employees with HCGS. On an 18-month cycle, as many as 600 additional workers join the permanent workforce during a refueling outage, which typically lasts about 23 days. PSEG's projection of 60 additional employees associated with license renewal for Salem represents a 9 percent increase above the 665 regular, full time employees assigned to Salem; a smaller percentage of the total employees of Salem and HCGS, including corporate and matrixed employees; and an even smaller percent of the total number of commuters accessing the site during a refueling outage.

Given these employment projections and the average number of vehicles per day currently using the roads in the vicinity of Salem (Table 2.9-3), PSEG concludes that impacts to transportation would be SMALL and would not warrant mitigation.

4.19 Historic and Archaeological Resources

NRC

> **The environmental report must "…assess whether any historic or archeological 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 archeological 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 archeological 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 1996b, Section 3.7.7, pg. 3-23)**

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 1996b).

In the context of the National Historic Preservation Act, the NRC has determined that the area of potential effect for a license renewal action is the area at the power plant site and its immediate environs which may be impacted by post-license renewal land-disturbing activities specifically related to license renewal, regardless of ownership or control of the land of interest. Salem is located on Artificial Island, an artificially-created land mass that resulted, in the early part of the 20th century, when the U. S. Army Corps of Engineers dredged the Delaware River and placed the fill within a progressively enlarged diked area established around a natural bar that projected into the river. No historic or archaeological sites are known or expected to be located within the site boundary. No archaeological or historical sites are known to be located within the transmission line corridors.

Currently, PSEG is not aware of any historic or archaeological resources that have been affected by Salem operations. Properties within 10 km (6 mi) of Salem that are listed on the National Register of Historic Places are identified in Section 2.11. Operation and maintenance of the station and associated transmission lines have not resulted in negative impacts to any listed property. PSEG has no plans to construct additional facilities related to license renewal. As discussed in Section 3.2, PSEG has no refurbishment plans and no refurbishment-related impacts are anticipated.

Through correspondence with the New Jersey and Delaware SHPOs, PSEG has requested concurrence that operation of Salem during the term of license renewal would have no effect on historic and archaeological resources. Copies of the correspondences are presented in Appendix D. PSEG concludes that continued operation of Salem over the license renewal term would not impact historic or archaeological resources. Therefore, impacts would be SMALL and mitigation would not 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 an analysis of alternative ways to mitigate the impacts of severe accidents at Salem. Appendix E 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 the 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 unmitigated 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] 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.

PSEG maintains a probabilistic safety assessment (PSA) model to evaluate the most significant risks of radiological release from Salem fuel into the reactor and from the reactor into the containment structure. A Level 1 PRA of Salem Units 1 and 2 was performed in 1988 and updated in 1990. The original IPE model was submitted in 1993 has been subsequently updated in 1996, 1997, 2002, 2003, 2006 and 2008 to maintain the design fidelity with the operating plant and reflect the latest PRA technology.

For the SAMA analysis, PSEG used the PSA model output as input to an NRC-approved consequence assessment code that calculates economic costs and dose to the public from hypothesized releases from the containment to the environment. The Level 3 Probabilistic Risk Assessment (PRA) uses the MELCOR Accident Consequences Code System Version 2 (MACCS2). MACCS2 requires certain agricultural-based economic data. These data were developed using data in the 2002 National Census of Agriculture (USDA 2004) and from the

Bureau of Economic Analysis (BEA 2008) for each of the 23 counties surrounding the plant, to a distance of 50 miles. Then, using NRC regulatory analysis techniques, PSEG calculated the monetary value of the unmitigated Salem severe accident risk. The result represents the monetary value of the base risk of dose to the public and workers, offsite and onsite economic costs, and replacement power. This value became a cost/benefit-screening tool for potential SAMAs; a SAMA whose cost of implementation exceeded the base cost-risk value could be rejected as being not cost-beneficial. Salem Units 1 and 2 are essentially identical in design and operation. Such differences that do exist are not believed to be significant from a risk perspective. As such, the Unit 1 PRA model that was employed to evaluate each of the risk benefits and averted costs for each of the SAMAs was viewed as also being applicable to Unit 2. That is, if a particular SAMA proves cost beneficial for Unit 1, it will also likewise be cost-beneficial for Unit 2.

PSEG used industry, NRC, and Salem-specific information to create a list of 27 SAMAs for consideration. PSEG analyzed this list to screen out any SAMAs that (1) would not apply to the Salem design, (2) had already been implemented at Salem, or (3) would achieve results that PSEG had already achieved at Salem by other means. Two of the SAMAs were screened out based on these criteria. Therefore, PSEG prepared cost estimates for 25 SAMAs and used the base risk value to screen out SAMAs that would not be cost-beneficial.

PSEG calculated the cost-risk reduction that would be attributable to each of the remaining SAMAs (assuming SAMA implementation) and re-quantified the cost-risk value. The difference between the base cost-risk value and the SAMA-reduced cost-risk value became the averted cost-risk, or the value of implementing the SAMA. PSEG then performed a cost/benefit comparison for these SAMAs using this averted cost-risk value and the corresponding cost estimates for implementing the specific SAMA.

PSEG performed additional sensitivity analyses to evaluate how the SAMA analysis would change if certain key parameters were changed. The results of the sensitivity analyses are discussed in Appendix E.

Based on the results of this SAMA analysis, PSEG identified 17 SAMAs that have the potential to reduce plant risk and be cost-beneficial at the 95th percentile. None are related to managing the effects of plant aging during the period of extended operation. The potentially cost-beneficial SAMAs will be considered for implementation through the established Salem Plant Health Committee processes.

4.21 Cumulative Impacts

PSEG considered the potential cumulative impacts of Salem's operations during the license renewal term. For the purposes of this analysis, past actions are those related to the resources at the time of plant licensing and construction, present actions are those related to the resources during current operations, and future actions are those actions that are reasonably foreseeable through the end of the plant operations, which would include the 20-year license renewal term. The geographic area affected by cumulative impacts depends on the resource being impacted.

The impacts of the proposed action are combined with past, present and reasonably foreseeable actions and could include individually minor but collectively significant actions taking place over a period of time. It is possible that a SMALL impact, when considered in combination with the impacts of other actions on the affected resources could result in MODERATE or LARGE impacts to the affected resource.

The principal facility with impacts that have the potential to be collectively significant when combined with impacts of Salem is HGCS. HCGS is adjacent to Salem on Artificial Island, and uses Delaware Estuary water and ground water, as does Salem. Both facilities release small amounts of radioactivity.

As indicated in Section 2.12.2.2, PSEG has notified the NRC of its intent to submit an ESP application during the second quarter of 2010 for potential new nuclear generating capacity on Artificial Island. This notification does not commit PSEG to submit an ESP application or to build new nuclear units, and does not project a timeframe for construction and operation of the new units, should the decision to proceed ultimately be made. Nor does PSEG's notification constitute approval of the ESP by the NRC. If the siting of new PSEG nuclear units proceeds, the cumulative impacts in the immediate vicinity of Salem and HCGS of that NRC licensing action in combination with issuance of licenses for the new units and renewal of the existing licenses for Salem and HCGS would be addressed in the ESP application and during the subsequent NRC approval process.

4.21.1 CUMULATIVE IMPACTS TO AQUATIC AND TERRESTRIAL RESOURCES

Aquatic Resources

Section 2.2 describes the aquatic environment affected by Salem and HCGS. Section 3.1 describes Salem's water use. Appendix F describes restoration projects in the Delaware Estuary that are a requirement of the Salem NJPDES permit and their results.

In the HCGS Environmental Report, Section 3.1 describes HCGS water use (PSEG 2009b).

PSEG is authorized by the DRBC for HCGS consumptive and non-consumptive use of Delaware Estuary water. PSEG is authorized by the DRBC for Salem consumptive and non-consumptive use of no more than 367,000 million liters (97,000 million gallons) of Delaware Estuary water in a single 30-day period. The freshwater flow into the Delaware Estuary averages 645 m^3 per second (22,783 ft^3/sec; PSEG 1984), and the tidal flow (or "flux") near the site (at River Km 80 [River Mile 50)] has been estimated to be 11,324 m^3/sec (400,000 ft^3/sec), which equates to 3.6×10^{11} m^3/year (1.3×10^{13} ft^3 /year) (PSEG 2006a). There are no large industrial facilities downstream of Artificial Island on either side of the Estuary. Beginning with an oil refinery in Delaware about 13 km (8 mi) upstream of Artificial Island, there are many industrial facilities on the Delaware River farther upstream of Salem and Hope Creek that could affect water quality or quantity, including some power generating facilities permitted to withdraw water from the Delaware River. These facilities are permitted as required, and have spill prevention and control plans in place, also as required. Any impacts to water quality and quantity from these facilities would be small.

PSEG has restored or preserved more than 20,000 acres of wetlands and upland buffers in the Delaware Estuary and constructed 13 constructed fish ladders on Delaware River tributaries in an effort to restore spawning runs of river herring. Estuarine wetlands are important for many reasons: they provide nursery areas for larval aquatic organisms, water filtration and storm surge buffers, to name a few. Fish ladders by-pass waterway obstructions, thus providing fish access to historic spawning locations. These projects were undertaken to address the potential for impacts to the fishery from Salem operations.

Over the years that the nuclear plants have been operating, the aquatic community in the Delaware Estuary has improved. Early results of the restoration projects indicate that they are successful. As a result of efforts to improve the Delaware Estuary water quality, and increase spawning and nursery habitats between 1968, when monitoring began, and today, species richness in the vicinity of the plants has remained constant and density has increased (i.e., there are as many different kinds of fish now as in 1968, and the number of fish has increased). (PSEG 2006a, Section 5)

PSEG has performed substantive analyses of the environmental effects of station operation on the Delaware Estuary aquatic community, generally in support of renewal of the best technology available determination in the Salem NJPDES permit (PSEG 2006a, Section 5). Analysis of the condition of the aquatic community does not distinguish between Salem and HCGS, and therefore would bound cumulative impacts. As discussed in Section 2.2, operation of both Salem and HCGS has had no adverse environmental impact on the Delaware Estuary aquatic community.

Salem and HCGS cumulative impacts to the Delaware Estuary aquatic communities are SMALL and are expected to remain SMALL during the license renewal term.

Terrestrial Resources

Section 2.4 describes the critical and important terrestrial habitats in the vicinity of Artificial Island. Artificial Island was created from dredge spoils in the early 20th century, so has no pristine terrestrial habitats, although it does have suitable raptor, including eagle, foraging habitat. Typical coastal plant and animal species have been observed on the island.

The most important habitat that could be affected by the cumulative impacts of Salem and HCGS operations is the Pinelands National Reserve, which preserves the New Jersey pine barrens. The Pine Barrens comprise 4,500 km^2 (1.1 million acres) of southern New Jersey Coastal Plain. The pine barrens' nutrient poor soils support fire-maintained pine communities, and many rare and unusual species such as carnivorous plants, bog turtles, and the pine barrens tree frog.

Despite the fact that the Garden State Parkway and the Atlantic City Expressway run through it, the Pine Barrens is rural and undeveloped. Utility corridors, including two transmission corridors originating at HCGS, cross parts of the pine barrens. The New Jersey Pinelands Commission is charged with preserving, protecting, and enhancing the Pinelands National Reserve. As part of this charge, the Commission developed a comprehensive management plan that includes requirements for siting, constructing, and maintaining transportation and utility corridor rights-of-way. PSE&G works with the Commission to ensure best vegetation management practices are used within the transmission corridors that cross a portion of the pine barrens. The third transmission corridor, which originates at HCGS, does not cross the pine barrens, but PSE&G and PHI (which share ownership of this corridor) employ best vegetation management practices in this corridor to ensure that sensitive resources are protected. PSE&G has no plans to construct additional corridors from Salem or HCGS. Any development in the Pinelands National Preserve must be approved by the Commission. Cumulative impacts of Salem and HCGS operations to terrestrial resources, which previously have been SMALL, will remain SMALL through the license renewal term.

4.21.2 CUMULATIVE IMPACTS TO GROUND WATER

Section 2.3 describes the ground-water resources available to the plants. PSEG has authorization from the NJDEP (NJDEP 2004) and DRBC (DRBC 2000) for consumptive use of up to 163 million liters (43.2 million gallons) of ground water per month at the Salem and HCGS sites combined. As noted in Section 4.21.1.1, there are no large industrial facilities within approximately 8 miles of Artificial Island. Artificial Island is bounded on three sides by the Delaware Estuary, and on the fourth by a 3.2-km (2-mi) or more buffer of marsh. The nearest potable offsite well is more than 5.6 km (3.5 mi) from the stations, across the Estuary, in Delaware. Impacts of both plants on ground-water resources have been SMALL and will remain SMALL during the license renewal term. There are no sources of additional impacts to ground water in the vicinity of Artificial Island. Cumulative impacts of Salem and HCGS operations, which previously have been SMALL, will remain SMALL throughout the license renewal term.

4.21.3 CUMULATIVE IMPACTS TO THREATENED OR ENDANGERED SPECIES

Section 2.5 describes the protected species that could be affected by facility operations. Five species of threatened or endangered sea turtles and the endangered shortnose sturgeon are known to occur in the Delaware Estuary. Salem and HCGS have been issued an incidental take statement by the NMFS that requires monitoring of the Salem intake screens for impinged sea turtles and shortnose sturgeon. Other provisions specify rescue and inspection procedures for any turtles impinged, limits on the number of turtles and shortnose sturgeon that can be impinged annually on the Salem intake screens, reporting requirements, and a requirement for reinitiation of consultation with the NMFS under Section 7 of the Endangered Species Act if the number of incidental takes reaches the permitted limits or new information is identified. (NMFS 1999b)

In the biological opinion that accompanies the incidental take statement, the determined that the number of incidental takes of endangered species established in the incidental take statement for Salem and HCGS would not likely result in jeopardy to the continued existence of any threatened or endangered sea turtle species or the shortnose sturgeon.

Based on the information provided above, PSEG concludes that the cumulative impact of Salem and HCGS operations on protected aquatic species, which previously have been SMALL, will remain SMALL during the license renewal term.

No protected terrestrial species are known from the PSEG property on Artificial Island, though one plant species does occur on one transmission line, and several protected animals are known to occur in the vicinity of the transmission lines. Resource agencies are responsible for ensuring that activities that could adversely affect protected species are controlled to minimize such impacts. As noted PSE&G and PHI use best vegetation management practices on transmission corridors Hence, the cumulative impacts of Salem and HCGS operations, which have previously been SMALL, will remain SMALL throughout the license renewal term.

4.21.4 SOCIOECONOMIC CUMULATIVE IMPACTS

Sections 2.6 through 2.9 describe the aspects of the region's socioeconomics that could be affected by renewal of the Salem and HCGS operating licenses. The stations are in Lower Alloways Creek Township in Salem County. PSEG pays property taxes to Lower Alloways Creek Township which transfers most of its property tax revenues to Salem County in exchange for services. PSEG's tax payments to Lower Alloways Creek Township are a MODERATE to LARGE share of the total tax revenues collected by Lower Alloways Creek Township. Total tax payments by PSEG for both facilities are a SMALL percentage of the taxes collected by Salem County.

More than half of Salem County is tidal and freshwater wetlands, lakes, ponds, and forests, and more than one-third of the total area is farmland. Only 10 percent of Salem County's land area is developed. Approximately 80 percent of the PSEG employees reside in Salem, Cumberland, or Gloucester counties in New Jersey or in New Castle County, Delaware. The annual growth rate in each of these counties since 1970 has been less than 2 percent, and usually less than 1 percent. PSEG is not aware of any major industrial or commercial facility planned for Salem County that would affect land use, or draw significant numbers of new residents.

PSEG does not anticipate adding additional staff to either facility during the license renewal term, but the environmental reports' analyses assumed an additional 60 staff at each plant, for a total of 120 additional households in the four-county region where most of the current staff reside.

During refueling outages, the workforce traveling to Artificial Island increases by approximately 600 people. The roads in the area accommodate this increase in traffic. Therefore, PSEG concludes that an additional 120 staff would not adversely impact traffic on local roads.

PSEG analyzed the impact of 120 additional staff and their families on housing and public water supply using the following assumptions: (1) all 120 direct jobs would be filled by in-migrating residents, (2) no indirect jobs would be filled by in-migrating residents, and (3) the residential distribution of the workers would resemble that of the current operations workforce.

PSEG assumed that 120 new staff would require 120 housing units. The area within an 80-km (50-mi) radius of Artificial Island has a population of approximately 5,000,000 people. Delaware averages 2.54 persons per household. Maryland averages 2.61, New Jersey averages 2.68, and Pennsylvania averages 2.48 persons per household (USCB 2000b), suggesting the existence of approximately 2 million housing units in the 80-km (50-mi) radius. It is reasonable to conclude that 120 additional employees would not create a discernible change in housing availability, rental rates, or housing values, or spur housing construction or conversion.

Impacts to the public water supply were determined by estimating the amount of water that would be required by the 120 new PSEG employees and their families, which is 109,701 liters per day (28,980 gpd; see Section 4.15). The increased demand would be imposed primarily on public water supply systems located in Salem, Gloucester, and Cumberland counties (in New Jersey) and New Castle County (in Delaware). These counties currently have excess public water supply capacity of approximately 129 million liters (34 million gallons) per day for Cumberland, Gloucester, and Salem counties (see Table 2.9-1) and more than 132 million liters (35 million) gallons per day for New Castle County (see Table 2.9-2). Any increase in water demand resulting from renewal of the Salem and HCGS operating licenses would not create shortages in capacity for the existing public water supply systems.

Based on the information provided above, PSEG concludes that the cumulative impacts of the continued operation of Salem and HCGS on regional socioeconomics, which previously have been SMALL, will remain SMALL throughout the license renewal term.

4.21.5 CUMULATIVE IMPACTS TO HUMAN HEALTH

Both Salem and HCGS have thermal discharges to the Delaware Estuary, a large brackish, tidally-influenced water body that allows their thermal plumes to disperse quickly. There are no other facilities that release thermal discharges to the Estuary in the vicinity of Salem and HCGS. Hence, the potential for enhancement of thermophilic organisms due to the cumulative impacts of Salem and HCGS operations, which previously have been SMALL, will remain SMALL throughout the license-renewal term.

The electric-field induced currents from transmission lines constructed to connect Salem and HCGS to the electric transmission grid are less than the NESC recommendations for preventing electric shock from induced currents. Therefore, these transmission lines do not significantly affect the overall potential for electric shock from induced currents within the analysis area. Hence, the Salem and HCGS cumulative impacts due to continued use of transmission lines constructed to connect the stations to the electric transmission grid, which previously have been SMALL, will remain SMALL during the license renewal term.

Radiological dose limits for protection of the public and workers have been developed by EPA and NRC to address the cumulative impacts of acute and long-term exposure to radiation and radioactive material. These dose limits are codified in 10 CFR 20 and 40 CFR 190. For the purpose of this analysis, the area within an 80-km (50-mi) radius of the three units was included.

The radiological environmental monitoring program conducted by PSEG in the vicinity of the site measures radiation and radioactive materials from all sources; therefore, the monitoring program measures cumulative radiological impacts. Levels of radioactivity measured are typical for an estuarine environment, and are mostly the result of natural-occurring nuclides or residual nuclides from atmospheric testing of atomic weapons. Thermoluminescent dosimeter (TLD) measurements in 2006 at offsite locations averaged 50 millirem for the year. TLD measurements at 2006 control locations averaged 52 millirem for the year. Preoperational measurements (1973 to 1976) averaged 55 millirem per year. (PSEG 2007b)

Salem and HCGS cumulative radiological impacts are limited by the provisions in 10 CFR 20 and 40 CFR 190. These impacts, which previously have been SMALL, will remain SMALL through the license renewal term.

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Chapter 5

Assessment of New and Significant Information

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5.1 Discussion

NRC

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

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

While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those Category 1 environmental issues that have been generically resolved [10 CFR 51.53(c)(3)(i)], the regulations do require that an applicant identify any new and significant information of which the applicant is aware [10 CFR 51.53(c)(3)(iv)]. The purpose of this requirement is to alert NRC staff to such information, so the staff can determine whether to seek the Commission's approval to waive or suspend application of the rule with respect to the affected generic analysis. NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) conclusions (NRC 1996b).

PSEG expects that new and significant information would include:

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

NRC does not specifically define the term "significant." For the purpose of its review, PSEG used guidance available in Council on Environmental Quality (CEQ) regulations. The National Environmental Policy Act authorizes CEQ to establish implementing regulations for federal agency use. NRC requires license renewal applicants to provide NRC with input, in the form of an environmental report, that NRC will use to meet National Environmental Policy Act requirements as they apply to license renewal (10 CFR 51.10).

CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), focus on significant environmental issues (40 CFR 1502.1), and eliminate from detailed study issues that are not significant [40 CFR 1501.7(a)(3)]. The CEQ guidance includes a lengthy definition of "significantly" that requires consideration of the context of the action and the intensity or severity of the impact(s) (40 CFR 1508.27). PSEG considered that MODERATE or LARGE impacts, as defined by NRC, would be significant. Chapter 4 presents the NRC definitions of SMALL, MODERATE, and LARGE impacts.

The new and significant assessment that PSEG conducted during preparation of this license renewal application included: (1) interviews with PSEG subject matter experts on the validity of the conclusions in the GEIS as they relate to Salem, (2) an extensive review of documents related to environmental issues at Salem and within the Delaware Estuary, (3) correspondence with state and federal agencies to determine if the agencies had concerns relevant to their resource areas that had not been addressed in the GEIS, (4) credit for PSEG environmental monitoring and reporting required by regulations and oversight of station facilities and operations by state and federal regulatory agencies (permanent activities that would bring significant issues to PSEG's attention), and (5) review of previous license renewal applications for issues relevant to the Salem application.

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

As part of its investigation for new and significant information, PSEG evaluated information about tritium in the ground water beneath the Salem site (Section 3.1.3). Based on that evaluation, PSEG has concluded that changes in tritium-related ground-water quality are not significant at Salem and would not preclude current or future uses of the ground water for the following reasons:

- Although tritium concentrations are elevated in the shallow aquifer beneath Salem, PSEG has been performing remedial actions since 2004, and concentrations continue to decrease.

- Tritium concentrations in ground water are due to an historic incident; the source has been eliminated.

- Tritium concentrations above neither the EPA Drinking Water Standard nor the NJDEP Ground Water Quality Criterion have migrated to the property boundary or into geologic formations deeper than the shallow aquifer. Offsite tritium concentrations are below regulatory limits.

- There is no human exposure pathway and, therefore, no threat to public or employee health or safety.

In its entirety, PSEG's assessment did not identify any new and significant information regarding the Salem environment or operations that would (1) make any generic conclusion codified by the NRC for Category 1 issues not applicable to Salem, (2) alter regulatory or GEIS statements regarding Category 2 issues, or (3) suggest any other measure of license renewal environmental impact.

Chapter 6

Summary of License Renewal Impacts and Mitigating Actions

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6.1 License Renewal Impacts

PSEG has reviewed the environmental impacts of renewing the Salem operating licenses and has concluded that impacts would be SMALL and would not require mitigation. This Environmental Report documents the basis for PSEG's conclusion. Chapter 4 incorporates by reference Nuclear Regulatory Commission (NRC) findings for the 51 Category 1 issues that apply to Salem, all of which have impacts that are SMALL (Appendix 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. PSEG identified minority and low-income populations, evaluated potential impacts to these populations alone, and determined that there are no issues that could have disproportionately high adverse impacts on environmental justice populations.

Table 6.1-1 identifies the impacts that Salem license renewal would have on resources associated with Category 2 issues. Because Salem and Hope Creek are on adjacent sites that share several attributes, including a common ground-water withdrawal permit, a common access road and matrixed employees, it is unreasonable to evaluate the impacts of one without considering the impacts of the other. In those instances when the cumulative impacts of both facilities provides a more appropriate assessment of impacts, the discussion in Table 6.1-1 includes those cumulative impacts.

Table 6.1-1 Environmental Impacts Related to License Renewal at Salem

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)	**NONE.** This issue does not apply because Salem does not use cooling towers or cooling ponds and withdraw make-up water from a small river.
Aquatic Ecology (for plants with once-through or cooling pond heat dissipation systems)		
25	Entrainment of fish and shellfish in early life stages	**SMALL.** PSEG has a current NJPDES permit which constitutes compliance with CWA Section 316(b) requirements to provide best technology available to minimize entrainment.
26	Impingement of fish and shellfish	**SMALL.** PSEG has a current NJPDES permit which constitutes compliance with CWA Section 316(b) requirements to provide best technology available to minimize impingement.
27	Heat shock	**SMALL.** PSEG has a current NJPDES permit with a thermal variance which constitutes compliance with CWA Section 316(a).
Ground-water Use and Quality		
33	Ground-water use conflicts (potable and service water, and dewatering; plants that use > 100 gpm)	**SMALL.** The combined permit for Salem and HCGS limits ground-water withdrawal to 1.135 million liters (300 million gallons) a year. Ground-water elevation data and the distance to off-site wells indicate that the Salem and HCGS use of ground water results in minimal impacts to off-site users.
34	Ground-water use conflicts (plants using cooling towers or cooling ponds and withdrawing makeup water from a small river)	**NONE.** This issue does not apply because Salem does not use cooling towers or cooling ponds nor withdraw make-up water from a small river.
35	Ground-water use conflicts (Ranney wells)	**NONE.** This issue does not apply because Salem does not use Ranney wells.
39	Ground-water quality degradation (cooling ponds at inland sites)	**NONE.** This issue does not apply because Salem does not use cooling ponds.
Terrestrial Resources		
40	Refurbishment impacts	**NONE.** This issue does not apply because refurbishment is not planned for Salem.
Threatened or Endangered Species		
49	Threatened or endangered species	**SMALL.** NMFS has issued a biological opinion that incidental takes of shortnose sturgeon and loggerhead, Kemp's ridley, and green sea turtles at the Salem intake have not jeopardized the continued existence of these species. One federally threatened plant grows on a section of one transmission corridor in Salem County, and two protected terrestrial animal species are know from the vicinity of two transmission corridors in Salem County. Vegetation management practices along the transmission corridors are developed and implemented in conjunction with appropriate regulatory agencies to minimize potential impacts on threatened or endangered species.
Air Quality		
50	Air quality during refurbishment (non-attainment and maintenance areas)	**NONE.** This issue does not apply because refurbishment is not planned for Salem.

Table 6.1-1 Environmental Impacts Related to License Renewal at Salem (continued)

No.	Category 2 Issue	Environmental Impact
Human Health		
57	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	**NONE.** This issue does not apply because Salem does not use a lake or canals, and does not use cooling towers or cooling ponds that discharge to a small river.
59	Electromagnetic fields, acute effects (electric shock)	**SMALL.** For the three transmission lines constructed to connect Salem to the electric grid, modeling predicts induced currents of 4.2 millamperes or less, which are all less than the maximum induced current recommended by the National Electrical Safety Code (i.e., 5 milliamperes) for preventing electric shock from induced current.
Socioeconomics		
63	Housing impacts	**SMALL.** The addition of 60 jobs would not noticeably affect a potential housing market of more than 2 million housing units.
65	Public water supply: public utilities	**SMALL.** Water suppliers in Salem, Gloucester and Cumberland counties, New Jersey and New Castle County, Delaware, have excess capacity. The addition of 60 jobs would not adversely affect the available water supply.
66	Public services: education (refurbishment)	**NONE.** This issue does not apply because refurbishment is not planned for Salem.
68	Off-site land use (refurbishment)	**NONE.** This issue does not apply because refurbishment is not planned for Salem.
69	Off-site land use (license renewal term)	**SMALL.** No station-induced changes to off-site land use are expected from license renewal because although Salem taxes represent approximately 20 percent of the taxes paid to Lower Alloways Creek Township, the Township's property tax payments are forwarded to Salem County in return for services. Salem Nuclear Generating Station taxes comprise less than 2 percent of Salem County property tax revenues. Taxes on the Energy and Environmental Resources Center are less than 3 percent of Salem city property tax revenues.
70	Public services: transportation	**SMALL.** The addition of 60 employees would not noticeably increase traffic or adversely affect level of service in the vicinity of Salem.
71	Historic and archaeological resources	**SMALL.** Salem is located on Artificial Island, which is a manmade land area created during the early 1900s. As such, the site never contained historical or archaeological resources. In addition, no archaeological or historical resources are known to exist on the transmission line corridors associated with Salem, and construction is not planned on-site or in the transmission corridors during the license renewal terms. Hence, no impacts to historic or archaeological resources are expected.
Postulated Accidents		
76	Severe accidents	**SMALL.** PSEG identified 17 potentially cost-beneficial SAMAs that could be examined further, but none is related to managing the effects of plant aging during the period of extended operation. The potentially cost beneficial SAMAs will be considered for implementation through the established Salem Plant Health Committee process.

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 must 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 activities have been determined to be SMALL and would not require mitigation other than mitigation already performed as part of the NJPDES permit requirements.

Current operations include monitoring activities that would continue during the license renewal term. PSEG performs routine monitoring to ensure the safety of workers, the public, and the environment. These activities include the gaseous and liquid radiological environmental monitoring program, non-radiological air quality emissions monitoring, radiological ground-water protection program, the NJPDES permit effluent monitoring, and biological monitoring to identify impacts of Salem on the fishery in the Delaware Estuary. These monitoring programs ensure that the station's permitted emissions and discharges are within regulatory limits and that any unusual or off-normal emissions/discharges would be quickly detected, allowing for mitigation of potential impacts.

Beginning in 1994, PSEG initiated its Estuary Enhancement Program as a condition of Salem's NJPDES permit. Since then it has enhanced, restored, or preserved more than 8,093 hectares (20,000 acres) of salt marsh, degraded wetlands, and adjacent uplands to fish and wildlife habitat. Appendix F describes the program. Impingement and entrainment losses will be offset by the greater than 20,000 acres of preserved or restored wetlands and upland buffers which provide nursery habitat for aquatic organisms. The NJPDES permit requires monitoring to track the success of the restoration, which is overseen by an Advisory Committee whose membership includes representatives from state and federal regulatory agencies and independent scientists.

In 2003 PSEG identified tritium in ground water, and in 2005 initiated a ground-water extraction program. The tritium remediation program is discussed in Section 2.3.

A revised Incidental Take Statement issued by NMFS on January 21, 1999, allows PSEG to take (impingement at the intake screens being the primary "take" mechanism) 5 Kemp's ridley turtles, 5 Atlantic green turtles, 30 loggerhead sea turtles, and 5 shortnose sturgeon per year (NMFS 1999a). Lethal take limits are 1 Kemp's ridley turtle, 1 Atlantic green turtle, 5 loggerhead sea turtles, and 5 shortnose sturgeon annually. The Incidental Take Statement includes the following "reasonable and prudent measures" to minimize takings of sea turtles and sturgeon:

- Removal of ice barriers by May 1 and replacement of ice barriers after October 24

- Three-times-per-week cleaning of intake trash racks between May 1 and November 15; daily cleaning of intake trash racks from June 1 to October 15

- Inspection of trash racks every two hours from June 1 through October 15

- Monitoring of trash racks hourly if a lethal take occurs during the June 1 through October 15 period

This Environmental Report identified no additional mitigation measures that are sufficiently beneficial to be warranted.

6.3 Unavoidable Adverse Impacts

NRC

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

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

- Solid radioactive wastes are a product of plant operations and permanent disposal of these materials must be arranged. Procedures for the disposal of nonradioactive and radioactive wastes are intended to reduce adverse impacts from these sources to acceptably low levels. A small impact will occur as long as the plant is in operation.

- Operation of Salem results in a very small increase in radioactivity in the air and water. Based on data collected since initial operation, the increase is less than the fluctuation in natural background levels and is expected to remain so over the renewal period.. Operation of Salem also creates a very low probability of accidental radiation exposure to inhabitants of the area.

- Operations of Salem results in consumptive use of Delaware Estuary water and in discharges to the Estuary. It also results in the consumptive use of ground water. PSEG is required to maintain ground-water use at 1.135 billion liters (300 million gallons) per year or less (for Salem and HCGS combined) and is required to maintain discharges at or below NJPDES permit requirements.

- Loss of adult and juvenile fish impinged on the traveling screens at the SWS and CWS intake structures.

- Loss of larval fish entrained at the SWS and CWS intake structures.

- Endangered shortnose sturgeon and individuals from three species of threatened or endangered sea turtles could be incidentally taken at the CWS and SWS intake structures. Mitigation of this impact is addressed in an existing incidental take permit.

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 Salem for the license renewal term will result in irreversible and irretrievable resource commitments, including the following:

- Nuclear fuel, which is used in the reactor and is converted to radioactive waste;
- Land required to permanently store or dispose offsite the following: spent nuclear fuel, low-level radioactive wastes generated as a result of plant operations, and nonradioactive industrial wastes generated from normal industrial operations;
- Elemental materials that will become radioactive; and
- Materials used for the normal industrial operations of the station 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 Salem site was established with the decision to convert approximately 89 hectares (220 acres) of Artificial Island, a marginally productive natural area created by the disposal of dredge spoils during the first half of the 1900s, to industrial use. The Final Environmental Statement related to construction and operation evaluated the impacts of constructing and operating Salem (AEC 1973). Natural resources that would be subjected to short-term use include land and water. Artificial Island and its immediate vicinity are largely undeveloped and rural. Currently approximately 1,700 hectares (4,200 acres) in 172 km (107 mi) of transmission corridor are associated with Salem.

Salem consumes relatively small amounts of brackish water from the Delaware Estuary, and ground water, thus the impacts are minor and would cease once the reactors cease operation.

After decommissioning the nuclear facilities at the site, 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 impacts. 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.

Chapter 7

Alternatives to the Proposed Action

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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 1996b, Section 8.1, pg. 8-1).**
>
> **"…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 1996d)**

Chapter 7 evaluates alternatives to renewal of the Salem operating licenses. The chapter identifies actions that PSEG might take and associated environmental impacts, if the NRC does not renew the plant's operating licenses. The chapter also addresses actions that PSEG has considered, but would not take, and discusses the bases for determining that such actions would be unreasonable.

The alternatives discussed in this chapter are "no-action" and "alternatives that meet system generating needs." In considering the level of detail and analysis that it should provide for each category, PSEG relied on the NRC decision-making standard for license renewal:

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

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

In characterizing environmental impacts from alternatives, the same definitions of SMALL, MODERATE, and LARGE presented in the introduction to Chapter 4 are used in this chapter.

7.1 No-Action Alternative

The "no-action alternative" refers to a scenario in which NRC does not renew the Salem operating licenses.

Salem is a generator of electricity in New Jersey owned 57.41 percent by PSEG and 42.59 percent by Exelon Generation LLC (PSEG 2008b). The EIA reports that the two Salem units provided approximately 19.3 terawatt-hours of electricity during 2006, with 2,304 megawatts (MWe) of net base-load electrical capacity (EIA 2007a) to residential and other consumers in the mid-Atlantic region. This power is sufficient to supply the electricity used by over 2 million homes and would be unavailable to customers in the event the Salem operating licenses are not renewed (EIA 2007a, EIA 2007b). PSEG thinks that any alternative to renewal of the Salem licenses would be unreasonable if it did not include replacing the capacity of the Salem units. Replacement could be accomplished by (1) building new base-load generating capacity, (2) purchasing power from the wholesale market, or (3) reducing power requirements through demand reduction. Section 7.2.1 describes each of these possibilities in detail, and Section 7.2.2 describes environmental impacts from feasible alternatives.

The Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996b) 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, PSEG would continue operating Salem until the existing licenses expire, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of the equivalently sized 1,175-megawatt-electric [MWe] Trojan Nuclear Plant (the "reference" pressurized-water reactor). In 2006 Salem Unit 1 and Unit 2 had a net capacity of 1,195 and 1,196 MWe, respectively (nominally 1200 MWe each) (PSEG 2009c). This description is applicable to decommissioning activities that PSEG would conduct at Salem.

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 2002) 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. PSEG adopts by reference the NRC conclusions regarding environmental impacts of decommissioning analyzed in the Decommissioning EIS.

PSEG considered whether the no-action alternative would have any beneficial impact on housing values in the socioeconomic region of influence. As discussed in Section 4.17.2, published studies of the impacts of nuclear plant operations on property (housing) values have conflicting results, but after considering these results in the context of site-specific circumstances, PSEG has concluded that Salem's operational impacts on property values, if any, are positive. PSEG also notes that the full impact of the no-action alternative on property values would not be realized until completion of decommissioning. Because the Salem Unit 2 license would not expire until 2020 without renewal, decommissioning of both Salem units under the no action alternative may not be complete until 2080, assuming that both units are decommissioned at once and decommissioning takes no more than the allowed 60 years from permanent cessation of Unit 2 operations (10 CFR 50.82 (a)(3)). Hence, decommissioning under the no-action alternative may not be complete until approximately 70 years beyond the date of this Environmental Report. PSEG believes that predicting property value impacts so far into the future would be too speculative to allow a useful comparison among alternatives.

Nevertheless, PSEG notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. Salem will have to be decommissioned 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. PSEG 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. PSEG concludes that the decommissioning impacts under the no-action alternative would not substantially differ from those occurring following license renewal, as identified in the GEIS (NRC 1996b) and in the NRC's Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities (NRC 2002). These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs. Hence, the discriminators between the proposed action and the no-action alternative lay 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.

7.2 Alternatives That Meet System Generating Needs

The power consumed in New Jersey is not limited to electricity generated within the state. New Jersey is a net importer of electric power, using more electricity than is generated within the state. In 2005, 83 terawatt-hours of electricity, approximately 60 percent of the power consumed in New Jersey, were supplied by generators located outside the state (EIA 2008a). New Jersey relies on electricity drawn from the PJM Interconnection to provide this imported power. The PJM Interconnection is a regional network that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

The current mix of power generation options within the PJM region is one indicator of what PSEG considers to be feasible alternatives. In 2006, electric generators connected to the PJM network had a total generating capacity of 164,905 MWe (PJM 2007a). This capacity includes units fueled by coal (41 percent), nuclear (19 percent), oil (8 percent), natural gas (26 percent), hydroelectric (5 percent), and renewable sources (1 percent) (PJM 2007b). In 2006, the electric industry in the PJM region provided 729 terawatt-hours of electricity (PJM 2007a). Power generation in the PJM region was dominated by coal (57 percent), followed by nuclear (35 percent), natural gas (6 percent), hydroelectric (2 percent), renewable sources (<1 percent), and oil (0.3 percent) (PJM 2007b). Figures 7.2-1 and 7.2-2 illustrate the electric industry generating capacity and energy output by fuel type for the PJM region. The entire PJM region is a net exporter of electric power, using less electricity than is generated within the region. In 2006, 45 terawatt-hours (gross) were exported out of the PJM region and 27 terawatt-hours (gross) were imported. Therefore the net result is 18 terawatt-hours exported (PJM 2007c).

Comparison of generating capacity with actual utilization of this capacity indicates that coal and nuclear are used by PJM substantially more relative to their PJM capacity than either oil-fired or gas-fired generation. This condition reflects the relatively low fuel cost and base-load 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 energy production for oil- and gas-fired facilities indicates a strong preference for gas firing over oil firing, indicative of the higher cost and greater air emissions associated with oil firing. Energy production from hydroelectric sources is similarly preferred from a cost standpoint, but capacity is limited and utilization can vary substantially depending on water availability.

7.2.1 ALTERNATIVES CONSIDERED

Technology Choices

For the purposes of this Environmental Report, alternative generating technologies were evaluated to identify candidate technologies that would be capable of replacing Salem's current nominal base-load capacity of approximately 2,400 MWe. PSEG accounted for the fact that Salem is a base-load generator and that any feasible alternative to Salem would also need to be able to generate base-load power. PSEG assumed that the region of interest (ROI) for purposes of this alternatives analysis includes the states of Delaware, Maryland, New Jersey, and Pennsylvania, which are the states within the PJM interconnection's network that are geographically closest to Salem.

Based on these evaluations, it was determined that new plant systems capable of replacing the capacity of Salem are limited to new nuclear, pulverized-coal, or gas-fired combined-cycle units for base-load operation. This conclusion is supported by the generation utilization information presented above that identifies coal as the most heavily used non-nuclear generating fuel type in the region. PSEG 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.

Recently, members of both industry and government have expressed interest in the development of nuclear power plants to provide new baseload generating capacity. Beginning in 2007, several utilities submitted applications for combined construction and operating licenses for new nuclear generating units. PSEG plans to submit an Early Site Permit application to the NRC during the second quarter of 2010 for new nuclear generating capacity in the immediate vicinity of Salem and HCGS on Artificial Island. An Early Site Permit would give PSEG the option at any time within 20 years of the permit's approval date to submit an application to the NRC to construct and operate the new nuclear facility. However, considering the length of time needed to obtain NRC approval for an Early Site Permit and a subsequent license to construct and operate a new nuclear facility, the facility would not likely be operational by 2016, which is the end of the current license term for the existing Salem Unit 1 (see "New Reactor Licensing Applications Schedules by Calendar Year," at http://www.nrc.gov/reactors/new-reactors/new-licensing-files/new-rx-licensing-app-legend.pdf).

For the purposes of the Salem license renewal environmental report, PSEG's analysis of new generating capacity alternatives includes the technologies it considers feasible: pulverized coal- and gas-fired units. PSEG 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.

Effects of Restructuring

Nationally, the electric power industry has been undergoing a transition from a regulated industry 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. Over the past few years, some states within the PJM region (Delaware, Illinois, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, and the District of Columbia) have transitioned to competitive wholesale and retail markets. Indiana, Kentucky, North Carolina, Tennessee, and West Virginia are not restructuring their electric power industry. Virginia signed restructuring legislation (House Bill 1172) into law in April 1998, but in February 2007 passed legislation that would replace the state's deregulated electric power market with a regulated one. (EIA 2007a)

In 1999, New Jersey enacted the "Electric Discount and Energy Competition Act." Provisions of the Act opened New Jersey's retail electric power market to competition and provided retail customers with a 10 percent rate reduction phased in over 4 years. The Act also required the State's electric utilities to divest their electric generation assets. Consequently, PSEG sold its generation assets, including Salem, to a separate unregulated wholesale power affiliate. The New Jersey Board of Public Utilities (NJBPU) provides strategic direction and policy guidance for energy production and use in the State, including the restructuring initiative (New Jersey

Statutes § 48:3-49 et seq). Similarly, in March 1999 Delaware passed the “Electric Utility Restructuring Act” of 1999, House Bill (HB 10) which included provisions to phase-in retail competition beginning October 1999 and ending April 2001. Pennsylvania enacted the “Electricity Generation Customer Choice and Competition Act” in December 1996 that allowed consumers to choose among competitive generation suppliers beginning with one third of the State's consumers by January 1999, two thirds by January 2000, and finally all consumers by January 2001. In December 1997, Maryland issued Order 8738 that established a framework for the restructuring of the electric power industry in that state. The plan's schedule was for a third of the State's consumers to have retail access by July 2000, another third by July 2001, and the entire state by July 2002. (EIA 2007a)

In 2001, New Jersey adopted the Renewables Portfolio Standards (RPS), which require all suppliers selling retail electricity in New Jersey (retail electric suppliers) to include alternative energy sources in the mix of energy that they sell (New Jersey Administrative Code § 14:8-2.1 et seq). Eligible resources may be located anywhere within the PJM region. The RPS divides renewables into two classes: Class I consists of energy produced from solar technologies, photovoltaic technologies, wind energy, fuel cells, geothermal technologies, wave or tidal action, and methane gas from landfills or sustainable biomass facilities. Class II consists of solid waste incinerators and hydropower facilities that are located in a retail competition area and meet certain environmental criteria. In 2006 the RPS were revised, significantly increasing the required percentages of Class I and Class II renewable energy, as well as specifying the required percentage of solar energy. In year 2009 the energy sold in New Jersey is required to be 0.16 percent solar power, 3.8 percent Class I, and 2.5 percent Class II. These percentages increase incrementally until the year 2021 when 22.5 percent of the retail electric energy sold in New Jersey must be from renewable sources. Suppliers have the option of satisfying these requirements either by participating in a trading program or by auctioning their production in the wholesale market to other suppliers (New Jersey Statutes § 48:3-49 et seq). Maryland and Pennsylvania established similar RPS programs in 2004 and Delaware in 2005 (DSIRE 2008).

The Electric Discount and Energy Competition Act requires suppliers to provide customers with emission data and the fuel mix used by the provider. Suppliers are also required to offer net metering for wind or solar photovoltaic systems of residential and small commercial customers at non-discriminatory rates. Net metering occurs when electric utilities permit customers to reduce their electric bills by generating their own power using small-scale renewable energy systems. The excess power that customers generate can be fed back to their utilities, actually running their electric meters backwards.

Alternatives

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

7.2.1.1 Construct and Operate Fossil-Fuel-Fired Generation

PSEG considered locating hypothetical new coal- and gas-fired Units at an existing PSEG power plant site and at an undetermined greenfield site. PSEG concluded that an existing power plant is preferred over any greenfield site for new construction because this approach would minimize environmental impacts by building on previously disturbed land and by making the most use possible of existing facilities, such as transmission lines, roads and parking areas, office buildings, and components of the cooling system. For the purpose of analysis, Salem is used as an example of a representative brownfield site containing an existing PSEG power plant. The impacts of locating hypothetical coal- and gas-fired units at the Salem site serve as a surrogate analysis for any PSEG site with an existing power plant. It must be emphasized, however, that the scenarios discussed in this section for new gas- and coal-fired units are hypothetical scenarios. PSEG does not have plans for such construction at Salem or any other existing PSEG power plant site.

Gas-Fired Generation

One unit with a nominal net capacity of 2,400 MWe could be assumed to replace the total 2,400 MWe Salem nominal net capacity. However, PSEG's experience indicates that, although custom-sized gas-fired units can be built, using standardized sizes is more economical. For purposes of this analysis, PSEG assumed development of a modern natural gas-fired combined-cycle plant with design characteristics similar to those being developed elsewhere in the PJM region, and with a generating capacity similar to Salem. The hypothetical plant would be composed of six pre-engineered natural gas-fired combined-cycle systems producing 400 MWe for a total of 2,400 MWe (GE Power 2001).

The characteristics of this plant and other relevant resources were used to define the gas-fired alternative. Table 7.2-1 presents the basic characteristics for the gas-fired alternative.

Coal-Fired Generation

NRC has routinely evaluated coal-fired generation alternatives for nuclear plant license renewal. For comparability to the gas-fired generation scenario, PSEG set the net power of the coal-fired unit equal to the gas-fired plants (2,400 MWe). The hypothetical plant would be composed of four pre-engineered supercritical pulverized coal-fired units producing 600 MWe of net plant power for a total of 2,400 MWe In defining the coal-fired alternative to Salem, New Jersey-specific input has been applied for direct comparison with this combined-cycle gas-fired plant.

Table 7.2-2 presents the basic coal-fired alternative emission control characteristics. The emissions control assumptions are based on the technologies recognized by the U.S. Environmental Protection Agency (EPA) for minimizing emissions and estimated emissions are based on the EPA published removal efficiencies (EPA 1998a). For the purpose of analysis, PSEG has assumed that coal and limestone (calcium carbonate) would be delivered to the site via barge.

7.2.1.2 Purchased Power

As noted in Section 7.2.1, electric industry restructuring initiatives in New Jersey and other states in the PJM region are designed to promote competition in energy supply markets by facilitating participation by generation companies. PJM has implemented market rules to appropriately anticipate and meet electricity demands in the resulting wholesale electricity market. As an additional facet of this restructuring effort, retail customers in the region now may choose any company with electric generation to supply their power. In view of these conditions, PSEG assumes for purposes of this analysis that adequate supplies of electricity would be available, and that purchased power would be a reasonable alternative to meet the Station's load requirements in the event the existing operating licenses for Salem are not renewed.

The source of this purchased power may reasonably include new generating facilities developed elsewhere in the PJM region. The technologies that would be used to generate this purchased power are similarly speculative. PSEG assumes that the generating technology used to produce purchased power would be one of those that NRC analyzed in the GEIS. For this reason, PSEG 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 and combined-cycle facilities fueled by natural gas are the most cost effective for providing base-load capacity.

PSEG anticipates that additional transmission infrastructure would be needed in the event purchased power must replace Salem capacity. From a local perspective, loss of Salem could require construction of new transmission lines to ensure local system stability. From a regional perspective, PJM's inter-connected transmission system is highly reliable, and the market-driven process for adding capacity in the region is expected to have a positive impact on overall system reliability.

7.2.1.3 Demand Side Management

Demand side management (DSM) programs include energy conservation and load management measures. As discussed in the GEIS (NRC 1996b), the DSM alternative does not fulfill the stated purpose and need of the proposed action because it does not "provide power generation capability."

Historically, state regulatory bodies required regulated utilities to institute programs designed to reduce demand for electricity. In a deregulated market, however, electric power generators may not be able to offer competitively priced power if they must retain an extensive conservation and load-modification-incentive program. In addition, a private company engaged in generating energy for the wholesale market, such as PSEG Nuclear, has no business connection to the end users of its electricity and, therefore, no ability to implement DSM. Because a company whose sole business is that of generating electricity and selling energy at wholesale has no ability to implement DSM, the NRC determined that NEPA does not require that an alternative involving electricity demand reduction through DSM be considered when the project purpose is to authorize a power plant to supply existing and future electricity demand (NRC 2005). The NRC determination was upheld by the U.S. Court of Appeals for the Seventh Circuit (2006). Nevertheless DSM is considered here because energy conservation and peak load management are important tools for meeting projected demand.

In New Jersey, the State of New Jersey Board of Public Utilities (NJBPU) promotes and advances DSM in the deregulated retail electric market. The NJBPU works in partnership with other state agencies, electric transmission/distribution utilities, business organizations, and environmental organizations to develop and implement "tools" to save energy. New Jersey's DSM program offerings are diverse, ranging from load curtailment incentives during periods of peak demand to rebates and financial incentives for commercial, industrial, and residential customers that install energy-efficient appliances and equipment and to the adoption by the New Jersey Department of Consumer Affairs of updated energy codes for new building construction.

A 2004 study commissioned by the NJBPU estimated the technical, economic, and achievable potential electricity savings in New Jersey from DSM measures through 2020. The study indicated that by the year 2020 the technical potential electricity savings, if all technically feasible conservation measures were implemented regardless of economics, would be approximately 16,999 gigawatt-hours (GWh) of electricity per year. If only the cost-effective measures were implemented, the economic potential electricity savings would be approximately 12,832 GWh per year. Capturing the entire economic potential through program activity was estimated to cost more than $5 billion over the 2004 to 2020 period. The achievable electricity savings at the 2004 program funding level of $85 million per year (Business as Usual) was estimated at 2,831 GWh per year or roughly one third the amount of electricity produced by HCGS in a given year. Under a very aggressive scenario (Advanced Efficiency), with a program funding level of $180 million per year, the achievable electricity savings was estimated to be 5,183 GWh per year or about 60 percent of the electricity produced by HCGS in a given year. Net program peak-demand savings potential estimates ranged from approximately 540 MWe by the year 2020 under the Business as Usual scenario to approximately 970 MWe under the Advanced Efficiency scenario (KEMA 2004).

In 2008, the Center for Energy, Economic & Environmental Policy (CEEEP) compared actual New Jersey electricity savings data for the years 2004 to 2007 to the estimates under both the Business as Usual case and the Advanced Efficiency case presented in the 2004 study. Between 2004 and 2007, conservation programs achieved approximately 939 GWh per year of avoided electricity use. This represents over 78% of the 2004 to 2007 Business as Usual savings potential of 1,205 GWh and almost 44% of the Advanced Efficiency scenario of 2,116 GWh (CEEEP 2008). Overall, the New Jersey Clean Energy Program reduced peak electric demand by a total of 87 MWe in 2007 (NJBPU 2008). It is evident that the New Jersey energy efficiency programs captured significantly less electricity savings than estimated by the 2004 study. However, CEEEP estimates that continuing the programs "as-is" would likely result in New Jersey meeting the Business as Usual case; however the savings estimated under the Advanced Efficiency case are not likely to be attained (CEEEP 2008).

Because PSEG Nuclear sells power into the wholesale electricity market through the PJM Interconnection (PJM), DSM measures are not within the Company's control. However, PJM has instituted measures to capture energy conservation potential and load management in its resource planning. Consequently, additional DSM measures in other nearby states that could, in addition to the programs promoted by the NJBPU, also offset some of the demand for electricity from Salem are already incorporated in the load forecast. As a practical matter, it would be highly unlikely that energy savings from demand reductions could be increased by an additional 2,400 MWe by 2020 to replace the Salem nominal base-load capacity of approximately 2,400 MWe.

The DSM alternative would produce different impacts than the other alternatives addressed. Unlike the discrete generation options, there would be no major generating facility construction and few ongoing operational impacts. However, the loss of Salem capacity could require construction of new transmission lines to ensure local system stability. The most significant effects would likely occur during installation or implementation of conservation measures, when old appliances may be replaced, buildings climate control systems may be retrofitted, or new control devices may be installed. In some cases, increases in efficiency may come from better management of existing control systems. While replaced or removed items may be recycled, volumes of land-filled trash could still increase.

The GEIS generally indicates that impacts from a DSM alternative are small and that some postulated effects (like increases in mercury, polychlorinated biphenyls [PCBs], or chlorofluorocarbon [CFC] releases as fluorescent bulbs, old transformers, or old refrigerators are replaced) may not prove to be significant because effective disposal methods can prevent health effects, and because more environmentally-benign alternatives are available (NRC 1996b).

Implementation of the DSM alternative reduces direct fuel use and environmental emissions from plant fuel cycles, workers' commuting, and plant operation and maintenance. Improvements in efficiency may also reduce consumption of fuels used for space or water heating at the same time they reduce electrical consumption. The DSM alternative would likely cause only minor and short-duration air quality impacts—use of best management practices during any construction activities and during retrofits or upgrades would minimize air quality impacts. New more energy-efficient appliances would further reduce already low air emissions. The overall impacts on air quality of the DSM alternative would be SMALL.

Implementation of the recycling programs in conjunction with disposing of old appliances, retrofitting buildings or installing new control devices would decrease the volumes of waste requiring disposal, though volumes of the trash sent to the landfills as a result of these DSM measures may still increase over a baseline. Overall, the impacts on waste generation would be SMALL.

The loss of Salem capacity could require construction of new transmission lines to ensure local system stability. The construction of these new lines could require clearing new rights-of-way and would likely cause only minor and short-duration land use and terrestrial ecology impacts—use of best management practices would minimize the impacts. Replacing and disposing of old inefficient appliances could potentially increase the size of landfills. Overall, impacts to land use and ecological resources would be SMALL.

Impacts to aquatic resources and water quality would be SMALL, but positive, as withdrawals from and discharges to the Delaware Estuary would cease. If more energy is conserved than is produced by Salem, then positive impacts to aquatic resources could extend beyond the Delaware Estuary to other water bodies. This net conservation of energy could result in less demand for power production at other plants and could lead to lower rates of water withdrawal and discharge at these power plants. The implementation of conservation measures, such as the increased use of mercury-containing compact fluorescent light bulbs and their impact to the environment after landfill disposal, would result in SMALL impacts to the aquatic environment. While mercury in landfills could leach into adjacent waterways, State and local landfill regulations could reduce or eliminate such pollution.

As noted in the GEIS, implementation of the DSM alternative would likely employ additional workers. The new jobs would be widely distributed across the state and possibly the entire U.S., and socioeconomic impacts would not be noticeable. However, shutdown of Salem would result in a sizable reduction in operating personnel compared to the current workforce of 1021 personnel, and the impact on the local community employment, taxes, housing, off-site land use, and public services could be significant. Thus, reduction in workforce would result in adverse socioeconomic impacts on the local community that are characterized as MODERATE. Lower-income families could benefit from weatherization and insulation programs. This positive effect would be greater than the adverse effect on the general population from loss of jobs because low-income households experience home energy burdens more than four times larger than the average household (OMB 2008).

In conclusion, although DSM is an important tool for meeting projected electricity demand and the impacts from the DSM alternative are generally small, DSM does not fulfill the stated purpose and need for license renewal of nuclear power plants, which is to "provide power generation capability" (NRC 1996b). DSM measures are already captured in state and regional load projections and additional DSM measures would offset only a fraction of the energy supply lost by the shutdown of Salem. In addition, the purpose for Salem license renewal is to allow PSEG Nuclear to sell wholesale power generated by Salem to meet future demand. Because PSEG Nuclear engages solely in the sale of wholesale electric power, the Company has no business connection to end users of its electricity and therefore no ability to implement DSM. For these reasons, PSEG Nuclear does not consider DSM to represent a reasonable alternative to renewal of the Salem operating licenses.

7.2.1.4 Other Alternatives

This section identifies alternatives that PSEG has determined are not reasonable for replacing Salem and the bases for these determinations. PSEG accounted for the fact that Salem is a base-load generator and that any feasible alternative to Salem would also need to be able to generate base-load power. PSEG assumed that only the states of Delaware, Maryland, New Jersey, and Pennsylvania comprise the ROI for purposes of this analysis. In performing this evaluation, PSEG relied heavily upon NRC's GEIS (NRC 1996b).

Wind

Wind power, due to its intermittent nature, is not suitable for base-load generation. As discussed in Section 8.3.1 of the GEIS, wind power systems produce power only when the wind is blowing at a sufficient velocity and duration. While recent advances in technology have improved wind turbine capacity, average annual capacity factors for wind power systems are relatively low (30 percent) compared to 90 to 95 percent industry average for a base-load plant such as a nuclear plant (EPRI 2006, NRRI 2007). In conjunction with energy storage mechanisms, wind power might serve as a means of providing base-load power. However, current energy storage technologies are too expensive to permit wind power to serve as a large base-load generator (Schainker 2006).

The energy potential in the wind is expressed by wind generation classes ranging from 1 (least energetic) to 7 (most energetic). Current wind technology can operate economically on Class 4 sites with the support of the federal production tax credit (AWEA 2008a), while Class 3 wind regimes will require further technical development for utility-scale application. In the ROI, the primary areas of good wind energy resources are the Atlantic coast and exposed hilltops, ridge crests, and mountain summits (EERE 2003). Offshore wind resources are abundant but the technology is not sufficiently demonstrated at this time. A panel review of New Jersey offshore wind issues completed in 2006 concluded that there are insufficient data to fully assess the impact of offshore wind in New Jersey and recommended the construction of a test wind farm, with a capacity of no more than 350 MWe, which could be used to study the impacts of offshore wind power development. Including this test wind farm, there are six offshore wind farms proposed along the coast of the ROI (Offshore Wind 2008). PSEG Renewable Generation is in a joint venture with Deepwater Wind as the preferred developer of a 350-megawatt wind farm located 16 to 20 miles off the coast of New Jersey. The New Jersey Energy Master Plan (New Jersey Governor's Office 2008) has a goal of providing at least 1,000 MW of offshore wind capacity by 2012, and by 2020, providing at least 3,000 MW of offshore wind capacity and 200 MW of onshore wind capacity.

Based on American Wind Energy Association estimates (AWEA 2008b), the ROI has the technical potential (the upper limit of renewable electricity production and capacity that could be brought online, without regard to cost, market acceptability, or market constraints) for roughly

6,855 MWe of installed wind power capacity. The full exploitation of wind energy is constrained by a variety of factors including land availability and land-use patterns, surface topography, infrastructure constraints, environmental constraints, wind turbine capacity factor, wind turbine availability, and grid availability. By 2008, a total of 301 MWe of wind energy had been developed in the ROI. Projected new capacity in various stages of planning or permit review within the ROI includes an additional 70 MWe of wind energy (AWEA 2008b).

Wind farms generally consist of 10 to 50 turbines in the range of 1-3 MWe. Estimates based on existing installations indicate that a utility-scale wind farm would be spread over 12 to 20 hectares (30 to 50 acres) per MWe of installed capacity (McGowan and Connors 2000). However, the actual area occupied by turbines, substations, and access roads may only be from 3 percent to 5 percent of the wind farm's total acreage. Thus the remaining area is available for other uses. When the wind farm is located on land already used for intensive agriculture the additional impact to wildlife and habitat will likely be minor, while disturbance caused by wind farms in more remote areas may be more significant. Therefore, replacement of the Salem nominal base-load capacity (approximately 2,400 MWe) with wind power, assuming a capacity factor of 30 percent, would require a large greenfield site about 111,500 hectares (288,000 acres) in size, of which approximately 4,700 hectares (10,880 acres) would be disturbed and unavailable for other uses. Although the State of New Jersey promotes wind power as a component of its Renewable Portfolio Standard, it concludes that wind, due to its intermittent nature, is unsuitable to provide base-load generating capacity (NJDEP 2005, New Jersey's Governor's Office 2008). Similarly, PSEG has concluded that wind power is not a reasonable alternative to Salem license renewal.

Solar

By its nature, solar power (photovoltaic and thermal) is intermittent and not suitable for base-load generation. As discussed in Section 8.3.2 of the GEIS, solar power systems produce power only when sunlight is available. The average annual capacity factors for solar power systems are relatively low (16 to 40 percent) compared to 90 to 95 percent industry average for a base-load plant such as a nuclear plant (NRRI 2007). In conjunction with energy storage mechanisms, solar power might serve as a means of providing base-load power. However, current energy storage technologies are too expensive to permit solar power to serve as a large base-load generator (Schainker 2006). Even without consideration of storage capacity, solar power technologies (photovoltaic and thermal) cannot currently compete with conventional fossil-fueled technologies in grid-connected applications due to high costs per kilowatt of capacity (NRC 1996b, EERE 2006a).

Solar power is not a technically feasible alternative for base-load generating capacity in the ROI. The ROI receives 3 to 5 kilowatt hours of solar radiation per square meter per day compared with 5.5 to 7.5 kilowatt hours per square meter per day in areas of the West, such as California, which are most promising for solar technologies (EERE 2008).

Finally, land requirements for solar plants are high. Estimates based on existing installations indicate that utility-scale plants would occupy at least 1 hectare (2.5 acres) per MWe for photovoltaic and 2 hectares (4.9 acres) per MWe for solar thermal systems (EERE 2004). Utility-scale solar plants have mainly been used in regions that receive high concentrations of solar radiation such as the western U.S. A utility-scale solar plant located in the ROI would occupy about 1.3 hectares (3.3 acres) per MWe for photovoltaic and 4.0 hectares (9.9 acres) per MWe for solar thermal systems. Therefore, replacement of Salem generating capacity with solar photovoltaic power, assuming a capacity factor of 16 percent would require dedication of about 18,000 hectares (44,500 acres). Replacement of Salem generating capacity with solar thermal power, assuming a capacity factor of 40 percent would require dedication of about 21,600 hectares (53,400 acres). Both would have large environmental impacts at a greenfield site.

PSEG has concluded that, due to the high cost of both generation and storage technologies, limited availability of sufficient incident solar radiation, and the amount of land needed, solar power is not a reasonable alternative to Salem license renewal.

Hydropower

About 209 MWe of utility generating capacity in the ROI comes from hydropower. The total amount of undeveloped hydropower that could feasibly be utilized in the ROI equals 1,113 MWe. This capacity is distributed over 5,376 different sites and would require a large amount of resources to develop. In addition, this capacity is less than needed to replace the Salem nominal base-load capacity of approximately 2,400 MWe. There are no undeveloped sites in the ROI that would be environmentally suitable for a single hydroelectric facility similar in generation size to Salem. (EERE 2006b, INEEL 1998)

As the GEIS points out in Section 8.3.4, hydropower's percentage of United States generating capacity is expected to decline because hydroelectric facilities have become difficult to site as a result of public concern over flooding, destruction of natural habitat, and alteration of natural river courses. A small number of hydropower projects, totaling 260 MWe, are being considered in the ROI (FERC 2006). The largest of these projects is 100 MWe. Even if they were built, these small hydropower projects could not replace the Salem nominal base-load capacity of approximately 2,400 MWe.

The GEIS estimates that hydroelectric power plants have a land use requirement of 400,000 hectares (1,000,000 acres) per 1,000 MWe (NRC 1996b). Based on this estimate, replacement of Salem generating capacity would require flooding approximately 965,500 hectares (2,385,900 acres), resulting in a large impact on land use. Further, operation of a hydroelectric facility would alter aquatic habitats above and below the dam, which would impact existing aquatic communities.

PSEG has concluded that, due to the lack of suitable sites in the ROI for a large hydroelectric facility and the large amount of land needed, hydropower is not a reasonable alternative to Salem license renewal.

Tidal, Ocean Thermal, and Wave

The most developed technologies to harness electrical power from the ocean are tidal power, ocean thermal energy, and wave power conversion. These technologies are still in the early stages of development and are not commercially available to replace a large baseload generator such as Salem.

Tidal power technologies extract energy from the diurnal flow of tidal currents caused by the gravitational pull of the moon. Unlike wind and wave power, tidal streams offer entirely predictable output. All coastal areas consistently experience two high and two low tides over a period of approximately 25 hours. However, because the lunar cycle is longer than a 24-hour day, the peak outputs differ by about an hour each day, and so tidal energy cannot be guaranteed at times of peak demand (Feller 2003).

Tidal power technologies consist of tidal turbines and barrages. Tidal turbines are similar in appearance to wind turbines that are mounted on the seabed. They are designed to exploit the higher energy density, but lower velocity, of tidal flows compared to wind. Tidal barrages are similar to hydropower dams in that they are dams with gates and turbines installed along the dam. When the tides produce an adequate difference in the level of the water on opposite sides of the dam, the gates are opened and water is forced through turbines, which turns a generator.

For those tidal differences to be harnessed into electricity, the difference in water height between the high and low tides must be at least 4.9 m (16 ft). There are only about 40 sites on the Earth with tidal ranges of this magnitude (EERE 2005a). The only sites with adequate tidal differences within the United States are in Maine and Alaska (CEC 2009). Therefore, tidal resources off the coast of the ROI do not provide a viable tidal energy resource.

Ocean thermal energy conversion (OTEC) technology capitalizes on the fact that the water temperatures decrease with depth. As long as the temperature between the warm surface water and the cold deep water differs by about 20°C (36°F), an OTEC system can produce a significant amount of power. The temperature gradient off of the coast of the ROI is less than 18°C (32°F) and not a good resource for OTEC technology. (NREL 2008)

Wave energy conversion takes advantage of the kinetic energy in the ocean waves (which are mainly caused by interaction of wind with the surface of the ocean). Wave energy offers an irregular, oscillatory, low-frequency energy source that must be converted to a 60-Hertz frequency before it can be added to the power grid (CEC 2009). Wave energy resources are best between 30 and 60 degrees latitude in both hemispheres and the potential tends to be greatest on western coasts (RNP 2007). Ocean Power Technologies, Inc. deployed a 40-kilowatt PowerBuoy wave energy converter off the coast of New Jersey in November 2005 (EERE 2005b).

PSEG believes that this technology has not matured sufficiently to support production for a facility the size of Salem, and PSEG has concluded that, due to cost and production limitations, tidal, ocean thermal, and wave technologies are not reasonable alternatives to Salem 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.

Geothermal energy can achieve capacity factors of 93 percent and can be used for base-load power where this type of energy source is available (NRRI 2007). Widespread application of geothermal energy is constrained by the geographic availability of the resource. In the U.S., high-temperature hydrothermal reservoirs are located in the western continental U.S., Alaska, and Hawaii. The ROI has low- to moderate-temperature resources that can be tapped for direct heat or for geothermal heat pumps, but electricity generation is not feasible with these resources (GHC 2008, EERE 2008).

Wood Energy

As discussed in the GEIS (NRC 1996b), 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 National Renewable Energy Laboratory, the ROI produces approximately 5.9 million dry metric tons (6.5 million dry tons) of wood waste annually (consisting of forest mill, and urban wood residues [NREL 2005]). Assuming the fuel has a nominal heat content of 9.961 million Btu per dry ton and a thermal conversion efficiency of 25 percent, the annual power potential of the ROI would be 4.7 million MW-hours (EIA 2008b, NRC 1996b). This is the equivalent to a 488-MWe base-load (90 percent capacity factor) power plant which is substantially less than the approximately 2,400-MWe nominal base-load capacity of Salem. The largest existing wood waste power plants in operation are 40 to 50 MWe in size.

Furthermore, Section 8.3.6 of the GEIS (NRC 1996b) states that 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 some wood resources are available in the ROI there is not enough to replace the capacity of Salem. PSEG 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 Salem license renewal.

Municipal Solid Waste

As discussed in Section 8.3.7 of the GEIS (NRC 1996b), 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 and stricter environmental emission controls.

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.

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 Salem license renewal.

PSEG 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 Salem license renewal.

Other Biomass-Derived Fuels

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

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

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

Petroleum

The ROI has several petroleum (oil)-fired power plants (PJM 2007d). The percentage of power generated by oil-fired electricity plants has decreased from 4.7 to 0.8 percent from 1990 to 2006 in the ROI (EIA 2007b). Petroleum prices are volatile but the expected long-term trend is for prices to increase. As a result, at some point in the future oil-fired operations will likely be more expensive than nuclear or coal-fired.

Also, construction and operation of an oil-fired plant would have environmental impacts. For example, Section 8.3.11 of the GEIS (NRC 1996b) estimates that construction of a 1,000-MWe oil-fired plant would require about 49 hectares (120 acres). Building an oil-fired plant with a net capacity equal to Salem would require about 117 hectares (288 acres). Additionally, operation of oil-fired plants would have impacts on the aquatic environment and air that would be similar to those from a coal-fired plant.

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

Fuel Cells

Fuel cell power plants are in the initial stages of commercialization. Although nearly 900 large stationary fuel cell systems have been built and operated worldwide, the global stationary fuel cell electricity generation capacity in 2007 was about 150 MWe (FCT 2007). The largest stationary fuel cell power plant ever built is the 11-MWe Goi Power Station in Ichihara, Japan (FC2000 2008). Even so, fuel cell power plants typically generate much less (2 MWe or lower) power (NRRI 2007). Accordingly, PSEG believes that fuel cell technology has not matured sufficiently to support production for a facility the size of Salem and that it is not a reasonable alternative to Salem license renewal.

Delayed Retirement

As the NRC noted in Section 8.3.13 of the GEIS (NRC 1996b), 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 station the size of Salem would appear to be unreasonable without major construction to upgrade or replace plant components.

Power-generating merchants within the PJM region have retired a large number of electricity generators, totaling over 5,700 MWe, with another 1,800 MWe pending. This has resulted in multiple reliability criteria violations. The problem has been magnified by steady load growth and sluggish generation additions (PJM 2007b). Some potential reliability issues have been forestalled through a combination of short lead-time transmission upgrades, voluntary deactivation deferrals, and implementation of a process that compensates generators that remain online beyond announced retirement dates. However, the Federal Energy Regulatory Commission recently determined that PJM cannot compel the owners of units scheduled for retirement to remain in service (PJM 2007b). For these reasons, the delayed retirement of non-nuclear generating units is not considered a reasonable alternative to Salem license renewal.

Combination of Alternatives

NRC indicated in Section 8.1 of the GEIS that, while many methods are available for generating electricity and a huge number of combinations or mixes can be assimilated to meet system needs, it would be impractical to analyze all the combinations. Therefore, NRC determined that 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 1996b).

Nevertheless, for the purpose of comparison, PSEG has assumed that a 400-MWe wind farm, along with four 400-MWe natural gas combined-cycle units and 400 MWe of power purchased from the wholesale electricity market could replace the Salem nominal generating capacity (approximately 2,400 MWe). When operating, the combined cycle plants can "follow" the wind load by ramping up and down quickly. When the wind is blowing hard, the combined cycle plant can be ramped down; when the wind is not blowing or is blowing too softly to turn the wind turbines, the combined-cycle plant can be ramped up. Power purchased from other generators in the PJM market would provide the balance of electricity needed.

Operation of the new natural gas-fired power plant would result in increased air emissions and other impacts. The impacts associated with the wind portion of the alternative – land use impacts, noise impacts, visual impacts, impacts on wildlife, etc. – would be more than the stand-alone natural gas alternative. The environmental impacts associated with power purchased from other generators would be similar to the impacts associated with the coal- and gas-fired alternatives, but would be located elsewhere within the PJM region.

PSEG concludes that it is very unlikely that the environmental impacts of any combination of generating and conservation options would be reduced to the level of impacts associated with renewal of the Salem operating licenses. Therefore, a combination of alternatives is not considered a reasonable alternative to Salem license renewal.

7.2.2 ENVIRONMENTAL IMPACTS OF ALTERNATIVES

This section evaluates the environmental impacts of alternatives that PSEG has determined to be reasonable alternatives to Salem license renewal: gas-fired generation, coal-fired generation, and purchased power. For the impacts of coal- and gas-fired generation that are not discussed specifically in this Environmental Report, the findings of the GEIS (NRC 1996b) regarding the impacts of such generation are adopted.

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 PSEG's reasons for defining the gas-fired generation alternative as a six-unit combined-cycle plant at Salem. Construction of a gas-fired unit would impact land use and could impact ecological, aesthetic, and cultural resources, but construction on an existing power plant site would minimize any impacts to these resources. Human health effects associated with air emissions would be of concern. Gas-fired generation facilities use much less water than nuclear power plants; therefore, aquatic biota losses due to cooling water withdrawals would be easily offset by the concurrent shutdown of the nuclear generator. The following subsections describe the effects of combined-cycle gas-fired generation in greater detail.

Air Quality

Natural gas is a relatively clean-burning fossil fuel that primarily emits nitrogen oxides (NO_X), a regulated pollutant, during combustion. A natural-gas-fired plant would also emit small quantities of sulfur oxides (SO_X), particulate matter, and carbon monoxide (CO), all of which are regulated pollutants. In addition, a natural-gas-fired plant would produce carbon dioxide (CO_2), a greenhouse gas. Control technology for gas-fired turbines focuses on NO_X emissions. From data published by EPA (EPA 2000a), the emissions from the natural gas-fired plant are estimated to be:

SO_X = 34 metric tons (37 tons) per year

NO_X = 554 metric tons (611 tons) per year

CO = 115 metric tons (127 tons) per year

CO_2 = 5,600,000 metric tons (6,200,000 tons) per year

Filterable Particulate Matter = 96 metric tons (106 tons) per year (all particulates from natural gas combustion are particulates with diameters less than 2.5 microns[($PM_{2.5}$])

In 2006, New Jersey was ranked 37th nationally in sulfur dioxide (SO_2) emissions and 43rd nationally in NO_X emissions from electric power plants (EIA 2007b). The acid rain requirements of the Clean Air Act Amendments of 1990 capped the nation's SO_2 emissions from power plants. Each company with fossil-fuel-fired units was allocated SO_2 allowances. To be in compliance with the Act, the companies must hold enough allowances to cover their annual SO_2 emissions. PSEG would need to obtain SO_2 credits to operate a fossil-fuel-fired plant.

In 1998, the EPA promulgated the NO_X SIP (State Implementation Plan) Call regulation that required 22 states, including New Jersey, Maryland, Delaware, and Pennsylvania, to reduce their NO_X emissions to address regional transport of ground-level ozone across state lines (EPA 1998b). In 2005, EPA issued the Clean Air Interstate Rule (CAIR), which was overturned in court during July 2008. The CAIR would have permanently capped emissions of SO_2 and NO_X in 28 eastern states and the District of Columbia using a cap and trade program. In December

2008 the court reversed its vacatur of CAIR. The EPA is now charged with making changes consistent with the Court's July opinion, including changing methodologies for allowance allocations. The Court did not set a deadline for the EPA to establish a new rule. The new EPA rule might be substantially different from the CAIR but would likely require PSEG to obtain enough NO_X credits to cover annual emissions either from the set-aside pool or by buying NO_X credits from other sources. Additionally, because all of New Jersey is treated as a non-attainment area for ozone, a new fossil-fuel-fired plant at an existing PSEG power plant site annually would need to purchase enough NO_X emission reduction credits to cover its emissions.

New Jersey has implemented the CO_2 Budget Trading Program cap-and-trade program for the electric power sector consistent with companion rules in nine other states. The Regional Greenhouse Gas Initiative (RGGI) is an ongoing effort, begun in September 2003, among Northeast and Mid-Atlantic States to develop and implement a regional CO_2 cap-and-trade program aimed at stabilizing and then reducing CO_2 emissions from large fossil fuel-fired electricity generating units in the region. New Jersey is a signatory state to the RGGI Memorandum of Understanding (MOU). The participating states agreed to stabilize power sector CO_2 emissions over the first six years of program implementation (2009 through 2014) at a level roughly equal to current emissions, and then initiating an emissions decline of 2.5 percent per year for the four years 2015 through 2018. This approach will result in a 2018 annual emissions budget that is 10 percent smaller than the initial 2009 annual emissions budget. The initial regional cap is 170.5 metric tons (188 million short tons) of CO_2 per year, which is approximately 4 percent above annual average regional emissions during the period 2000 through 2004 for electric generating units that will be subject to the program. New Jersey is auctioning the CO_2 allowances and the availability of adequate allowances for a new fossil generation unit cannot be determined at this time. Although the cost of each CO_2 allowance in the initial September 2008 auction was $3.07, future prices cannot be predicted. Additional information on the RGGI is available at http://www.rggi.org/home.

Locating the gas-fired units in the ROI would increase the CO_2 emissions by about 5.5 million metric tons (6.2 million tons) per year. In comparison, the CO_2 emission budget for the entire RGGI, which includes the ROI plus six other states, is 170.5 metric tons (188 million tons) of CO_2 per year in 2018, as was explained above. Accordingly, the addition of 2,400 MWe of gas-fired generation would likely challenge compliance with this budget. Salem does not emit CO_2 in the generation of electric power for sale.

NO_X effects on ozone levels, SO_2 allowances, CO_2 credits and NO_X 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. PSEG concludes that emissions from the gas-fired alternative would noticeably alter local air quality, but would not cause or contribute to violations of National Ambient Air Quality Standards in the region. Air quality impacts would therefore be SMALL to MODERATE.

Waste Management

The GEIS concludes that the solid waste generated from a natural-gas fired power plant would be minimal (NRC 1996b). The only noteworthy waste would be from spent selective catalytic reduction (SCR) used for NO_X control. PSEG concludes that gas-fired generation waste management impacts would be SMALL.

Other Impacts

Construction of the gas-fired alternative on an existing plant site would impact the construction site and the supporting utility corridors. If the gas-fired units were located at Salem, PSEG estimates that 34 hectares (84 acres) on the previously disturbed Salem site would be needed for a plant site, and impacts to land use and terrestrial resources would be SMALL. Aesthetic impacts, erosion and sedimentation, fugitive dust, and construction debris impacts would be noticeable but SMALL with appropriate controls.

A new gas pipeline would likely be required to supply the fuel for the gas turbine generators in this alternative. To the extent practicable, PSEG would route the pipeline along existing, previously disturbed, right-of-way to minimize impacts. A new pipeline of approximately 50.8-cm (20-inch) diameter would require a 30.5-m (100-ft)-wide corridor. This new construction may also necessitate an upgrade of the state-wide pipeline network. Impacts to land use would be SMALL.

PSEG estimates an average construction workforce of 1,056 employees with a peak of 1,910 workers. Socioeconomic impacts from the construction workforce would be minimal, if worker relocation is not required, which would be the case if, like Salem, the site is near metropolitan areas such as the cities of Salem, Wilmington, Bridgeton, and Vineland. However, PSEG estimates a reduced workforce of 84 for gas operations, resulting in adverse socioeconomic impacts due to the loss of 1,021 personnel responsible for operational activities and the 600 additional personnel employed during outages. Loss of the operational and temporary personnel would impact various aspects of the local community including employment, taxes, housing, offsite land use, economic structure, and public services (NRC 1996b). PSEG believes these impacts would be MODERATE in the GEIS-defined high population area surrounding Salem (see Section 2.6).

If the gas-fired units were located at Salem, impacts to aquatic resources and water quality would be smaller than the impacts of the existing Salem units due to changes in the plant's cooling water withdrawals from and discharges to the Delaware Estuary. These impacts would be offset by the concurrent shutdown of Salem. PSEG considers that impacts to water resources would be SMALL. The stacks and boilers would have visual impacts but be consistent with the industrial nature of the site. Impacts to cultural resources would be unlikely because the site is an artificial island as described in Section 2.11.

7.2.2.2 Coal-Fired Generation

NRC evaluated environmental impacts from coal-fired generation alternatives in the GEIS (NRC 1996b). 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 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 PSEG has defined in Section 7.2.1.1 would be located at an existing PSEG power plant site and, for the purpose of evaluating impacts, that site is assumed to be Salem. A coal plant comparable to the 2,400-MWe gas plant chosen for this alternatives analysis could be comprised of four 600-MWe (net) units.

Air Quality

A coal-fired plant would emit SO_2, NO_X, particulate matter, and CO, all of which are federally regulated pollutants. A coal-fired plant also would emit mercury, which is a regulated pollutant in New Jersey. In addition, a coal-fired plant would produce carbon dioxide (CO_2), a greenhouse gas. As Section 7.2.1.1 indicates, PSEG has assumed a plant design that would minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. Using data published by the Energy Information Administration (EIA 2007c) and the EPA (EPA 1998a, EPA 2006b), the coal-fired alternative emissions are estimated to be as follows:

SO_2 = 5,822 metric tons (6,418 tons) per year

NO_X = 1,740 metric tons (1,919 tons) per year

CO = 1,740 metric tons (1,919 tons) per year

CO_2 = 19,200,000 metric tons (21,100,000 tons) per year

Mercury = 289 kilograms (637 pounds) per year

Particulates:

PM_{10} (particulates having a diameter of less than 10 microns) = 49 metric tons (54 tons per year)

$PM_{2.5}$ (particulates having a diameter of less than 2.5 microns) = 13 metric tons (14 tons per year)

The discussion in Section 7.2.2.1 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 climate change and acid rain as potential impacts. In 2005 EPA issued the Clean Air Mercury Rule, which has now been overturned by the courts. While the future is unclear, EPA likely will have to promulgate a new rule to address limits on mercury emissions. Notwithstanding, New Jersey has adopted mercury emissions control standards applicable to coal-fired boilers (see N.J.A.C. 7:27-27).

New Jersey has implemented the CO_2 Budget Trading Program cap-and-trade program for the electric power sector consistent with companion rules in nine other states. The Regional Greenhouse Gas Initiative (RGGI) is an ongoing effort, begun in September 2003, among Northeast and Mid-Atlantic States to develop and implement a regional CO_2 cap-and-trade program aimed at stabilizing and then reducing CO_2 emissions from large fossil fuel-fired electricity generating units in the region. New Jersey is a signatory state to the RGGI Memorandum of Understanding (MOU). The participating states agreed to stabilize power sector CO_2 emissions over the first six years of program implementation (2009 through 2014) at a level roughly equal to current emissions, and then initiating an emissions decline of 2.5 percent per year for the four years 2015 through 2018. This approach will result in a 2018 annual emissions budget that is 10 percent smaller than the initial 2009 annual emissions budget. The initial regional cap is 170.5 metric tons (188 million short tons) of CO_2 per year, which is approximately 4 percent above annual average regional emissions during the period 2000 through 2004 for electric generating units that will be subject to the program. New Jersey is auctioning the CO_2 allowances and the availability of adequate allowances for a new fossil generation unit cannot be determined at this time. The cost of each CO_2 allowance in the initial September 2008 auction was $3.07, however, future prices can not be predicted. More information on the RGGI is available at http://www.rggi.org/home.

Locating the coal-fired units in the ROI would increase the CO_2 emissions by over 19 million metric tons (21 million tons) per year. In comparison, the CO_2 emission budget for the entire RGGI, which includes the ROI plus six other states, is 170.5 metric tons (188 million tons) of CO_2 per year in 2018, as was explained above. Accordingly, the addition of 2,400 MWe of coal-fired generation would likely challenge compliance with this budget. Salem does not emit CO_2 in the generation of electric power for sale..PSEG concludes that federal legislation and large-scale issues, such as global climate change and acid rain, are indications of concerns about destabilizing important attributes of air resources. However, SO_2 emission allowances, mercury emission allowances, CO_2 credits, NO_X credits, low NO_X burners, overfire air, fabric filters or electrostatic precipitators, and scrubbers are now or likely will be in the future regulatorily imposed mitigation measures. As such, PSEG 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

PSEG concurs with the GEIS assessment that the coal-fired alternative would generate substantial solid waste. The coal-fired plant would annually consume about 7.0 million metric tons (7.7 million tons) of coal having an ash content of 6.13 percent. After combustion, 45 percent of this ash, approximately 191,000 metric tons (211,000 tons) per year, would be marketed for beneficial reuse. The remaining ash, approximately 235,000 metric tons (259,000 tons) per year, would be collected and disposed of in an authorized disposal facility. In addition, approximately 147,000 metric tons (163,000 tons) of scrubber sludge would be disposed of each year (based on annual limestone usage of about 191,000 metric tons [211,000 tons]). PSEG estimates that ash and scrubber waste disposal over a 20-year plant life (the time considered for license renewal) would require approximately 52 hectares (128 acres).

PSEG believes that proper siting, current waste management practices, and current waste monitoring practices would prevent waste disposal from destabilizing any resources. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, PSEG believes that waste disposal for the coal-fired alternative would have MODERATE impacts; the impacts of increased waste disposal would be noticeable, but would not destabilize any important resource, and further mitigation would not be warranted.

Other Impacts

PSEG estimates that construction of the power block for a coal-fired plant would require 134 hectares (331 acres) and ash disposal would require an additional 104 hectares (256 acres) of land and associated terrestrial habitat over 40 years, or 52 hectares (128 acres) over the 20-year license renewal term. Because much of this construction would be on previously disturbed land, impacts to land use and ecological resources would be SMALL to MODERATE.

Delivery of coal and limestone by barge would require construction of a barge offloading facility and a conveyor system to the coal yard which would affect the terrestrial habitat along the waterfront as well as aqueous habitat associated with the construction, maintenance, and operation of the offloading facility. Only 5 percent of the coal delivered to New Jersey is transported by barge but Logan Generating Company and Mercer Generating Station located further up the Delaware River than Salem, receive coal via barge (EIA 2008c, EIA 2008d).

PSEG estimates an average construction workforce of 1,920 employees with a peak of 3,708 workers. Socioeconomic impacts from the construction workforce would be minimal, if worker relocation is not required, for a site located near a large metropolitan area. PSEG estimates an operational workforce of 326 workers for the coal-fired alternative. This is a sizable reduction in operating personnel compared to Salem's 1,021 personnel, and the impact on the local community employment, taxes, housing, off-site land use, and public services could be significant. Thus, reduction in workforce would result in adverse socioeconomic impacts characterized as MODERATE.

Impacts to aquatic resources and water quality would be less than impacts of Salem, due to the new plant's use of the cooling water from and discharge to the Delaware Estuary, and installation of cooling towers, and would be offset by the concurrent shutdown of Salem. Therefore PSEG concludes that impacts to aquatic resources would be SMALL. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of onsite. The stacks, boilers, and barge deliveries would increase the visual impact but be consistent with the industrial nature of the site. Impacts to cultural resources would be unlikely because the site is an artificial island. Impacts to visual resources and cultural resources would be SMALL.

7.2.2.3 Purchased Power

As discussed in Section 7.2.1.2, PSEG assumes that the generating technology used under the purchased power alternative would be one of those that NRC analyzed in the GEIS. PSEG 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 ROI. PSEG believes that imports from outside the PJM region would not be required. However, the replacement capacity, wherever located in the ROI, would have similar environmental impacts as those described above on a regional basis.

As also indicated in Section 7.2.1.2 new transmission lines are essential for New Jersey to meet the growing demand for electricity. PJM has already identified a number of areas in which additional transmission facilities are needed to ensure the continued reliability of the region's electric grid (PJM 2007d). Long-term power purchases, therefore, would require the construction of additional transmission capacity. Additions and changes to the present transmission network would occur on previously undisturbed land either along existing transmission line rights-of-way or along new transmission corridors. PSEG concludes that the land use impact of such transmission line additions would be SMALL to MODERATE. In general, land use changes would be so minor that they would neither destabilize nor noticeably alter any important land use resources. Given the potential length of new transmission corridors into southern New Jersey, it is reasonable to assume that, in some cases, land use changes would be clearly noticeable, which is a characteristic of an impact that is MODERATE.

PSEG believes that impacts associated with the purchase of power would be SMALL to MODERATE; the impacts could be noticeable, but would not destabilize any important resource, and further mitigation would not be warranted.

7.2.2.4 Conclusion

Based on the analyses done for reasonable alternatives that could generate the same amount of electricity as generated by Salem, PSEG concludes that no alternative is environmentally preferable. Furthermore, the gas-fired and coal-fired generation alternatives would have significant carbon emissions in comparison to Salem license renewal.

Table 7.2-1 Gas-Fired Alternative

Characteristic	Basis
Plant size = 2,400 MWe ISO rating net combined cycle consisting of six 400-MWe systems with heat recovery steam generators	Manufacturer's standard size gas-fired combined-cycle plant (≤ Salem nominal base-load capacity of approximately 2,400 MWe) (GE Power 2001)
Plant size = 2,502 MWe ISO rating gross	Based on 4 percent onsite power usage
Number of Units = 6	Assumed
Fuel type = natural gas	Assumed
Fuel heating value = 1,034 Btu/ft^3	2007 value for gas used in New Jersey (EIA 2008e, Table 14.A)
Fuel SO_X content = 0.00066 lb/MMBtu	(EPA 2000a, Table 3.1-2a; INGAA 2000)
NO_X control = selective catalytic reduction (SCR) with steam/water injection	Best available technology for minimizing NO_x emissions (EPA 2000a, Table 3.1-1)
Fuel NO_X content = 0.0109 lb/MMBtu	Typical for large selective catalytic reduction-controlled gas fired units with water injection (EPA 2000b, Table 3.1 Database)
Fuel CO content = 0.00226 lb/MMBtu	Typical for large SCR-controlled gas fired Units (EPA 2000b, Table 3.1 Database)
Fuel PM_{10} content = 0.0019 lb/MMBtu	(EPA 2000a, Table 3.1-2a)
Fuel CO_2 content = 110lb/MMBtu	(EPA 2000a, Table 3.1-2a)
Heat rate = 5,687 Btu/kWh	GE Power 2001
Capacity factor = 0.90	Assumed based on performance of modern baseload plants

Note: The difference between "net" and "gross" is electricity consumed onsite.
Note: The heat recovery steam generators do not contribute to air emissions.
Btu = British thermal Unit
CO = Carbon monoxide
CO_2 = Carbon dioxide
ft^3 = cubic foot
ISO rating = International Organization for Standardization 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 electrical
NO_X = nitrogen oxides
PM_{10} = particulates having diameter of 10 microns or less
SOx = oxides of sulfur
≤ = less than or equal to

Table 7.2-2 Coal-Fired Alternative

Characteristic	Basis
Plant size = 2,400 MWe ISO rating net consisting of four 600 MWe (net) units	Size set = to gas-fired alternative ≤ Salem nominal base-load capacity of 2,400 MWe)
Plant size = 2,552MWe ISO rating gross	Based on 6 percent onsite power usage
Number of units = 4	Assumed
Boiler type = supercritical tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions (EPA 1998a)
Fuel type = bituminous, pulverized coal	Typical for coal used in New Jersey
Fuel heating value = 11,890 Btu/lb	2007 value for coal used in New Jersey (EIA 2008e, Table 15.A)
Fuel ash content by weight = 6.13 percent	2007 value for coal used in New Jersey (EIA 2008e, Table 15.A)
Fuel sulfur content by weight = 0.88 percent	2007 value for coal used in New Jersey (EIA 2008e, Table 15.A)
Uncontrolled NO_X emission = 10.0 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)
Uncontrolled CO_2 emission = 5,510 lb/ton	Typical for pulverized bituminous coal, tangentially fired, dry-bottom, NSPS (EPA 1998a)
Heat rate = 9,069 Btu/kWh	EIA forecast for a new supercritical coal-fired plants beginning operation in 2015 - 2020 (EIA 2008f, Table 47)
Capacity factor = 0.90	Typical for large coal-fired units
NO_X control = low NO_X burners, over-fire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated technology for minimizing NO_X emissions (EPA 1998a)
Particulate control = fabric filters (baghouse-99.9 percent removal efficiency)	Best available technology for minimizing particulate emissions (EPA 1998a)
SO_X control = Wet scrubber - limestone (95 percent removal efficiency)	Best available technology for minimizing SO_X emissions (EPA 1998a)
Hg control = wet limestone scrubber with fabric filter (baghouse – 96 percent removal efficiency)	Best available technology and widely demonstrated for minimizing Hg (EPA 1998a)

Note: The difference between "net" and "gross" is electricity consumed onsite.
Btu = British thermal Unit
CO = carbon monoxide
CO_2 = carbon dioxide
ISO rating = International Organization of Standardization 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 electrical
NO_X = nitrogen oxides
SO_X = oxides of sulfur
Hg = mercury
≤ = less than or equal to

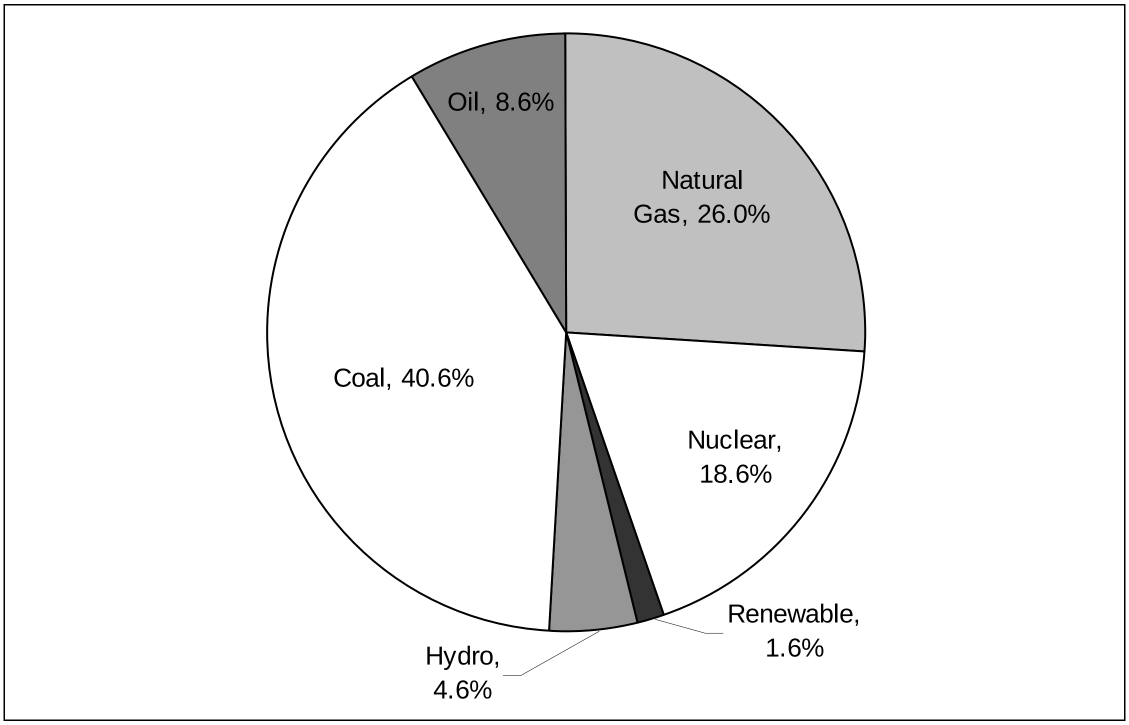

Figure 7.2-1 PJM Regional Generating Capacity (2006)

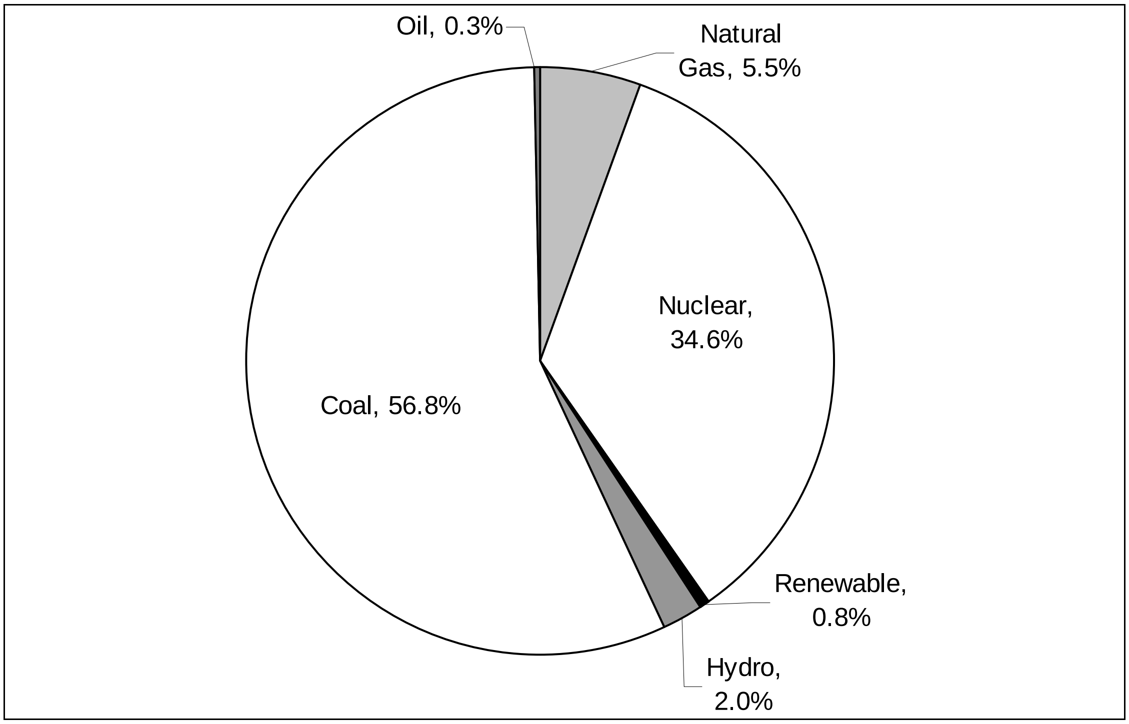

Figure 7.2-2 PJM Regional Energy Output by Fuel Type (2006)

Chapter 8

Comparison of Environmental Impact of License Renewal with the Alternatives

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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 the Salem licenses renewal and Chapter 7 analyzes impacts of reasonable alternatives. Table 8.0-1 summarizes environmental impacts of the proposed action (license renewal) and the reasonable 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 Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996b) identified as major considerations in an alternatives analysis. For example, although the NRC concluded that air quality impacts from the proposed action would be small (Category 1), the GEIS identified major human health concerns associated with air emissions from alternatives (Section 7.2.2). Therefore, Table 8.0-1 includes a comparison of the air impacts from the proposed action to those of 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 Alternatives			
		Base Case (Decommissioning)	With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Land Use	SMALL	SMALL	SMALL to MODERATE	SMALL	SMALL to MODERATE
Water Quality	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Air Quality	SMALL	SMALL	MODERATE	SMALL to MODERATE	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	SMALL to MODERATE	SMALL	SMALL to MODERATE
Threatened or Endangered Species	SMALL	SMALL	SMALL	SMALL	SMALL
Human Health	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Socioeconomics	SMALL	SMALL	MODERATE	MODERATE	MODERATE
Waste Management	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Aesthetics	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Cultural Resources	SMALL	SMALL	SMALL	SMALL	SMALL

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.

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

LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource. 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.

Table 8.0-2 Impacts Comparison Detail

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives: With Coal-Fired Generation	No-Action Alternatives: With Gas-Fired Generation	No-Action Alternatives: With Purchased Power
Alternative Descriptions				
Salem license renewal for 20 years, followed by decommissioning	Decommissioning following expiration of current Salem licenses. Adopting by reference, as bounding for Salem decommissioning, GEIS description (NRC 1996b, Section 7.1)	New construction at an existing site, assumed to be Salem	New construction at an existing site, assumed to be Salem	Would involve construction of new generation capacity in the PJM region. Adopting by reference GEIS description of alternate technologies (Section 7.2.1.2)
		Upgrade of barge slip or installation of a new rail spur.	Construct 50.8-cm (20-inch) diameter gas pipeline in a 30.5-m (100-foot) wide corridor. May require upgrades to existing pipelines	
				Construct new transmission lines to interconnect to the PJM region
		Four 600-MWe (net) tangentially-fired, dry bottom units; capacity factor 0.90	Six pre-engineered 400-MWe gas-fired combined-cycle systems with heat recovery steam generators, producing combined total of 2,400 MWe. Capacity factor 0.90	

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives: With Coal-Fired Generation	No-Action Alternatives: With Gas-Fired Generation	No-Action Alternatives: With Purchased Power
		Construct cooling tower(s) and construct/modify intake/discharge system	Construct / modify intake/discharge system	
		Pulverized bituminous coal, 11,890 Btu/lb; 9,069 Btu/kWh; 6.1% ash; 0.88% sulfur; 10 lb/ton nitrogen oxides; 6.7 x 10^6 metric tons (7.7 x 10^6 tons) coal/yr	Natural gas, 1,034 Btu/ft^3; 5,687 Btu/kWh; 0.0003 kg (0.00066 lb) sulfur/MMBtu; 0.005 kg (0.0109 lb) NOx/MMBtu; 512,000,000 m^3 (18,000,000,000 ft^3) gas/yr	
		Low NOx burners, over-fire 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); 191,000 metric tons (211,000 tons) lime/yr		
		Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency)		
665 permanent, 270 corporate, and 86 matrixed employees		313 workers (Section 7.2.2.2)	88 workers (Section 7.2.2.1)	

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives: With Coal-Fired Generation	No-Action Alternatives: With Gas-Fired Generation	No-Action Alternatives: With Purchased Power
Land Use Impacts				
SMALL – Adopting by reference Category 1 issue findings (Appendix A, Table A-1, Issues 52, 53)	SMALL – Not an impact evaluated by GEIS (NRC 1996b)	SMALL to MODERATE – 134 hectares (331 acres) required for the powerblock and associated facilities at Salem location; 52 hectares (128 acres) for ash/sludge disposal for a 20-year period (Section 7.2.2.2)	SMALL– 34 hectares (84 acres) for facility at Salem location (Section 7.2.2.1). New gas pipeline would be built to connect with existing gas pipeline corridor	SMALL to 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 1996b)
Water Quality Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 3 and 6-11). One Category 2 ground-water issue applies (and Section 4.5, Issue 33). Four Category 2 ground- water issues don't apply (Section 4.1, Issue 13; Section 4.6, Issue 34; 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 less than Salem by using cooling towers and discharge to the Delaware Estuary. (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 1996b)

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives With Coal-Fired Generation	No-Action Alternatives With Gas-Fired Generation	No-Action Alternatives With Purchased Power
Air Quality Impacts				
SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 51). One Category 2 issue does not apply (Section 4.11, Issue 50).	SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issue 88)	MODERATE – 5,822 metric tons (6,418 tons) SOx/yr 1,740 metric tons (1,919 tons) NOx/yr 1,740 metric tons (1,919 tons) CO/yr 13 metric tons (14 tons) $PM_{2.5}$/yr 49 metric tons (54 tons) PM_{10}/yr 289 kg (637 lb) mercury/yr 19,200,000 metric tons (21,100,000 tons) CO_2/yr (Section 7.2.2.2)	SMALL to MODERATE – 34 metric tons (37 tons) SOx/yr 554 metric tons (611 tons) NOx/yr 115 metric tons (127 tons) CO/yr 96 metric tons (106 tons) $PM_{2.5}$/yr[a] 5,600,000 metric tons (6,200,000 tons) CO_2 /yr (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of air quality impacts from alternate technologies (NRC 1996b)
Ecological Resource Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A 1, Issues 15-24 and 45-48). Three Category 2 issues apply (Section 4.2, Issue 25; Section 4.3, Issue 26; and Section 4.4, Issue 27) One Category 2 issue not applicable (Section 4.9, Issue 40).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 90)	SMALL to MODERATE – 52 hectares (128 acres) of the existing site could be required for ash/sludge disposal over a 20-year period. (Section 7.2.2.2)	SMALL – Construction 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 1996b)

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Threatened or Endangered Species Impacts				
SMALL – No Federally threatened or endangered species are known residents at the site. One federally threatened species occurs in a transmission corridor, and two other protected species are known to occur in the vicinity of transmission corridors. (Section 4.10, Issue 49)	SMALL – Not an impact evaluated by GEIS (NRC 1996b)	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
Human Health Impacts				
SMALL – Adopting by reference Category 1 issues (Table A-1, Issues 56, 58, 61, 62). One Category 2 issue does not apply (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 1996b)	SMALL – Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions (NRC 1996b)	SMALL to MODERATE – Adopting by reference GEIS description of human health impacts from alternate technologies (NRC 1996b)

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives: With Coal-Fired Generation	No-Action Alternatives: With Gas-Fired Generation	No-Action Alternatives: With Purchased Power
Socioeconomic Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 64, 67). Two Category 2 issues findings are not applicable (Section 4.16, Issue 66 and Section 4.17.1, Issue 68). Location in high population area with no growth controls minimizes potential for housing impacts. Section 4.14, Issue 63). Station property tax payments represents approximately 20 percent of the taxes paid to Lower Alloways Creek Township and less than 10 percent each of the city of Salem and Salem County's total tax revenues (Section 4.17..2, Issue 69). Because the tax revenues collected from Salem are provided to Salem County by Lower Alloways Creek Township in exchange for government services, and impacts to the county are small, the impacts of license renewal are considered SMALL. Capacity of public water supply and transportation infrastructure minimizes potential for related impacts (Section 4.15, Issue 65; and Section 4.18, Issue 70). Two Category 2 issues do not apply (Section 4.16, Issue 66 and Section 4.17.1, Issue 68).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 91)	MODERATE – Reduction in permanent work force at Salem could adversely affect surrounding counties. (Section 7.2.2.2)	MODERATE – Reduction in permanent work force at Salem could adversely affect surrounding counties. (Section 7.2.2.1)	MODERATE – Adopting by reference GEIS description of socioeconomic impacts from alternate technologies (NRC 1996b)

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives		
		With Coal-Fired Generation	**With Gas-Fired Generation**	**With Purchased Power**
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)	MODERATE – 235,000 metric tons (259,000 tons) of coal ash and 147,000 metric tons (163,000 tons) of scrubber sludge annually would require 52 hectares (128 acres) over a 20-year period. (Section 7.2.2.2)	SMALL – The only noteworthy waste would be from spent selective catalytic reduction (SCR) used for NOX control. (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of waste management impacts from alternate technologies (NRC 1996b)
Aesthetic Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 73, 74)	SMALL – Not an impact evaluated by GEIS (NRC 1996b)	SMALL – Visual impacts would be consistent with the industrial nature of the site. (Section 7.2.2.2)	SMALL– Steam turbines and stacks would create visual impacts comparable to those from existing Salem facilities (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies (NRC 1996b)
Cultural Resource Impacts				
SMALL – SHPO consultation minimizes potential for impact (Section 4.19, Issue 71). Because the site is an artificial island made of dredge spoils, impacts to cultural resources are unlikely.	SMALL – Not an impact evaluated by GEIS (NRC 1996b)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site. (Section 7.2.2.2)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site. (Section 7.2.2.1)	SMALL – Adopting by reference GEIS description of cultural resource impacts from alternate technologies (NRC 1996b)

Table 8.0-2 Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives: With Coal-Fired Generation	No-Action Alternatives: With Gas-Fired Generation	No-Action Alternatives: With Purchased Power

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.
LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource (10 CFR 51, Subpart A, Appendix B, Table B 1, Footnote 3).

[a] All TSP for gas-fired alternative is $PM_{2.5}$.

Btu	=	British thermal unit	NOx	=	nitrogen oxide
ft^3	=	cubic foot	PJM	=	regional electric distribution network
gal	=	gallon	$PM_{2.5}$	=	particulates having diameter less than 2.5 microns
GEIS	=	Generic Environmental Impact Statement (NRC 1996)	PM_{10}	=	particulates having diameter less than 10 microns
kWh	=	kilowatt-hour	SHPO	=	State Historic Preservation Officer
lb	=	pound	SOx	=	sulfur dioxide
MM	=	million	TSP	=	total suspended particulates
MW	=	megawatt	yr	=	year

Chapter 9

Status of Compliance

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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 PSEG has obtained for current Salem operations. In this context, PSEG uses "authorizations" to include any permits, licenses, approvals, or other entitlements. PSEG expects to continue renewing these authorizations, where appropriate, during the current license period and throughout the period of extended operations associated with renewal of the Salem operating licenses. Because the NRC regulatory focus is prospective, Table 9.1-1 does not include authorizations that PSEG obtained for past activities that did not include continuing obligations.

Preparatory to applying for renewal of the Salem license to operate, PSEG conducted an assessment to identify any new and significant environmental information (Chapter 5). The assessment included interviews with subject experts, review of Salem environmental documentation, and communication with state and federal environmental protection agencies. Based on this assessment, PSEG concludes that Salem is in substantive compliance with applicable environmental standards and requirements. Minor deviations from applicable standards or requirements are immediately corrected, and notification is provided to regulatory agencies as required. For example, Salem identified a single deviation in its cooling water discharge above a NJPDES permit residual chlorine limitation. PSEG has corrected the deviation, implemented corrective actions, and provided notification to the NJDEP.

Table 9.1-2 lists additional environmental authorizations and consultations related to NRC renewal of the Salem licenses to operate. As indicated, PSEG anticipates needing relatively few such authorizations and consultations. Sections 9.1.2 through 9.1.4 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 the continued existence of 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, and with NMFS for marine species, or both. USFWS and NMFS have issued joint procedural regulations at Title 50 in the Code of Federal Regulations (CFR) Part 402, Subpart B, that address consultation, and USFWS maintains the joint list of threatened and endangered species at 50 CFR 17.

Although not required of an applicant by federal law or NRC regulation, PSEG has chosen to invite comment from federal and state agencies regarding potential effects that Salem license renewal might have. Appendix C includes copies of PSEG correspondence with USFWS, NMFS, NJDEP and the Delaware Department of Natural Resources and Environmental Control and replies that have been received. In 1993, NMFS issued a biological opinion that the continued operation of Salem would not jeopardize threatened or endangered aquatic species (NMFS 1993). NMFS reviewed that opinion in 1999 and found that Salem does not jeopardize any threatened or endangered aquatic species (NMFS 1999b).

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 any undertaking to, prior to issuing the license, take into account the effect of the undertaking on historic properties and to afford the Advisory Council on Historic Preservation an opportunity to comment on the undertaking. Advisory 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, PSEG has chosen to invite comment on the proposed license renewal for Salem by the New Jersey and Delaware SHPOs. Appendix D contains a copy of PSEG's letter to the New Jersey and Delaware SHPOs and the SHPOs responses that have been received.

9.1.4 WATER QUALITY (401) CERTIFICATION

Federal Clean Water Act Section 401 requires an applicant seeking a federal license for an activity that may result in a discharge to navigable waters to provide the licensing agency with a certification by the state where the discharge would originate indicating that applicable state water quality standards will not be violated as a result of the discharge (33 USC 1341). Salem’s 401 Certification is provided in Appendix G. The NRC has indicated in its Generic Environmental Impact Statement for License Renewal that issuance of an NPDES permit by a state implies continued Section 401 certification by the state (NRC 1996b, Section 4.2.1.1). Section 402(b) of the Clean Water Act provides that the Governor of any State can apply to the Administrator of the Environmental Protection Agency to administer the NPDES Program in the State. On April 13, 1982, the New Jersey State NJPDES Permit Program, Pretreatment Program, and State regulation of Federal facilities were approved by EPA. The incorporated rules at N.J.A.C. 7:14A were adopted March 6, 1981, giving the State of New Jersey authorization to implement the NPDES permitting program. Accordingly, as evidence of continued Section 401 certification by New Jersey, PSEG is providing the existing Salem NJPDES permit (NJ0005622) (included in Appendix B). In addition the cover letter to the NJDEP dated January 31, 2006, transmitting the application for renewal of the permit, and NJDEP’s acknowledgment of receipt for the application is also provided in Appendix B. Issuance of the renewed permit is pending. Because the NJPDES permit was filed in a timely manner, Salem continues to operate under an authorized administratively-continued permit.

9.1.5 COASTAL ZONE MANAGEMENT PROGRAM COMPLIANCE

The federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on an applicant for a federal license to conduct an activity that could affect a state's coastal zone. Salem Nuclear Generating Station, located in Salem County, is within the New Jersey Coastal Management Area (NJDEP 2007c). Therefore, a determination is necessary from the NJDEP Land Use Regulation Program that the proposed NRC license renewal is consistent with New Jersey's Coastal Management Program. The certification package prepared by PSEG, which provides the basis for the required determination, has been prepared and submitted to the NJDEP Land Use Regulation Program at the time of submittal of this application in accordance with applicable regulations.

Salem Nuclear Generating Station is not within the Delaware Coastal Management Area.

Table 9.1-1 Authorizations for Current Salem Operations

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
U. S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10	License to operate	Salem 1 – DPR-70 Salem 2 – DPR-75	Issued: 8/13/1976 Expires: 8/13/2016 Issued: 5/20/1981 Expires: 4/18/2020	Operation of Salem
U. S. Army Corps of Engineers	33 CFR 330	Nationwide Permit	CENAP-OP-R-2006-6232-45	Issued: 7/14/2008 Expires: 7/14/2010	Maintenance Dredging
U. S. Department of Transportation	49 CFR Part 107, Subpart G, 49 U.S.C. 5108	Certificate of Registration	US DOT ID 997370 061908 002 018QS	Issued: 7/1/2008 Expires: 6/30/2011	Hazardous Material Registration Statement
Delaware River Basin Commission	Delaware River Basin Compact, Section 3.8	Groundwater Allocation Permit	D-90-71	Issued: 11/15/2000 Expires: 11/15/2010	Ground-water withdrawal of up to 43.2 million gallons/month (30-days) and 300 million gallons/year
Delaware River Basin Commission	Delaware River Basin Compact, Section 3.8	Surface Water Permit	DRBC Docket No. D-68-20-CP (revision 2)	Issued: 9/13/2001 Expires: 9/13/2026	Construction and operation of Salem.
Delaware River Basin Commission	Delaware River Basin Compact (DRBC) Resolutions Nos. 71-4 and 71-4	Water Use Contract	76-EP-482	Issued: 1/13/1977 Expires: None	Water Use contract for Delaware River water withdrawal in compliance with D-68-20-CP

Table 9.1-1 Authorizations for Current Salem Operations (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Delaware River Basin Commission	Delaware River Basin Compact, Section 3.8	Approval of wells and installation/allocation of ground water	D75-94	Issued: 8/27/1975 Expires: None	Ground-water withdrawal – Well No. 5 – 23 million gallons/ month
U.S. Department of Commerce, National Oceanic and Atmospheric Administration, and National Marine Fisheries Service	Section 7 of the Endangered Species Act of 1973 (16 USC 1531-1544)	Incidental Take Statement - sea turtles and shortnose sturgeon	NA	Issued: 5/14/1993 Expires: None	Possession and disposition of impinged or stranded sea turtles and shortnose sturgeon
New Jersey Department of Environmental Protection	Clean Water Act (33 USC 1251 et seq.), N.J. Statutes Annotated (N.J.S.A.) Water Pollution Control Act 58:10A et seq. and N.J. Administrative Code (N.J.A.C.)7:14A et seq.	New Jersey Pollutant Discharge Elimination System Permit	NJ0005622	Issued: 6/29/2001 Effective: 8/1/2001 Expires: 7/31/2006 Administratively continued while renewal application is being reviewed.	Wastewater (industrial surface water, thermal surface water and stormwater runoff) surface water discharge to Delaware River
New Jersey Department of Environmental Protection	New Jersey Water Supply Management Act, N.J.S.A 58:1A-1 et seq	Water Allocation Permit for Salem and HCGS	Activity No: WAP040001 Program Interest ID: 2216P	Issued: 12/30/2004 Effective: 1/1/2005 Expires: 1/31/2010	Ground-water withdrawal of up to 43.2 million gallons/month (30 days) and 300 million gallons/year.
New Jersey Department of Environment Protection	Clean Air Act (42 USC 7401)	Air Pollution Control Operating Permit (Title V Operating Permit)	BOP080001	Issued: 2/2/2005 Modified: 3/26/2009 Expires: 2/1/2010	Air emissions from all sources

Table 9.1-1 Authorizations for Current Salem Operations (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
New Jersey Department of Environmental Protection	N.J.S.A. 23:8A-1 and N.J.S.A. 13:8A-1 et seq	Grant of Permanent Right-of-Way	None	Issued: 11/4/1971	Transmission Corridor
New Jersey Department of Environmental Protection	N.J.A.C., Title 7, Chapter 1E (NJAC 7:1E-1 et seq.)	Discharge Prevention, Containment, and Countermeasure (DPCC) Plan and Discharge Cleanup and Removal (DCR) Plan Approval	170400041000	Issued: 3/4/2009 Expires: 7/27/2011	DPCC/DCR Program: Discharge Prevention, Containment and Countermeasure Plan; Discharge Cleanup and Removal Plan; Spill Prevention, Control and Countermeasure Plan; Hazardous Waste Contingency Plan; Stormwater Pollution Prevention Plan; Core Plan
New Jersey Department of Environmental Protection	Safe Drinking Water Act	Public Water Supply Identification Number	1704300	Issued: 9/4/1980 Expires: None	Water quality data input into compliance database
New Jersey Department of Environmental Protection	N.J.A.C. 7:26-38.8	Medical Waste Generator Certificate	34571	Issued: 8/14/1992 Expires: Renewed annually	Generation of regulated medical waste
New Jersey Department of Environmental Protection	N.J.S.A. 13:19-1	Coastal Areas Facility Review Act (CAFRA) Permit	1704-02-0001.3 CAF 040001	Issued: 9/23/2004 Expires: 9/23/2009	Land use associated with the construction of DM Plant

Table 9.1-1 Authorizations for Current Salem Operations (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
New Jersey Department of Environmental Protection	N.J.S.A. 13:19-1	CAFRA Permit	1704-02-0001.3 CAF 040002	Issued: 3/24/2005 Expires: 3/24/2010	Land use associated with the construction of Maintenance and Project Support Bldg.
New Jersey Department of Environmental Protection	N.J.S.A. 13:19-1, 13:9B-1 and 13:1D-1	CAFRA Permit	1704-02-0001.4 CAF 050003	Issued: 12/1/2005 Expires: 12/1/2010	Land use associated with the construction of NAB Parking Lot
New Jersey Department of Environmental Protection	N.J.S.A. 13:19-1, 13:9B-1 and 13:1D-1	Freshwater Wetlands (FWW) Permit	1704-02-0001.4 FWW 050002	Issued: 12/1/2005 Expires: 12/1/2010	Land use associated with the construction of NAB Parking Lot
New Jersey Department of Environmental Protection	N.J.S.A. 12:5-1, 13:19-1, 13:9B-1 and 13:1D-1	CAFRA Permit	1704-02-0001.4 CAF 050002	Issued: 8/16/2005 Expires: 8/16/2010	Land use associated with the construction of Security Vehicle Barrier System
New Jersey Department of Environmental Protection	N.J.S.A. 12:5-1, 13:19-1, 13:9B-1 and 13:1D-1	FWW Permit	1704-02-0001.4 FWW 050001	Issued: 8/16/2005 Expires: 8/16/2010	Land use associated with the construction of Security Vehicle Barrier System
New Jersey Department of Environmental Protection	N.J.S.A. 12:5-1, 13:19-1, 13:9B-1 and 13:1D-1	FWW Permit	1704-02-0001.4 FWW 050002	Issued: 8/16/2005 Expires: 8/16/2010	Land use associated with the construction of Security Vehicle Barrier System
New Jersey Department of Environmental Protection	N.J.S.A. 12:5-1, 13:19-1, 13:9B-1 and 13:1D-1	Waterfront Development Permit	1704-02-0001.4 WFD 050001	Issued: 8/16/2005 Expires: 8/16/2010	Land use associated with the construction of Security Vehicle Barrier System

Table 9.1-1 Authorizations for Current Salem Operations (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
The State of New Jersey	N.J.S.A. 12:3-23	Riparian Easement Grant	68-12	Issued: 1/10/1974 Expires: None	Construction and Maintenance of Access Roads
The State of New Jersey	N.J.S.A. 12:3-23	Riparian License	69-80	Issued: 8/29/1972 Expires: None	Construction of Intake and Discharge System
U.S. Department of the Army	52 Stat. 804, 33 USC 558b and 53 Stat. 1414, 33USC 558b-1	Deed of Easement		Issued: 4/24/1968 Expires: None	Construction on and use of Artificial Island
U.S. Environmental Protection Agency	RCRA, Section 3010	Acknowledgement of Notification of Hazardous Waste Activity	NJD077070811	Acknowledged: 9/13/1989 Expires: None	Hazardous Waste Generation
U.S. Environmental Protection Agency	USEPA Facility Repose Plan (40 CFR 9 and 112), and the USEPA Hazardous Waste Contingency Plan (40 CFR 265 Subparts C and D)	Facility Response Plan Approval	0200087	Pending	Spill/Discharge Response Program
U.S. Environmental Protection Agency	Spill Prevention, Control, and Countermeasure (SPCC) rule (40 CFR 112)	Spill Prevention, Control, and Countermeasure (SPCC) Plan Approval		Pending	Spill/Discharge Prevention Program
Lower Alloways Creek Township	Lower Alloways Creek Township Code	Preliminary and Final Site Plan Approval	SP-1-05	Issued: 5/25/2005 Expires: None	Operating a Shooting Range
Lower Alloways Creek Township	Lower Alloways Creek Township Code	Preliminary and Final Site Plan Approval	SP-2-05	Issued: 8/24/2005 Expires: None	Improvements to Employee Parking Lots B & C

Table 9.1-1 Authorizations for Current Salem Operations (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Lower Alloways Creek Township	Lower Alloways Creek Township Code	Minor Site Plan Approval	SP-3-04	Issued: 10/27/2004 Expires: None	Salem HCGS DM Plant Upgrades
Lower Alloways Creek Township	Lower Alloways Creek Township Code, Land Development Chapter, Section 5.07B2	Renewal of Conditional Use Permit	CU-07-1	Issued: 12/19/2007 Expires: 12/19/2012	Continued Storage of Radioactive Material (Spent Fuel Storage Pools)
Lower Alloways Creek Township	Lower Alloways Creek Township Code, Land Development Chapter, Section 5.07B2	Conditional Use Approval/ Preliminary Site Plan Approval	SP-1-04	Issued: 5/26/2004 Expires: 5/26/2009	Construction of ISFSI Facility and temporary storage of spent nuclear fuel
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	0018-29-09-X	Issued: 10/23/2008 Expires: 12/31/2009	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-NJ002-L09	Issued: 10/28/2008 Expires: 12/31/2009	Transportation of radioactive waste into the State of Tennessee

Table 9.1-2 Authorizations for Salem License Renewal[a]

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License renewal	Environmental Report submitted in support of license renewal application
U.S. Fish and Wildlife Service	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires federal agency issuing a license to consult with the U.S. Fish and Wildlife Service if there is reason to believe that an endangered or threatened species may be present in the area and that implementation of such action will likely affect such species (Appendix C)
New Jersey Department of Environmental Protection	Clean Water Act Section 401 (33 USC 1341)	Certification	State issuance of NJPDES permit (Section 9.1.5) constitutes 401 certification (Appendix B)
New Jersey Department of Environmental Protection, Land Use Regulations	Federal Coastal Zone Management Act (16 USC 1452 et seq.)	Certification	Requires the federal agency issuing the license (NRC) to verify that the State of New Jersey has determined that renewal of the Salem operating license would be consistent with the federally approved State Coastal Zone Management program. The applicant (PSEG) has requested the consistency determination from the NJDEP by submitting a certification of consistency for review.
New Jersey Department of Environmental Protection, Division of Parks and Forestry	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Requires the federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer (SHPO). SHPO must concur that license renewal will not affect any sites listed or eligible for listing on the National Register of Historic Places (Appendix D)

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 probably could be constructed and operated to comply with applicable environmental quality standards and requirements. PSEG notes that increasingly stringent air quality protection requirements could make the construction of a large fossil-fueled power plant infeasible in many locations. PSEG also notes that the EPA has revised its 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.

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Chapter 10

References

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

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Appendix A

NRC NEPA Issues for License Renewal of Nuclear Power Plants

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PSEG has prepared this environmental report in accordance with the requirements of U.S. Nuclear Regulatory Commission (NRC) regulation 10 CFR 51.53. NRC included in the regulation a list of National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants.

Table A-1 lists these 92 issues and identifies the section in which PSEG addressed each applicable issue in this environmental report. For organization and clarity, PSEG has assigned a number to each issue and uses the issue numbers throughout the environmental report.

Table A-1. Salem Units 1 & 2 Environmental Report Discussion of License Renewal NEPA Issues[a]

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 Salem has no plans to undertake.
2. Impacts of refurbishment on surface water use	1	NA	Issue applies to an activity, refurbishment, that Salem has no plans to undertake.
3. Altered current patterns at intake and discharge structures	1	4 Introduction	4.2.1.2.1/4-5
4. Altered salinity gradients	1	4 Introduction	4.2.1.2.2/4-4
5. Altered thermal stratification of lakes	1	NA	Issue applies to a plant feature, discharge to a lake, that Salem does not have.
6. Temperature effects on sediment transport capacity	1	4 Introduction	4.2.1.2.3/4-8
7. Scouring caused by discharged cooling water	1	4 Introduction	4.2.1.2.3/4-6
8. Eutrophication	1	4 Introduction	4.2.1.2.3/4-9
9. Discharge of chlorine or other biocides	1	4 Introduction	4.2.1.2.4/4-10
10. Discharge of sanitary wastes and minor chemical spills	1	4 Introduction	4.2.1.2.4/4-10
11. Discharge of other metals in waste water	1	4 Introduction	4.2.1.2.4/4-10
12. Water use conflicts (plants with once-through cooling systems)	1	4 Introduction	4.2.1.3/4-13
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	NA, and discussed in Section 4.1	Issue applies to a plant feature, cooling ponds or cooling towers, that Salem does not have.
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	NA	Issue applies to an activity, refurbishment, that Salem has no plans to undertake.
15. Accumulation of contaminants in sediments or biota	1	4 Introduction	4.2.1.2.4/4-10
16. Entrainment of phytoplankton and zooplankton	1	4 Introduction	4.2.2.1.1/4-15
17. Cold shock	1	4 Introduction	4.2.2.1.5/4-18
18. Thermal plume barrier to migrating fish	1	4 Introduction	4.2.2.1.6/4-19
19. Distribution of aquatic organisms	1	4 Introduction	4.2.2.1.6/4-19

Table A-1. Salem Units 1 & 2 Environmental Report Discussion of License Renewal NEPA Issues[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
20. Premature emergence of aquatic insects	1	4 Introduction	4.2.2.1.7/4-20
21. Gas supersaturation (gas bubble disease)	1	4 Introduction	4.2.2.1.8/4-21
22. Low dissolved oxygen in the discharge	1	4 Introduction	4.2.2.1.9/4-23
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4 Introduction	4.2.2.1.10/4-24
24. Stimulation of nuisance organisms (e.g., shipworms)	1	4 Introduction	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	4.2	4.2.2.1.2/4-16
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	4.3	4.2.2.1.3/4-16
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	4.4	4.2.2.1.4/4-17
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	NA	Issue applies to a heat dissipation system, cooling towers, that Salem does not have.
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	NA	Issue applies to a heat dissipation system, cooling towers, that Salem does not have.
30. Heat shock for plants with cooling-tower-based heat dissipation systems	1	NA	Issue applies to a heat dissipation system, cooling towers, that Salem does not have.
Groundwater Use and Quality			
31. Impacts of refurbishment on groundwater use and quality	1	NA	Issue applies to an activity, refurbishment, that Salem has no plans to undertake.

Table A-1. Salem Units 1 & 2 Environmental Report Discussion of License Renewal NEPA Issues[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
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 Salem 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 and 4.8.2.1/4-118
34. Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	NA, and discussed in Section 4.6	Issue applies to a plant feature, cooling towers, that Salem does not have.
35. Groundwater use conflicts (Ranney wells)	2	NA, and discussed in Section 4.7	Issue applies to a plant feature, Ranney wells, that Salem does not have.
36. Groundwater quality degradation (Ranney wells)	1	NA	Issue applies to a feature, Ranney wells, that Salem does not have.
37. Groundwater quality degradation (saltwater intrusion)	1	4 Introduction	4.8.2/4-118
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	NA	Issue applies to a feature, cooling ponds, that Salem 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, that Salem 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 Salem has no plans to undertake.
41. Cooling tower impacts on crops and ornamental vegetation	1	NA	Issue applies to a feature, cooling towers, that Salem does not have.
42. Cooling tower impacts on native plants	1	NA	Issue applies to a feature, cooling towers, that Salem does not have.
43. Bird collisions with cooling towers	1	NA	Issue applies to a feature, cooling towers, that Salem does not have.
44. Cooling pond impacts on terrestrial resources	1	NA	Issue applies to a feature, cooling ponds, that Salem does not have.
45. Power line right-of-way management (cutting and herbicide application)	1	4 Introduction	4.5.6.1/4-71

Table A-1. Salem Units 1 & 2 Environmental Report Discussion of License Renewal NEPA Issues[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
46. Bird collisions with power lines	1	4 Introduction	4.5.6.2/4-74
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4 Introduction	4.5.6.34-77
48. Floodplains and wetlands on power line right-of-way	1	4 Introduction	4.5.7.7/4-81
Threatened or Endangered Species (for all plants)			
49. Threatened or endangered species	2	4.10	4.1/4-1
Air Quality			
50. Air quality during refurbishment (non-attainment and maintenance areas)	2	NA, and discussed in Section 4.11	Issue applies to an activity, refurbishment, that Salem does not plan to undertake.
51. Air quality effects of transmission lines	1	4 Introduction	4.5.2/4-62
Land Use			
52. Onsite land use	1	4 Introduction	3.2/3-1
53. Power line right-of-way land use impacts	1	4 Introduction	4.5.3/4-62
Human Health			
54. Radiation exposures to the public during refurbishment	1	NA	Issue applies to an activity, refurbishment, that Salem has no plans to undertake.
55. Occupational radiation exposures during refurbishment	1	NA	Issue applies to an activity, refurbishment, that Salem has no plans to undertake.
56. Microbiological organisms (occupational health)	1	4 Introduction	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	NA, and discussed in Section 4.12	Issue applies to plant features, cooling lakes, canals or towers, that Salem does not have.
58. Noise	1	4 Introduction	4.3.7/4-49
59. Electromagnetic fields, acute effects	2	4.13	4.5.4.1/4-66
60. Electromagnetic fields, chronic effects	NA	4 Introduction	
61. Radiation exposures to public (license renewal term)	1	4 Introduction	4.6.2/4-87
62. Occupational radiation exposures (license renewal term)	1	4 Introduction	4.6.3/4-95

Table A-1. Salem Units 1 & 2 Environmental Report Discussion of License Renewal NEPA Issues[a] (Continued)

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 - not applicable to Salem) 4.7.1/4-101 (renewal term)
64. Public services: public safety, social services, and tourism and recreation	1	4 Introduction	Refurbishment (not applicable to Salem) Renewal Term 4.7.3/4-104 (public safety) 4.7.3.3/4-106 (safety) 4.7.3.44-107 (social) 4.7.3.6/4-107 (tourism, recreation)
65. Public services: public utilities	2	4.15	3.7.4.5/3-19 (refurbishment - not applicable to Salem) 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 Salem does not plan to undertake.
67. Public services: education (license renewal term)	1	4 Introduction	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 Salem does not plan 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 - not applicable to Salem) 4.7.3.2/4-106 (renewal term)
71. Historic and archaeological resources	2	4.19	3.7.7/3-23 (refurbishment - not applicable to Salem) 4.7.7/4-114 (renewal term)
72. Aesthetic impacts (refurbishment)	1	NA	Issue applies to an activity, refurbishment, that Salem has no plans to undertake.
73. Aesthetic impacts (license renewal term)	1	4 Introduction	4.7.6/4-111
74. Aesthetic impacts of transmission lines (license renewal term)	1	4 Introduction	4.5.8/4-83

Table A-1. Salem Units 1 & 2 Environmental Report Discussion of License Renewal NEPA Issues[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Postulated Accidents			
75. Design basis accidents	1	4 Introduction	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) 5.3.3.5/5-95 (economic) 5.4/5-106 (mitigation) 5.5.2/5-114 (summary)
Uranium Fuel Cycle and Waste Management			
77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4 Introduction	6.2/6-8
78. Offsite radiological impacts (collective effects)	1	4 Introduction	Not in GEIS.
79. Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4 Introduction	Not in GEIS.
80. Nonradiological impacts of the uranium fuel cycle	1	4 Introduction	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 Introduction	6.4.2/6-36 (low-level def) 6.4.3/6-37 (low-level volume) 6.4.4/6-48 (renewal effects)
82. Mixed waste storage and disposal	1	4 Introduction	6.4.5/6-63
83. Onsite spent fuel	1	4 Introduction	6.4.6/6-70
84. Nonradiological waste	1	4 Introduction	6.5/6-86
85. Transportation	1	4 Introduction	6.3/6-31, as revised by Addendum 1, August 1999.
Decommissioning			
86. Radiation doses (decommissioning)	1	4 Introduction	7.3.1/7-15
87. Waste management (decommissioning)	1	4 Introduction	7.3.2/7-19 (impacts) 7.4/7-25 (conclusions)
88. Air quality (decommissioning)	1	4 Introduction	7.3.3/7-21 (air) 7.4/7-25 (conclusions)
89. Water quality (decommissioning)	1	4 Introduction	7.3.4/7-21 (water) 7.4/7-25 (conclusions)

Table A-1. Salem Units 1 & 2 Environmental Report Discussion of License Renewal NEPA Issues[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
90. Ecological resources (decommissioning)	1	4 Introduction	7.3.5/7-21 (ecological) 7.4/7-25 (conclusions)
91. Socioeconomic impacts (decommissioning)	1	4 Introduction	7.3.7/7-19 (socioeconomic) 7.4/7-24 (conclusions)
Environmental Justice			
92. Environmental justice	NA	2.6.2	

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).

Appendix B

NPDES Permit

This Appendix contains a copy of Salem Generating Station's New Jersey Pollutant Discharge Elimination System permit NJ 0005622, which authorizes the discharge of wastewater to the Delaware River and stipulates the conditions of the permit. Also attached is the cover letter to the New Jersey Department of Environmental Protection dated January 31, 2006, transmitting the application for renewal of the permit, and NJDEP's acknowledgment of receipt for the application.

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Table of Contents

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DONALD T. DIFRANCESCO
Acting Governor

State of New Jersey
Department of Environmental Protection

Division of Water Quality
P.O. Box 029, Trenton, NJ 08625-029
FAX: (609) 984-7938

Robert C. Shinn, Jr.
Commissioner

Salem Permit Program
Received
JUL 03 2001
File # ____________

June 29, 2001

Dear Interested Party:

Re: PSEG Nuclear LLC
Salem Generating Station
Lower Alloways Creek, Salem County
NJPDES Permit No. NJ0005622

In view of your expressed interest in the above noted subject, enclosed is a copy of the final NJPDES permit renewal for the above referenced facility. This NJPDES permit renewal serves to finalize the December 8, 2000, draft permit action issued by the New Jersey Department of Environmental Protection ("the Department") and includes a Response to Comments document.

This final permit action continues the wetlands restoration and fish ladder related requirements contained in the July 20, 1994, NJPDES permit. Specifically, with reference to the wetlands restoration requirement, PSEG was required to restore a minimum of 10,000 acres of salt marsh wetlands to provide more fish breeding and nursery areas, thereby increasing ecological productivity. To implement these NJPDES permit requirements, PSEG created the Estuary Enhancement Program (EEP). To date, the EEP has restored and/or preserved over 20,500 acres of land in and around the Delaware Estuary, making this the largest privately funded wetlands restoration project in the nation.

During the public comment period, the Department received extensive written comments as well as public testimony at the January 23 and January 25, 2001, public hearings. Many interested parties commented specifically on the EEP and the wetland restoration requirements. While many commentors praised the environmental benefits of the wetlands restoration program, some commentors expressed specific concern regarding the continued need to use herbicides to meet restoration goals for portions of the Alloways Creek site. Given this concern, the Department would like to inform you of one significant change in the Administrative Record pertaining specifically to this issue that has occurred since the end of the public comment period on March 14, 2001. By way of a letter dated June 8, 2001, PSEG informed the Department of its decision to make certain changes to the restoration program for the Alloways Creek site. Specifically, PSEG stated that it would cease utilizing herbicides for the management of approximately 1,000 acres of the western portion of the Alloways Creek site; retain these 1,000 acres of *Phragmites*-dominated wetlands; and purchase approximately 1,000 additional acres to ensure compliance with the permit conditions. The Department intends to pursue implementation of this decision by PSEG with appropriate refinements, as necessary. This issue is further discussed in the Response 48 included in the enclosed Response to Comments document.

The Department would also like to note that, in response to comments from the US Fish and Wildlife Service, PSEG has agreed to fund the construction of two additional fish ladders in New Jersey, provided suitable sites are available. In addition, PSEG has agreed to fund construction of an artificial reef in New Jersey. These commitments are included as conditions in Part IV of this final permit action.

This NJPDES permit action involves several complex issues and the Department staff will be pleased to provide any additional information that you may need. Please feel free to contact Susan Rosenwinkel of the Bureau of Point Source Permitting-Region 2, if you have any additional questions. Ms. Rosenwinkel may be reached at (609) 292-4860.

On behalf of the Department, I thank you for your interest in the protection of our state's valuable natural resources.

Sincerely,

Narinder K. Ahuja

Narinder K. Ahuja
Director

Enclosures

State of New Jersey

DONALD T. DIFRANCESCO
Acting Governor

Department of Environmental Protection
Division of Water Quality
P.O. Box 029 Trenton, NJ 08625-0029
Phone: (609) 292-4860
Fax: (609) 984-7938

Robert C. Shinn, Jr.
Commissioner

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

R. Edwin Selover
PSEG SERVICES CORPORATION
80 PARK PLAZA, T5A
NEWARK, NJ 07102-4194

JUN 29 2001

Re: Final Surface Water Renewal Permit Action
Category: B -Industrial Wastewater
NJPDES Permit No. NJ0005622
PUBLIC SERVICE ENERGY GROUP NUCLEAR LLC
Lower Alloways Creek, Salem County

Dear Mr. Selover::

Enclosed is a **final** New Jersey Pollutant Discharge Elimination System (NJPDES) ~~permit action~~ identified above which has been issued in accordance with N.J.A.C. 7:14A.

A summary of the significant and relevant comments received on the draft action during the public comment period, the Department's responses, and an explanation of any changes from the draft action have been included in the Response to Comments document attached hereto as per N.J.A.C. 7:14A-15.16.

Any requests for an adjudicatory hearing shall be submitted in writing by certified mail, or by other means which provide verification of the date of delivery to the Department, within 30 days of receipt of this Surface Water Renewal Permit Action in accordance with N.J.A.C. 7:14A-17.2. You may also request a stay of any contested permit condition as per N.J.A.C. 7:14A-17.6 et seq. The adjudicatory hearing request must be accompanied by a completed Adjudicatory Hearing Request Form; the stay request must be accompanied by a completed Stay Request Form (forms enclosed).

All monitoring shall be conducted in accordance with 1) the Department's "Field Sampling Procedures Manual" applicable at the time of sampling (N.J.A.C. 7:14A-6.5(b)4), and/or 2) the method approved by the Department in Part IV of the permit. The Field Sampling Procedures Manual is available through Maps and Publications Sales Office; Bureau of Revenue, PO Box 417, Trenton, New Jersey 08625, at (609) 777-1038.

Questions or comments regarding the final action should be addressed to Susan Rosenwinkel at (609) 292-4860

Sincerely,

Pilar Patterson

Pilar Patterson, Chief
Bureau of Point Source Permitting – Region 2

Enclosures
cc: Permit Distribution List
Masterfile #: 15646; PI #: 46814

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ADJUDICATORY HEARING REQUEST CHECKLIST AND TRACKING FORM FOR INDIVIDUAL NJPDES PERMITS*

I. Permit Being Appealed:

Facility Name: PSEG NUCLEAR LLC
Masterfile Number: 15646
Program Interest (PI) Number: 46814

Issuance Date of Final Permit Decision: 06/29/2001
Permit Number: NJ0005622

II. Person Requesting Hearing:

Name/Organization ______________________ Name of Attorney (if applicable) ______________________

Address ______________________ Address of Attorney ______________________

Telephone Number ______________________ Telephone Number of Attorney ______________________

III. Status of Person Requesting Hearing (Check One):

_____ Permittee under the permit number identified above.
Complete A. and C. through I. of Section IV. below.

_____ Person seeking consideration as a party to the action.
Complete B. through I. of Section IV. below.

IV. Include the following information as part of your request:

A. If you are a permittee under the permit number identified above:
1. For the Office of Legal Affairs only, a copy of the permit clearly indicating the permit number and issuance date;
2. A list of the specific contested permit condition(s) and the legal or factual question(s) at issue for each condition, including the basis of any objection;
3. The relevance of the legal and/or factual issues to the permit decision;
4. Suggested revised or alternative permit conditions and how they meet the requirements of the State or Federal Act; and
5. Information supporting the request or other written documents relied upon to support the request, unless this information is already in the administrative record (in which case, such information shall be specifically referenced in the request).

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B. If you are a <u>person seeking consideration as a party to the action</u>:
1. A statement setting forth each legal or factual question alleged to be at issue;
2. A statement setting forth the relevance of the legal or factual issue to the permit decision, together with a designation of the specific factual areas to be adjudicated;
3. A clear and concise factual statement of the nature and scope of your interest which meets the criteria set forth at N.J.A.C. 7:14A-17.3(c)4;
4. A statement that, upon motion by any party granted by the administrative law judge, or upon order of the administrative law judge's initiative, you shall make yourself, all persons you represent, and all of your officers, directors, employees, consultants, and agents available to appear and testify at the administrative hearing, if granted;
5. Specific references to the contested permit conditions, as well as suggested revised or alternative permit conditions, including permit denials, which, in your judgment, would be required to implement the purposes of the State Act;
6. Identification of the basis for any objection to the application of control or treatment technologies, if identified in the basis or fact sheets, and the alternative technologies or combination of technologies which, in your judgment, are necessary to satisfy the requirements of the State Act;

C. The date you received notification of the final permit decision;

D. The names and addresses of all persons whom you represent;

E. A statement as to whether you raised each legal and factual issue during the public comment period in accordance with N.J.A.C. 7:14A-15.13;

F. An estimate of the amount of time required for the hearing;

G. A request, if necessary, for a barrier-free hearing location for disabled persons;

H. A clear indication of any willingness to negotiate a settlement with the Department prior to the Department's processing of your hearing request to the Office of Administrative Law; and

I. This form, completed, signed and dated with all of the information listed above, including attachments, to:
1. Office of Legal Affairs
ATTENTION: Adjudicatory Hearing Requests
Department of Environmental Protection
401 East State Street
PO Box 402, Trenton, New Jersey 08625-0402
2. Pilar Patterson, Chief
Bureau of Point Source Permitting – Region 2
Department of Environmental Protection
401 East State Street
PO Box 029, Trenton, New Jersey 08625-0029
3. Any other person named on the permit (if you are a permittee under that permit).
4. The permittee(s) (if you are a person seeking consideration as a party to the action).

V. Signature: ______________________________ Date: __________

Susan Rosenwinkel, Bureau of Point Source Permitting – Region 2

*For NJPDES permits, the procedures for requesting an adjudicatory hearing on a final permit decision and for the Department's evaluation and processing of such requests are set forth in N.J.A.C. 7:14A-17.

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STAY REQUEST AND TRACKING FORM

Permit Containing Condition(s) to Be Stayed:

PSEG NUCLEAR LLC

Issuance Date of Final Permit Decision	Permit Number
06/29/2001	NJ0005622

II. Person Requesting the Stay(s):

_______________________	_______________________
Name/Organization	Name of Attorney (if applicable)
_______________________	_______________________
_______________________	_______________________
_______________________	_______________________
Address	Address of Attorney
_______________________	_______________________
Telephone Number	Telephone Number of Attorney

N.J.A.C. 7:14A-17.6 provides for stays of contested permit conditions. In order for the Department to consider a request for stay, the person making the request must submit a written request to the Department by certified mail or other means which provides verification of the date of delivery. In the request for a stay of each permit condition, a written evaluation must be submitted which addresses each of the factors at N.J.A.C. 7:14A-17.6(c). Briefly stated, these factors include: 1) the permittee's ability to comply with the permit condition using existing treatment facilities, ~~2) the permittee's~~ ability to comply with the permit condition by implementing low cost short-term modifications ~~to~~ the existing treatment facility, 3) the level of pollutant control actually achieved using short term modifications, 4) the cost to comply with the condition and 5) the environmental impacts granting a stay will have on the receiving waterbody.

This completed stay request form, along with the evaluations mentioned above, shall be submitted to both Pilar Patterson, Chief, Bureau of Point Source Permitting – Region 2, Division of Water Quality, Department of Environmental Protection, PO Box 029, Trenton, New Jersey, 08625-0029 and the Office of Legal Affairs, Department of Environmental Protection, PO Box 402, Trenton, New Jersey 08625-0402. A person seeking consideration as party to the action who has requested an adjudicatory hearing in accordance with N.J.A.C. 7:14A-17.2 may also request a stay provided notice of the request is also provided to the permittee(s).

Signature: ______________________________ Date: ____________

*For NJPDES permits, the procedures for requesting a stay of a final permit condition and for the Department's evaluation and processing of such requests are set forth in N.J.A.C. 7:14A-17.

Permit Number NJ0005622

Table of Contents

This Permit Package Contains the Items Listed Below

New Jersey Department of Environmental Protection

NEW JERSEY POLLUTANT DISCHARGE ELIMINATION SYSTEM

The New Jersey Department of Environmental Protection hereby grants you a NJPDES permit for the facility/activity named in this document. This permit is the regulatory mechanism used by the Department to help ensure your discharge will not harm the environment. By complying with the terms and conditions specified, you are assuming an important role in protecting New Jersey's valuable water resources. Your acceptance of this permit is an agreement to conform with all of its provisions when constructing, installing, modifying, or operating any facility for the collection, treatment, or discharge of pollutants to waters of the state. If you have any questions about this document, please feel free to contact the Department representative listed in the permit cover letter. Your cooperation in helping us protect and safeguard our state's environment is appreciated.

Permit Number: NJ0005622

Final: Surface Water Renewal Permit Action

Permittee:
PSEG NUCLEAR LLC
FOOT OF HANCOCKS BRIDGE ROAD
LOWER ALLOWAYS CREEK, NJ 08038-0000

Co-Permittee:

Property Owner:
PSEG NUCLEAR LLC
FOOT OF HANCOCKS BRIDGE ROAD
LOWER ALLOWAYS CREEK, NJ 08038-0000

Location Of Activity:
PSEG NUCLEAR LLC
FOOT OF HANCOCKS BRIDGE ROAD
LOWER ALLOWAYS CREEK, NJ 08038-0000

Authorization(s) Covered Under This Approval	Issuance Date	Effective Date	Expiration Date
B -Industrial Wastewater	06/29/2001	08/01/2001	07/31/2006

By Authority of:
Commissioner's Office

Narinder K. Ahuja
DEP AUTHORIZATION
Narinder Ahuja
Director
Division of Water Quality

(Terms, conditions and provisions attached hereto)

Division of Water Quality

PSEG GENERATING STA (SALEM)
Lower Alloways Creek

Permit No. NJ0005622
Discharge to Surface Water
Surface Water Renewal Permit Action

PART I
GENERAL REQUIREMENTS:
NJPDES

A. General Requirements of all NJPDES Permits

1. Requirements Incorporated by Reference

a. The permittee shall comply with all conditions set forth in this permit and with all the applicable requirements incorporated into this permit by reference. The permittee is required to comply with the regulations, including those cited in paragraphs b. through e. following, which are in effect as of the effective date of the final permit.

b. General Conditions

Penalties for Violations	N.J.A.C. 7:14-8.1 et seq.
Incorporation by Reference	N.J.A.C. 7:14A-2.3
Toxic Pollutants	N.J.A.C. 7:14A-6.2(a)4i
Duty to Comply	N.J.A.C. 7:14A-6.2(a)1 & 4
Duty to Mitigate	N.J.A.C. 7:14A-6.2(a)5 & 11
Inspection and Entry	N.J.A.C. 7:14A-2.11(e)
Enforcement Action	N.J.A.C. 7:14A-2.9
Duty to Reapply	N.J.A.C. 7:14A-4.2(e)3
Signatory Requirements for Applications and Reports	N.J.A.C. 7:14A-4.9
Effect of Permit/Other Laws	N.J.A.C. 7:14A-6.2(a)6 & 7 & 2.9(c)
Severability	N.J.A.C. 7:14A-2.2
Administrative Continuation of Permits	N.J.A.C. 7:14A-2.8
Permit Actions	N.J.A.C. 7:14A-2.7(c)
Reopener Clause	N.J.A.C. 7:14A-6.2(a)10
Permit Duration and Renewal	N.J.A.C. 7:14A-2.7(a) & (b)
Consolidation of Permit Process	N.J.A.C. 7:14A-15.5
Confidentiality	N.J.A.C. 7:14A-18.2 & 2.11(g)
Fee Schedule	N.J.A.C. 7:14A-3.1
Treatment Works Approval	N.J.A.C. 7:14A-22 & 23

c. Operation And Maintenance

Need to Halt or Reduce not a Defense	N.J.A.C. 7:14A-2.9(b)
Proper Operation and Maintenance	N.J.A.C. 7:14A-6.12

d. Monitoring And Records

Monitoring	N.J.A.C. 7:14A-6.5
Recordkeeping	N.J.A.C. 7:14A-6.6
Signatory Requirements for Monitoring Reports	N.J.A.C. 7:14A-6.9

e. Reporting Requirements

Planned Changes	N.J.A.C. 7:14A-6.7
Reporting of Monitoring Results	N.J.A.C. 7:14A-6.8
Noncompliance Reporting	N.J.A.C. 7:14A-6.10 & 6.8(h)
Hotline/Two Hour & Twenty-four Hour Reporting	N.J.A.C. 7:14A-6.10(c) & (d)
Written Reporting	N.J.A.C. 7:14A-6.10(e) &(f) & 6.8(h)
Duty to Provide Information	N.J.A.C. 7:14A-2.11, 6.2(a)14 & 18.1
Schedules of Compliance	N.J.A.C. 7:14A-6.4
Transfer	N.J.A.C. 7:14A-6.2(a)8 & 16.2

GENERAL REQUIREMENTS Page 1 of 1

PSEG NUCLEAR LLC, Lower Alloways Creek

Permit No.NJ0005622
DSW000002 Surface Water Renewal Permit Action

PART II

GENERAL REQUIREMENTS: DISCHARGE CATEGORIES

A. Additional Requirements Incorporated By Reference

1. Requirements for Discharges to Surface Waters

a. In addition to conditions in Part I of this permit, the conditions in this section are applicable to activities at the permitted location and are incorporated by reference. The permittee is required to comply with the regulations which are in effect as of the effective date of the final permit.

i. Surface Water Quality Standards N.J.A.C. 7:9B-1

ii. Water Quality Management Planning Regulations N.J.A.C. 7:15

B. General Conditions

1. Scope

a. The issuance of this permit shall not be considered as a waiver of any applicable federal, state, and local rules, regulations and ordinances.

2. Permit Renewal Requirement

a. Permit conditions remain in effect and enforceable until and unless the permit is modified, renewed or revoked by the Department.

b. Submit a complete permit renewal application: 180 days before the Expiration Date.

3. Notification of Non-Compliance

a. The permittee shall notify the Department of all non-compliance when required in accordance with N.J.A.C. 7:14A-6.10 by contacting the DEP HOTLINE at 1-877-WARNDEP (1-877-927-6337).

b. The permittee shall submit a written report as required by N.J.A.C. 7:14A-6.10 within five days.

4. Notification of Changes

a. The permittee shall give written notification to the Department of any planned physical or operational alterations or additions to the permitted facility when the alteration is expected to result in a significant change in the permittee's discharge and/or residuals use or disposal practices including the cessation of discharge in accordance with N.J.A.C. 7:14A-6.7.

b. Prior to any change in ownership, the current permittee shall comply with the requirements of N.J.A.C. 7:14A-16.2, pertaining to the notification of change in ownership.

5. Access to Information

a. The permittee shall allow an authorized representative of the Department, upon the presentation of credentials, to enter upon a person's premises, for purposes of inspection, and to access / copy any records that must be kept under the conditions of this permit.

6. Operator Certification

a. Pursuant to N.J.A.C. 7:10A-1.1 et seq. every wastewater system not exempt pursuant to N.J.A.C. 7:10A-1.1(b) requires a licensed operator. The operator of a system shall meet the Department's requirements pursuant to N.J.A.C. 7:10A-1.1 and any amendments. The name of the proposed operator, where required shall be submitted to the Department at the address below, in order that his/her qualifications may be determined prior to initiating operation of the treatment works.

i. Notifcations shall be submitted to:
NJDEP
Examination and Licensing Unit
P.O. Box 417
Trenton, New Jersey 08625
(609)777-1012

b. The permittee shall notify the Department of any changes in licensed operator within two weeks of the change.

7. Operation Restrictions

a. The operation of a waste treatment or disposal facility shall at no time create: (a) a discharge, except as authorized by the Department in the manner and location specified in Part III of this permit; (b) any discharge to the waters of the state or any standing or ponded condtion for water or waste, except as specifically authorized by a valid NJPDES permit.

PART III
LIMITS AND MONITORING REQUIREMENTS

A. 048C SW OUTFALL 48C

Location Description

Samples obtained for this internal monitoring point shall be collected after all treatment has been performed but prior to mixing with any circulating water system effluent. The permittee has the ability to route the discharge from 48C to DSN's 481, 482, 484 and/or 485.

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - A - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Monthly Average	1 / Day	Calculated	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	1 / Day	Calculated	January thru December	Final	
Solids, Total Suspended	Effluent Gross Value	30 MG/L	Monthly Average	2 / Month	Composite	January thru December	Final	
Solids, Total Suspended	Effluent Gross Value	100 MG/L	Daily Maximum	2 / Month	Composite	January thru December	Final	
Nitrogen, Ammonia Total (as N)	Effluent Gross Value	35 MG/L	Monthly Average	2 / Month	Composite	January thru December	Final	
Nitrogen, Ammonia Total (as N)	Effluent Gross Value	70 MG/L	Daily Maximum	2 / Month	Composite	January thru December	Final	
Petroleum Hydrocarbons	Effluent Gross Value	10 MG/L	Monthly Average	2 / Month	Grab	January thru December	Final	
Petroleum Hydrocarbons	Effluent Gross Value	15 MG/L	Daily Maximum	2 / Month	Grab	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Gross Value	REPORT MG/L	Monthly Average	2 / Month	Composite	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Gross Value	50 MG/L	Daily Maximum	2 / Month	Composite	January thru December	Final	

B. 481A SW OUTFALL 481A

Location Description

Samples shall be obtained at the discharge "standpipe" which is a point after combination of the two circulators and introduction of all other wastewater components. Unless service water system is being discharged, the effluent limits of 0.2 mg/L (daily max.) and "monitor only" (monthly average) apply for CPO.

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - B - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Monthly Average	1 / Day	Calculated	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	1 / Day	Calculated	January thru December	Final	
pH	Effluent Gross Value	6.0 SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Effluent Gross Value	9.0 SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
LC50 Statre 96hr Acu Cyprinodon	Effluent Gross Value	50 %EFFL	Daily Minimum	2 / Year	Composite	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	REPORT MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.3 MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.5 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.2 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Monthly Average	1 / Day	Continuous	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Daily Maximum	1 / Day	Continuous	January thru December	Final	

C. 482A SW OUTFALL 482A

Location Description

Samples shall be obtained at the discharge "standpipe" which is a point after combination of the two circulators and introduction of all other wastewater components. Unless service water system is being discharged, the effluent limits of 0.2 mg/L (daily max.) and "monitor only" (monthly average) apply for CPO.

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - C - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Monthly Average	1 / Day	Calculated	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	1 / Day	Calculated	January thru December	Final	
pH	Effluent Gross Value	6.0 SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Effluent Gross Value	9.0 SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
LC50 Statre 96hr Acu Cyprinodon	Effluent Gross Value	50 %EFFL	Daily Minimum	2 / Year	Composite	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	REPORT MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.3 MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.5 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.2 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Monthly Average	1 / Day	Continuous	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Daily Maximum	1 / Day	Continuous	January thru December	Final	

D. 483A SW OUTFALL 483A

Location Description

Samples shall be obtained at the discharge "standpipe" which is a point after combination of the two circulators and introduction of all other wastewater components. Unless service water system is being discharged, the effluent limits of 0.2 mg/L (daily max.) and "monitor only" (monthly average) apply for CPO.

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - D - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Monthly Average	1 / Day	Calculated	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	1 / Day	Calculated	January thru December	Final	
pH	Effluent Gross Value	6.0 SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Effluent Gross Value	9.0 SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.3 MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	REPORT MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.5 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.2 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Monthly Average	1 / Day	Continuous	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Daily Maximum	1 / Day	Continuous	January thru December	Final	

E. 484A SW OUTFALL 484A

Location Description

Samples shall be obtained at the discharge "standpipe" which is a point after combination of the two circulators and introduction of all other wastewater components. Unless service water system is being discharged, the effluent limits of 0.2 mg/L (daily max.) and "monitor only" (monthly average) apply for CPO..

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - E - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Monthly Average	1 / Day	Calculated	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	1 / Day	Calculated	January thru December	Final	
pH	Effluent Gross Value	6.0 SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Effluent Gross Value	9.0 SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
LC50 Statre 96hr Acu Cyprinodon	Effluent Gross Value	50 %EFFL	Daily Minimum	2 / Year	Composite	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	REPORT MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.3 MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.5 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.2 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Monthly Average	1 / Day	Continuous	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Daily Maximum	1 / Day	Continuous	January thru December	Final	

F. 485A SW OUTFALL 485A

Location Description

Samples shall be obtained at the discharge "standpipe" which is a point after combination of the two circulators and introduction of all other wastewater components. Unless service water system is being discharged, the effluent limits of 0.2 mg/L (daily max.) and "monitor only" (monthly average) apply for CPO.

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - F - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Monthly Average	1 / Day	Calculated	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	1 / Day	Calculated	January thru December	Final	
pH	Effluent Gross Value	6.0 SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Effluent Gross Value	9.0 SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
LC50 Statre 96hr Acu Cyprinodon	Effluent Gross Value	50 %EFFL	Daily Minimum	2 / Year	Composite	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	REPORT MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.3 MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.5 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.2 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Monthly Average	1 / Day	Continuous	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Daily Maximum	1 / Day	Continuous	January thru December	Final	

G. 486A SW OUTFALL 486A

Location Description

Samples shall be obtained at the discharge "standpipe" which is a point after combination of the two circulators and introduction of all other wastewater components. Unless service water system is being discharged, the effluent limits of 0.2 mg/L (daily max.) and "monitor only" (monthly average) apply for CPO.

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - G - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Monthly Average	1 / Day	Calculated	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	1 / Day	Calculated	January thru December	Final	
pH	Effluent Gross Value	6.0 SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Effluent Gross Value	9.0 SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Minimum	1 / Week	Grab	January thru December	Final	
pH	Intake From Stream	REPORT SU	Daily Maximum	1 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.3 MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	REPORT MG/L	Monthly Average	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.5 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Chlorine Produced Oxidants	Effluent Gross Value	0.2 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Monthly Average	1 / Day	Continuous	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Daily Maximum	1 / Day	Continuous	January thru December	Final	

H. 487B SW OUTFALL 487B

Location Description

Samples shall be obtained from the discharge monitoroing point of the #3 Skim Tank. DSN 487B discharges to Zone 5 of the Delaware River

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - H - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Monthly Average	1 / Batch	Calculated	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	1 / Batch	Calculated	January thru December	Final	
pH	Effluent Gross Value	6.0 SU	Daily Minimum	1 / Batch	Grab	January thru December	Final	
pH	Effluent Gross Value	9.0 SU	Daily Maximum	1 / Batch	Grab	January thru December	Final	
Solids, Total Suspended	Effluent Gross Value	REPORT MG/L	Monthly Average	1 / Batch	Grab	January thru December	Final	
Solids, Total Suspended	Effluent Gross Value	100 MG/L	Daily Maximum	1 / Batch	Grab	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Monthly Average	1 / Batch	Grab	January thru December	Final	
Temperature, oC	Effluent Gross Value	43.3 DEG.C	Daily Maximum	1 / Batch	Grab	January thru December	Final	
Petroleum Hydrocarbons	Effluent Gross Value	REPORT MG/L	Monthly Average	1 / Batch	Grab	January thru December	Final	
Petroleum Hydrocarbons	Effluent Gross Value	15 MG/L	Daily Maximum	1 / Batch	Grab	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Gross Value	REPORT MG/L	Monthly Average	1 / Batch	Grab	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Gross Value	50 MG/L	Daily Maximum	1 / Batch	Grab	January thru December	Final	

I. 489A SW OUTFALL 489A

Location Description

Samples for DSN 489 shall be obtained at the terminus of the oil/water separator. DSN 489 discharges to Zone 5 of the Delaware River.

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - I - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Monthly Average	1 / Month	Calculated	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	1 / Month	Calculated	January thru December	Final	
pH	Effluent Gross Value	6.0 SU	Daily Minimum	1 / Month	Grab	January thru December	Final	
pH	Effluent Gross Value	9.0 SU	Daily Maximum	1 / Month	Grab	January thru December	Final	
Solids, Total Suspended	Effluent Gross Value	100 MG/L	Daily Maximum	1 / Month	Grab	January thru December	Final	
Solids, Total Suspended	Effluent Gross Value	30 MG/L	Monthly Average	1 / Month	Grab	January thru December	Final	
Petroleum Hydrocarbons	Effluent Gross Value	10 MG/L	Monthly Average	1 / Month	Grab	January thru December	Final	
Petroleum Hydrocarbons	Effluent Gross Value	15 MG/L	Daily Maximum	1 / Month	Grab	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Gross Value	REPORT MG/L	Monthly Average	1 / Month	Grab	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Gross Value	50 MG/L	Daily Maximum	1 / Month	Grab	January thru December	Final	

J. FACA SW OUTFALL FACA

Location Description

Samples collected at DSN's 481A, 482A and 483A shall be reported as a whole to represent the thermal discharge from Unit 1. DSN's 481A, 482A and 483A discharge to Zone 5 of the Delaware River.

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - J - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Temperature, oC	Raw Sew/influent	REPORT DEG.C	Monthly Average	Continuous	Continuous	January thru December	Final	
Temperature, oC	Raw Sew/influent	REPORT DEG.C	Daily Maximum	Continuous	Continuous	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Monthly Average	Continuous	Continuous	January thru December	Final	
Temperature, oC	Effluent Gross Value	46.1 DEG.C	Daily Maximum	Continuous	Continuous	June thru September	Final	
Temperature, oC	Effluent Gross Value	43.3 DEG.C	Daily Maximum	Continuous	Continuous	October thru May	Final	
Temperature, oC	Effluent Net Value	REPORT DEG.C	Monthly Average	1 / Day	Calculated	January thru December	Final	
Temperature, oC	Effluent Net Value	15.3 DEG.C	Daily Maximum	1 / Day	Calculated	January thru December	Final	

K. FACB SW OUTFALL FACB

Location Description

Samples collected at DSN's 484A, 485A and 486A shall be reported as a whole to represent the thermal discharge from Unit 2. DSN's 484A, 485A and 486A discharge to Zone 5 of the Delaware River.

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - K - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Temperature, oC	Raw Sew/influent	REPORT DEG.C	Monthly Average	Continuous	Continuous	January thru December	Final	
Temperature, oC	Raw Sew/influent	REPORT DEG.C	Daily Maximum	Continuous	Continuous	January thru December	Final	
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Monthly Average	Continuous	Continuous	January thru December	Final	
Temperature, oC	Effluent Gross Value	46.1 DEG.C	Daily Maximum	Continuous	Continuous	June thru September	Final	
Temperature, oC	Effluent Gross Value	43.3 DEG.C	Daily Maximum	Continuous	Continuous	October thru May	Final	
Temperature, oC	Effluent Net Value	REPORT DEG.C	Monthly Average	1 / Day	Calculated	January thru December	Final	
Temperature, oC	Effluent Net Value	15.3 DEG.C	Daily Maximum	1 / Day	Calculated	January thru December	Final	

L. FACC SW OUTFALL FACC

Location Description

Samples collected at DSN's 481-486 shall be reported as a whole to represent the thermal discharge and circulating water system intake flow from the facility as a whole. DSN's 481-486 discharge to Zone 5 of the Delaware River.

Discharge Categories

Industrial Wastewater

Surface Water DMR Reporting Requirements:

Submit a Monthly DMR: within twenty-five days after the end of every month beginning from the effective date of the permit (EDP).

Table III - L - 1: Surface Water DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Flow, In Conduit or Thru Treatment Plant	Raw Sew/influent	3024 MGD	Monthly Average	1 / Day	Calculated	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Raw Sew/influent	REPORT MGD	Daily Maximum	1 / Day	Calculated	January thru December	Final	
Thermal Discharge Million BTUs per Hr	Effluent Net Value	REPORT MBTU/HR	Monthly Average	1 / Day	Calculated	January thru December	Final	
Thermal Discharge Million BTUs per Hr	Effluent Net Value	30600 MBTU/HR	Daily Maximum	1 / Day	Calculated	January thru December	Final	

PART IV

SPECIFIC REQUIREMENTS: NARRATIVE

Notes and Definitions

A. Footnotes

B. Definitions

Industrial Wastewater

A. MONITORING REQUIREMENTS

1. Standard Monitoring Requirements

a. Each analysis required by this permit shall be performed by a New Jersey Certified Laboratory that is certified to perform that analysis.

b. The Permittee shall perform all water/wastewater analyses in accordance with the analytical test procedures specified in 40 CFR 136 unless other test procedures have been approved by the Department in writing or as otherwise specified in the permit.

c. All sampling shall be conducted in accordance with the Department's Field Sampling Procedures Manual; or an alternate method approved by the Department in writing.

d. All monitoring shall be conducted as specified in Part III.

e. All sample frequencies expressed in Part III are minimum requirements. However, if additional samples are taken, analytical results shall be reported as appropriate.

f. Annual and semi-annual wastewater testing shall be conducted in a different quarter of each year so that tests are conducted in each of the four permit quarters of the permit cycle. Testing may be conducted during any month of the permit quarters.

g. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

B. RECORDKEEPING

1. Standard Recordkeeping Requirements

a. The permittee shall retain records of all monitoring information including all calibration and maintenance records, all original strip chart recordings for continuous monitoring instrumentation, copies of all reports, and all data used to complete the application for this permit.

b. Records of monitoring information shall include the date, locations and time of sampling or measurements, the individual who performed the sampling or measurements, the date the samples were collected, the date the samples were analyzed, the individual who performed the analysis, the analytical method used, and the results.

c. The permittee shall retain copies of all reports required by a NJPDES permit and records of all data used to complete the application for a NJPDES permit for a period of at least 5 years unless otherwise required by 40 CFR Part 503.

d. The permittee shall allow an authorized representative of the Department, upon the presentation of credentials, to enter upon a person's premises, for purposes of inspection, and to access / copy any records that must be kept under the conditions of this permit.

C. REPORTING

1. Standard Reporting Requirements

a. The permittee shall submit all required monitoring results to the DEP on the forms provided to the following addresses:

i. NJDEP
Division of Water Quality
Bureau of Permit Management
P.O. Box 029
Trenton, New Jersey 08625

ii. DRBC
P. O. Box 7360
West Trenton, New Jersey 08628

b. If requested by the Water Compliance and Enforcement Bureau, please send the information requested to the following address:

i. Southern Bureau of Water Compliance and Enforcement
One Port Center
2 Riverside Drive, Suite 201
Camden, NJ 08103.

c. For submittal of paper monitoring report forms:

i. All monitoring reports shall be signed by the highest ranking official having day-to-day managerial and operational responsibilities for the discharging facility in accordance with N.J.A.C. 7:14A-6.9.

ii. The highest ranking official may delegate responsibility to sign in accordance with NJAC 7:14A-6.9(c).

d. Monitoring reports shall be completed in accordance with the current Discharge Monitoring Report Manual and any updates.

e. If monitoring for a parameter is not required for that monitoring period, the permittee is required to report "CODE=N" on that Monitoring Report Form.

f. For intermittent discharges, the permittee shall obtain a sample during at least one of the discharge events occurring during a monitoring period. Report "NODI" only if there are no discharge events during the entire monitoring period.

D. SUBMITTALS

1. Standard Submittal Requirements

a. The permittee shall amend the Operation & Maintenance Manual whenever there is a change in the treatment works design, construction, operations or maintenance which substantially changes the treatment works operations and maintenance procedures.

E. FACILITY MANAGEMENT

1. Discharge Requirements

a. The permittee shall discharge at the location(s) specified in PART III of this permit.

b. The permittee shall not discharge foam, or cause objectionable deposits, or foaming of the receiving water.

c. The permittee's discharge shall not produce objectionable color or odor in the receiving stream.

d. The discharge shall not exhibit a visible sheen.

e. The Permittee is authorized to use the following additives:

i. DSN's 481-486: sodium hypochlorite may be used in the service water system, if needed, in excess of two hours per day to allow for continuous chlorination to control macroinvertebrate fouling.

ii. DSN's 481-486: Sodium hypochlorite may also be added to the circulating water system to control biofouling, upon prior notification to the Department. As part of this notification, the permittee shall provide the Department with a methodology for sodium hypochlorite addition. Upon approval by the Department, in writing, chlorine produced oxidants may not be discharged from DSN's 481-486 for more than two hours per day where chlorine produced oxidants shall be monitored three times per day at DSN's 481-486 during this two hour period. A daily maximum effluent limitation of 0.2 mg/L would apply during the chlorination of the main condensers where the permittee would be required to maintain a log noting the time and duration of chlorination of the main condensers.

iii. DSN 48C: The permittee is authorized to use the following additives in the steam plant and the non-radioactive waste disposal system: ammonium hydroxide, hydrazine, ethanolamine, which are used for corrosion control in the plant steam systems; sodium hypochlorite, hydrogen peroxide, sodium hydroxide, and a coagulant aid, which are used in the non-radioactive liquid waste diposal treatment system; and sodium hydroxide and sufuric acid, which are used to regulate demineralizers.

iv. DSN 487B: Ammonia and hydrazine are used for corrosion control in the auxiliary boiler blowdown which affects.

v. All outfalls: If the permittee decides to begin using additional agents or replace the above agents in the future for any outfalls, the permittee must notify the Department at least 180 days prior to use so that the permit may be reopened, if necessary, to incorporate any additional limitations deemed necessary.

2. Applicability of Discharge Limitations and Effective Dates

a. The effluent limitations contained in PART III apply for the full term of this permit action.

3. Operation, Maintenance and Emergency conditions

a. The permittee shall operate and maintain treatment works and facilities which are installed or used by the permittee to achieve compliance with the terms and conditions of the permit as specified in the Operation & Maintenance Manual.

b. The permittee shall develop emergency procedures to ensure effective operation of the treatment works under emergency conditions in accordance with NJAC 7:14A-6.12(d).

4. Toxicity Testing Requirements-Acute Whole Effluent Toxicity

a. The permittee shall conduct toxicity tests on its wastewater discharge in accordance with the provisions in this section. Such testing will determine if appropriately selected effluent concentrations adversely affect the test species.

b. Acute toxicity tests shall be conducted using the test species and method identified in Part III of this permit.

c. Any test that does not meet the specifications of N.J.A.C. 7:18, laboratory certification regulations, must be repeated within 30 days of the completion of the initial test. The repeat test shall not replace subsequent testing required in Part III.

d. The permittee shall collect and analyze the concentration of ammonia-N in the effluent on the day a sample is collected for WET testing. The required ammonia-N analysis may be conducted on an aliquot of the acute toxicity testing composite sample. This result is to be reported on the Biomonitoring Report Form.

e. Submit an Acute Methodology Questionnaire: within 60 days from the effective date of the permit (EDP). The permittee shall resubmit after any change of laboratory occurs.

f. Submit an acute whole effluent toxicity test report: within twenty-five days after the end of every 6 month monitoring period beginning from the effective date of the permit (EDP) The permittee shall submit toxicity test results on appropriate forms.

g. Test reports shall be submitted to:
New Jersey Department of Environmental Protection
Division of Water Quality, Bureau of Point Source Permitting Region 2, P.O. Box 029, Trenton, New Jersey 08625.

5. Toxicity Reduction Implementation Requirements (TRIR)

a. The permittee shall initiate a tiered toxicity investigation if two out of six consecutive WET tests demonstrate that the effluent does not comply or will not comply with the toxicity limit specified in Part III of this permit.

i. If the exceedence of the toxicity limit is directly caused by a documented facility upset, or other unusual event which has been identified and appropriately remedied by the permittee, the toxicity test data collected during the event may be eliminated when determining the need for initiating a TRIR upon written Department approval.

b. The permittee shall begin toxicity characterization within 30 days of the end of the monitoring period when the second toxicity test exceeds the toxicity limits in Part III. The monitoring frequency for toxicity testing shall be increased to monthly. Up to 12 additional tests may be required.

i. The permittee may return to the toxicity testing frequency specified in Part III if four consecutive toxicity tests conducted during the Toxicity Characterization do not exceed the toxicity limit.

ii. If two out of any six consecutive, acceptable tests again exceed the toxicity limit in Part III, the permittee shall repeat Toxicity Reduction Implementation Requirements.

c. The permittee shall initiate a preliminary toxicity identification (PTI) upon the third exceedence of the toxicity limit specified in Part III during toxicity characterization.

i. The permittee may return to the monitoring frequency specified in PART III while conducting the PTI. If more frequent WET testing is performed during the PTI, the permittee submit all biomonitoring reports to the DEP and report the results for the most sensitive species on the DMR.

ii. As appropriate, the PTI shall include:
(1) treatment plant performance evaluation,
(2) pretreatment program information,
(3) evaluation of ammonia and chlorine produced oxidants levels and their effect on the toxicity of the discharge,
(4) evaluation of chemical use and processes at the facility, and
(5) an evaluation of incidental facility procedures such as floor washing, and chemical spill disposal which may contribute to effluent toxicity.

iii. If the permittee demonstrates that the cause of toxicity is the chlorine added for disinfection or the ammonia concentration in the effluent and the chlorine and/or ammonia concentrations are below the established water quality based effluent limitation for chlorine and/or ammonia, the permittee shall identify the procedures to be used in future toxicity tests to account for chlorine and/or ammonia toxicity in their preliminary toxicity identification report.

iv. The permittee shall submit a Preliminary Toxicity Identification Notification within 15 months of triggering TRIR. This notification shall include a determination that the permittee intends to demonstrate compliance OR plans to initiate a CTI.

d. The permittee must demonstrate compliance with the WET limitation in four consecutive WET tests to satisfy the requirements of the Toxicity Reduction Investigation Requirements. After successful completion, the permittee may return to the WET monitoring frequency specified in PART III.

e. The permittee shall initiate a Comprehensive Toxicity Investigation (CTI) if the PTI does not identify the cause of toxicity and a demonstration of consistent compliance with the toxicity limit in Part III can not be made.

b. As described later under item G.13. for FAC C, circulating water system intake flow is calculated as the sum of the twelve individual circulating water pump flows and reported as a monthly average in million gallons per day. The flow of each individual circulating water pump is calculated as the product of the number of operating hours for that pump for the reporting period and the flow rate for that pump. The flow rate for each individual circulating water pump shall be determined at least annually using a Rhodamine WT dye tracer evaluation ("the Tracer Evaluation"). The permittee shall continue Tracer Evaluation testing in accordance with the same schedule as in the July 20, 1994 permit to the best extent practicable. For example, if the dye tracer evaluation was performed in March 2000 under the July 20, 1994 permit, the dye tracer evaluation under this renewal permit shall be performed in March 2001, to the best extent practicable and provided representative operations are occuring. The Department recognizes that outages, pump maintenance or other operational conditions may result on the annual tracer evaluation test being unable to be conducted in the exact same month as the previous year. Prior to performing each annual test, the appropriate Enforcement Element must be notified regarding the use of any dye.

   i. Upon completion of the Tracer Evaluation for each individual pump, the permittee shall report the following to the Department: 1) Date of Rhodamine WT dye tracer evaluation; 2) Final concentration of dye in discharge; 3) Total dye discharged; and 4) Flow rate of circulating water pump(s) tested.

   ii. The report required to be submitted pursuant to G.1.b. above shall be submitted with the DMR for the month which follows the month that the Tracer Evaluation is performed. The individual circulating water pump flow rates determined for each pump shall be used in calculating the circulating water system intake, as required for FAC C in Part III, for the month which follows the month that the Tracer Evaluation was performed.. F~~or example, if the Tracer~~ Evaluation was performed in March, the Tracer Evaluation report shall be submitted as an attachment to the DMR for April where the Tracer Evaluation results shall be used in calculating the circulating water system intake for April's DMR for FAC C.

2. Intake Screens and Fish Return System - Section 316 Special Condition.

a. The permittee shall ensure proper operation and maintenance of its Ristroph Traveling Screens at all times to minimize impingement effects on aquatic life. The permittee shall conduct semi-annual training of its employees operating the screens to ensure awareness of the function of the screens in reducing mortality of aquatic life. Training shall be conducted in early Spring. Training shall also be conducted in late Fall, after the summer season, so that station personnel can review the operation again to see what actions could be taken to improve biological efficacy. The permittee must provide upon the Department's request any material in this training at any time to ensure that it is appropriate and comprehensive.

b. Further Study and Enhancements.

   i. The permittee shall submit a ranking of best to worst (i.e. most vulnerable or frail) Representative Important Species (RIS) for which the Ristroph screens are most effective at minimizing mortality.

   ii. Based on the results of G.2.b.i, the permittee shall submit a proposed Work Plan for a study to determine ways to minimize the stresses and mortalities found associated with the fish return sluice and sampling pool which shall consider alternate flows, velocities, and depth profiles as part of this Work Plan. This Work Plan shall also consider an evaluation of fish mortality of the fish return system independent from the Ristroph screens to determine mortality rates as fish re-enter the estuary. Emphasis should be placed on reducing potential mortality of susceptible species.

   iii. PSEG shall submit the findings per G.2.b.i to the Department within 90 days of the effective date of the permit (EDP) and the proposed Work Plan required in G.2.b.ii within EDP + 180 days.

b. As described later under item G.13. for FAC C, circulating water system intake flow is calculated as the sum of the twelve individual circulating water pump flows and reported as a monthly average in million gallons per day. The flow of each individual circulating water pump is calculated as the product of the number of operating hours for that pump for the reporting period and the flow rate for that pump. The flow rate for each individual circulating water pump shall be determined at least annually using a Rhodamine WT dye tracer evaluation ("the Tracer Evaluation"). The permittee shall continue Tracer Evaluation testing in accordance with the same schedule as in the July 20, 1994 permit to the best extent practicable. For example, if the dye tracer evaluation was performed in March 2000 under the July 20, 1994 permit, the dye tracer evaluation under this renewal permit shall be performed in March 2001, to the best extent practicable and provided representative operations are occuring. The Department recognizes that outages, pump maintenance or other operational conditions may result on the annual tracer evaluation test being unable to be conducted in the exact same month as the previous year. Prior to performing each annual test, the appropriate Enforcement Element must be notified regarding the use of any dye.

   i. Upon completion of the Tracer Evaluation for each individual pump, the permittee shall report the following to the Department: 1) Date of Rhodamine WT dye tracer evaluation; 2) Final concentration of dye in discharge; 3) Total dye discharged; and 4) Flow rate of circulating water pump(s) tested.

   ii. The report required to be submitted pursuant to G.1.b. above shall be submitted with the DMR for the month which follows the month that the Tracer Evaluation is performed. The individual circulating water pump flow rates determined for each pump shall be used in calculating the circulating water system intake, as required for FAC C in Part III, for the month which follows the month that the Tracer Evaluation was performed.. F~~or example, if the Tracer~~ Evaluation was performed in March, the Tracer Evaluation report shall be submitted as an attachment to the DMR for April where the Tracer Evaluation results shall be used in calculating the circulating water system intake for April's DMR for FAC C.

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   i. The permittee shall submit a ranking of best to worst (i.e. most vulnerable or frail) Representative Important Species (RIS) for which the Ristroph screens are most effective at minimizing mortality.

   ii. Based on the results of G.2.b.i, the permittee shall submit a proposed Work Plan for a study to determine ways to minimize the stresses and mortalities found associated with the fish return sluice and sampling pool which shall consider alternate flows, velocities, and depth profiles as part of this Work Plan. This Work Plan shall also consider an evaluation of fish mortality of the fish return system independent from the Ristroph screens to determine mortality rates as fish re-enter the estuary. Emphasis should be placed on reducing potential mortality of susceptible species.

   iii. PSEG shall submit the findings per G.2.b.i to the Department within 90 days of the effective date of the permit (EDP) and the proposed Work Plan required in G.2.b.ii within EDP + 180 days.

iv. The permittee shall implement the study outlined in the Work Plan described in G.2.b.ii within 60 days of the Department's approval of the Work Plan. The Work Plan shall outline the time frame necessary for completion of the study where these time frames are subject to the Department's approval.

v. Based on these findings, the Department reserves the right to impose new requirements regarding the intake screens and/or fish return system and sampling pool. Any such new requirements shall be installed pursuant to a schedule to be set forth by the Department at the time the new requirements are imposed. Any such requirements will be incorporated as a minor modification to the NJPDES permit.

3. **Wetland Restoration and Enhancement Efforts - Section 316 Special Condition.**

a. The permittee shall continue to implement the Estuary Enhancement Program in restoring, enhancing and/or preserving wetlands within the region of the Delaware Estuary (primarily within New Jersey; not more than 20% of the acres restored or enhanced under the program to be located within Delaware and/or Pennsylvania) as follows:.

i. restore an aggregate of no less than 10,000 acres of (1) diked wetlands (including salt hay farms, muskrat impoundments and/or agricultural impoundments) to normal daily tidal inundation so as to become functional salt marsh; and/or (2) wetlands dominated by common reed (Phragmites australis) to primarily Spartina species with other naturally occurring marsh grasses (e.g. Distichilis spicata, Juncus spp.); and/or (3) upland buffer. The permittee shall secure access to or control of such lands so as to have title ownership or deed restriction as may be necessary to assure the continued protection of said lands from development;.

ii. An Upland Buffer shall mean an area of land adjacent to wetlands or open water which minimizes adverse impacts on the wetlands and serves as an integral component of the wetland ecosystem;.

iii. the acreage restored, enhanced and/or preserved pursuant to i. and ii. above shall comprise an aggregate of no less than 10,000 acres; provided, however, the permittee only will be credited one acre toward the 10,000 acre aggregate for every three acres of Upland Buffer acquired or restricted pursuant to G.2.a. ii. above.

b. The permittee shall implement the Management Plans for Dennis, Commercial, Maurice River Township, the Bayside Tract, Cohansey, Alloways, the Rocks (in Delaware) and Cedar Swamp (in Delaware). The Management Plans and any necessary revisions are automatically incorporated as conditions of this NJPDES permit.

c. Replacement Acreage - In order to comply with G.3.a. above, the Department may require the permittee to acquire additional lands to serve as "replacement acreage" for any acreage deemed "failed" by the Department.

i. Conservation Restriction - The permittee shall impose a Conservation Restriction on any replacement acreage acquired under G.3.c., which shall name the Department as a Grantee of the Conservation Restriction. The Conservation Restriction shall be in the form of Attachment A of the July 20, 1994 NJPDES permit and shall be recorded by the permittee. There shall be no liens superior to the Conservation Restriction on the lands in question, proof of which shall be provided by the permittee through a title search and/or title insurance. The permittee shall regularly inspect the property and take appropriate action to prevent or correct a violation of the Conservation Restriction notwithstanding that such violation was by a person other than the permittee.

ii. Management Plans - The permittee shall design and file Management Plan(s) for any replacement acreage acquired under G.3.c. not later than 1 year after securing control of such lands. Contemporaneous with the submission of a Management Plan to the Department, the permittee shall provide copies of said Plan to the County Library in the affected County. The permittee shall publicly notice the time and place that the Management Plan is available for review in a daily or weekly newspaper circulated in the affected County. The permittee shall complete implementation of the Management Plan consistent with the schedule approved by NJDEP and included in the Management Plan. The permittee must continue to implement the Management Plan(s) with respect to maintenance during any period of time the NJPDES permit is extended, including any lands that have met the success criteria.

d. Establishment of the EEPAC - The permittee shall establish an Estuary Enhancement Advisory Committee (EEPAC) to serve as a body to provide technical advice to the permittee concerning any continuing implementation of the existing Management Plans as well as the development and implementation of any future Management Plans for replacement acreage that may be needed. The EEPAC shall also provide technical advice concerning the design, implementation, modifications and interpretation of the Biological Monitoring Program (as described later under item G.6). Any future Management Plans(s) as well as any changes to the Biological Monitoring Program must be submitted to the EEPAC for technical advice prior to submission to the Department for approval. All materials presented at any EEPAC meetings shall be distributed to EEPAC members at least one week in advance of any meeting.

i. The permittee shall request, subject to the Department's approval, members of the EEPAC to consist of representatives from at least three agencies having jurisdiction over wetland restoration activities and/or aquatic resources (a minimum of one representative from each agency); ~~a minimum of two~~ scientists with appropriate wetlands expertise; a minimum of three scientists with appropriate expertise in aquatic resources; and representatives from Cape May, Cumberland and Salem Counties (as appointed by the governments of Cape May, Cumberland and Salem Counties). The Department shall designate two representatives from its Division of Fish and Wildlife as well as a representative from its Mosquito Control Commission. The permittee shall designate a representative to serve on the EEPAC and to serve as the EEPAC's chair.

ii. A complete list of EEPAC members shall be submitted to the Department for approval. Comply with the requirement: within 90 days from the effective date of the permit (EDP).

iii. The EEPAC shall meet at least twice per year where at least one meeting shall include a tour of some or all of the wetland restoration sites. Upon finalization of this permit, all references to the "MPAC" and "MAC" in any documentation required under the July 20, 1994 permit, or incorporated therein by reference, shall be interpreted to mean "EEPAC".

4. Fish Ladders - Section 316 Special Condition.

a. The permittee has installed eight fish ladders (five under the terms of the July 20, 1994 permit.) The locations for these fish ladders are as follows: Sunset Lake, NJ; McGinnis Pond, DE; McColley's Pond, DE; Silver Lake, DE; Coursey's Pond, DE; Cooper River, NJ; Garrisons Lake, DE and Moores Lake, DE. The permittee shall operate and maintain these fish ladders in accordance with the developed operations and maintenance manuals or ensure that agreements exist that require other parties to be responsible for operations and maintenance. The permittee shall provide formal notification to the ladder owner of any maintenance issues identified during the routine inspections. Routine inspections during the upstream adult migration period shall be performed to ensure that the ladders are operating as designed. Documentation concerning inspections and any maintenance issues shall be made available to the Department upon request.

b. The permittee shall install two additional fish ladder sites in New Jersey at sites suitable for production of alewife or blueback herring. PSEG and NJDEP shall work cooperatively together to identify appropriate sites and PSEG shall submit the candidate sites to NJDEP for approval in advance of installing fish ladders.

c. The permittee shall perform juvenile and adult passage of river herring in connection with the fish ladder sites identified in G.4.a. and G.4.b.above, where the monitoring results shall be included in the annual Biological Monitoring Program Report as required under G.6.a.iv.

d. The permittee shall continue to stock any impoundments until at least 5 adult river herring per acre of impoundment successfully complete upstream migration into each impoundment.

5. **Further Study of Intake Protection Technologies - Section 316 Special Condition.**

a. Multi-Sensory Hybrid Intake Protection Technology: PSEG shall study the feasibility of: 1) strobe light technology; 2) air bubble technology; 3) sound deterrent. These technologies shall be studied individually as well as in various combinations as a hybrid system. The objective of this study is to minimize impacts to those species that do not survive well off the intake traveling screens as well as those species that are most affected by Salem's operations (as indicated by Conditional Mortality Rates). The concerns and limitations documented by ESSA in its report for the 1994 Cage Tests; 1998 Cage Tests; and the in-situ tests shall be considered in the development of any Plan of Study with regard to any sound deterrent technologies. Also related to sound deterrents, far field attraction behavior or potential acclimation shall also be considered as part of any plan of study. Given these requirements, the permittee shall:.

i. Present a Plan of Study regarding the above technologies to the Department and distribute this to the EEPAC. Submit a description of planned activities: within 180 days from the effective date of the permit (EDP).

ii. Not later than sixty days after receipt of the Department's approval of the Plan of Study, PSEG shall ~~implement the Plan of Study in~~ accordance with the schedule approved by the Department, subject to species availability.

iii. PSEG shall complete the Study identified in 5.1.ii and file a report of the results to the Department in accordance with a schedule approved by the Department in the Plan of Study.

6. **Biological Monitoring Program - Section 316 Special Condition.**

a. The permittee shall develop and implement an improved biological monitoring program under this renewal permit. This biological monitoring program shall include, at a minimum: abundance monitoring for adult and juvenile passage of river herring as well as stocking in connection with the eight fish ladder sites; improved impingement and entrainment monitoring; review and discussion as to the appropriateness of Atlantic Silverside as a representative important species; improved bay-wide abundance monitoring; continued detrital production monitoring (including vegetative cover mapping, quantitative field sampling and geomorphology); continued study of the fish utilization of restored wetlands; and other special monitoring studies as may be recommended by the EEPAC and/or the Department and subsequently required by the Department. Additional special studies could include residual pesticide release monitoring for any replacement acreage deemed necessary under item G.3.c. where details of this monitoring is described in Part IV of the July 20, 1994 permit, as well as gear efficiency studies or catchability studies for bay-wide abundance monitoring. Until such time as an improved Biological Monitoring Program is developed and approved, the permittee shall continue in its monitoring efforts as specified in the existing (at the time of this renewal permit issuance) Biological Monitoring Program.

i. As described previously under G.3.d., the EEPAC shall provide advice regarding any improved Biological Monitoring Program. An improved Biological Monitoring Program Work Plan, shall be submitted to the EEPAC for technical advice prior to submission of the Work Plan to the Department for approval (which shall include a reporting schedule).

ii. The permittee shall submit to the Department for approval an improved Biological Monitoring Program Work Plan, which addresses the components described in item G.6.a. within EDP + 270 days.

iii. Not later than sixty days after receipt of the Department's approval of the Work Plan, the permittee shall implement the Work Plan. The improved Biological Monitoring Program Work Plan is automatically incorporated as a condition of this permit upon final approval by the Department.

iv. The results of any monitoring performed as part of the existing (at the time of this NJPDES renewal issuance) biological monitoring program and the improved biological monitoring program shall be submitted annually by June 30 of that following year in an annual report. Contemporaneous with submission of said results to the Department, the permittee shall forward the results to each member of the EEPAC for technical review.

v. Any proposed modifications to the Work Plan (as may be necessary based on Biological Monitoring Program results) shall be submitted to the EEPAC, for technical review, prior to submission to the Department for the Department's approval.

7. Entrainment and Impingement Abundance Monitoring - Section 316 Special Condition.

a. Until such time as an improved entrainment sampling plan is developed as required under G.6.a. above, the permittee shall continue to conduct entrainment sampling during normal Station operations at a minimum frequency three days per week, from April - September and once per week from October through March, weather and operational conditions permitting. During normal Station operations, nighttime sampling shall be included and a minimum of six abundance samples shall be collected per sampling day, weather and operational conditions permitting.

b. Until such time as an improved impingement sampling plan is developed as required under G.6.a. above, the permittee shall continue to conduct impingement sampling during normal Station operations at a minimum frequency of three days per week, weather and operational conditions permitting. During normal Station operations, nighttime sampling shall be included and a minimum of ten samples shall be collected per sampling day, weather and operational conditions permitting.

c. The results of all entrainment and impingment abundance monitoring shall be reported in the Biological Monitoring Program Annual Report which is due by June 30 of each following year as referenced above in G.6.a.iv. or as established in the Biological Monitoring Program Work Plan, approved by the Department.

8. Expansion of Analyses - Section 316 Special Condition.

a. Analysis of Losses at the Station - The analysis of losses at the Station shall be supplemented with the following information as recommended in the June 14, 2000 ESSA Report: 1)A further assessment of the biomass lost to the ecosystem for all RIS; 2) The contribution of RIS other than Bay Anchovy to the forage available for commercial and recreationally important species; 3) A more detailed analysis of the levels of uncertainty in the production and catch foregone estimate; 4) Projected increases in RIS abundance in the estimates of catch and production foregone. PSEG shall consider ESSA's recommendations relative to these issues in the development of the Work Plan.

b. Expansion of Analysis with regard to Entrainment Sampling - The analysis of losses at the Station shall be supplemented with the following additional information as recommended in the June 14, 2000 ESSA Report:.

i. The uncertainty of the estimated historic annual entrainment loss estimates should be characterized and presented as ranges with maximum and minimum levels.

ii. Any error in the estimation of natural mortality rate and the effect on CMR estimates with the Extended Empirical Impingement Model (EEIM) (which was used to derive estimates of CMR for alewife, blueback herring, American shad, white perch and spot) shall be investigated. The uncertainty with the CMR estimates shall also be characterized and presented.

c. The analyses specified in items G.8.a. and G.8.b. shall be provided to the Department in accordance with the schedule defined in the Department approved Work Plan. Based on the fact that ESSA did not recommend wedgewire screens, dual flow fine mesh screens, modular inclined screens, and a retrofit with a new closed-cycle cooling system, a revised fisheries analysis will not have a bearing on the inclusion of the above referenced alternate intake protection technologies at this time.

i. The permittee shall submit to the Department for approval a Work Plan including those supplemental analyses and additional information listed in G.8.a and G.8.b above. The Work Plan shall be submitted to the Department within EDP + 6 months and shall include a schedule for completion of the analyses.

ii. Not later than sixty days after receipt of the Department's approval of the Work Plan, the permittee shall implement the Work Plan. The Work Plan is automatically incorporated as a condition of this permit upon final approval by the Department.

9. Special Studies - Section 316 Special Condition.

a. Study of the Hydrodynamics at the Intake of the Station.

i. The flow field in front of the intake and the existence of vortices at the intake shall be observed and photographed during: (1) an extreme low tide (2) when the current is strongest, namely at mid tide on the flood and mid tide on the ebb.

ii. The pumping records of each pump should be examined to determine if the flow distribution is asymmetrical among the intake bays, particularly the most northern bay and the most southern bay (i.e. two outer bays).

iii. The bathymetric chart of the area and other relevant hydrodynamic data should be examined to determine the potential for a strong back eddy during the ebb in Ship Wreck Bay immediately to the south of the intake. If such an eddy exists, it will be observable from shore and from the air when the ebb current is at a maximum. The chart and other relevant hydrodynamic data may also provide insight into the flow field entering the dredged channel from the side.

b. Study of Enhancements to Entrainment and Impingement Sampling.

i. An analysis of the optimum sampling frequency for entrainment and impingement shall be conducted considering any episodic nature of the entrainment process. This needs to take explicit account of the shape of the zone of entrainment as well as the hydrodynamic study discussed above in G.9.a.

ii. Alternative entrainment sampling methods with less process error shall be investigated. PSEG shall submit a Plan of Study for evaluating alternative entrainment sampling methods within EDP + 6 months.

c. PSEG shall present its findings regarding the Study of the Hydrodynamics at the Intakes of the Plant and the Study of Enhancements to Entrainment and Impingement Sampling as follows:.

i. PSEG shall present its findings regarding the Study of the Hydrodynamics at the Intakes of the Plant to the Department within EDP + 180 days.

ii. PSEG shall present its findings regarding the Study of Enhancements to Entrainment and Impingement Sampling to the Department within 30 months following receipt of the Departments' approval of the Plan of Study.

d. Reopener - Upon completion of 9.c, the Department may reassess and adjust the entrainment and/or impingement sampling frequencies and/ sampling locations as included in the Biological Monitoring Program. The Department may also define alternative entrainment sampling methods to reduce process error, which is also included in the Biological Monitoring Program.

10. Intake Protection Technology Reopener / Submission of Documents - Section 316 Special Condition

a. Intake Protection Technology Reopener- The Department reserves the right to implement any available intake protection technology so long as the costs are not wholly disproportionate to the environmental benefits. The Department is committed to implementation of any and all such technologies it determines to be viable as a result of further studies. These intake protection technologies could include, but are not limited to, improvements to the fish return system, sound deterrents, strobe lights, air bubbles, revised frefueling outages and construction of a jetty. Any such new technologies shall be implemented pursuant to a schedule to be set forth by the Department at the time the new requirements are imposed. Depending on the specifics, such new requirements will be incorporated either as a major or minor modification to the NJPDES permit.

b. Submission of Documents - The permittee shall submit all documents specified in items G.2-G.9 and G.12.b, including, without limitation, workplan feasibility studies, further analyses, and reports, to the following person:

Director, Division of Fish and Wildlife
501 East State Street, P.O. Box 400
Trenton, NJ 08625-0400

11. Termination of Section 316(a) Variance/Penalties - Section 316 Special Condition.

a. Notwithstanding any other provision of this permit, the Department specifically reserves the right to seek termination of the Section 316(a) variance granted or termination of this permit based on the permittee's noncompliance with any term or condition of this permit. Further, the Department specifically reserves the right to seek penalties pursuant to N.J.S.A. 58:10A-10 et seq. based on the permittee's noncompliance with any term or condition of this permit.

12. Submissions as part of any NJPDES Renewal Application - Section 316 Special Condition.

a. Section 316 Determinations upon Reissuance.

i. If upon renewal, the permittee wants the Section 316(a) variance to be continued, the request for the variance along with a basis for its continuance must be submitted at the time of application for the renewal permit. The Department's Section 316(a) determination shall include, but not be limited to: 1) a review of whether the nature of the thermal discharge or the aquatic population associated with the Station have changed; 2) whether the measures required under the Special Conditions have assured the protection and propagation of the balanced indigenous population; 3) whether the best scientific methods to assess the effect of the permittee's cooling system have changed; 4) whether the technical knowledge of stresses caused by the cooling system has changed.

ii. With respect to Section 316(b), the Department's determination shall include, but not be limited to, an evaluation of whether technologies, their costs and benefits, and potential for application at Salem have changed. This shall include, at a minimum, revised outages and seasonal flow reductions.

b. Production Measurement of the Wetland Restoration Sites.

i. As part of any renewal application, the permittee shall include estimates of overall fish production from all PSEG wetland restoration sites as well as the fish ladders. The permittee shall utilize appropriate methods, which may include bioenergetics. The Department acknowledges that these "estimates" are subject to many environmental variables. Measures of productivity shall be expressed in the same units as the analysis of losses at the intake structure.

c. Conditional Mortality Rates.

i. As part of any renewal application, the permittee shall estimate a CMR for striped bass and, dependent upon availability of data from non-PSEG controlled monitoring programs, estimate CMR's for other finfish RIS, absent issuance of regulations or guidance recommending use of other analytical methodologies or availability of superior analytical methodologies for application at Salem.

13. Special Monitoring Requirements.

a. DSN's 481-486.

i. Effluent flow - Effluent flow is calculated daily as the sum of the circulating water flow and the service water flow. The circulating water flow for each outfall is calculated as the number of operating hours of the circulating water pumps and the flow rates for each pump. The service water contribution is calculated from the service water pump operating hours times the design flow rate of the service water pumps. The flow rates measured over the course of a calendar day shall be averaged on a daily basis consistent with the definition of daily discharge pursuant to N.J.A.C. 7:14A-1.2. These daily discharge points shall be utilized for the purposes of completing discharge monitoring reports as well as for calculation purposes.

ii. Effluent Temperature - Effluent temperature shall be measured at DSN's 481-486 on a continuous basis. Effluent flow for DSN's 481 - 486 is reported on DMR's as indicated in Part III. The effluent temperature values measured over the course of a calendar day shall be averaged on a daily basis consistent with the definition of daily discharge pursuant to N.J.A.C.7:14A-1.2. These daily discharge points shall be utilized for the purposes of completing discharge monitoring reports as well as for calculation purposes.

iii. Chlorine Produced Oxidants - Option 1: The daily maximum limitation of 0.2 mg/L shall apply when predominantly circulating water system water is being discharged through DSN's 481 - 486. Option 2: The daily maximum limitation of 0.5 mg/L and the monthly average limitation of 0.3 mg/L shall apply when only service water system non-contact cooling water is discharged through DSN's 481 - 486. Under normal operating conditions (i.e. no outage), the permittee discharges under an Option 1 scenario.

iv. Intake pH - One sample of intake water shall be analyzed for pH and shall be reported as intake pH for DSN's 481-486.

b. FAC A and FAC B.

i. Intake Temperature - Intake temperature shall be measured at the intake to the main circulating water system for Units 1 and 2 on a continuous basis. The intake temperatures from Units 1 and 2 shall be averaged to obtain the intake temperature for FAC A (Unit 1) as well as the intake temperature for FAC B (Unit 2). In the event that one of the temperature monitoring devices is out of service (such as for calibration and maintenance) the other temperature monitoring device will be applied to both units for reporting intake temperature.

ii. Effluent temperature for FAC A and FAC B shall be calculated and reported as follows:

Effluent Temperature for FAC A = [(Eff. Temp. at DSN 481 x Eff. Flow at DSN 481) + (Eff. Temp at DSN 482 x Eff. Flow at DSN 482) + (Eff. Temp at DSN 483x Eff. Flow at DSN 483)] / (Eff. Flow at DSN 481+ Eff. Flow at DSN 482+ Eff. Flow at DSN 483)

Effluent Temperature for FAC B = [(Eff. Temp at DSN 484 x Eff. Flow at DSN 484) + (Eff. Temp at DSN 485 x Eff. Flow at DSN 485) + (Eff. Temp at DSN 486 x Eff. Flow at DSN 486)] / (Eff. Flow at DSN 484+ Eff. Flow at DSN 485+ Eff. Flow at DSN 486).

iii. Differential Temperature - Differential temperature shall be calculated by subtracting the daily intake temperature from the daily effluent temperature where the values for intake temperature and effluent temperature values are explained above. The permittee calculates differential temperature on an hourly basis where the daily differential temperature is an arithmetic average of the values obtained during the course of the day. This is consistent with the definition of "daily discharge" in accordance with N.J.A.C. 7:14A-1.2.

c. FAC C.

i. Intake Flow - Intake flow for the circulating water system is calcualted as the sum of the twelve individual circulating water system intakes and reported as a monthly average in million gallons per day. The flow of each individual circulating water pump shall be calculated as the product of the number of operating hours for that pump for the reporting period and the flow rate for that pump. The flow rate for each respective pump shall be assessed on an annual basis in accordance with the Tracer Evaluation Requirement included as item G.1. For the purposes of DMR reporting, the intake flow values measured over the course of a calendar day shall be averaged on a daily basis consistent with the definition of daily discharge pursuant to N.J.A.C.7:14A-1.2.

ii. Thermal Discharge - Thermal discharge in MBTU/Hr is the total heat released from Unit 1 (FAC A) and Unit 2 (FAC B) where it shall be calculated as follows:

Thermal Discharge FAC C (MBTU/Hr) = [M1Cp(Teff-Tint)]Unit 1 + [M2Cp(Teff-Tint)]Unit 2 / 1,000,000

Where:
M1 = Mass flow rate of water from Unit 1 in lbs/hour (includes circulating water flow as well as service water flow)
M2 = Mass flow rate of water from Unit 2 in lbs/hour (includes circulating water flow as well as service water flow)
Mass flow rate is equal to flow in gal/hour x 8.34 lb/gallon
Teff = effluent temperature from Unit (e.g. Unit 1)
Tint = intake temperature from Unit
Cp is the specific heat capacity of water which is 1 BTU/lb degrees Fahrenheit.

d. DSN 48C and DSN 489: During periods of maintenance, calibration or failure of the flow meter, flow can be calculated using the operating hours of the discharge pumps times the flow rate of the discharge pumps.

14. Other Regulatory Requirements.

a. The permittee shall discharge so as not to violate the Delaware River Basin Commission Water Quality Regulations as amended for Zone 5 waters. This includes the stream quality objectives for radioactivity namely: alpha emitters- maximum 3 pc/L (picocuries per liter) and beta emitters - maximum 1000 pc/L. The permittee shall ensure compliance with the heat dissipation area set forth in any current DRBC docket.

b. The permittee shall comply with all regulations set forth in N.J.S.A. 26:2D-1 et seq. regarding Radiation Protection. All radioactive wastes shall be collected, removed, and disposed of in accordance with N.J.S.A. 7:28-11.1 et seq..

c. The permittee is licensed by the U.S. Nuclear Regulatory Commission (USNRC) and responsible to that agency for compliance with radiological effluent limitations, monitoring requirements, and other licensing conditions.

d. The permittee is required to comply with Section 4.2 of Appendix B to the NRC Facility Operating Licenses Nos. DPR-70 and DPR -75 which includes National Marine Fisheries Service's (NMFS) Section 7 Consultation Biological Opinion related to the operation of Salem Units 1 and 2 Generating Stations, including attachments, and all subsequent amendments as may be approved by NMFS. All correspondence between the permittee and the NMFS specifically related to Salem's effects on threatened and endangered species shall be sent to the Department at the following address:

Director, Division of Fish and Wildlife
501 East State Street, P.O. Box 400
Trenton, NJ 08625-0400

15. Construction of Artificial Reefs

a. The permittee shall fund an escrow account on the amount of Five Hundred Thousand Dollars ($500,000) within EDP plus 90 days. The monies in the Escrow Account shall be made available to the Department for the construction and installation of artificial reefs.

R. Edwin Selover
Senior Vice President
and General Counsel

Law Department
80 Park Plaza, T5A, Newark, NJ 07102-4194
tel: 973.430.6450 fax: 973.639.0741
email: edwin.selover@pseg.com

PSEG
Services Corporation

January 31, 2006

VIA HAND DELIVERY

New Jersey Department of Environmental Protection
Bureau of Permit Management
Division of Water Quality
PO Box 029
Trenton, NJ 08625-0029
Attn: Administrative Review Unit

Re: Salem Generating Station
NJPDES Permit No. NJ 0005622
Application for Renewal

PSEG Nuclear LLC ("PSEG") submits herewith its renewal application ("Application") for NJPDES Permit No. NJ0005622 ("Permit") for the Salem Generating Station (the "Station"). An executive summary and table of contents for the Application are contained in Volume 1. The certification required pursuant to N.J.A.C. 7:14A-4.9 is contained in Volume 2. The Application totals 14 volumes.

This Application requests renewal of the thermal variance granted in the Station's existing Permit pursuant to Section 316(a) of the Clean Water Act ("CWA"), supported by a demonstration consistent with Custom Requirement G.12.a.i of the Permit. In addition, this Application contains a Comprehensive Demonstration Study ("CDS") prepared in accordance with the Requirements Applicable to Cooling Water Intake Structures for Phase II Existing Facilities under Section 316(b) of the CWA, promulgated by the United States Environmental Protection Agency on July 9, 2004. This Application also demonstrates compliance with the current Permit, and evaluates the production of the Permit-required conservation measures and the impact of the Station on the Delaware Estuary as requested by the Department of Environmental Protection in letters dated September 8, 2003 and July 12, 2004.

-2-

If you have any questions or require further information concerning this submission, please do not hesitate to contact me, or Mr. Mark Strickland at (973) 430-7911. Please sign the attached receipt where indicated and return it with the courier.

Very truly yours,

R. Edwin Selover

Senior Vice President and General Counsel

Enclosures

-3-

Receipt of Salem NJPDES Renewal Application

The New Jersey Department of Environmental Protection has received fourteen (14) binders entitled "Salem NJPDES Permit Renewal Application," Volumes 1 through 14, on this 31 day of January, 2006.

William F. Boehle
Name:
New Jersey Department of Environmental Protection

Appendix C

Special Status Species Correspondence

Salem Nuclear Generating Station Environmental Report

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Table of Contents

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PSEG Nuclear LLC
P.O. Box 236, Hancocks Bridge, New Jersey 08038-0236

PSEG
Nuclear LLC

March 4, 2009

LR-E09-059

John Staples, Supervisor
Federal Activities and Endangered Species Program
New Jersey Field Office
U.S. Fish and Wildlife Service
927 N. Main Street, Heritage Square, Bldg D
Pleasantville, NJ 08232

SUBJECT: Salem and Hope Creek Generating Stations
Request for Information on Threatened or Endangered Species

Dear Mr. Staples:

In 2009, PSEG Nuclear plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for the Salem and Hope Creek Generating Stations (referred to respectively as Salem and HCGS), which are located on adjacent sites within a 740-acre parcel of property owned by PSEG Nuclear on the southern end of Artificial Island in Lower Alloways Creek Township, Salem County, New Jersey. The existing licenses for Salem Units 1 and 2 were issued for 40-year terms that expire in 2016 and 2020, respectively. The operating license for the single HCGS unit was also issued for a 40-year term that expires in 2026. License renewal would extend the operating period of each reactor for an additional 20 years.

The NRC requires that the license renewal applications for Salem and HCGS include environmental reports assessing potential environmental impacts from operation during the license renewal terms. One of these potential environmental impacts would be the effect of license renewal on threatened or endangered species located on the Salem and HCGS sites, their immediate environs, and transmission line corridors routed to connect the plants to the existing transmission system. Accordingly, the NRC requires that the environmental report for each license renewal application assess such a potential effect (10 CFR 51.53). Later, during its review of the proposed license renewal environmental reports pursuant to the National Environmental Policy Act (NEPA), the NRC will use that assessment to evaluate whether a basis exists to request consultation with your office under Section 7 of the Endangered Species Act.

I am contacting you now in order to obtain input regarding issues that may need to be addressed in the Salem and HCGS license renewal environmental reports, and to help me identify any information your staff believes would be helpful to expedite NRC's consultation.

Beginning early in the twentieth century, Artificial Island was created by placing dredge spoils within a diked area established by the U.S. Army Corps of Engineers on the eastern shore of the Delaware River. The 1,500-acre island is low and flat with an average elevation of approximately 9 ft above mean sea level (msl) and a maximum elevation of approximately 18 ft msl. Habitat surrounding the PSEG-owned property on Artificial Island can best be characterized as tidal marsh and grassland with some upland woodland vegetation. It is low quality for wildlife and is not an important natural resource area. Artificial Island is located approximately 18 miles southeast of Wilmington, Delaware (see enclosed Figure 1). Philadelphia is about 30 miles and Salem, New Jersey, is 7.5 miles northeast of Artificial Island.

There are three transmission corridors containing four 500-kV transmission lines that connect the Salem and HCGS sites to the regional electricity grid (see enclosed Figure 2). These transmission corridors are considered by the NRC to be within the scope of its environmental reviews for the Salem and HCGS license renewals. In New Jersey, they are owned and maintained by Public Service Electric and Gas Company (PSE&G) (a subsidiary of Public Service Enterprise Group, which also owns PSEG Nuclear). In Delaware, a single line is owned and maintained by Pepco (a regulated electric utility that is a subsidiary of Pepco Holdings, Inc.). The total length of all three corridors is approximately 106 miles, which cross Camden, Gloucester, and Salem Counties in New Jersey and New Castle County in Delaware. All corridors traverse local marshland (adjacent to the Salem and HCGS sites), as well as agricultural and forested lands located away from the sites. Each corridor is 350 feet wide, except for one, which narrows to 200 feet for approximately 8 miles. One line crosses the Delaware River north of the Salem and HCGS sites and extends into Delaware.

Based on a review of information available on the New Jersey Department of Environmental Protection (NJDEP) website (county records of "rare species and natural communities"), information provided by Delaware, and previous on-site surveys, PSEG Nuclear believes that no federally- or state-listed threatened or endangered plant or animal species reside on the Salem or HCGS sites.

However, one federally-threatened plant species occurs on the Salem – New Freedom South transmission corridor (see enclosed Figure 2), and some state-listed threatened terrestrial animal species occur within Salem County and the counties crossed by the transmission corridors (see Table 1), and these species may occasionally migrate through the sites. A population of *Helonias bullata* (swamp pink) has been located between transmission towers 9/4 and 10/1, near Jericho Road in Salem County. Terrestrial animal species known to occur in the subject counties include the bald eagle, peregrine falcon, osprey, Cooper's hawk, bobolink, and grasshopper sparrow. Ospreys are known to nest on transmission towers near the sites. Also, shortnose sturgeon and five federally-listed species of sea turtles occur in the Delaware River near the Salem and HCGS sites.

PSEG Nuclear does not expect Salem or HCGS operations during the license renewal terms (an additional 20 years) to adversely affect threatened or endangered species at the station sites, the immediate environs, or the transmission line corridors because license renewal will not alter existing operations. No expansion of existing facilities is planned, and no structural modifications or other refurbishments have been identified that are necessary to support license renewal. Maintenance activities during the license renewal term would be restricted to previously disturbed areas. No additional land-disturbance or activities that would affect the Delaware River are anticipated in support of license renewal. Both PSE&G and Pepco have established maintenance procedures for transmission lines that involve minimal disturbance of land, wetlands, and streams and are unlikely to adversely affect any threatened or endangered species.

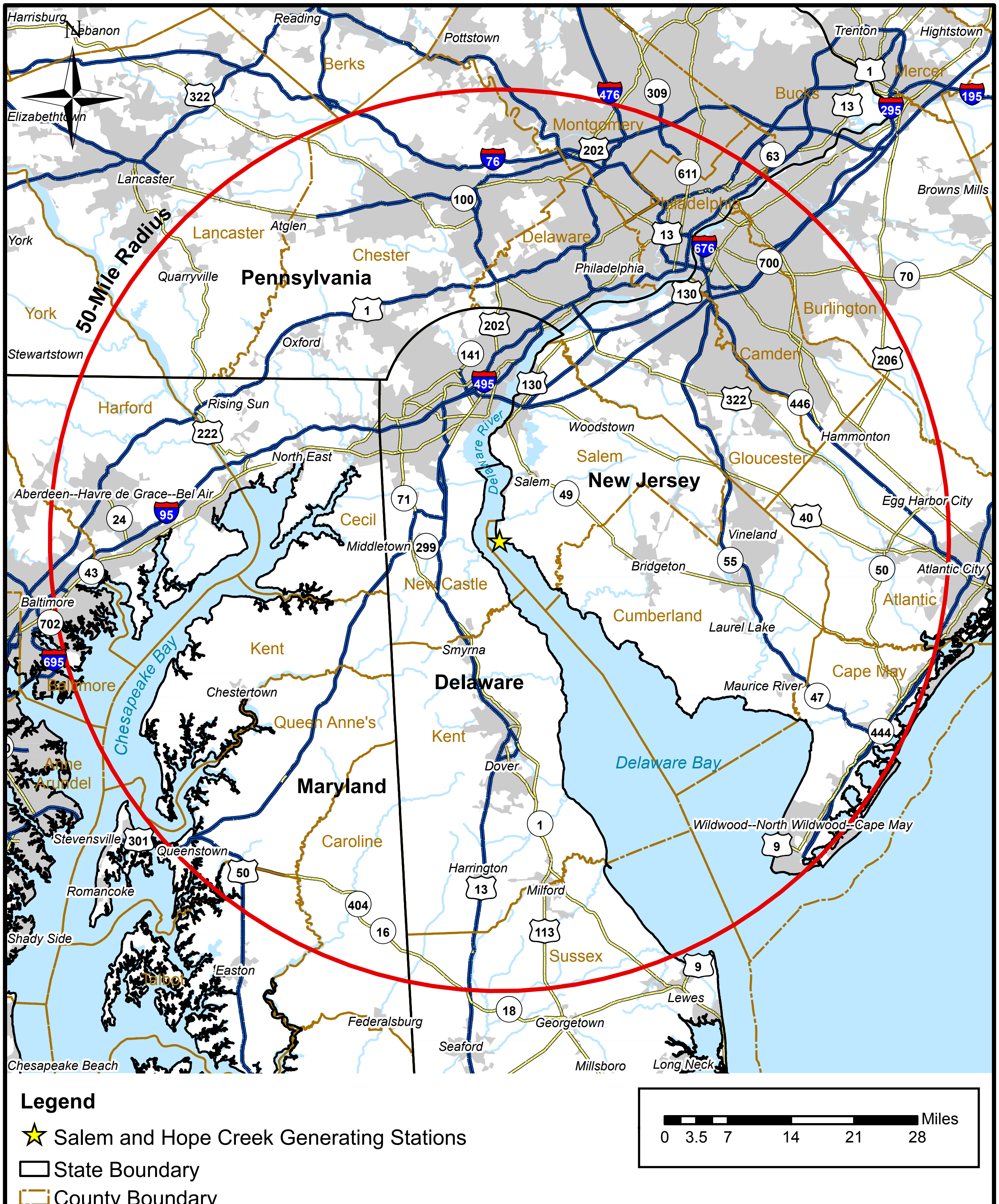
After your review of the information provided in this letter,I would appreciate your sending a letter detailing any concerns you have about potential impacts to threatened or endangered species or critical habitat in the area of the Salem and HCGS or along associated transmission corridors. PSEG Nuclear will include copies of this letter and your response in the environmental reports submitted to the NRC as part of the Salem and HCGS license renewal applications.

Please do not hesitate to call me at 856-339-7902, if there are questions or you need additional information to complete a review of the proposed action. Thank you in advance for your assistance.

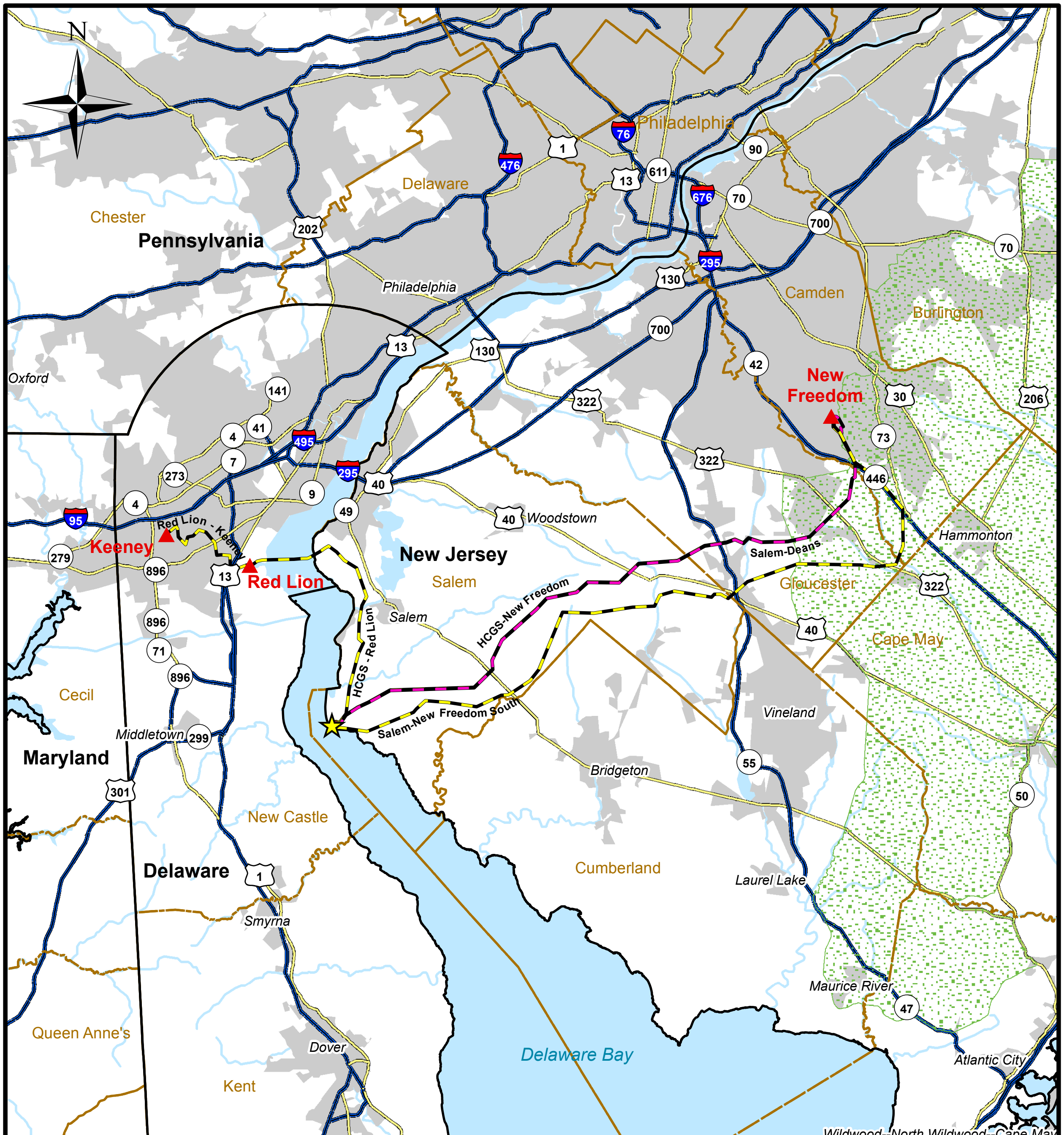
Sincerely,

Edward J. Keating
Sr. Environmental Advisor

Enclosure: Figure 1 – 50-Mile Region
Figure 2 – Transmission lines associated with Salem and HCGS
Table 1 – Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines



Salem and Hope Creek Generating Stations
PSEG
License Renewal Environmental Report
Figure 1. 50-Mile Region



Legend

- Salem and Hope Creek Generating Stations
- Transmission Line analyzed in Hope Creek ER
- Transmission Line analyzed in Salem ER
- Substation
- State Boundary
- County Boundary
- Primary Highway with Limited Access
- Primary Highway
- Urban Area
- Pinelands
- Water

Miles: 0 2.5 5 10 15

Salem and Hope Creek Generating Stations
PSEG
License Renewal Environmental Report
Figure 2. Transmission Lines

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines

Scientific Name	Common Name	Status		County[c]
		Federal[a]	State[a,b]	
Mammals				
Lynx rufus	Bobcat	-	E	Salem
Birds				
Accipiter cooperii	Cooper's hawk	-	T/T	Gloucester, Salem
Ammodramus henslowii	Henslow's sparrow	-	E	Gloucester
A. savannarum	Grasshopper sparrow	-	T/S	Salem
Bartramia longicauda	Upland sandpiper	-	E	Gloucester, Salem
Buteo lineatus	Red-shouldered hawk	-	E/T	Gloucester
Circus cyaneus	Northern harrier	-	E/U	Salem
Cistothorus platensis	Sedge wren	-	E	Salem
Dolichonyx oryzivorus	Bobolink	-	T/T	Salem
Falco peregrinus	Peregrine falcon	-	E	Camden, Gloucester, Salem
Haliaeetus leucocephalus	Bald eagle	-	E	Gloucester, Salem
Melanerpes erythrocephalus	Red-headed woodpecker	-	T/T	Camden, Gloucester, Salem
Pandion haliaetus	Osprey	-	T/T	Gloucester, Salem
Passerculus sandwichensis	Savannah sparrow	-	T/T	Salem
Podilymbus podiceps	Pied-billed grebe	-	E/S	Salem
Pooecetes gramineus	Vesper sparrow	-	E	Gloucester, Salem
Strix varia	Barred owl	-	T/T	Gloucester, Salem
Reptiles and Amphibians				
Ambystoma tigrinum tigrinum	Eastern tiger salamander	-	E	Gloucester, Salem
Clemmys insculpta	Wood turtle	-	E	Gloucester
C. muhlenbergii	Bog turtle	T	E	Camden, Gloucester, Salem
Crotalus horridus horridus	Timber rattlesnake	-	E	Camden
Hyla andersoni	Pine barrens treefrog	-	E	Camden, Gloucester, Salem
Pituophis melanoleucus	Northern pine snake	-	T	Camden, Gloucester, Salem
Caretta caretta	Loggerhead sea turtle	T	E	Delaware River[d]
Lepidochelys kempi	Kemp's ridley	E	E	Delaware River[d]
Dermochelys coriacea	Leatherback turtle	E	E	Delaware River[d]
Eretmochelys imbricata	Hawksbill turtle	E	E	Delaware River[d]
Chelonia mydas	Atlantic green turtle	T	T	Delaware River[d]
Fish				
Acipenser brevirostrum	Shortnose sturgeon	E	E	Delaware River[d]
A. oxyrinchus oxyrinchus	Atlantic sturgeon	C	-	Delaware River[d]
Insects				
Nicrophorus americanus	American burying beetle	E	E	Camden, Gloucester

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status Federal[a]	Status State[a,b]	County[c]
Plants				
Aeschynomene virginica	Sensitive joint vetch	T	E	Camden, Gloucester, Salem
Aplectrum hyemale	Putty root	-	E	Gloucester
Aristida lanosa	Wooly three-awn grass	-	E	Camden, Salem
Asimina triloba	Pawpaw	-	E	Gloucester
Aster radula	Low rough aster	-	E	Camden, Gloucester, Salem
Bouteloua curtipendula	Side oats grama grass	-	E	Gloucester
Cacalia atriplicifolia	Pale Indian plantain	-	E	Camden, Gloucester
Calystegia spithamaea	Erect bindweed	-	E	Camden, Salem
Cardamine longii	Long's bittercress	-	E	Gloucester
Carex aquatilis	Water sedge	-	E	Camden
C. bushii	Bush's sedge	-	E	Camden
C.cumulata	Clustered sedge	-	E	Camden
C. limosa	Mud sedge	-	E	Gloucester
C. polymorpha	Variable sedge	-	E	Gloucester
Castanea pumila	Chinquapin	-	E	Gloucester, Salem
Cercis canadensis	Redbud	-	E	Camden
Chenopodium rubrum	Red goosefoot	-	E	Camden
Commelina erecta	Slender dayflower	-	E	Camden
Cyperus lancastriensis	Lancaster flat sedge	-	E	Camden, Gloucester
C. polystachyos	Coast flat sedge	-	E	Salem
C. pseudovegetus	Marsh flat sedge	-	E	Salem
C. retrofractus	Rough flat sedge	-	E	Camden, Gloucester
Dalibarda repens	Robin-run-away	-	E	Gloucester
Diodia virginiana	Larger buttonweed	-	E	Camden
Draba reptans	Carolina Whitlow-grass	-	E	Camden, Gloucester
Eleocharis melanocarpa	Black-fruit spike-rush	-	E	Salem
E. equisetoides	Knotted spike-rush	-	E	Gloucester
E. tortilis	Twisted spike-rush	-	E	Gloucester
Elephantopus carolinianus	Carolina elephant-foot	-	E	Gloucester, Salem
Eriophorum gracile	Slender cotton-grass	-	E	Gloucester
E. tenellum	Rough cotton-grass	-	E	Camden, Gloucester
Eupatorium capillifolium	Dog fennel thoroughwort	-	E	Camden
E. resinosum	Pine barren boneset	-	E	Camden, Gloucester,
Euphorbia purpurea	Darlington's glade spurge	-	E	Salem

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status Federal[a]	Status State[a,b]	County[c]
Glyceria grandis	American manna grass	-	E	Camden
Gnaphalium helleri	Small everlasting	-	E	Camden
Gymnopogon brevifolius	Short-leaf skeleton grass	-	E	Gloucester
Helonias bullata	Swamp-pink	T	E	Camden, Gloucester, Salem
Hemicarpha micrantha	Small-flower halfchaff sedge	-	E	Camden
Hottonia inflata	Featherfoil	-	E	Salem
Hydrastis canadensis	Golden seal	-	E	Camden
Hydrocotyle ranunculoides	Floating marsh-pennywort	-	E	Salem
Hypericum adpressum	Barton's St. John's-wort	-	E	Salem
Juncus caesariensis	New Jersey rush	-	E	Camden
J. torreyi	Torrey's rush	-	E	Camden
Kuhnia eupatorioides	False boneset	-	E	Camden
Lemna perpusilla	Minute duckweed	-	E	Camden, Salem
Limosella subulata	Awl-leaf mudwort	-	E	Camden
Linum intercursum	Sandplain flax	-	E	Camden, Salem
Luzula acuminate	Hairy wood-rush	-	E	Gloucester, Salem
Melanthium virginicum	Virginia bunchflower	-	E	Camden, Gloucester, Salem
Micranthemum micranthemoides	Nuttall's mudwort	-	E	Camden, Gloucester
Muhlenbergia capillaris	Long-awn smoke grass	-	E	Gloucester
Myriophyllum tenellum	Slender water-milfoil	-	E	Camden
M. pinnatum	Cut-leaf water-milfoil	_	E	Salem
Nelumbo lutea	American lotus	-	E	Camden, Salem
Nuphar microphyllum	Small yellow pond-lily	-	E	Camden
Onosmodium virginianum	Virginia false-gromwell	-	E	Camden, Gloucester, Salem
Ophioglossum vulgatum pycnostichum	Southern adder's tongue	-	E	Salem
Panicum aciculare	Bristling panic grass	-	E	Gloucester
Penstemon laevigatus	Smooth beardtongue	-	E	Gloucester
Plantago pusilla	Dwarf plantain	-	E	Camden
Platanthera flava flava	Southern rein orchid	-	E	Camden
Pluchea foetida	Stinking fleabane	-	E	Camden
Polemonium reptans	Greek-valerian	-	E	Salem
Polygala incarnata	Pink milkwort	-	E	Camden, Gloucester

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status: Federal[a]	Status: State[a,b]	County[c]
Prunus angustifolia	Chickasaw plum	-	E	Camden, Gloucester, Salem
Pycnanthemum clinopodioides	Basil mountain mint	-	E	Camden
P. torrei	Torrey's mountain mint	-	E	Gloucester
Quercus imbricaria	Shingle oak	-	E	Gloucester
Q .lyrata	Overcup oak	-	E	Salem
Rhododendron atlanticum	Dwarf azalea	-	E	Salem
Rhynchospora globularis	Coarse grass-like beaked-rush	-	E	Camden, Gloucester, Salem
R. knieskernii	Knieskern's beaked-rush	T	E	Camden
Sagittaria teres	Slender arrowhead	-	E	Camden
Scheuchzeria palustris	Arrow-grass	-	E	Camden, Gloucester
Schwalbea americana	Chaffseed	E	E	Camden
Scirpus longii	Long's woolgrass	-	E	Camden
S. maritimus	Saltmarsh bulrush	-	E	Camden
Scutellaria leonardii	Small skullcap	-	E	Salem
Spiranthes laciniata	Lace-lip ladies' tresses	-	E	Gloucester
Stellaria pubera	Star chickweed	-	E	Camden
Triadenum walteri	Walter's St. John's wort	-	E	Camden
Utricularia biflora	Two-flower bladderwort	-	E	Gloucester, Salem
Valerianella radiata	Beaked cornsalad	-	E	Gloucester
Verbena simplex	Narrow-leaf vervain	-	E	Camden, Gloucester
Vernonia glauca	Broad-leaf ironweed	-	E	Gloucester, Salem
Vulpia elliotea	Squirrel-tail six-weeks grass	-	E	Camden, Gloucester, Salem
Wolffiella floridana	Sword bogmat	-	E	Salem
Xyris fimbriarta	Fringed yellow-eyed grass	-	E	Camden

a. E = Endangered; T = Threatened; C = Candidate; - = Not listed.

b. State status for birds separated by a slash (/) indicates a dual status. First status refers to the state breeding population, and the second status refers to the migratory or winter population. S = Stable species (a species whose population is not undergoing any long-term increase or decrease within its natural cycle); U = Undetermined (a species about which there is not enough information available to determine the status) (NJDEP 2008b).

c. Source of county occurrence: USFWS (undated); NJDEP (2008a); (NJDEP (2008c).

d. Sea turtles and sturgeon were not included in county lists maintained by USFWS (undated) and NJDEP (2008a), but are known by PSEG to occur in the Delaware River (see text).

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PSEG Nuclear LLC
P.O. Box 236, Hancocks Bridge, New Jersey 08038-0236

PSEG
Nuclear LLC

March 4, 2009

LR-E09-055

Mary Colligan, Assistant Regional Administrator
Protected Resources Division
National Marine Fisheries Service
One Blackburn Drive
Gloucester, MA 01930

SUBJECT: Salem and Hope Creek Generating Stations
Request for Information on Threatened or Endangered Species

Dear Ms. Colligan:

In 2009, PSEG Nuclear plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for the Salem and Hope Creek Generating Stations (referred to respectively as Salem and HCGS), which are located on adjacent sites within a 740-acre parcel of property owned by PSEG Nuclear on the southern end of Artificial Island in Lower Alloways Creek Township, Salem County, New Jersey. The existing licenses for Salem Units 1 and 2 were issued for 40-year terms that expire in 2016 and 2020, respectively. The operating license for the single HCGS unit was also issued for a 40-year term that expires in 2026. License renewal would extend the operating period of each reactor for an additional 20 years.

The NRC requires that the license renewal applications for Salem and HCGS include environmental reports assessing potential environmental impacts from operation during the renewal terms. One of these potential environmental impacts would be the effect of license renewal activities on threatened or endangered species located on the Salem and HCGS sites, their immediate environs, and transmission line corridors connecting the plants to the existing transmission system. Accordingly, the NRC requires that the environmental report for each license renewal application assess such a potential effect (10 CFR 51.53). Later, during its review of the license renewal environmental reports pursuant to the National Environmental Policy Act (NEPA), the NRC will use that assessment to evaluate whether a basis exists to request consultation with your office under Section 7 of the Endangered Species Act.

I am contacting you now in order to obtain input regarding issues that may need to be addressed in the Salem and HCGS license renewal environmental reports, and to help me identify any information your staff believes would be helpful to expedite NRC's consultation.

Beginning early in the twentieth century, Artificial Island was created by placing dredge spoils within a diked area established by the U.S. Army Corps of Engineers on the eastern shore of the Delaware River. The 1,500-acre island is low and flat with an average elevation of approximately 9 ft above mean sea level (msl) and a maximum elevation of approximately 18 ft msl. Habitat surrounding the PSEG-owned property on Artificial Island can best be characterized as tidal marsh and grassland with some upland woodland vegetation. It is low quality for wildlife and is not an important natural resource area. Artificial Island is located approximately 18 miles southeast of Wilmington, Delaware (see enclosed Figure1). Philadelphia is about 30 miles and Salem, New Jersey, is 7.5 miles northeast of Artificial Island.

There are three transmission corridors containing four 500-kV transmission lines that connect the Salem and HCGS sites to the regional electricity grid (see enclosed Figure 2). These transmission corridors are considered by the NRC to be within the scope of its environmental reviews for the Salem and HCGS license renewals. In New Jersey, the lines are owned and maintained by Public Service Electric and Gas Company (PSE&G) (a subsidiary of Public Service Enterprise Group, which also owns PSEG Nuclear). In Delaware, a single line is owned and maintained by Pepco (a regulated electric utility that is a subsidiary of Pepco Holdings, Inc.). The total length of all three corridors is approximately 106 miles, which cross Camden, Gloucester, and Salem Counties in New Jersey and New Castle County in Delaware. All corridors traverse local marshland (adjacent to the Salem and HCGS sites), as well as agricultural and forested lands located away from the sites. Each corridor is 350 feet wide, except for one, which narrows to 200 feet for approximately 8 miles.

Based on a review of information available on the New Jersey Department of Environmental Protection (NJDEP) website (county records of "rare species and natural communities"), information provided by Delaware, and previous on-site surveys, PSEG Nuclear believes that no federally- or state-listed threatened or endangered plant or animal species resides on the Salem or HCGS sites.

However, one federally-threatened plant species occurs on the Salem-New Freedom South transmission corridor (see enclosed Figure 2), and some state-listed threatened terrestrial animal species occur within Salem County and the counties crossed by the transmission corridors (see enclosed Table 1) and these species may occasionally migrate through the sites. A population of *Helonias bullata* (swamp pink) has been located between towers 9/4 and 10/1, near

Jericho Road in Salem County. Terrestrial animal species known to occur in the subject counties include the bald eagle, peregrine falcon, osprey, Cooper's hawk, bobolink, and grasshopper sparrow. Ospreys are known to nest on transmission towers near the sites. Also, shortnose sturgeon and five species of federally-listed sea turtles are known to occur in the Delaware River near the Salem and HCGS sites.

Both Salem and HCGS withdraw cooling and service water from the Delaware River through intake systems with trash racks, traveling screens, and fish return systems. A biological opinion prepared by the National Marine Fisheries Service (NMFS) in 1993 following consultation with the NRC addressed the impacts of operating the Salem and HCGS intake structures on shortnose sturgeon (*Acipenser brevirostrum*) and on Kemp's ridley (*Lepidochelys kempi*), loggerhead (*Caretta caretta*), and Atlantic green (*Chelonia mydas*) sea turtles. The biological opinion contained an Incidental Take Statement (updated in 1999) authorizing the incidental taking of these four species and specifying measures necessary to minimize impacts of the Salem intake structures on sea turtles. The NMFS anticipated that, annually, five shortnose sturgeon, five Kemp's ridley, five Atlantic green, and 30 loggerhead sea turtles could be taken during operation of Salem. The incidental take is expected to be in the form of injuries and mortalities. Lethal take limits for these species are five shortnose sturgeon, one Kemp's ridley, two Atlantic green, and five loggerhead sea turtles. PSEG continues to operate Salem in accordance with the terms and conditions of the 1993 Biological Opinion and updated Incidental Take Statement.

Eighteen sturgeon have been captured at Salem and HCGS since monitoring was initiated (1978 - 2007). Although five sea turtle species occur in the Delaware River, only three (loggerhead, Kemp's ridley, and Atlantic green) are typically observed near the Salem and HCGS facilities. The other two species (leatherback [*Dermochelys coriacea*] and hawksbill [*Eretmochelys imbricate*]) are uncommon to the Delaware River. No sea turtles have been captured at HCGS. Nearly 100 sea turtles have been captured at Salem since it began operation, including 72 loggerheads (1979 - 2001), 24 Kemp's ridley turtles (1980 – 1993), and 3 Atlantic green turtles (1980 – 1992). Since 2001, no threatened or endangered sea turtles have been captured at Salem.

PSEG Nuclear does not expect license renewal to alter existing operations. No expansion of existing facilities is planned, and no structural modifications have been identified to support license renewal. Maintenance activities during the license renewal term would be restricted to previously disturbed areas. No additional land-disturbance or activities that would affect the Delaware River are anticipated in support of license renewal. Both PSE&G and Pepco have established maintenance procedures for transmission corridors that involve minimal disturbance of land, wetlands, and streams and are unlikely to adversely affect any threatened or endangered species.

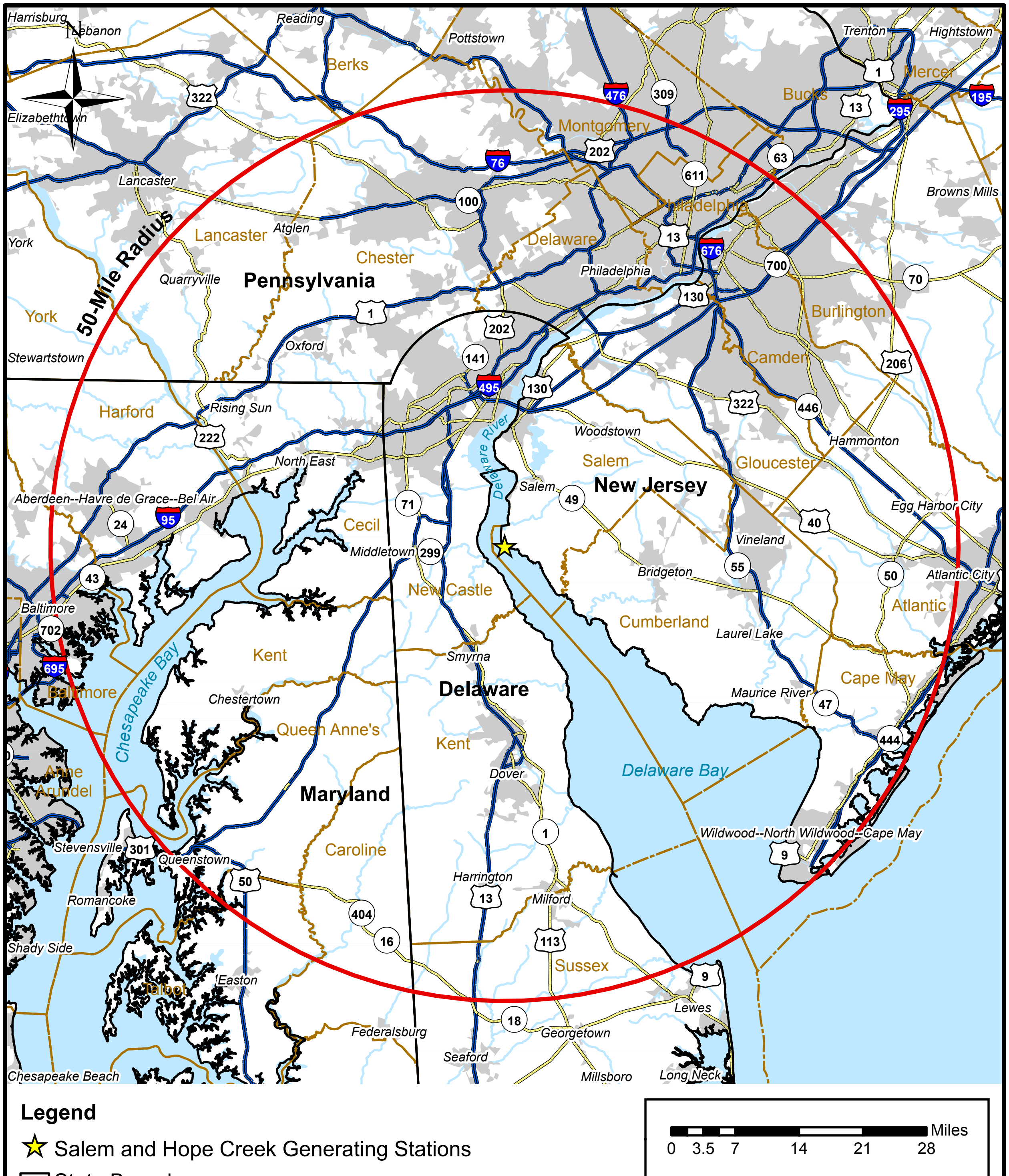
After your review of the information provided in this letter, I would appreciate your sending a letter detailing any concerns you may have about any listed species or critical habitat in the area of the Salem and HCGS sites and the associated transmission corridors. PSEG Nuclear will include copies of this letter and your response in the environmental reports that will be submitted to the NRC as part of the Salem and HCGS license renewal applications.

Please do not hesitate to call me at 856-339-7902, if there are questions or you need additional information to complete a review of the proposed action. Thank you in advance for your assistance.

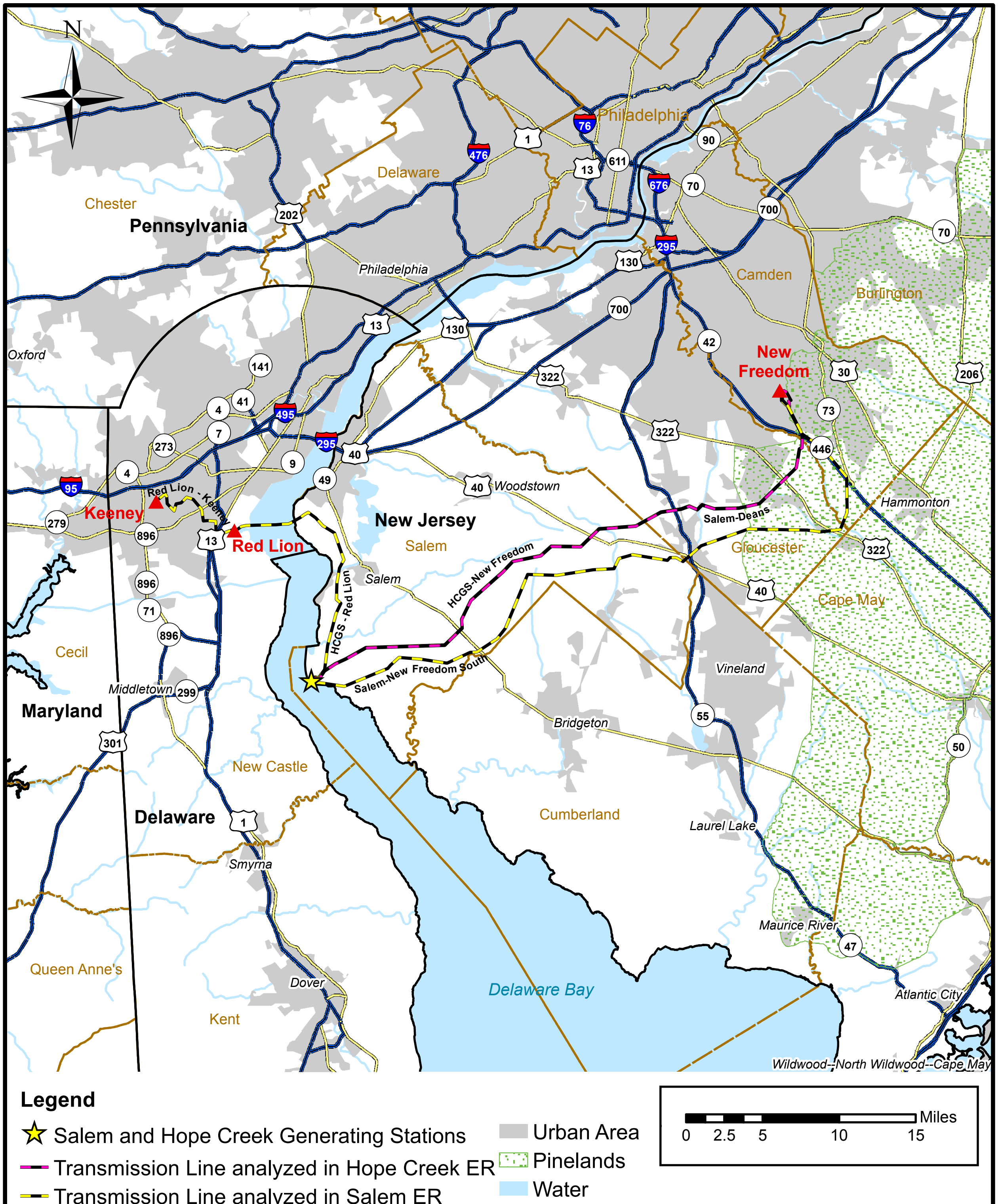
Sincerely,

Edward J. Keating
Sr. Environmental Advisor

Enclosure: Figure 1 – 50-Mile Region
Figure 2 – Transmission lines associated with Salem and HCGS
Table 1 – Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines



Salem and Hope Creek Generating Stations
PSEG
License Renewal Environmental Report
Figure 1. 50-Mile Region



Salem and Hope Creek Generating Stations
PSEG
License Renewal Environmental Report
Figure 2. Transmission Lines

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines

Scientific Name	Common Name	Status Federal[a]	Status State[a,b]	County[c]
Mammals				
Lynx rufus	Bobcat	-	E	Salem
Birds				
Accipiter cooperii	Cooper's hawk	-	T/T	Gloucester, Salem
Ammodramus henslowii	Henslow's sparrow	-	E	Gloucester
A. savannarum	Grasshopper sparrow	-	T/S	Salem
Bartramia longicauda	Upland sandpiper	-	E	Gloucester, Salem
Buteo lineatus	Red-shouldered hawk	-	E/T	Gloucester
Circus cyaneus	Northern harrier	-	E/U	Salem
Cistothorus platensis	Sedge wren	-	E	Salem
Dolichonyx oryzivorus	Bobolink	-	T/T	Salem
Falco peregrinus	Peregrine falcon	-	E	Camden, Gloucester, Salem
Haliaeetus leucocephalus	Bald eagle	-	E	Gloucester, Salem
Melanerpes erythrocephalus	Red-headed woodpecker	-	T/T	Camden, Gloucester, Salem
Pandion haliaetus	Osprey	-	T/T	Gloucester, Salem
Passerculus sandwichensis	Savannah sparrow	-	T/T	Salem
Podilymbus podiceps	Pied-billed grebe	-	E/S	Salem
Pooecetes gramineus	Vesper sparrow	-	E	Gloucester, Salem
Strix varia	Barred owl	-	T/T	Gloucester, Salem
Reptiles and Amphibians				
Ambystoma tigrinum tigrinum	Eastern tiger salamander	-	E	Gloucester, Salem
Clemmys insculpta	Wood turtle	-	E	Gloucester
C. muhlenbergii	Bog turtle	T	E	Camden, Gloucester, Salem
Crotalus horridus horridus	Timber rattlesnake	-	E	Camden
Hyla andersoni	Pine barrens treefrog	-	E	Camden, Gloucester, Salem
Pituophis melanoleucus	Northern pine snake	-	T	Camden, Gloucester, Salem
Caretta caretta	Loggerhead sea turtle	T	E	Delaware River[d]
Lepidochelys kempi	Kemp's ridley	E	E	Delaware River[d]
Dermochelys coriacea	Leatherback turtle	E	E	Delaware River[d]
Eretmochelys imbricata	Hawksbill turtle	E	E	Delaware River[d]
Chelonia mydas	Atlantic green turtle	T	T	Delaware River[d]
Fish				
Acipenser brevirostrum	Shortnose sturgeon	E	E	Delaware River[d]
A. oxyrinchus oxyrinchus	Atlantic sturgeon	C	-	Delaware River[d]
Insects				
Nicrophorus americanus	American burying beetle	E	E	Camden, Gloucester

Table 1   Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status: Federal[a]	Status: State[a,b]	County[c]
Plants				
Aeschynomene virginica	Sensitive joint vetch	T	E	Camden, Gloucester, Salem
Aplectrum hyemale	Putty root	-	E	Gloucester
Aristida lanosa	Wooly three-awn grass	-	E	Camden, Salem
Asimina triloba	Pawpaw	-	E	Gloucester
Aster radula	Low rough aster	-	E	Camden, Gloucester, Salem
Bouteloua curtipendula	Side oats grama grass	-	E	Gloucester
Cacalia atriplicifolia	Pale Indian plantain	-	E	Camden, Gloucester
Calystegia spithamaea	Erect bindweed	-	E	Camden, Salem
Cardamine longii	Long's bittercress	-	E	Gloucester
Carex aquatilis	Water sedge	-	E	Camden
C. bushii	Bush's sedge	-	E	Camden
C.cumulata	Clustered sedge	-	E	Camden
C. limosa	Mud sedge	-	E	Gloucester
C. polymorpha	Variable sedge	-	E	Gloucester
Castanea pumila	Chinquapin	-	E	Gloucester, Salem
Cercis canadensis	Redbud	-	E	Camden
Chenopodium rubrum	Red goosefoot	-	E	Camden
Commelina erecta	Slender dayflower	-	E	Camden
Cyperus lancastriensis	Lancaster flat sedge	-	E	Camden, Gloucester
C. polystachyos	Coast flat sedge	-	E	Salem
C. pseudovegetus	Marsh flat sedge	-	E	Salem
C. retrofractus	Rough flat sedge	-	E	Camden, Gloucester
Dalibarda repens	Robin-run-away	-	E	Gloucester
Diodia virginiana	Larger buttonweed	-	E	Camden
Draba reptans	Carolina Whitlow-grass	-	E	Camden, Gloucester
Eleocharis melanocarpa	Black-fruit spike-rush	-	E	Salem
E. equisetoides	Knotted spike-rush	-	E	Gloucester
E. tortilis	Twisted spike-rush	-	E	Gloucester
Elephantopus carolinianus	Carolina elephant-foot	-	E	Gloucester, Salem
Eriophorum gracile	Slender cotton-grass	-	E	Gloucester
E. tenellum	Rough cotton-grass	-	E	Camden, Gloucester
Eupatorium capillifolium	Dog fennel thoroughwort	-	E	Camden
E. resinosum	Pine barren boneset	-	E	Camden, Gloucester,
Euphorbia purpurea	Darlington's glade spurge	-	E	Salem

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status Federal[a]	Status State[a,b]	County[c]
Glyceria grandis	American manna grass	-	E	Camden
Gnaphalium helleri	Small everlasting	-	E	Camden
Gymnopogon brevifolius	Short-leaf skeleton grass	-	E	Gloucester
Helonias bullata	Swamp-pink	T	E	Camden, Gloucester, Salem
Hemicarpha micrantha	Small-flower halfchaff sedge	-	E	Camden
Hottonia inflata	Featherfoil	-	E	Salem
Hydrastis canadensis	Golden seal	-	E	Camden
Hydrocotyle ranunculoides	Floating marsh-pennywort	-	E	Salem
Hypericum adpressum	Barton's St. John's-wort	-	E	Salem
Juncus caesariensis	New Jersey rush	-	E	Camden
J. torreyi	Torrey's rush	-	E	Camden
Kuhnia eupatorioides	False boneset	-	E	Camden
Lemna perpusilla	Minute duckweed	-	E	Camden, Salem
Limosella subulata	Awl-leaf mudwort	-	E	Camden
Linum intercursum	Sandplain flax	-	E	Camden, Salem
Luzula acuminate	Hairy wood-rush	-	E	Gloucester, Salem
Melanthium virginicum	Virginia bunchflower	-	E	Camden, Gloucester, Salem
Micranthemum micranthemoides	Nuttall's mudwort	-	E	Camden, Gloucester
Muhlenbergia capillaris	Long-awn smoke grass	-	E	Gloucester
Myriophyllum tenellum	Slender water-milfoil	-	E	Camden
M. pinnatum	Cut-leaf water-milfoil	_	E	Salem
Nelumbo lutea	American lotus	-	E	Camden, Salem
Nuphar microphyllum	Small yellow pond-lily	-	E	Camden
Onosmodium virginianum	Virginia false-gromwell	-	E	Camden, Gloucester, Salem
Ophioglossum vulgatum pycnostichum	Southern adder's tongue	-	E	Salem
Panicum aciculare	Bristling panic grass	-	E	Gloucester
Penstemon laevigatus	Smooth beardtongue	-	E	Gloucester
Plantago pusilla	Dwarf plantain	-	E	Camden
Platanthera flava flava	Southern rein orchid	-	E	Camden
Pluchea foetida	Stinking fleabane	-	E	Camden
Polemonium reptans	Greek-valerian	-	E	Salem
Polygala incarnata	Pink milkwort	-	E	Camden, Gloucester

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status: Federal[a]	Status: State[a,b]	County[c]
Prunus angustifolia	Chickasaw plum	-	E	Camden, Gloucester, Salem
Pycnanthemum clinopodioides	Basil mountain mint	-	E	Camden
P. torrei	Torrey's mountain mint	-	E	Gloucester
Quercus imbricaria	Shingle oak	-	E	Gloucester
Q .lyrata	Overcup oak	-	E	Salem
Rhododendron atlanticum	Dwarf azalea	-	E	Salem
Rhynchospora globularis	Coarse grass-like beaked-rush	-	E	Camden, Gloucester, Salem
R. knieskernii	Knieskern's beaked-rush	T	E	Camden
Sagittaria teres	Slender arrowhead	-	E	Camden
Scheuchzeria palustris	Arrow-grass	-	E	Camden, Gloucester
Schwalbea americana	Chaffseed	E	E	Camden
Scirpus longii	Long's woolgrass	-	E	Camden
S. maritimus	Saltmarsh bulrush	-	E	Camden
Scutellaria leonardii	Small skullcap	-	E	Salem
Spiranthes laciniata	Lace-lip ladies' tresses	-	E	Gloucester
Stellaria pubera	Star chickweed	-	E	Camden
Triadenum walteri	Walter's St. John's wort	-	E	Camden
Utricularia biflora	Two-flower bladderwort	-	E	Gloucester, Salem
Valerianella radiata	Beaked cornsalad	-	E	Gloucester
Verbena simplex	Narrow-leaf vervain	-	E	Camden, Gloucester
Vernonia glauca	Broad-leaf ironweed	-	E	Gloucester, Salem
Vulpia elliotea	Squirrel-tail six-weeks grass	-	E	Camden, Gloucester, Salem
Wolffiella floridana	Sword bogmat	-	E	Salem
Xyris fimbriarta	Fringed yellow-eyed grass	-	E	Camden

a. E = Endangered; T = Threatened; C = Candidate; - = Not listed.

b. State status for birds separated by a slash (/) indicates a dual status. First status refers to the state breeding population, and the second status refers to the migratory or winter population. S = Stable species (a species whose population is not undergoing any long-term increase or decrease within its natural cycle); U = Undetermined (a species about which there is not enough information available to determine the status) (NJDEP 2008b).

c. Source of county occurrence: USFWS (undated); NJDEP (2008a); (NJDEP (2008c).

d. Sea turtles and sturgeon were not included in county lists maintained by USFWS (undated) and NJDEP (2008a), but are known by PSEG to occur in the Delaware River (see text).

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
NORTHEAST REGION
55 Great Republic Drive
Gloucester, MA 01930-2276

APR 15 2009

Edward J. Keating
PSEG Nuclear, LLC
PO Box 236
Hancocks Bridge, New Jersey 08038-0236

Re: Salem and Hope Creek Generating Stations

Dear Mr. Keating,

This is in response to your letter dated March 4, 2009 regarding PSEG Nuclear's plan to apply to the US Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for the Salem and Hope Creek Generating Stations (Salem and HCGS), which are located on adjacent sites within a 740-acre parcel of property at the southern end of Artificial Island in Lower Alloways Creek Township, Salem County, New Jersey. The existing licenses for Salem Units 1 and 2 expire in 2016 and 2020, respectively and the operating license for the single HCGS unit expires in 2026. License renewal would extend the operating period of each reactor for an additional 20 years. PSEG is in the early stages of preparing environmental reports assessing the impacts of relicensing on threatened and endangered species in anticipation of the National Environmental Policy Act (NEPA) and Endangered Species Act (ESA) reviews that will be required during the relicensing process.

Species Listed under the Endangered Species Act
As noted in your letter, several species listed by NOAA's National Marine Fisheries Service (NMFS) occur in the Delaware River where the intakes for both facilities are located. Four species of sea turtles occur seasonally (May – November) in the Delaware River estuary, including the threatened loggerhead (*Caretta caretta*), and endangered Kemp's ridley (*Lepidochelys kempi*), green *(Chelonia mydas*), and leatherback (*Dermochelys coriacea*) sea turtles. Additionally, a population of endangered shortnose sturgeon (*Acipenser brevirostrum*) occurs in the Delaware River.

Consultation pursuant to Section 7 of the ESA between NRC and NMFS on the effects of the operation of these facilities has been ongoing since 1979. A Biological Opinions (Opinion) was issued by NMFS in April 1980 in which NMFS concluded that the ongoing operation of the facilities was not likely to jeopardize the continued existence of shortnose sturgeon. Consultation was reinitiated in 1988 due to the documentation of impingement of sea turtles at the Salem facility. An Opinion was issued on January 2, 1991 in which NMFS concluded that the ongoing operation was not likely to jeopardize shortnose sturgeon, Kemp's ridley, green or loggerhead sea turtles. Consultation was reinitiated in 1992 due to the number of sea turtle impingements at the Salem intake exceeding the number exempted in the 1991 Incidental Take Statement. A new Opinion was issued on August 4, 1992. Consultation was again reinitiated in January 1993 when the number of sea turtle impingements exceeded the 1992 ITS with an Opinion issued on May 14, 1993. In 1998 the NRC requested that NMFS modify the Reasonable and Prudent Measures and Terms and Conditions of the ITS, and, specifically, remove a sea turtle study requirement. NMFS responded to this request in a letter dated January 21, 1999. Accompanying this letter was a revised ITS which served to amend the May 14, 1993 Opinion.

Since monitoring of the intakes was initiated in 1978, 18 shortnose sturgeon and 99 sea turtles have been recovered from the Salem intakes. No shortnose sturgeon or sea turtles have been observed at the Hope Creek intakes. No sea turtles have been captured at Salem since 2001. As the relicensing is not expected to result in changes in operation at either facility, it is likely that the potential for take of these species will continue, at least at the Salem facility. As such, NMFS agrees that a formal Section 7 consultation will be necessary. NMFS looks forward to working with you and the NRC in the development of the Biological Assessment. NMFS expects that the Biological Assessment will include an analysis of effects on the species of sea turtles noted above as well as endangered shortnose sturgeon. The BA should discuss effects of the intake and any associated discharge (pollutants as well as heated effluent) as well as any other project related operations that may affect these species (e.g., any ongoing sampling studies that may occur in Delaware Bay or the Delaware River). Please note that status reviews are currently ongoing for shortnose sturgeon and loggerhead sea turtles. As such, NMFS recommends that prior to the submittal of an environmental report to the NRC, PSEG confirm the status of these species with NMFS.

Technical Assistance for Candidate Species
Candidate species are those petitioned species that are actively being considered for listing as endangered or threatened under the ESA, as well as those species for which NMFS has initiated an ESA status review that it has announced in the *Federal Register*.

Atlantic sturgeon (*Acipenser oxyrinchus oxyrinchus*) occur in the Delaware River. In 2006, NMFS initiated a status review for Atlantic sturgeon to determine if listing as threatened or endangered under the ESA is warranted. The Status Review Report was published on February 23, 2007. NMFS is currently considering the information presented in the Status Review Report to determine if any listing action pursuant to the ESA is warranted at this time. If it is determined that listing is warranted, a final rule listing the species could be published within a year from the date of publication of the listing determination or proposed rule. As a candidate species, Atlantic sturgeon receive no substantive or procedural protection under the ESA; however, NMFS recommends that project proponents consider implementing conservation actions to limit the potential for adverse effects on Atlantic sturgeon from any proposed project. Please note that once a species is proposed for listing the conference provisions of the ESA apply (see 50 CFR 402.10). As the listing status for this species may change, NMFS recommends that PSEG obtain updated status information from NMFS prior to the submission of the environmental report to FERC.

My staff looks forward to working with PSEG and the NRC during the relicensing process. Should you have any questions regarding this correspondence, please contact Julie Crocker of my staff at (978)282-8480 or by e-mail (Julie.Crocker@noaa.gov).

Sincerely,

Mary Colligan

Mary A. Colligan
Assistant Regional Administrator for
Protected Resources

EC: Crocker, F/NER3

File Code: Sec 7 NRC Salem and Hope Creek Nuclear

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PSEG Nuclear LLC
P.O. Box 236, Hancocks Bridge, New Jersey 08038-0236

PSEG
Nuclear LLC

March 4, 2009

LR-E09-057

David Jenkins, Chief
Endangered and Nongame Wildlife
New Jersey Department of Environmental Protection
Division of Fish and Wildlife
P.O. Box 400
Trenton, NJ 08652-0400

SUBJECT: Salem and Hope Creek Generating Stations
Request for Information on Threatened or Endangered Species

Dear Mr. Jenkins:

In 2009, PSEG Nuclear plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for the Salem and Hope Creek Generating Stations (referred to respectively as Salem and HCGS), which are located on adjacent sites within a 740-acre parcel of property owned by PSEG Nuclear on the southern end of Artificial Island in Lower Alloways Creek Township, Salem County, New Jersey. The existing licenses for Salem Units 1 and 2 were issued for 40-year terms that expire in 2016 and 2020, respectively. The operating license for the single HCGS unit was also issued for a 40-year term that expires in 2026. License renewal would extend the operating period of each reactor for an additional 20 years.

The NRC requires that the license renewal applications for Salem and HCGS include environmental reports assessing potential environmental impacts from operation during the license renewal term. One of these potential environmental impacts would be the effect of license renewal on threatened or endangered species located on the Salem and HCGS sites, their immediate environs, and transmission line corridors connecting the plants to the existing transmission line system. Accordingly, the NRC requires that the environmental report for each license renewal application assess such a potential effect (10 CFR 51.53). Later, during its review of the proposed license renewals pursuant to the National Environmental Policy Act (NEPA), the NRC will use that assessment to evaluate whether a basis exists to request consultation with your office under Section 7 of the Endangered Species Act.

95-2168 REV. 7/99

I am contacting you now in order to obtain input regarding issues that may need to be addressed in the Salem and HCGS license renewal environmental reports, and to help me identify any information your staff believes would be helpful to expedite NRC's consultation.

Beginning early in the twentieth century, Artificial Island was created by placing dredge spoils within a diked area established by the U.S. Army Corps of Engineers on the eastern shore of the Delaware River. The 1,500-acre island is low and flat with an average elevation of approximately 9 ft above mean sea level (msl) and a maximum elevation of approximately 18 ft msl. Habitat surrounding the PSEG-owned property on Artificial Island has been characterized as tidal marsh and grassland with some upland woodland vegetation. It is low quality for wildlife and is not an important natural resource area. Artificial Island is located approximately 18 miles southeast of Wilmington, Delaware (see enclosed Figure 1). Philadelphia is about 30 miles and Salem, New Jersey, is 7.5 miles northeast of the Artificial Island.

There are three transmission corridors containing four 500-kV transmission lines that connect the Salem and HCGS sites to the regional electricity grid (see enclosed Figure 2). These transmission corridors are considered by the NRC to be within the scope of its environmental reviews for the Salem and HCGS license renewals. In New Jersey, the lines are owned and maintained by Public Service Electric and Gas Company (PSE&G) (a subsidiary of Public Service Enterprise Group, which also owns PSEG Nuclear). In Delaware, a single line is owned and maintained by Pepco (a regulated electric utility that is a subsidiary of Pepco Holdings, Inc.). Each corridor is 350 feet wide, except for one, which narrows to 200 feet for approximately 8 miles. The total length of all three corridors is approximately 106 miles, which cross Camden, Gloucester, and Salem Counties in New Jersey and New Castle County in Delaware. All corridors traverse local marshland (adjacent to the Salem and HCGS sites), as well as agricultural and forested lands located away from the sites. One line crosses the Delaware River north of the Salem and HCGS sites and extends into Delaware.

Based on a review of information available on the New Jersey Department of Environmental Protection (NJDEP) website (county records of "rare species and natural communities"), information provided by Delaware, and previous on-site surveys, PSEG Nuclear believes that no federally- or state-listed threatened or endangered plant or animal species resides on the Salem or HCGS sites.

However, one federally-threatened plant species occurs on the Salem-New Freedom South transmission corridor (see enclosed Figure 2), and some state-listed threatened terrestrial animal species occur within Salem County and the counties crossed by the transmission corridors (see enclosed Table 1), and these species may occasionally migrate through the sites. A population of Helonias bullata (swamp pink) has been located between towers 9/4 and 10/1, near Jericho Road in Salem County. Terrestrial animal species known to occur in the subject counties include the bald eagle, peregrine falcon, osprey, Cooper's hawk, bobolink, and grasshopper sparrow. Ospreys are known to nest on transmission towers near the sites. Also, shortnose sturgeon and five species of federally-listed sea turtles are known to occur in the Delaware River near the Salem and HCGS sites.

PSEG Nuclear does not expect Salem or HCGS operations during the license renewal terms (an additional 20 years) to adversely affect threatened or endangered species at the station sites, the immediate environs, or the transmission line corridors because license renewal will not alter existing operations. No expansion of existing facilities is planned, and no structural modifications or other refurbishments have been identified that are necessary to support license renewal. Maintenance activities during the license renewal term would be restricted to previously disturbed areas. No additional land-disturbance or activities that would affect the Delaware River are anticipated in support of license renewal. Both PSE&G and Pepco have established maintenance procedures for transmission corridors that involve minimal disturbance of land, wetlands, and streams and are unlikely to adversely affect any threatened or endangered species.

After your review of the information provided in this letter, I would appreciate your sending a letter detailing any concerns you may have about any listed species or critical habitat in the area of the Salem and HCGS sites and the associated transmission corridors. PSEG Nuclear will include copies of this letter and your response in the environmental reports that will be submitted to the NRC as part of the Salem and HCGS license renewal applications.

Please do not hesitate to call me at 856-339-7902, if there are questions or you need additional information to complete a review of the proposed action. Thank you in advance for your assistance.

Sincerely,

Edward J. Keating
Sr. Environmental Advisor

Enclosure: Figure 1 – 50-Mile Region
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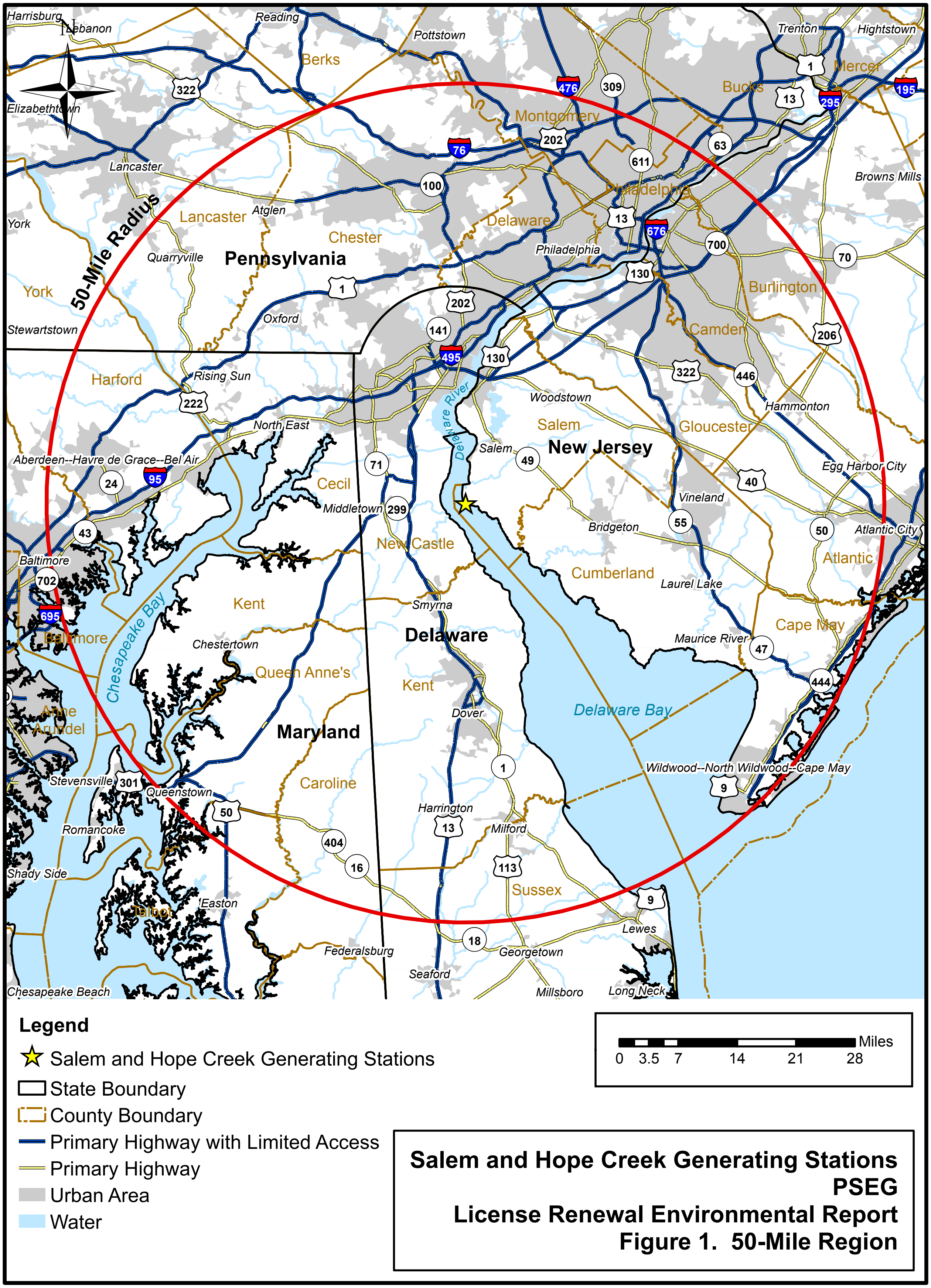

Salem and Hope Creek Generating Stations
PSEG
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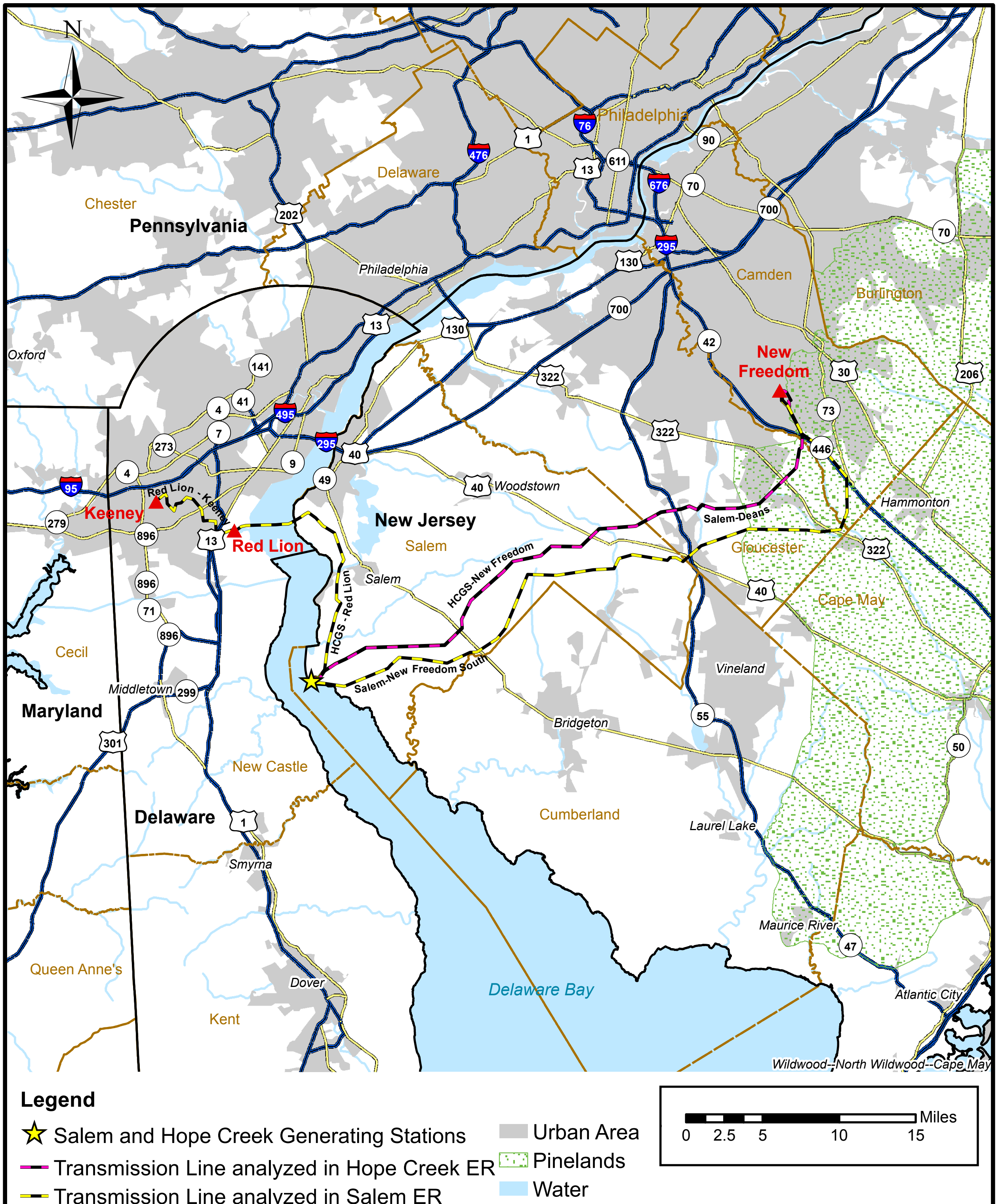

Salem and Hope Creek Generating Stations
PSEG
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Figure 2. Transmission Lines

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Scientific Name	Common Name	Status		County[c]
		Federal[a]	State[a,b]	
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Birds				
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A. savannarum	Grasshopper sparrow	-	T/S	Salem
Bartramia longicauda	Upland sandpiper	-	E	Gloucester, Salem
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Circus cyaneus	Northern harrier	-	E/U	Salem
Cistothorus platensis	Sedge wren	-	E	Salem
Dolichonyx oryzivorus	Bobolink	-	T/T	Salem
Falco peregrinus	Peregrine falcon	-	E	Camden, Gloucester, Salem
Haliaeetus leucocephalus	Bald eagle	-	E	Gloucester, Salem
Melanerpes erythrocephalus	Red-headed woodpecker	-	T/T	Camden, Gloucester, Salem
Pandion haliaetus	Osprey	-	T/T	Gloucester, Salem
Passerculus sandwichensis	Savannah sparrow	-	T/T	Salem
Podilymbus podiceps	Pied-billed grebe	-	E/S	Salem
Pooecetes gramineus	Vesper sparrow	-	E	Gloucester, Salem
Strix varia	Barred owl	-	T/T	Gloucester, Salem
Reptiles and Amphibians				
Ambystoma tigrinum tigrinum	Eastern tiger salamander	-	E	Gloucester, Salem
Clemmys insculpta	Wood turtle	-	E	Gloucester
C. muhlenbergii	Bog turtle	T	E	Camden, Gloucester, Salem
Crotalus horridus horridus	Timber rattlesnake	-	E	Camden
Hyla andersoni	Pine barrens treefrog	-	E	Camden, Gloucester, Salem
Pituophis melanoleucus	Northern pine snake	-	T	Camden, Gloucester, Salem
Caretta caretta	Loggerhead sea turtle	T	E	Delaware River[d]
Lepidochelys kempi	Kemp's ridley	E	E	Delaware River[d]
Dermochelys coriacea	Leatherback turtle	E	E	Delaware River[d]
Eretmochelys imbricata	Hawksbill turtle	E	E	Delaware River[d]
Chelonia mydas	Atlantic green turtle	T	T	Delaware River[d]
Fish				
Acipenser brevirostrum	Shortnose sturgeon	E	E	Delaware River[d]
A. oxyrinchus oxyrinchus	Atlantic sturgeon	C	-	Delaware River[d]
Insects				
Nicrophorus americanus	American burying beetle	E	E	Camden, Gloucester

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status		County[c]
		Federal[a]	State[a,b]	
Plants				
Aeschynomene virginica	Sensitive joint vetch	T	E	Camden, Gloucester, Salem
Aplectrum hyemale	Putty root	-	E	Gloucester
Aristida lanosa	Wooly three-awn grass	-	E	Camden, Salem
Asimina triloba	Pawpaw	-	E	Gloucester
Aster radula	Low rough aster	-	E	Camden, Gloucester, Salem
Bouteloua curtipendula	Side oats grama grass	-	E	Gloucester
Cacalia atriplicifolia	Pale Indian plantain	-	E	Camden, Gloucester
Calystegia spithamaea	Erect bindweed	-	E	Camden, Salem
Cardamine longii	Long's bittercress	-	E	Gloucester
Carex aquatilis	Water sedge	-	E	Camden
C. bushii	Bush's sedge	-	E	Camden
C.cumulata	Clustered sedge	-	E	Camden
C. limosa	Mud sedge	-	E	Gloucester
C. polymorpha	Variable sedge	-	E	Gloucester
Castanea pumila	Chinquapin	-	E	Gloucester, Salem
Cercis canadensis	Redbud	-	E	Camden
Chenopodium rubrum	Red goosefoot	-	E	Camden
Commelina erecta	Slender dayflower	-	E	Camden
Cyperus lancastriensis	Lancaster flat sedge	-	E	Camden, Gloucester
C. polystachyos	Coast flat sedge	-	E	Salem
C. pseudovegetus	Marsh flat sedge	-	E	Salem
C. retrofractus	Rough flat sedge	-	E	Camden, Gloucester
Dalibarda repens	Robin-run-away	-	E	Gloucester
Diodia virginiana	Larger buttonweed	-	E	Camden
Draba reptans	Carolina Whitlow-grass	-	E	Camden, Gloucester
Eleocharis melanocarpa	Black-fruit spike-rush	-	E	Salem
E. equisetoides	Knotted spike-rush	-	E	Gloucester
E. tortilis	Twisted spike-rush	-	E	Gloucester
Elephantopus carolinianus	Carolina elephant-foot	-	E	Gloucester, Salem
Eriophorum gracile	Slender cotton-grass	-	E	Gloucester
E. tenellum	Rough cotton-grass	-	E	Camden, Gloucester
Eupatorium capillifolium	Dog fennel thoroughwort	-	E	Camden
E. resinosum	Pine barren boneset	-	E	Camden, Gloucester,
Euphorbia purpurea	Darlington's glade spurge	-	E	Salem

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status Federal[a]	Status State[a,b]	County[c]
Glyceria grandis	American manna grass	-	E	Camden
Gnaphalium helleri	Small everlasting	-	E	Camden
Gymnopogon brevifolius	Short-leaf skeleton grass	-	E	Gloucester
Helonias bullata	Swamp-pink	T	E	Camden, Gloucester, Salem
Hemicarpha micrantha	Small-flower halfchaff sedge	-	E	Camden
Hottonia inflata	Featherfoil	-	E	Salem
Hydrastis canadensis	Golden seal	-	E	Camden
Hydrocotyle ranunculoides	Floating marsh-pennywort	-	E	Salem
Hypericum adpressum	Barton's St. John's-wort	-	E	Salem
Juncus caesariensis	New Jersey rush	-	E	Camden
J. torreyi	Torrey's rush	-	E	Camden
Kuhnia eupatorioides	False boneset	-	E	Camden
Lemna perpusilla	Minute duckweed	-	E	Camden, Salem
Limosella subulata	Awl-leaf mudwort	-	E	Camden
Linum intercursum	Sandplain flax	-	E	Camden, Salem
Luzula acuminate	Hairy wood-rush	-	E	Gloucester, Salem
Melanthium virginicum	Virginia bunchflower	-	E	Camden, Gloucester, Salem
Micranthemum micranthemoides	Nuttall's mudwort	-	E	Camden, Gloucester
Muhlenbergia capillaris	Long-awn smoke grass	-	E	Gloucester
Myriophyllum tenellum	Slender water-milfoil	-	E	Camden
M. pinnatum	Cut-leaf water-milfoil	_	E	Salem
Nelumbo lutea	American lotus	-	E	Camden, Salem
Nuphar microphyllum	Small yellow pond-lily	-	E	Camden
Onosmodium virginianum	Virginia false-gromwell	-	E	Camden, Gloucester, Salem
Ophioglossum vulgatum pycnostichum	Southern adder's tongue	-	E	Salem
Panicum aciculare	Bristling panic grass	-	E	Gloucester
Penstemon laevigatus	Smooth beardtongue	-	E	Gloucester
Plantago pusilla	Dwarf plantain	-	E	Camden
Platanthera flava flava	Southern rein orchid	-	E	Camden
Pluchea foetida	Stinking fleabane	-	E	Camden
Polemonium reptans	Greek-valerian	-	E	Salem
Polygala incarnata	Pink milkwort	-	E	Camden, Gloucester

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status		County[c]
		Federal[a]	State[a,b]	
Prunus angustifolia	Chickasaw plum	-	E	Camden, Gloucester, Salem
Pycnanthemum clinopodioides	Basil mountain mint	-	E	Camden
P. torrei	Torrey's mountain mint	-	E	Gloucester
Quercus imbricaria	Shingle oak	-	E	Gloucester
Q .lyrata	Overcup oak	-	E	Salem
Rhododendron atlanticum	Dwarf azalea	-	E	Salem
Rhynchospora globularis	Coarse grass-like beaked-rush	-	E	Camden, Gloucester, Salem
R. knieskernii	Knieskern's beaked-rush	T	E	Camden
Sagittaria teres	Slender arrowhead	-	E	Camden
Scheuchzeria palustris	Arrow-grass	-	E	Camden, Gloucester
Schwalbea americana	Chaffseed	E	E	Camden
Scirpus longii	Long's woolgrass	-	E	Camden
S. maritimus	Saltmarsh bulrush	-	E	Camden
Scutellaria leonardii	Small skullcap	-	E	Salem
Spiranthes laciniata	Lace-lip ladies' tresses	-	E	Gloucester
Stellaria pubera	Star chickweed	-	E	Camden
Triadenum walteri	Walter's St. John's wort	-	E	Camden
Utricularia biflora	Two-flower bladderwort	-	E	Gloucester, Salem
Valerianella radiata	Beaked cornsalad	-	E	Gloucester
Verbena simplex	Narrow-leaf vervain	-	E	Camden, Gloucester
Vernonia glauca	Broad-leaf ironweed	-	E	Gloucester, Salem
Vulpia elliotea	Squirrel-tail six-weeks grass	-	E	Camden, Gloucester, Salem
Wolffiella floridana	Sword bogmat	-	E	Salem
Xyris fimbriarta	Fringed yellow-eyed grass	-	E	Camden

a. E = Endangered; T = Threatened; C = Candidate; - = Not listed.
b. State status for birds separated by a slash (/) indicates a dual status. First status refers to the state breeding population, and the second status refers to the migratory or winter population. S = Stable species (a species whose population is not undergoing any long-term increase or decrease within its natural cycle); U = Undetermined (a species about which there is not enough information available to determine the status) (NJDEP 2008b).
c. Source of county occurrence: USFWS (undated); NJDEP (2008a); (NJDEP (2008c).
d. Sea turtles and sturgeon were not included in county lists maintained by USFWS (undated) and NJDEP (2008a), but are known by PSEG to occur in the Delaware River (see text).

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State of New Jersey
DEPARTMENT OF ENVIRONMENTAL PROTECTION

JON S. CORZINE
Governor

NJ Division of Fish and Wildlife
Dave Chanda, Director
P.O. Box 400
Trenton, NJ 08625-0400
Visit our website at www.njfishandwildlife.com

MARK N. MAURIELLO
Acting Commissioner

April 2, 2009

Mr. Edward Keating
Sr. Environmental Advisor
PSEG Nuclear LLC
P.O. Box 236
Hancocks Bridge, NJ 08038-0236

Dear Mr. Keating:

I am in receipt of your letter dated March 4, 2009, requesting that the Endangered and Nongame Species Program (ENSP) provide information addressing concerns about listed species or critical habitat located at the Salem and Hope Creek Generating Stations and along associated transmission corridors. We appreciate the opportunity to comment on listed wildlife species issues and look forward to a dialogue focusing on these concerns in the future.

A good starting point for identifying impacts of continued operations at Salem and HCGS on listed species would be for PSEG to review the ENSP's Landscape Project mapping and request a Natural Heritage Program (NHP) database search for rare species (including plants) documented in the above-mentioned areas. Although it is stated in your letter that the license renewal will not alter existing operations, and therefore will not adversely affect listed species, there may be species occurrences that have been documented since the last required database search. Furthermore, there may have been additions to either the state endangered species list or list of indigenous nongame wildlife (covering threatened species) since the last search was completed. Once you have identified which species may occur within the project area, we will then be able to more adequately address concerns and identify what PSEG can do to minimize impacts if operations continue. At that time, if necessary, we would also like to open a discussion on how and under what circumstances transmission corridors are maintained.

In general, we have concerns regarding impingements/captures of shortnose sturgeon, Atlantic sturgeon and sea turtles in the cooling intakes at the Salem Creek facility. Although Atlantic sturgeon are not listed in NJ, we are in the process of proposing rules that will add the species to our endangered species list within the next six months or so. In addition, the National Marine Fisheries Service (NMFS) is planning to list Atlantic

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sturgeon as Threatened in the region, though the timing of this is uncertain. Your Environmental Assessment / Impact Statement should address current and future PSEG efforts to avoid/minimize impacts to these rare species.

In your letter, you state that swamp pink occurs along one of the transmission corridors and that no adverse impacts are expected since existing operations will not be altered. The Office of Natural Lands Management has requested that you provide information on the management regime for the swamp pink occurrence and vicinity, assuming that PSEG periodically performs corridor maintenance where this species occurs Again, if you have not submitted a recent data request to the NHP (which will include plants) you should do so.

Once again, thank you for the opportunity to comment on listed species issues. If you have any questions or need additional information, please contact Jeanette Bowers-Altman of my staff at 856-629-0261.

Sincerely,

C. David Jenkins, Jr.

C. David Jenkins, Jr., Chief
Endangered and Nongame Species Program

c. Bob Cartica, Administrator – Office of Natural Lands Management

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PSEG Nuclear LLC
P.O. Box 236, Hancocks Bridge, New Jersey 08038-0236

PSEG
Nuclear LLC

March 4, 2009

LR-E09-056

Ms. Edna Stetzar
Natural Heritage and Endangered Species Program
Division of Fish and Wildlife Service
Delaware Department of Natural Resources and Environmental Control
4876 Hay Point Landing Road
Smyrna, DE 19977

SUBJECT: Salem and Hope Creek Generating Stations
Request for Information on Threatened or Endangered Species

Dear Ms. Stetzar:

In 2009, PSEG Nuclear plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for the Salem and Hope Creek Generating Stations (referred to respectively as Salem and HCGS), which are located on adjacent sites within a 740-acre parcel of property owned by PSEG Nuclear on the southern end of Artificial Island in Lower Alloways Creek Township, Salem County, New Jersey. The existing licenses for Salem Units 1 and 2 were issued for 40-year terms that expire in 2016 and 2020, respectively. The operating license for the single HCGS unit was also issued for a 40-year term that expires in 2026. License renewal would extend the operating period of each reactor for an additional 20 years.

The NRC requires that the license renewal applications for Salem and HCGS include environmental reports assessing potential environmental impacts from operation during the license renewal term. One of these potential environmental impacts would be the effect of license renewal on threatened or endangered species located on the Salem and HCGS sites, their immediate environs, and transmission line corridors routed to connect the plants to the existing transmission system. Accordingly, the NRC requires that the environmental report for each license renewal application assess such a potential effect (10 CFR 51.53). Later, during its review of the proposed license renewals pursuant to the National Environmental Policy Act (NEPA), the NRC will use that assessment to evaluate whether a basis exists to request consultation with your office under Section 7 of the Endangered Species Act.

I am contacting you now in order to obtain input regarding issues that may need to be addressed in the Salem and HCGS license renewal environmental reports, and to help me identify any information your staff believes would be helpful to expedite NRC's consultation.

Beginning early in the twentieth century, Artificial Island was created by placing dredge spoils within a diked area established by the U.S. Army Corps of Engineers on the eastern shore of the Delaware River. The 1,500-acre island is low and flat with an average elevation of approximately 9 ft above mean sea level (msl) and a maximum elevation of approximately 18 ft msl. Habitat surrounding the PSEG-owned property on Artificial Island can best be characterized as tidal marsh and grassland with some upland woodland vegetation. It is low quality for wildlife and is not an important natural resource area. Artificial Island is located approximately 18 miles southeast of Wilmington, Delaware (see enclosed Figure 1). Philadelphia is about 30 miles and Salem, New Jersey, is 7.5 miles northeast of Artificial Island.

There are three transmission corridors containing four 500-kV transmission lines that connect the Salem and HCGS sites to the regional electricity grid (see enclosed Figure 2). These transmission corridors are considered by the NRC to be within the scope of its environmental reviews for the Salem and HCGS license renewals. In New Jersey, the lines are owned and maintained by Public Service Electric and Gas Company (PSE&G) (a subsidiary of Public Service Enterprise Group, which also owns PSEG Nuclear). In Delaware, a single line is owned and maintained by Pepco (a regulated electric utility that is a subsidiary of Pepco Holdings, Inc.). The total length of all three corridors is approximately 106 miles, which cross Camden, Gloucester, and Salem Counties in New Jersey and New Castle County in Delaware. All corridors traverse local marshland (adjacent to the Salem and HCGS sites), as well as agricultural and forested lands located away from the sites. Each corridor is 350 feet wide, except for the HCGS-Red Lion and Red Lion-Keeney line, which narrows to 200 feet for approximately 8 miles. This line was originally constructed to connect Salem to the existing transmission system; therefore any impacts of the line/corridor are assessed in the Salem license renewal environmental report. When HCGS was constructed, several changes in transmission line connections with Salem were made. The Salem-Keeney line was disconnected from Salem and reconnected to HCGS. A new substation, Red Lion, was also constructed on the HCGS-Keeney transmission line. Hence the line is now referred to as the HCGS-Red Lion and Red Lion-Keeney lines. Because this transmission line extends into Delaware, the NRC requires that the environmental report for the Salem license renewal application assess whether any threatened or endangered species in Delaware would be affected by the license renewal (10 CFR 51.53(c)(3)(ii)(K)).

Based on a review of information available on the New Jersey Department of Environmental Protection (NJDEP) website (county records of "rare species and natural communities"), information provided by Delaware, and previous on-site surveys, PSEG Nuclear believes that no federally- or state-listed threatened or endangered plant or animal species resides on the Salem or HCGS sites.

However, one federally-threatened plant species occurs on the Salem-New Freedom South transmission corridor (see enclosed Figure 2) in New Jersey, and some state-listed threatened terrestrial animal species occur within Salem County and the counties crossed by the transmission corridors, including New Castle County (see enclosed Table 1), and these species may occasionally migrate through the sites or along the transmission corridors. Terrestrial animal species known to occur in the subject counties include the bald eagle, peregrine falcon, osprey, Cooper's hawk, bobolink, and grasshopper sparrow. Ospreys are known to nest on transmission towers near the sites. Also, shortnose sturgeon and five species of federally-listed sea turtles are known to occur in the Delaware River near the Salem and HCGS sites.

PSEG Nuclear does not expect Salem or HCGS operations during the license renewal terms (an additional 20 years) to adversely affect threatened or endangered species at the station sites, the immediate environs, or the transmission line corridors because license renewal will not alter existing operations. No expansion of existing facilities is planned, and no structural modifications or other refurbishments have been identified that are necessary to support license renewal. Maintenance activities during the license renewal term would be restricted to previously disturbed areas. No additional land-disturbance or activities that would affect the Delaware River are anticipated in support of license renewal. Both PSE&G and Pepco have established maintenance procedures for transmission corridors that involve minimal disturbance of land, wetlands, and streams and are unlikely to adversely affect any threatened or endangered species.

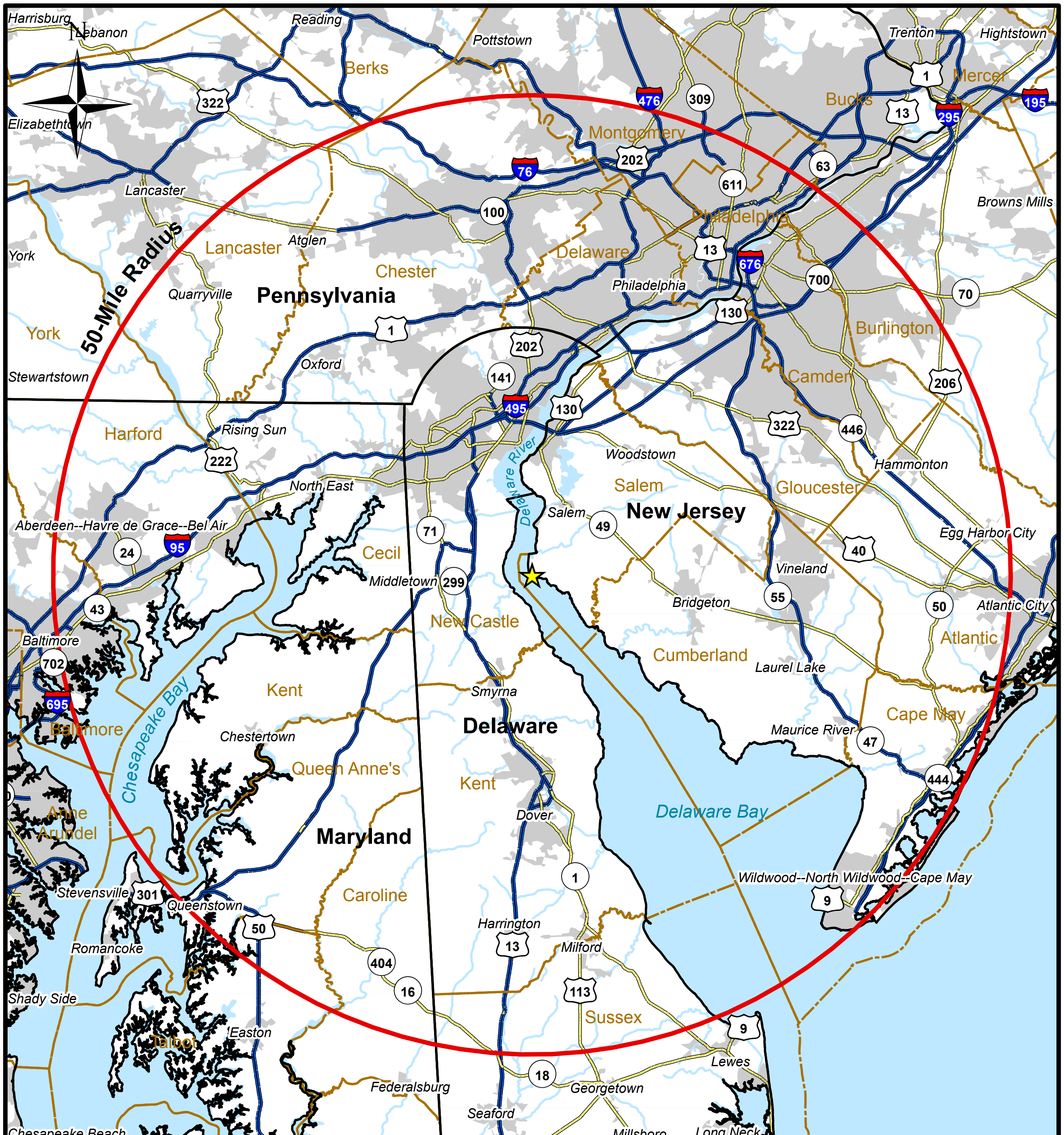
After your review of the information provided in this letter, I would appreciate your sending a letter detailing any concerns you may have about any listed species or critical habitat in the area of the Salem and HCGS sites and the associated transmission corridor in Delaware. PSEG Nuclear will include copies of this letter and your response in the environmental reports that will be submitted to the NRC as part of the Salem and HCGS license renewal applications.

Please do not hesitate to call me at 856-339-7902, if there are questions or you need additional information to complete a review of the proposed action. I am aware of your fee schedule as specified on your website. Thank you in advance for your assistance.

Sincerely,

Edward J. Keating
Sr. Environmental Advisor

Enclosure: Figure 1 – 50-Mile Region
Figure 2 – Transmission lines associated with Salem and HCGS
Table 1 – Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines

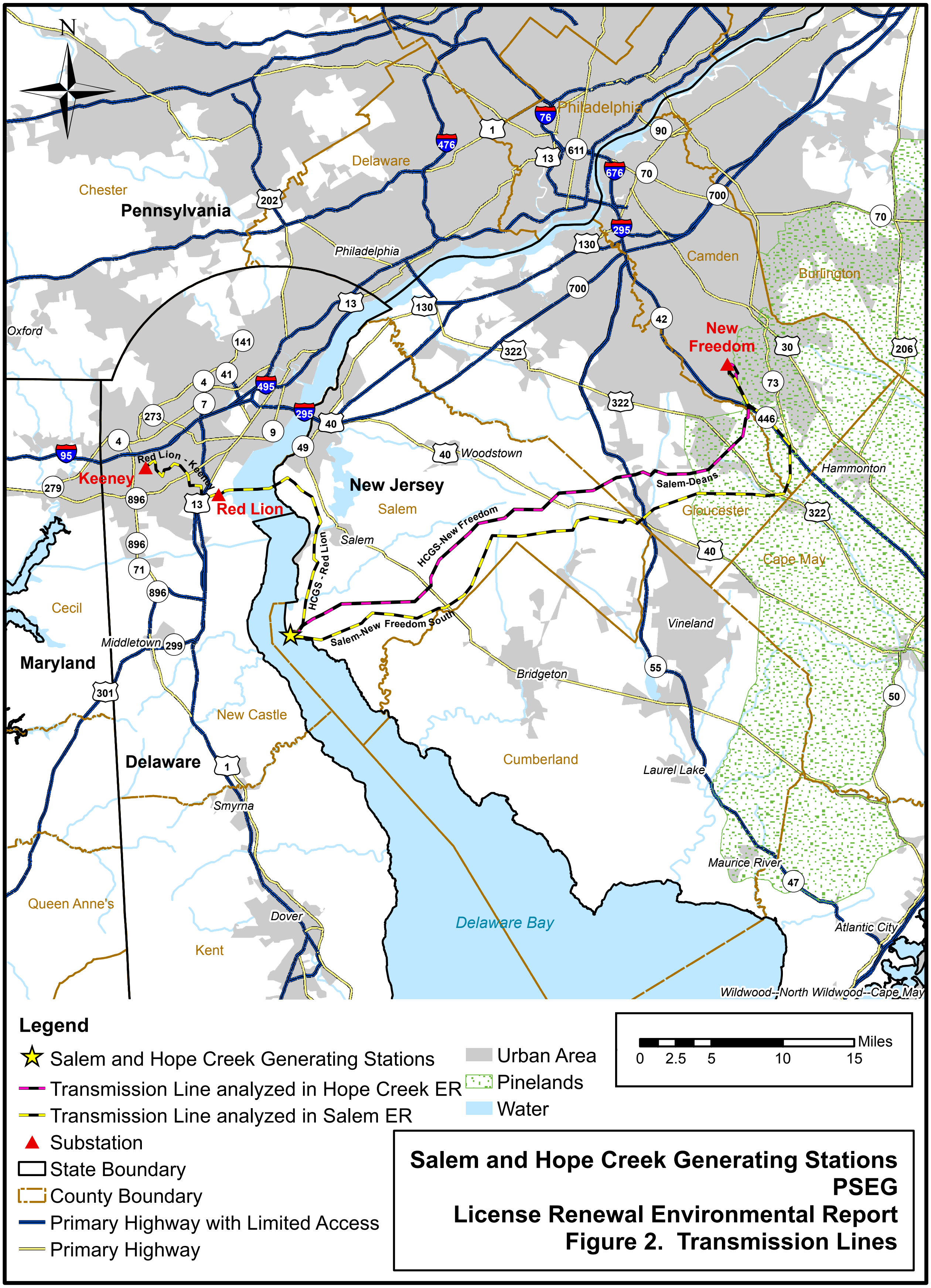


Legend

- Salem and Hope Creek Generating Stations
- State Boundary
- County Boundary
- Primary Highway with Limited Access
- Primary Highway
- Urban Area
- Water

Miles
0 3.5 7 14 21 28

Salem and Hope Creek Generating Stations
PSEG
License Renewal Environmental Report
Figure 1. 50-Mile Region



Salem and Hope Creek Generating Stations
PSEG
License Renewal Environmental Report
Figure 2. Transmission Lines

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines

Scientific Name	Common Name	Status Federal[a]	Status State[a,b]	County[c]
Mammals				
Lynx rufus	Bobcat	-	E	Salem
Birds				
Accipiter cooperii	Cooper's hawk	-	T/T	Gloucester, Salem
Ammodramus henslowii	Henslow's sparrow	-	E	Gloucester
A. savannarum	Grasshopper sparrow	-	T/S	Salem
Bartramia longicauda	Upland sandpiper	-	E	Gloucester, Salem
Buteo lineatus	Red-shouldered hawk	-	E/T	Gloucester
Circus cyaneus	Northern harrier	-	E/U	Salem
Cistothorus platensis	Sedge wren	-	E	Salem
Dolichonyx oryzivorus	Bobolink	-	T/T	Salem
Falco peregrinus	Peregrine falcon	-	E	Camden, Gloucester, Salem
Haliaeetus leucocephalus	Bald eagle	-	E	Gloucester, Salem
Melanerpes erythrocephalus	Red-headed woodpecker	-	T/T	Camden, Gloucester, Salem
Pandion haliaetus	Osprey	-	T/T	Gloucester, Salem
Passerculus sandwichensis	Savannah sparrow	-	T/T	Salem
Podilymbus podiceps	Pied-billed grebe	-	E/S	Salem
Pooecetes gramineus	Vesper sparrow	-	E	Gloucester, Salem
Strix varia	Barred owl	-	T/T	Gloucester, Salem
Reptiles and Amphibians				
Ambystoma tigrinum tigrinum	Eastern tiger salamander	-	E	Gloucester, Salem
Clemmys insculpta	Wood turtle	-	E	Gloucester
C. muhlenbergii	Bog turtle	T	E	Camden, Gloucester, Salem
Crotalus horridus horridus	Timber rattlesnake	-	E	Camden
Hyla andersoni	Pine barrens treefrog	-	E	Camden, Gloucester, Salem
Pituophis melanoleucus	Northern pine snake	-	T	Camden, Gloucester, Salem
Caretta caretta	Loggerhead sea turtle	T	E	Delaware River[d]
Lepidochelys kempi	Kemp's ridley	E	E	Delaware River[d]
Dermochelys coriacea	Leatherback turtle	E	E	Delaware River[d]
Eretmochelys imbricata	Hawksbill turtle	E	E	Delaware River[d]
Chelonia mydas	Atlantic green turtle	T	T	Delaware River[d]
Fish				
Acipenser brevirostrum	Shortnose sturgeon	E	E	Delaware River[d]
A. oxyrinchus oxyrinchus	Atlantic sturgeon	C	-	Delaware River[d]
Insects				
Nicrophorus americanus	American burying beetle	E	E	Camden, Gloucester

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status Federal[a]	Status State[a,b]	County[c]
Plants				
Aeschynomene virginica	Sensitive joint vetch	T	E	Camden, Gloucester, Salem
Aplectrum hyemale	Putty root	-	E	Gloucester
Aristida lanosa	Wooly three-awn grass	-	E	Camden, Salem
Asimina triloba	Pawpaw	-	E	Gloucester
Aster radula	Low rough aster	-	E	Camden, Gloucester, Salem
Bouteloua curtipendula	Side oats grama grass	-	E	Gloucester
Cacalia atriplicifolia	Pale Indian plantain	-	E	Camden, Gloucester
Calystegia spithamaea	Erect bindweed	-	E	Camden, Salem
Cardamine longii	Long's bittercress	-	E	Gloucester
Carex aquatilis	Water sedge	-	E	Camden
C. bushii	Bush's sedge	-	E	Camden
C.cumulata	Clustered sedge	-	E	Camden
C. limosa	Mud sedge	-	E	Gloucester
C. polymorpha	Variable sedge	-	E	Gloucester
Castanea pumila	Chinquapin	-	E	Gloucester, Salem
Cercis canadensis	Redbud	-	E	Camden
Chenopodium rubrum	Red goosefoot	-	E	Camden
Commelina erecta	Slender dayflower	-	E	Camden
Cyperus lancastriensis	Lancaster flat sedge	-	E	Camden, Gloucester
C. polystachyos	Coast flat sedge	-	E	Salem
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E. equisetoides	Knotted spike-rush	-	E	Gloucester
E. tortilis	Twisted spike-rush	-	E	Gloucester
Elephantopus carolinianus	Carolina elephant-foot	-	E	Gloucester, Salem
Eriophorum gracile	Slender cotton-grass	-	E	Gloucester
E. tenellum	Rough cotton-grass	-	E	Camden, Gloucester
Eupatorium capillifolium	Dog fennel thoroughwort	-	E	Camden
E. resinosum	Pine barren boneset	-	E	Camden, Gloucester,
Euphorbia purpurea	Darlington's glade spurge	-	E	Salem

Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status Federal[a]	Status State[a,b]	County[c]
Glyceria grandis	American manna grass	-	E	Camden
Gnaphalium helleri	Small everlasting	-	E	Camden
Gymnopogon brevifolius	Short-leaf skeleton grass	-	E	Gloucester
Helonias bullata	Swamp-pink	T	E	Camden, Gloucester, Salem
Hemicarpha micrantha	Small-flower halfchaff sedge	-	E	Camden
Hottonia inflata	Featherfoil	-	E	Salem
Hydrastis canadensis	Golden seal	-	E	Camden
Hydrocotyle ranunculoides	Floating marsh-pennywort	-	E	Salem
Hypericum adpressum	Barton's St. John's-wort	-	E	Salem
Juncus caesariensis	New Jersey rush	-	E	Camden
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Linum intercursum	Sandplain flax	-	E	Camden, Salem
Luzula acuminate	Hairy wood-rush	-	E	Gloucester, Salem
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Pluchea foetida	Stinking fleabane	-	E	Camden
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Table 1 Endangered and Threatened Species Recorded in Salem County and Counties Crossed by Transmission Lines (Continued)

Scientific Name	Common Name	Status		County[c]
		Federal[a]	State[a,b]	
Prunus angustifolia	Chickasaw plum	-	E	Camden, Gloucester, Salem
Pycnanthemum clinopodioides	Basil mountain mint	-	E	Camden
P. torrei	Torrey's mountain mint	-	E	Gloucester
Quercus imbricaria	Shingle oak	-	E	Gloucester
Q .lyrata	Overcup oak	-	E	Salem
Rhododendron atlanticum	Dwarf azalea	-	E	Salem
Rhynchospora globularis	Coarse grass-like beaked-rush	-	E	Camden, Gloucester, Salem
R. knieskernii	Knieskern's beaked-rush	T	E	Camden
Sagittaria teres	Slender arrowhead	-	E	Camden
Scheuchzeria palustris	Arrow-grass	-	E	Camden, Gloucester
Schwalbea americana	Chaffseed	E	E	Camden
Scirpus longii	Long's woolgrass	-	E	Camden
S. maritimus	Saltmarsh bulrush	-	E	Camden
Scutellaria leonardii	Small skullcap	-	E	Salem
Spiranthes laciniata	Lace-lip ladies' tresses	-	E	Gloucester
Stellaria pubera	Star chickweed	-	E	Camden
Triadenum walteri	Walter's St. John's wort	-	E	Camden
Utricularia biflora	Two-flower bladderwort	-	E	Gloucester, Salem
Valerianella radiata	Beaked cornsalad	-	E	Gloucester
Verbena simplex	Narrow-leaf vervain	-	E	Camden, Gloucester
Vernonia glauca	Broad-leaf ironweed	-	E	Gloucester, Salem
Vulpia elliotea	Squirrel-tail six-weeks grass	-	E	Camden, Gloucester, Salem
Wolffiella floridana	Sword bogmat	-	E	Salem
Xyris fimbriarta	Fringed yellow-eyed grass	-	E	Camden

a. E = Endangered; T = Threatened; C = Candidate; - = Not listed.

b. State status for birds separated by a slash (/) indicates a dual status. First status refers to the state breeding population, and the second status refers to the migratory or winter population. S = Stable species (a species whose population is not undergoing any long-term increase or decrease within its natural cycle); U = Undetermined (a species about which there is not enough information available to determine the status) (NJDEP 2008b).

c. Source of county occurrence: USFWS (undated); NJDEP (2008a); (NJDEP (2008c).

d. Sea turtles and sturgeon were not included in county lists maintained by USFWS (undated) and NJDEP (2008a), but are known by PSEG to occur in the Delaware River (see text).

STATE OF DELAWARE
DEPARTMENT OF NATURAL RESOURCES & ENVIRONMENTAL CONTROL
DIVISION OF FISH & WILDLIFE
NATURAL HERITAGE & ENDANGERED SPECIES
4876 HAY POINT LANDING ROAD
SMYRNA, DELAWARE 19977
TELEPHONE: (302) 653-2880
FAX: (302) 653-3431

April 21, 2009
(*Request received March 6, 2009*)

Edward J. Keating
PSEG Nuclear LLC
PO Box 236
Hancocks Bridge, NJ 08038-0236

RE: Operating license renewal-Salem and Hope Creek Generating Stations
Alignment from Artificial Island, NJ across DE River ending in New Castle County, DE

Dear Mr. Keating:

Thank you for contacting the Natural Heritage and Endangered Species program about information on rare, threatened and endangered species, unique natural communities, and other significant natural resources as they relate to the above referenced project.

Rare Species

The attached table (Table 1) includes a list of species of greatest conservation need (SCGN[1]) that occur within or in close proximity to the transmission alignment that begins at the Salem and Hope Creek generating stations, crosses the Delaware River, and ends just south of Newark in New Castle County, DE. We have not surveyed all of the areas within Delaware and additional rare species may occur within the alignment.

Currently there are no concerns with license renewal of the existing alignment, however, if maintenance activities are planned (tree clearing, heavy equipment access), further coordination with our Division will be necessary. Several SGCN and habitat that potentially supports those species could be impacted by maintenance activities depending on the scope of work.

State Natural Area

A portion of the alignment occurs within a State Natural Area. State Natural Areas involve areas of land or water, or of both land and water, whether in public or private ownership, which either

[1] Species of greatest conservation need (SGCN) are identified in the Delaware Wildlife Action Plan (DEWAP). DEWAP is a comprehensive strategy for conserving the full array of native wildlife and habitats-common and uncommon- as vital components of the state's natural resources. This document can be viewed via our program website at http://www.dnrec.state.de.us/nhp. This document also contains a list of species of greatest conservation need, species-habitat associations, and maps of key wildlife habitat

PSEG 2009 Hope Crk-Salem-license renewal

Delaware's Good Nature Depends on You!

retains or has reestablished its natural character (although it need not be undisturbed), or has unusual flora or fauna, or has biotic, geological, scenic or archaeological features of scientific or educational value. State Natural Areas are depicted on maps maintained by the Department of Natural Resources and Environmental Control, Division of Parks and Recreation, Natural Areas Program, as approved by the Department Secretary and upon recommendation by a governor appointed Natural Areas Advisory Council.

If you require further information about State Natural Areas, please contact Eileen Butler, Natural Areas Program Manager, at (302) 739-9235.

Key Wildlife Habitat

A portion of the alignment occurs within areas mapped as key wildlife habitat in the Delaware Wildlife Action Plan (DEWAP). DEWAP is a comprehensive strategy for conserving the full array of native wildlife and habitats-common and uncommon- as vital components of the state's natural resources. This document can be viewed via our program website at http://www.dnrec.state.de.us/nhp. This document also contains a list of species of greatest conservation need as well as species-habitat associations.

We are continually updating records on Delaware's rare, threatened and endangered species, unique natural communities and other significant natural resources. If the start of the project is delayed more than a year past the date of this letter, please contact us again for the latest information. If you have any questions, please contact me at (302) 653-2880 ext. 101.

Sincerely,
Edna J. Stetzar
Edna J. Stetzar
Biologist/Environmental Review Coordinator

(Please see Invoice on next page)

PSEG 2009 Hope Crk-Salem license renewal

INVOICE
- PAYMENT DUE -

It is our policy to charge a fee for this environmental review service. This letter constitutes an invoice for $70.00 ($35.00/hour for 2 hours). Please make your check payable to "Delaware Division of Fish and Wildlife" and submit to:

DE Division of Fish and Wildlife
89 Kings Hwy.
Dover, DE 19901
ATTN: Carla Cassell-Carter

In order for us to properly process your payment, you must reference
"PSEG 2009 Hope Crk-Salem license renewal" **on your check.**

cc: Carla Cassell-Carter, Fish and Wildlife Coordination/Accounting; Code to 9892

PSEG 2009 Hope Crk-Salem license renewal

Table 1. A review of our GIS database indicates the following species of greatest conservation need occur within or adjacent to the transmission alignment that begins at the Salem and Hope Creek generating stations, crosses the Delaware River, and ends just south of Newark in New Castle County, DE.

Scientific Name	Common Name	Taxon	State Rank	State Status	Global Rank	Federal Status
Buteo lineatus	Red-shouldered Hawk	Bird	S2B/S3N		G5	
Coccyzus erythropthalmus	Black-billed Cuckoo	Bird	S1B		G5	
Pandion haliaetus	Osprey	Bird	S3B		G5	
Caretta caretta	loggerhead sea turtle	Reptile	†SNA	E	G3	T
Chelonia mydas	green sea turtle	Reptile	†SNA	E	G3	T
Dermochelys coriacea	leatherback sea turtle	Reptile	†SNA	E	G2	E
Lepidochelys kempii	Kemp's ridley sea turtle	Reptile	†SNA	E	G1	E
**Glyptemys muhlenbergii*	Bog turtle	Reptile	S1	E	G3	T
Acipenser brevirostrum	short-nosed sturgeon	Fish	S3N		G3	E
Acipenser oxyrinchus	Atlantic sturgeon	Fish	S2	E	G3	C
Dromogomphus spinosus	black-shouldered spinyleg	Damselfly	S2		G5	
Enallagma vesper	vesper bluet	Damselfly	S2		G5	
Cuphea viscosissima	blue waxweed	Plant	S2		G5	
Isotria verticillata	Large whorled pogonia	Plant	S2		G5	
Lysimachia hybrid	False-hybrid loosestrife	Plant	S2		G5	

†SNA rank is currently being re-evaluated due to evidence that indicates the Delaware Estuary is an important foraging and developmental habitat for sea turtles

** A review of our GIS database has revealed that there may be suitable habitat for the federally listed bog turtle (Glyptemys muhlenbergii) within or in close proximity to the transmission alignment.*

State Rank: S1- extremely rare within the state (typically 5 or fewer occurrences); S2- very rare within the state (6 to 20 occurrences); S3-rare to uncommon in Delaware, B - Breeding; N - Nonbreeding; SX-Extirpated or presumed extirpated from the state. All historical locations and/or potential habitat have been surveyed; SH- Historically known, but not verified for an extended period (usually 15+ years); there are expectations that the species may be rediscovered; SE-Non-native in the state (introduced through human influence); not a part of the native flora or fauna., SNR-not yet ranked in Delaware, SNA-occurences in DE of limited conservation value

State Status: E – endangered, i.e. designated by the Delaware Division of Fish and Wildlife as seriously threatened with extinction in the state;

Global Rank: G1 - imperiled globally because of extreme rarity (5 or fewer occurrences worldwide); G2 - imperiled globally because of great rarity (6 to 20 occurrences); G3 - either very rare and local throughout its range (21 to 100 occurrences) or found only locally in a restricted range; G4 - apparently secure globally but uncommon in parts of its range; G5 - secure on a global basis but may be uncommon locally; T_ - variety or subspecies rank; Q – questionable taxonomy;

Federal Status: E – endangered, i.e. designated by the U.S. Fish and Wildlife Service as being in danger of extinction throughout its range; T – threatened, i.e. designated by USFWS as being likely to become endangered in the foreseeable future throughout all or a significant portion of its range; C-candidate – Taxa for which the U.S. Fish and Wildlife Service has on file enough substantial information on biological vulnerability and threat(s) to support proposals to list them as endangered or threatened species.

PSEG 2009 Hope Crk-Salem license renewal

Appendix D

State Historic Preservation Officer Correspondence

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PSEG Nuclear LLC
P.O. Box 236, Hancocks Bridge, New Jersey 08038-0236

PSEG
Nuclear LLC

March 4, 2009

LR-E09-060

Daniel Saunders, Deputy State Historic Preservation Officer
New Jersey Department of Environmental Protection
Natural and Historic Resources
Historic Preservation Office
P.O. Box 404
Trenton, New Jersey 08625-0404

SUBJECT: Salem and Hope Creek Generating Stations License Renewal
Request for Information on Historic and Archaeological Resources

Dear Mr. Saunders:

In 2009, PSEG Nuclear plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for Salem and Hope Creek Generating Stations (referred to respectively as Salem and HCGS), which are located on adjacent sites within a 740-acre parcel of property owned by PSEG Nuclear on the southern end of Artificial Island in Lower Alloways Creek Township, Salem County, New Jersey. The existing licenses for the Salem Units 1 and 2 were issued for 40-year terms that expire in 2016 and 2020, respectively. The operating license for the single HCGS unit was also issued for a 40-year term that expires in 2026. License renewal would extend the operating period of each reactor for an additional 20 years.

The NRC requires that the license renewal applications for Salem and HCGS include environmental reports assessing potential environmental impacts from operation during the license renewal terms. One of these potential environmental impacts would be the effect license renewal activities on historic or archaeological resources located on the Salem and HCGS sites and transmission line corridors routed to connect the plants to the existing transmission system. Accordingly, the NRC requires that the environmental report for each license renewal application assess such a potential effect (10 CFR 51.53). Later, during its review of the license renewal environmental reports pursuant to the National Environmental Policy Act (NEPA), the NRC will consult with your office in accordance with 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).

I am contacting you now in order to obtain input regarding issues that may need to be addressed in the Salem and HCGS license renewal environmental reports, and to help me identify any information your staff believes would be helpful to expedite NRC's review.

Beginning early in the twentieth century, Artificial Island was created by placing dredge spoils within a diked area established by the U.S. Army Corps of Engineers on the eastern shore of the Delaware River. The 1,500-acre island is low and flat with an average elevation of approximately 9 ft above mean sea level (msl) and a maximum elevation of approximately 18 ft msl. Habitat surrounding the PSEG-owned property on Artificial Island can best be characterized as tidal marsh and grassland with some upland woodland vegetation. It is low quality for wildlife and is not an important natural resource area. Artificial Island is located approximately 18 miles southeast of Wilmington, Delaware (see enclosed Figure 1). Philadelphia is about 30 miles and Salem, New Jersey, is 7.5 miles northeast of Artificial Island.

There are three transmission corridors containing four 500-kV transmission lines that connect the Salem and HCGS sites to the regional electricity grid (see enclosed Figure 2). These transmission corridors are considered by the NRC to be within the scope of its environmental reviews for the Salem and HCGS license renewals. In New Jersey, they are owned and maintained by Public Service Electric and Gas Company (PSE&G) (a subsidiary of Public Service Enterprise Group, which also owns PSEG Nuclear). In Delaware, a single line is owned and maintained by Pepco (a regulated electric utility that is a subsidiary of Pepco Holdings, Inc.). The total length of all three corridors is approximately 106 miles, which cross Camden, Gloucester, and Salem Counties in New Jersey, and New Castle County in Delaware. All corridors traverse local marshland (adjacent to the Salem and HCGS sites), as well as agricultural and forested lands located away from the sites. Each corridor is 350 feet wide, except for one, which narrows to 200 feet for approximately 8 miles. One line crosses the Delaware River north of the Salem and HCGS sites and extends into Delaware.

Using the National Register Information System (NRIS) on-line database, PSEG Nuclear has identified six sites currently listed on the National Register of Historic Places that are located in Salem County, New Jersey within a six-mile radius of Salem and HCGS (see enclosed Table 1). No archaeological or historic sites are known to be located within the transmission corridors.

PSEG Nuclear does not expect Salem or HCGS operations during the license renewal terms (an additional 20 years) to adversely affect archaeological or historic resources at the station sites, the immediate environs, or the transmission line corridors because license renewal will not alter current operations. No expansion of existing facilities is planned, and no structural modifications or other refurbishments have been identified that are necessary to support license renewal. Maintenance activities during the license renewal term would be restricted to previously disturbed areas. No additional land-disturbance is anticipated in support of license renewal. Both PSE&G and Pepco have established maintenance procedures for transmission corridors that involve minimal land disturbance and are unlikely to result in inadvertent encounters with potential historic or archaeological sites.

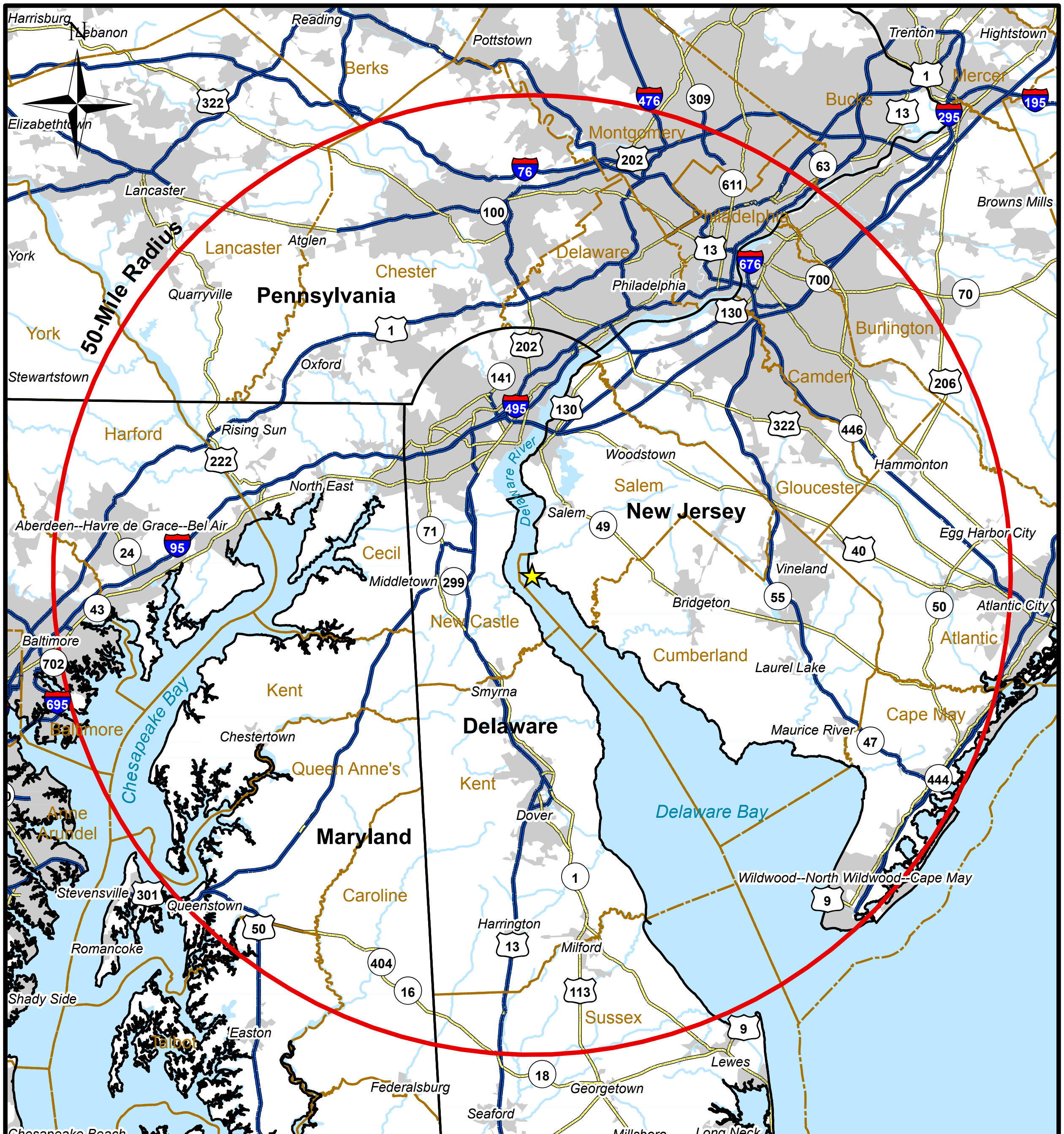
After your review of the information provided in this letter, I would appreciate your sending a letter detailing any concerns you may have about historic/archaeological properties in the area of the Salem and HCGS sites and the associated transmission corridors, or alternatively, confirming my conclusion that operation of Salem and HCGS over the license renewal terms would have no effect on known historic or archaeological properties in New Jersey. PSEG Nuclear will include copies of this letter and your response in the environmental reports that will be submitted to the NRC as part of the Salem and HCGS license renewal applications.

Please do not hesitate to call me at 856-339-7902, if there are questions or you need additional information to complete a review of the proposed action. Thank you in advance for your assistance.

Sincerely,

Edward J. Keating
Sr. Environmental Advisor

Enclosures: Figure 1 – Fifty-mile region
Figure 2 – Transmission lines associated with Salem and HCGS
Table 1 – Sites Listed on the National Register of Historic Places within a 6-mile Radius of Salem and Hope Creek Generating Stations

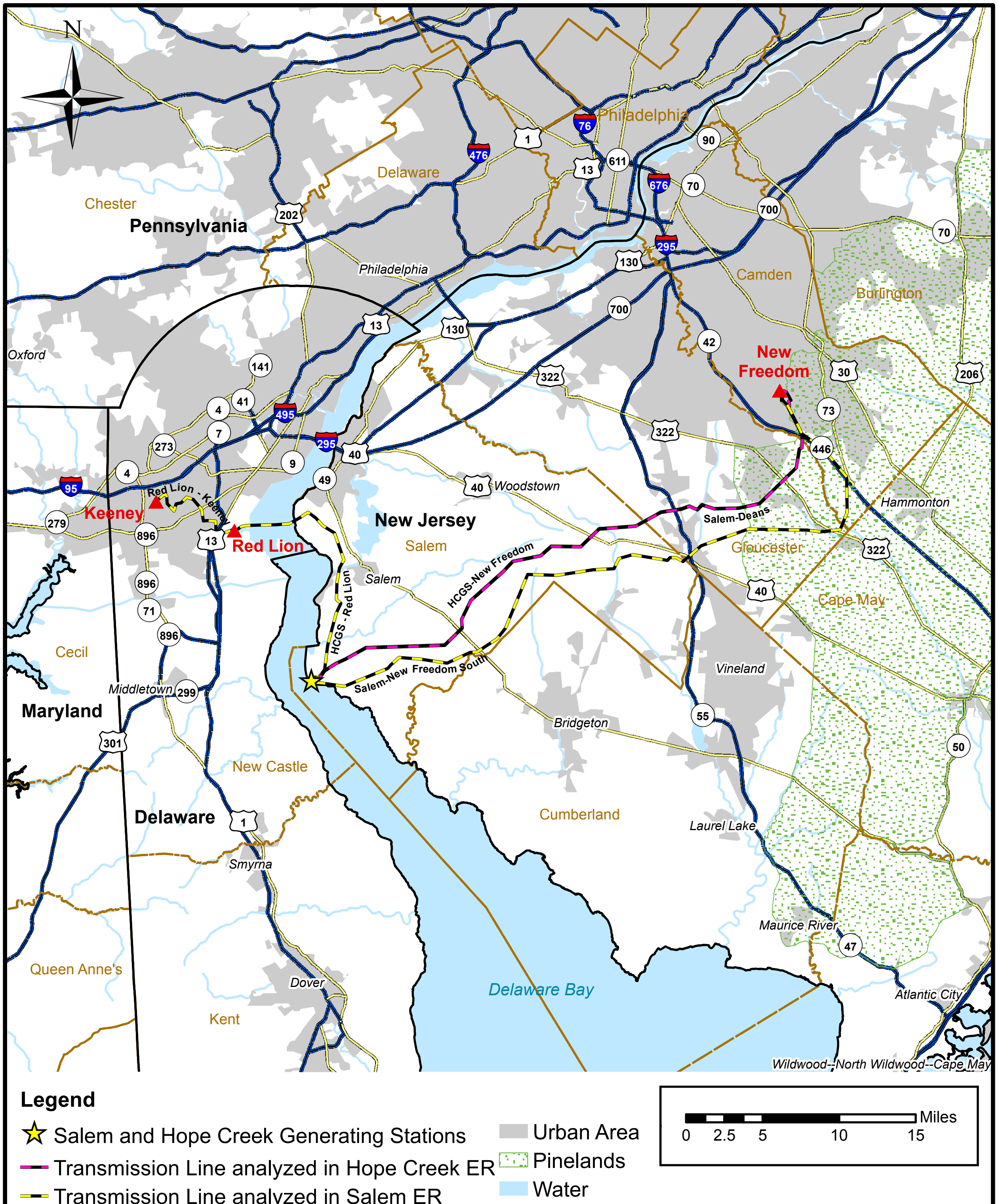


Legend

- ★ Salem and Hope Creek Generating Stations
- State Boundary
- County Boundary
- Primary Highway with Limited Access
- Primary Highway
- Urban Area
- Water

Miles: 0, 3.5, 7, 14, 21, 28

Salem and Hope Creek Generating Stations
PSEG
License Renewal Environmental Report
Figure 1. 50-Mile Region



Salem and Hope Creek Generating Stations
PSEG
License Renewal Environmental Report
Figure 2. Transmission Lines

Table 1. Sites Listed on the National Register of Historic Places within a 10-km (6-mi) Radius of Salem Generating Station

Resource Name	Address	City	Distance (km [mi]) from Station
Salem County, New Jersey			
Alloways Creek Friends Meetinghouse	Buttonwood Avenue, 150 ft. West of Main Street	Hancock's Bridge	8 (5)
Hancock House	3 Front Street	Hancock's Bridge	8 (5)
Holmes, Benjamin, House	West of Salem on Fort Elfsborg-Hancock's Bridge Road	Salem	10 (6)
Nicholson, Abel and Mary, House	Junction of Hancocks Branch and Fort Elfsborg Road, Elsinsboro Township	Salem	8 (5)
Nicholson, Sarah and Samuel, House	2 miles South of Salem on Amwellbury Road	Salem	10 (6)
Ware, Joseph, House	134 Poplar Street	Hancock's Bridge	6 (4)
New Castle County, Delaware			
Ashton Historic District	North of Port Penn on Thormton Road	Port Penn	8 (5)
Augustine Beach Hotel	South of Port Penn on DE 9	Port Penn	6 (4)
Cleaver House	Off Biddle's Corner Road	Port Penn	10 (6)
Dilworth House	Off DE 9	Port Penn	8 (5)
Gordon, J.M., House	Route 44	Odessa	8 (5)
Green Meadow	Thomas Landing Road (DE 440), Appoquinimink Hundred	Odessa	6 (4)
Grose, Robert, House	1000 Port Penn Road	Port Penn	8 (5)
Hart House	East of Taylors Bridge on DE 453	Taylor's Bridge	5 (3)
Hazel Glen	West of Port Penn on DE 420	Port Penn	8 (5)
Higgins, S., Farm	Route 423	Odessa	8 (5)
Johnson Home Farm	Co. Road 453 East of Junction with DE 9, Blackbird Hundred	Taylor's Bridge	6 (4)
Liston House	East of Taylors Bridge on DE 453	Taylor's Bridge	6 (4)
Misty Vale	Route 423	Odessa	10 (6)
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Reedy Island Range Rear Light	Junction of DE 9 and Road 453	Taylor's Bridge	8 (5)
Thomas, David W., House	326 Thomas Landing Road, Appoquinimink Hundred	Odessa	8 (5)
Vandegrift, J., House	Route 44	Odessa	8 (5)

PSEG Nuclear LLC
P.O. Box 236, Hancocks Bridge, New Jersey 08038-0236

PSEG
Nuclear LLC

March 4, 2009

LR-E09-058

Timothy A. Slavin, State Historic Preservation Officer
Department of the State of Delaware
Division of Historical and Cultural Affairs
State Historic Preservation Office
21 The Green
Dover, Delaware 19901

SUBJECT: Salem and Hope Creek Generating Stations License Renewal
Request for Information on Historic and Archaeological Resources

Dear Mr. Slavin:

In 2009, PSEG Nuclear plans to apply to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for Salem and Hope Creek Generating Stations (referred to respectively as Salem and HCGS), which are located on adjacent sites within a 740-acre parcel of property owned by PSEG Nuclear on the southern end of Artificial Island in Lower Alloways Creek Township, Salem County, New Jersey. The existing licenses for Salem Units 1 and 2 were issued for 40-year terms that expire in 2016 and 2020, respectively. The operating license for the single HCGS unit was also issued for a 40-year term that expires in 2026. License renewal would extend the operating period of each reactor for an additional 20 years.

The NRC requires that the license renewal applications for Salem and HCGS include environmental reports assessing potential environmental impacts from operation during the license renewal terms. One of these potential environmental impacts would be the effect of license renewal activities on historic or archaeological resources located on the Salem and HCGS sites and transmission line corridors connecting the plants to the existing transmission system. Accordingly, the NRC requires that the environmental report for each license renewal application assess such a potential effect (10 CFR 51.53). Later, during its review of the license renewal environmental reports pursuant to the National Environmental Policy Act (NEPA), the NRC will consult with your office in accordance with 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).

95-2168 REV. 7/99

I am contacting you now in order to obtain input regarding issues that may need to be addressed in the Salem and HCGS license renewal environmental reports, and to help me identify any information your staff believes would be helpful to expedite NRC's consultation.

Beginning early in the twentieth century, Artificial Island was created by placing dredge spoils within a diked area established by the U.S. Army Corps of Engineers on the eastern shore of the Delaware River. The 1,500 acre island is low and flat with an average elevation of approximately 9 ft above mean sea level (msl) and a maximum elevation of approximately 18 ft msl. Habitat surrounding the PSEG-owned property on Artificial Island can best be characterized as tidal marsh and grassland with some upland woodland vegetation. It is low quality for wildlife and is not an important natural resource area. Artificial Island is located approximately 18 miles southeast of Wilmington, Delaware (see enclosed Figure 1). Philadelphia is about 30 miles and Salem, New Jersey, is 7.5 miles northeast of Artificial Island.

There are three transmission corridors containing four 500-kV transmission lines that connect the Salem and HCGS sites to the regional electricity grid (see enclosed Figure 2). These transmission corridors are considered by the NRC to be within the scope of its environmental reviews for the Salem and HCGS license renewals. In New Jersey, the lines are owned and maintained by Public Service Electric and Gas Company (PSE&G) (a subsidiary of Public Service Enterprise Group, which also owns PSEG Nuclear). In Delaware, a single line is owned and maintained by Pepco (a regulated electric utility that is a subsidiary of Pepco Holdings, Inc.). The total length of all three corridors is approximately 106 miles, which cross Camden, Gloucester, and Salem Counties in New Jersey, and New Castle County in Delaware. All corridors traverse local marshland (adjacent to the Salem and HCGS sites), as well as agricultural and forested lands located away from the sites. Each corridor is 350 feet wide, except for the HCGS-Red Lion and Red-Lion-Keeney line, which narrows to 200 feet for approximately 8 miles. This line was originally constructed to connect Salem to the existing transmission system, any impacts of the line/corridor are assessed in the Salem license renewal environmental report. When HCGS was constructed, several changes in transmission line connections with Salem were made. The Salem-Keeney line was disconnected from Salem and reconnected to HCGS. A new substation, Red Lion, was also constructed on the HCGS-Keeney transmission line. Hence the line is now referred to as the HCGS-Red Lion and Red Lion-Keeney lines. Because this transmission line extends into Delaware, the NRC requires that the environmental report for the Salem license renewal application assess whether any historic or archaeological properties will be affected by the proposed project (10 CFR 51.53(c)(3)(ii)(K)), since the line was originally constructed to connect Salem to the existing transmission system.

Using the National Register Information System (NRIS) on-line database, PSEG Nuclear has identified 19 sites currently listed on the National Register of Historic

Places that are located in New Castle County, Delaware within a six-mile radius of Salem and HCGS (see enclosed Table 1). No archaeological or historic sites are known to be located within the HCGS-Red Lion and Red Lion-Keeney transmission corridor.

PSEG Nuclear does not expect Salem or HCGS operations during the license renewal terms (an additional 20 years) to adversely affect archaeological or historic resources at the station sites, the immediate environs, or the transmission line corridors because license renewal will not alter existing operations. No expansion of existing facilities is planned, and no structural modifications or other refurbishments have been identified that are necessary to support license renewal. Maintenance activities during the license renewal term would be restricted to previously disturbed areas. No additional land-disturbance is anticipated in support of license renewal. Both PSE&G and Pepco have established maintenance procedures for transmission corridors that involve minimal land disturbance and are unlikely to result in inadvertent encounters with potential historic or archaeological sites.

After your review of the information provided in this letter, I would appreciate your sending a letter detailing any concerns you may have about historic/archaeological properties in the area of the Salem and HCGS sites and the HCGS-Red Lion and Red Lion-Keeney transmission corridors, or alternatively, confirming the conclusion that operation of Salem and HCGS over the license renewal terms would have no effect on known historic or archaeological properties in Delaware. PSEG Nuclear will include copies of this letter and your response in the environmental reports that will be submitted to the NRC as part of the Salem and HCGS license renewal applications.

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Edward J. Keating
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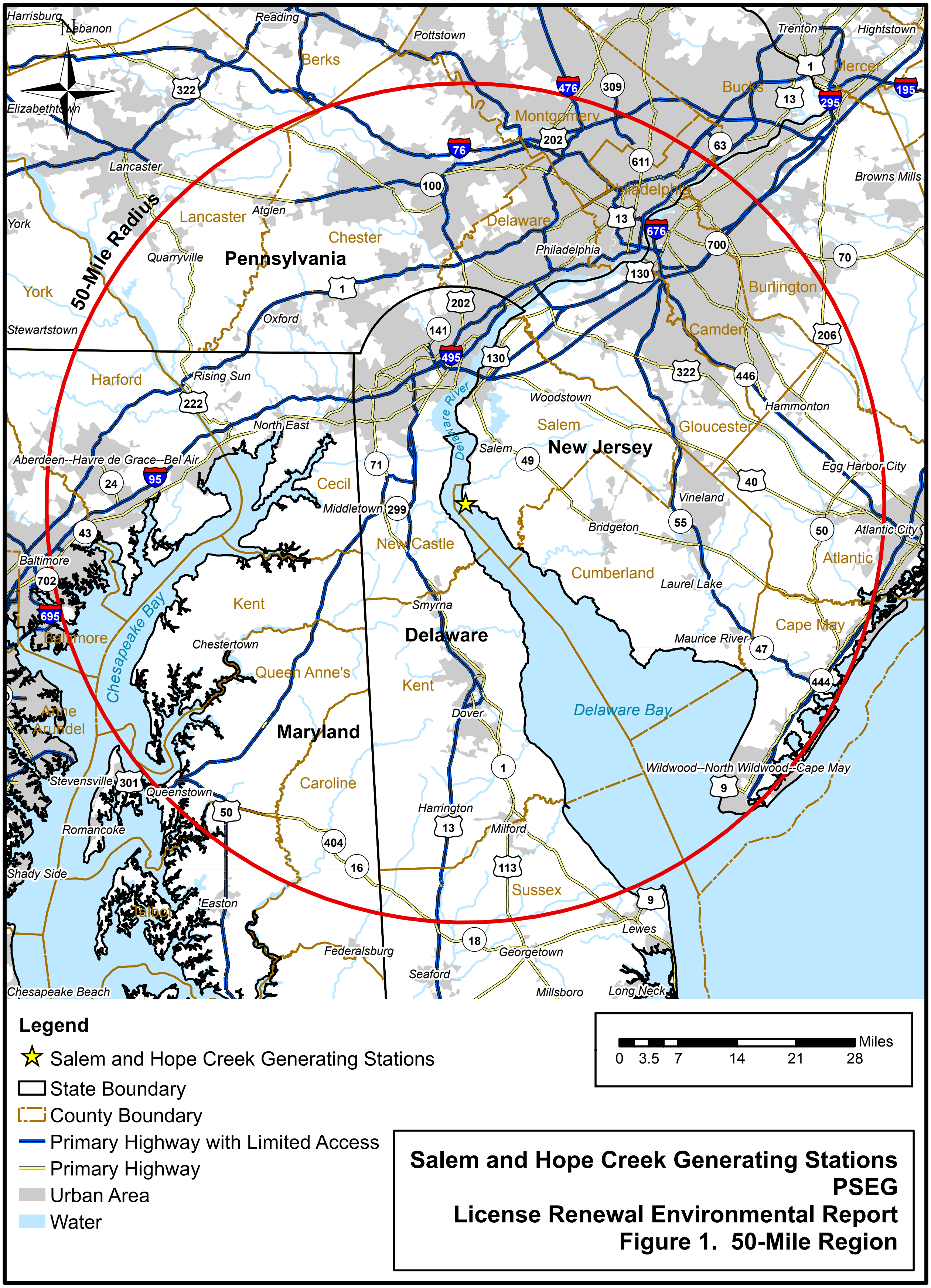
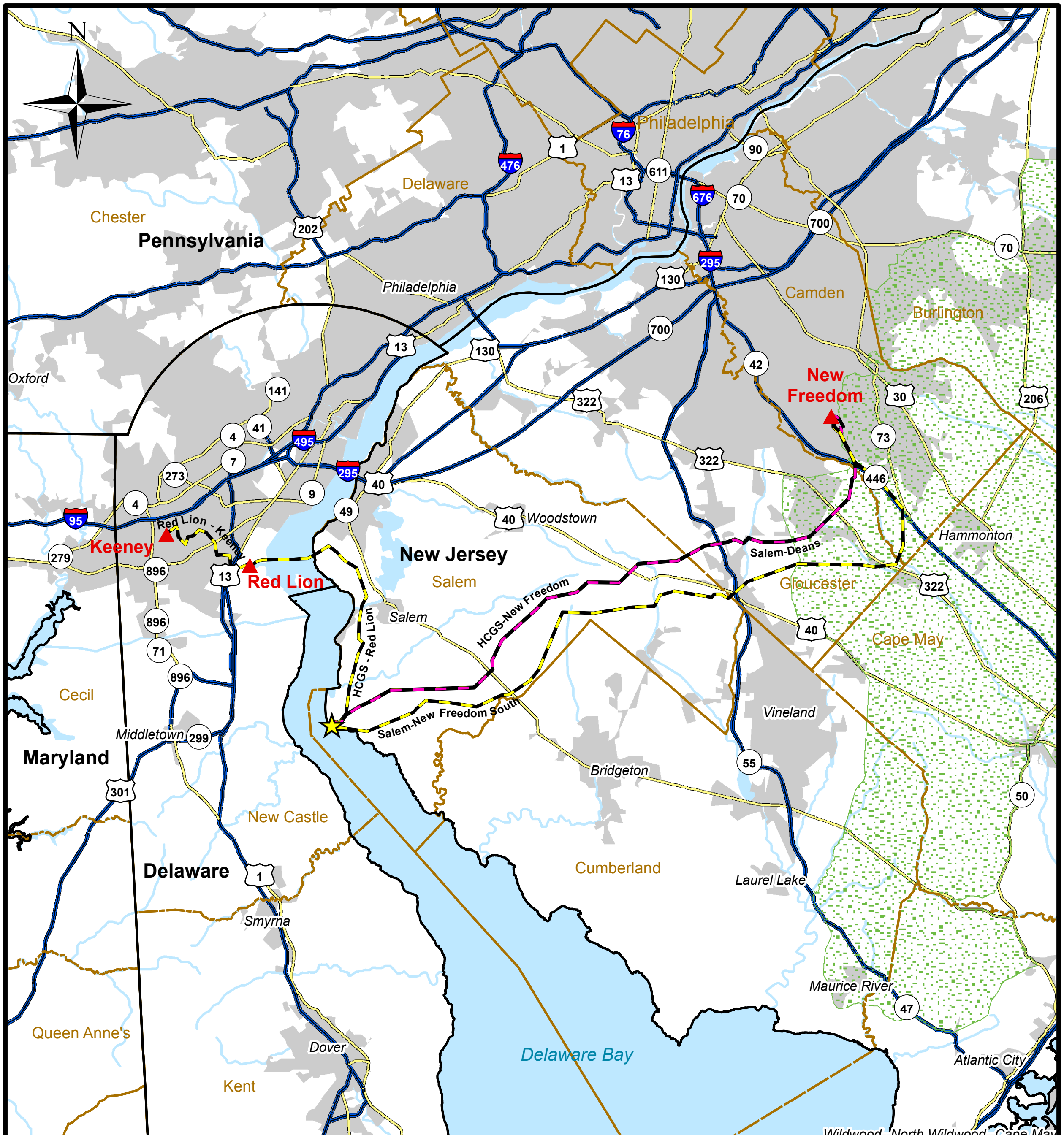


Salem and Hope Creek Generating Stations
PSEG
License Renewal Environmental Report
Figure 1. 50-Mile Region



Legend

- Salem and Hope Creek Generating Stations
- Transmission Line analyzed in Hope Creek ER
- Transmission Line analyzed in Salem ER
- Substation
- State Boundary
- County Boundary
- Primary Highway with Limited Access
- Primary Highway
- Urban Area
- Pinelands
- Water

Miles: 0 2.5 5 10 15

Salem and Hope Creek Generating Stations
PSEG
License Renewal Environmental Report
Figure 2. Transmission Lines

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Appendix E
SAMA ANALYSIS

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List of Tables

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Acronyms Used in Attachment E

AFW	auxiliary feedwater
AFWST	auxiliary feedwater storage tank
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
BE	basic event
BWR	boiling water reactor
BWST	borated water storage tank
CAC	containment air coolers
CC	component cooling
CDB	core damage bin
CDF	core damage frequency
CF	containment failure
CFCU	containment fan cooler units
CRD	control rod drive
CS	containment spray
CST	condensate storage tank
DH	decay heat
DW	demineralized water
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFIC	emergency feedwater initiation and control
EFW	emergency feedwater
EG	emergency generator
EPRI	electric power research institute
EPZ	emergency planning zone
ET	event tree
F&O	fact and observation
FP	fire protection
FPC	Florida Power Corporation
FT	fault tree
FWP	feedwater pump
HEP	human error probability
HEPA	high efficiency particle air
HLCR	hot leg creep rupture
HPI	high pressure injection
HRA	human reliability analysis
HVAC	heating ventilation and air-conditioning
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

Acronyms Used in Attachment E

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
MG	motor generator
MMACR	modified maximum averted cost-risk
MOR	model of record
MOV	motor operated valve
MSIV	main steam isolation valve
MSPI	mitigating systems performance index
NEI	Nuclear Energy Institute
NPSH	net positive suction head
NRC	U.S. Nuclear Regulatory Commission
OECR	off-site economic cost risk
OTSG	once-through steam generator
PACR	potential averted cost-risk
PORV	power operated relief valve
PRA	probabilistic risk analysis
PSA	probabilistic safety assessment
PWR	pressurized water reactor
RB	reactor building
RCP	reactor coolant pump
RCS	reactor coolant system
RDR	real discount rate
RHR	residual heat removal
RPV	reactor pressure vessel
RRW	risk reduction worth
RSP	Remote Shutdown Panel
RWCU	Reactor Water Cleanup
RWST	refueling water storage tank
SAMA	severe accident mitigation alternative
SBLC	standby liquid control
SBO	station blackout
SDS	seismic damage states
SG	steam generator
SGS	Salem Nuclear Generating Station
SGTR	steam generator tube rupture
SI	safety injection
SRP	Standard Review Plan
SRV	safety relief valve
SW	service water
SWGR	switchgear
WOG	Westinghouse Owner’s Group

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SEVERE ACCIDENT MITIGATION ALTERNATIVES

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

E.1 METHODOLOGY

The methodology selected for this analysis, which is based on the NEI 05-01 guidance, 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 (OECR). These values provide a measure of both the likelihood and consequences of a core damage event. The SAMA process consists of the following steps:

- Baseline Risk Monetization – Use U.S. Nuclear Regulatory Commission (NRC) regulatory analysis techniques to calculate the monetary value of the unmitigated severe accident risk. This becomes the maximum averted cost-risk (MACR) that is possible (Section E.4). The following plant specific risk analyses are used to support this process:

  - The SGS Level 1 and 2 Probabilistic Risk Assessment (PRA) models (Section E.2) provide estimates of the risk related to core melt scenarios. These models evaluate the likelihood of a core melt and the performance of the containment structures after core melt has occurred. The external events contributions, which have historically been evaluated separately from the internal events contributors, are incorporated as described in Section E.5.

  - The Level 1 and 2 PRA output, site-specific meteorology, demographic, land use, and emergency response data are used as input in performing a Level 3 PRA using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section E.3). The results of the Level 3 PRA provide estimates of the consequences of core melt scenarios.

- Develop an initial plant specific SAMA list based on the SGS PRA, Individual Plant Examination (IPE), Individual Plant Examination – External Events (IPEEE), and documentation from the industry and NRC. This process is defined in more detail in Section E.5 and the Phase 1 SAMA list is provided in Table E.5-3.

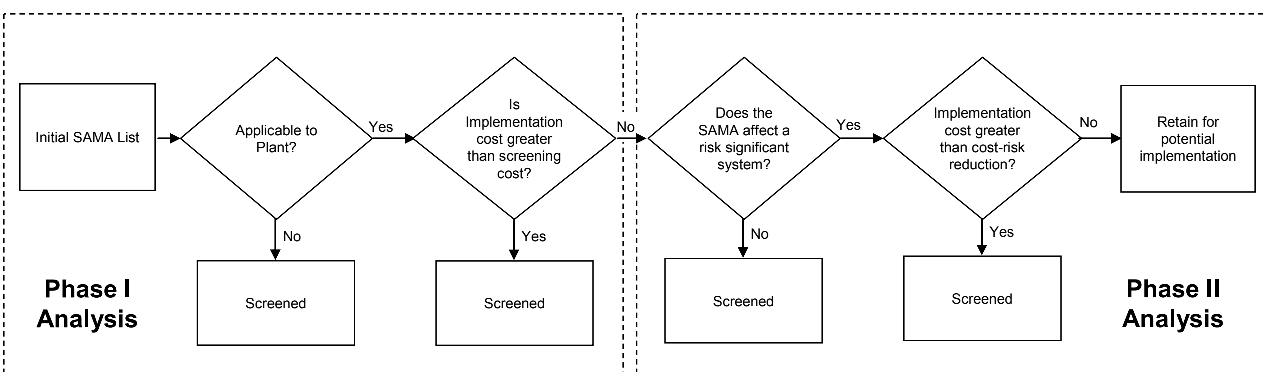
- Phase 1 SAMA Analysis – Screen out SAMA candidates that are not applicable to the SGS design or are of low benefit in pressurized water reactors (PWRs) such as SGS, candidates that have already been implemented at SGS or whose benefits have been achieved at SGS using other means, and candidates whose estimated cost exceeds the possible MACR (Section E.5). The result of this process is the Phase 2 SAMA list, which is provided as Table E.6-1.

- Phase 2 SAMA Analysis – Calculate the monetary value of the risk reduction attributable to each remaining SAMA candidate and compare it to the SAMA's implementation cost to identify the net cost-benefit. PRA insights are also used to screen SAMA candidates in this phase (Section E.6).

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

- Conclusions – Summarize results and identify conclusions (Section E.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.



E.2 SALEM PRA MODEL

A Level 1 PRA of SGS Units 1 and 2 was performed in 1988 and updated in 1990. The original IPE model was submitted in 1993 has been subsequently updated in 1996, 1997, 2002, 2003, 2006 and 2008 to maintain the design fidelity with the operating plant and reflect the latest PRA technology. The following subsections provide more detailed information related to the evolution of the Salem Internal Events PRA model and the current results. These topics include:

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

Section E.5.1.6 provides a description of the process used to integrate external events contribution into the Salem SAMA process; therefore, no additional discussion of the external events model is included here.

Table E.2-1, at the end of this document, provides a summary of the PRA models created since the IPE.

E.2.1 PRA Model Changes since IPE Submittal (PSEG 1993)

The original 1993 Individual Plant Examination (IPE) Level 1 model was completed in July 1993. The IPE provided level 1 and 2 analyses. The core damage frequency (CDF) was calculated for internal events including and excluding internal events. The large early release frequency (LERF) was also calculated in the IPE. This data was calculated on a unit-specific basis.

E.2.1.1 PRA Model 1.0 Update (PSEG 1996b)

The PRA Model 1.0 update was completed in August of 1996 to reflect data as of July of 1996. The CDF and LERF values were calculated on a unit-specific basis as done in the previous revision. As seen in Table E.2-1, the difference between the CDF and LERF values of each unit are similar.

E.2.1.2 PRA Model 2.0 Update (PSEG 1998)

The Salem PRA Model 1.0 was updated in August of 1998 to incorporate changes as of March of 1997. Much like the previous revisions to the PRA model, the 2.0 update also calculates the CDF and LERF on a unit-specific basis.

E.2.1.3 PRA Model 3.0 Update (PSEG 2002)

This PRA Model, Revision 3, was first released in November 16, 2001 as a rough draft, or interim report, to accommodate the Westinghouse Owner's Group (WOG) certification process. After receiving the WOG Certification comments on December 7, 2001, PSEG chose to delay issuance of Revision 3 until all Grade "A" and certain Grade "B" comments by the Certification Team were resolved. By January 31, 2002 these comments were incorporated in the model, and the model was requantified. However, quantification and documentation were not finalized until the May/June 2002 timeframe.

It is important to note that the Salem PRA model was originally modeled for each of the 2 Units individually. Starting with Model Revision 3.0, the SGS PRA was performed for Unit 1 only on the basis that the unit differences in system configurations and success criteria are minimal and that the plant specific data are averaged between the two units. The SGS PRA analyzes only one unit as of the model of record (MOR).

The following is a list of changes made to Revision 3 of the PRA model as a result of the WOG certification comments:

- The recovery tables used in the .IN file are revised slightly.
- HRA dependency numbers were applied; this was a Grade "A" finding for HRA; HR-3.
- The SW trees (11SW, 12 SW, X11SW, X12SW, and IE-TSW) were modified to fix the missing dominant cutsets. Also, event trees Ie-tp and IE-S3 were modified to

revise RSC1 to RSC2. These were Grade “A” finding for dominant cutsets missing; QU-1.

- Common cause failures of 5 and 6 SW pumps fail to run and strainers plugging are assigned a value of 1.0E-9, until further clarification of the NUREG methodology. Also, all plant specific developed initiating events models now have CCF values applied; they are multiplied by 365. IE-TCC, IE-TVC, IE-VSW, and IE-TSW initiators are developed. IE-TCC and IE-TSW are revised; the other two trees were modeled correctly before. These changes are believed to have responded to WOG Certification team’s comments on Data, which was assigned a Grade “A”.

- IE-TSW modified to remove RSW, since no credit is now being given to the SW recovery.

- Requirement for manual actuation of the FW is now modeled; human error MFW-XHE-FO-COND is added; AFWNORM fault tree affected.

- SW trees 11SW and 12 SW modified to credit recovery of SW bay during in-service testing.

- SEC related fault trees modified to allow for EOOS modeling; boseca1 (b1, c1), and siseca1 (b1, and c1) are affected.

- SBO coping battery time is modified to four hours; no offsite power recovery is allowed after that.

- The values for some CCF values and some data, based on the latest findings.

- Revisions made to the modeling of the switchgear fans; VSE and VSW trees affected.

- Latest HRA data are applied.

- Cia.lgc and cib.lgc are revised to properly model operator actions for isolation of containment valves following accidents.

The most notable change is the Level II LERF methodology. The methodology for performing Level I PRA is the same as before; however, the methodology for calculating LERF II has changed significantly through usage of a simplified model.

E.2.1.4 PRA Model 3.1 Update (PSEG 2004a)

The PRA model for this revision, Model 3.1, was frozen in July 2003. The Salem PRA Model 3.1 revision changes include modifying the PRA for an on the spot EOOS change to make the charging pumps symmetric and also add standby options, add changes for the feedwater line break and main steamline break initiators for Risk Informed-Inservice Inspection (RI-ISI), add changes to make the CDF smaller for having an EDG unavailable, and add some working file items.

The following is a list of specific changes made to PRA Model 3.1 which includes the above items as well as additional detailed modifications.

- Fault trees DAM, RCPNOCCW, RCPSL1, SJSHPI1, SJSREC1, and UHB were revised to make the charging pumps symmetric. Making them symmetric allows either pump to be running, and have a standby option in EOOS. This was also done for an EOOS on the spot change for working file item SA02-014.
- Modifications for feedwater line break and main steam line break initiators were made for RI-ISI. These initiators had higher probabilities of core damage thanother similar plants based on input from a contractor who worked on the Salem RI-ISI project. These adjustments were made to fault trees IFB and MSO, and fault tree MSI was added. Similar adjustments were also made to event trees TFB, TFB-2, TSBI, TSBI2, and TSBO, and event tree and TSBO2 was added.
- Human actions were added to manually close the service water turbine header isolation valve or valves. One action is to close the valve or valves from the Control Room, and the other is to close the valve or valves locally. This is proceduralized, but this is not obvious in the procedures, and a high failure probability 0.3 is assigned to both HEPs. These actions were added to fault trees 11SW, X11SW, and X11SWS.

- Human actions were added to align alternate power sources for the fuel oil transfer pumps, and supply fuel oil to day tanks from a truck. The HEP for aligning alternate power sources is 0.25, and the HEP for supplying fuel oil using a truck is 0.75. Each is estimated, and has one basic event. For the common mode failure, if both are in a cutest, a value of 0.5625 was used, which is three times the product of 0.25 and 0.75. All of these numbers are estimates and could use HRA analyses. Also, the common mode failure probability should not be greater than any of its parts, and should not be greater than 0.25. The human actions to cross tie power and use a truck to supply fuel oil were added to fault trees 4KV1A, 4KV1AS, 4KV1B, 4KV1BS, 4KV1C, 4KV1CS, FOT, and FOTS.

- Human actions were added for EDG recovery. These are for single and common mode failures, and are added based on numbers in NUREG/CR-4550. These were added for both failure to run and failure to start.

- The recovery of offsite power probabilities for 4 and 12 hours were revised based on more accurate lognormal curve probabilities. The new probabilities are higher.

- The second 125vdc and 28vdc battery chargers were added. This is working file item SA02-008. The second battery chargers were added to fault trees 1A125, X1A125, 1B125, X1B125, 1C125, X1C125, 28V1ADE, X28V1ADE, X281ADES, 28V1BDE, X28V1BDE, and X281BDES. Human actions were also added for closing the second battery chargers.

- Additional cutset editing was added for additional accident sequences based on how previous cutset editing was done. This includes adding recovery of an EDG or EDGs as discussed above. This was needed in part because new sequences that have high frequencies result, and editing the new sequences significantly reduces the CDF.

- Service water fault trees 11SW, X11SW, X11SWS, 12SW, X12SW, and X12SWS were modified so LOP and non-LOP sequences are not quantified together. This required separating non-LOP and LOP branches in the service water fault trees.

Previously non-LOP and LOP service water cutsets were included in the same sequence. This also required making a new house event for service water, XHOS-LOPSW, and adding it to the BED files.

- AMSAC was changed in fault trees AMSACAFW and AMSACTTP. These changes were to add basic events for the AMSAC being unavailable for testing or maintenance and an AMSAC control circuit failure so one of these events can be used for AMSAC itself. More detailed pressure transmitter basic events were added, and the power supplies for AMSAC were modeled in more detail. Failure of turbine trip was included because it leads to core damage for ATWS. The previous PRA also has failure of turbine trip leading to core damage for ATWS.

- Salem Unit 3 was modeled as two units in fault tree 1XMFRS. Salem Unit 3 has two gas turbines, each of which has enough power for both Salem units.

- Success criteria was added for a single service water pump and EDG. This was done by deleting the LOCA BED file and only having the LOOP BED file in the IN file for equations YF-LP, YSI-LP, PO1-LP, PO2-LP, WH-LP, and YSR-LP.

- New EDG fault trees 4KV1AS, FOTS, X4KV1AS, 4KV1BS, X4KV1BS, 4KV1CS, and X4KV1CS for a short DG run time were added. These were added for closing the service water turbine header isolation valves because these valves should close soon after a LOP, and power from a DG is only needed for a short time. This also required making a lot of new logic loop breaking fault trees.

E.2.1.5 PRA Model 3.2 Update (PSEG 2005b)

The PRA Model 3.2 modifications were made mainly to support the risk-informed extension of the emergency diesel generator allowed outage time. A rough draft of PRA Model 3.2 was completed in the August 2004 timeframe and was ***neither approved nor put into use*** by Salem. The following are changes made from PRA Model 3.1 to 3.2. As seen later in Section E.2.1.5, PRA Model 3.2 is considered as input to Model 3.2A.

- Conversion of the Salem PRA model from the WinNUPRA software platform to using the CAFTA suite of codes.
- Development of the LERF model integrated with the CAFTA CDF model.
- Disposition of all working file issues through August 2, 2004 (e.g., revision to the electric power switchyard model, crosstie of the Service Water System from Unit 2, etc.).
- Resolution of all of the remaining Significance Level “B” comments from the WOG Certification review (e.g., refinement of the common cause failure parameter values for Service Water pumps and strainers, and emergency diesel generators).
- Incorporation of changes made to the internal events model for the Salem fire PRA (e.g., crosstie of charging pump from Unit 2, refinement of the containment isolation fault tree, etc.).
- Incorporation into the integrated risk model the fire-induced core damage scenarios involving a loss of the offsite power.
- Incorporation of the seismic PRA core damage scenarios into the integrated risk model.
- Various model enhancements to support the risk-informed extension of the emergency diesel generator allowed outage time (e.g., offsite power recovery modification, turbine-driven Auxiliary Feedwater pump failure rate, etc.).

E.2.1.6 PRA Model 3.2A Update (PSEG 2006)

In March 2006, the PRA Model 3.2A was approved. The design input to this calculation is the PRA model documentation for model Revision 3.1 and associated subsections (including systems, data, initiating events, etc.). The subsequent Revision 3.2 is also considered as input to the 3.2A update. However, Revision 3.2 was not officially accepted by Salem.

The following describes the changes made to create Salem PRA model 3.2A.

- Removed all of the top level gates that are not used in the quantification of the CDF or LERF model. Only @TCDF and @TLERF remain. The eliminated top level gates remain available in the 3.2 model revision.

- The gate NRAC-8H in the recovery CAFTA fault tree models the recovery of offsite power given the plant tripped because of switchgear ventilation problems. If the plant had tripped because of these switchgear problems, it seems unlikely that offsite power can be restored using these same switchgear components within 8 hours. The plant tripped because conditions in the rooms degraded enough to cause the breakers to disconnect or act spuriously because ventilation failed or could not be controlled. To cool down the rooms enough to regain proper breaker operation sufficient to tie back in offsite power within 8 hours is optimistic. The recovery structure was removed.

- In the recovery tree, gate NRAC-OSP models recovery of offsite power (with 24 hours) to permit mitigation using PCS following loss of offsite power and failure of AFW (primarily TDAFW). This recovery is applied to scenarios with failure to initiate feed and bleed or those that are not long-term failures (e.g., loss of switchgear ventilation or recirculation failure). However one of the initiators is %TP - transient with PCS unavailable found under recovery gate GFIN110. It is a general practice not to model recovery of PCS when the initiator causes loss of PCS. We assume catastrophic failures of main feedwater or condensate when the initiator is loss of PCS. Hence the structure was changed. Gate G-POWERLOSS was removed and replaced with G-POWERLOSS-PCS. This new gate has the same inputs including DG1OF3FAIL and G1XM2A0. But new structure IE-TE-REC-PCS was added instead of IE-TE-REC. IE-TE-REC-PCS has 3 of the same inputs as IE-TE-REC (G-LOOP-1L, G-LOOP-2L and G-LOOP-3L) with new input IE-LOOP-PCS that contains the transient with PCS available initiator %TT ANDed with loss of the grid.

- In the current structure, the centrifugal charging pump (21) is modeled but it's maintenance term (CVS-MDP-TM-CVN21) is set to 1.0. This term was copied and moved under the top gate, RSX-GUX1100, modeling the crosstie to Unit 2 and the PDP pump. This effectively fails the crosstie option for all cases.

- DCP-XHE-XC models cross connecting a failed DC cabinet to a powered cabinet in an attempt to power the other PORV. Currently there is neither a commitment to proceduralize this action nor modify existing equipment to allow this to occur. Hence the value of this action is set to 1.0. Also see U2-1-CTLPWRXTIE in table below.

- ACP-XHE-FO-CTFOT models cross tying power to a fuel oil transfer pump that is without power. Currently there is neither a commitment to proceduralize this action nor modify existing equipment to allow this to occur. Hence the value of this action is set to 1.0.

- Several strainer and service water pump common cause basic events have an operator action embedded in their failure probability (see table of basic events below). The strainer basic events have an embedded probability of 0.1 that the operator will not follow Emergency Operating procedures and mitigate the strainer plugging. The pump common cause events have an embedded 0.1 probability that the operators will not shut down the plant by following Tech Spec 3.0.3 on failure of multiple SW pumps. This probability has been extracted from the basic events and modeled in new basic event SWS-XHE-FO-CCF. The provisional value is set at 0.1 and is found under GSWS1002 and GSWS1003. These gates model 6/6 and 5/6 pump/strainer trains failing.

- The value for the seal LOCA basic event RCS-SLOCA-SPLIT was changed from 2.5E-01 to 1.0E+00. The reason for the change is that given a loss of seal injection and thermal barrier cooling we assume that a seal LOCA will occur. Now the basic event serves as a flag. Furthermore, for LOSP cutsets, a seal LOCA is expected to develop. Hence there should be no cutsets involving the basic event RCS-SLOCA-SPLIT and initiator loss of offsite power (%TE or plant induced LOOPS). The fault tree structure already takes this into account. All LOSP initiators and induced LOSP events should propagate through the LOSP sequences and not through the small LOCA sequences. Under the disallowed maintenance and test combinations structure (DAM-GDAM100) a gate was added to disallow cutsets where %TE or other initiators modeling induced LOSP is ANDED with the seal LOCA split fraction RCS-SLOCA-SPLIT. See gate GDAMLOOP00, child of DAM-GDAM100.

- Recovery gate NREDG-4 models the recovery of emergency diesel generators within 4 hours given a blackout and induced seal LOCA. In general, the practice is not to model equipment recovery. This structure has been removed from the recovery fault tree.

- Previously, the HEP ACP-XHE-FO-GTG appeared to be tied to whether there was *NOT* a seal LOCA. This was a surrogate for the timing involved where it was thought that the gas turbine could be started quickly enough to avert a seal LOCA. The new modeling takes credit for starting and loading the gas turbine in SBO sequences, but not in averting a seal LOCA because there is not sufficient time. The HEP was recalculated after walking down the process with operations and determining the stress and realistic timing of the process. The new HEP value is 4.5E-02. See calculation P0149060002-2608.

- In the 3.2 model, cutsets resulted that model maintenance of the RHR 11 pump with the CCW heat exchanger 12. This models the unavailability of both trains of RHR, which is not allowed by Tech Specs. See new gate GDAMECC46 under the disallowed test and maintenance portion of the fault tree. This new gate models the combinations of RHR pump 11 with CCW heat exchanger 12, and RHR pump 12 with CCW heat exchanger 11 as disallowed combinations.

- In the 3.2 model, two operator actions are modeled to represent maintaining AFW suction source. One model is refilling the AFW storage tank (AFS-XHE-FO-REFIL) via the demineralized water system and the other model is switching suction to the demineralized water system (AFS-XHE-FO-XFER). Because these two actions are very similar, involve the same systems, and would take place at nearly the same time (if the refill function failed, then the realignment would immediately be attempted) they have been replaced with a single action, namely AFS-XHE-FO-H20LT (water long term after 6 hours). In addition, the action has been moved higher up in the AFW fault tree structure because there is now only one action. AFS-XHE-FO-H20LT is a child to gates AFSMDP11-SUCTION, AFSMDP12-SUCTION, AFSTDP13-SUCTION representing AFW pumps 11, 12 and the TDP respectively. In addition, the structure of the suction source model was changed such that if the normal check valve fails dependently or independently, no refill or realignment of suction is possible. The assumption is that the pump becomes damaged because of the failed suction check valve.

- The Unit 2 PDP pump was added to the fault tree structure as a backup to the loss of all Unit 1 injection. Inadvertently, the Unit 2 structure was also inserted under GDEP131 which models auxiliary spray. This was not the intention. Therefore, the structure under gate GDEP131 was changed to remove Unit 2 PDP from supplying Unit 1 auxiliary spray. Gate G1RP112 was replaced with new gate G1RP113 that only models Unit 1 charging pumps in support of auxiliary spray.

- Changed the loss of DC power initiator to make use of the current data found in NUREG/CR-5750. We are using the Function Impact (FI) mean frequency of 2.06E-3/plant/year from Table D-11 of NUREG/CR-5750 (note: also reported as 2.1E-3/plant/year in Table 3-1). Salem has 3 DC buses, so the frequency per bus is: 6.9E-04/yr.

- Many HEPs were reviewed to determine if there are procedures supporting the actions or whether the probability of the HEP is in the normal range. The following table addresses those actions that have been reviewed.

Operator Action	Description	Comments	Action Needed
ACP-XHE-FO-12EE	Failure to switch supply power for No 12 230vcc turbine control center from 1F to 1H.	This was identified after the start of the HRA update A procedure for this switch was not found	No procedure – set to 1.0
ACP-XHE-FO-R11TW	Failure to switch supply power for No. 11 230vcc turbine control center from 1F to 1H.	This was identified after the start of the HRA update A procedure for this switch was not found	No procedure – set to 1.0

Operator Action	Description	Comments	Action Needed
ACP-XHE-FO-R12TW	Failure to realign infeeds to 12W turbine control center	Same as ACP-XHE-FO-R11TW	No procedure – set to 1.0
CHS-XHE-FO-1CHE6	Start of standby chiller in the initiating event fault tree.	Basis is normal HEP for normal action under low stress during normal plant operation.	Too low of value. The action is not used in the IE fault tree -- it's used to start the back-up U-2 chilled water pump to support the U-2 Emergency Air Compressor. Per the System NB, the 22 Chilled water pump auto starts on the start of U2 EAC. There is a BE for the auto start actuation signal, so the operator action is deleted.
CNS-XHE-FO-1CN45 and CNS-XHE-FO-1CN47 and MFW-XHE-FO-1BF38	Operator fails to override failed bypass circuit for CN45 / CN47 / BF38	This is an unimportant event. It was set to .1 and didn't show up in the dominant cutsets. Then we set to 1.0 with no change in CDF. Finally, it was reduced to 1E-9 to reduce clutter.	None of the non-recoverable hardware BEs from this part of the tree show up in the cutsets, so there's no need for the operator action. Deleted
DCP-XHE-XC	Failure to cross-connect DC distribution cabinets	A detailed HEP probability calculation has not been done yet.	No procedure. Set to 1.0.
RD-ABV	Fail to Provide Alternate Cooling by Opening Door/Using Portable Fan	A detailed HEP probability calculation has not been done yet.	There are neither procedures, room heatup calcs nor ventilation tests to validate these actions for use in CCP, RHR and AFW rooms as modeled in Rev 3.2.Set probability to 1.0

Operator Action	Description	Comments	Action Needed
RD4	FAIL TO OPEN DOORS /USE FANS FOR VSW (TNE, TE)	Rev 3.2 value is based on an HEP calculator analysis using fire procedure S1.OP-AB.FIRE-0002 which provides direction to open doors. It is acknowledged that there is currently not a direct procedure to use following non-fire losses of HVAC.	Set probability to 1.0E-02 bases on analysis of using S1.OP-AB.FIRE-0002 to direct this action.
RHR-XHE-FO-SHDCL	Failure to align RHR for shutdown cooling	Probability was based on action being a normal plant action, with low stress and sufficient time, with several chances for recovery. In 3,000 reactor years worldwide, there has not been a failure to align shutdown cooling.	This value is too low and the basis is improper. The action is to go to SDC to mitigate a SGTR, not at their leisure as part of going to Mode 5. Byron/Braidwood operator action for establishing SDC during SGTR is 1RH-NR-SGTRHSYCA = 4.3E-3 with a recovery factor of 0.1. Will use 4.3E-4 for Salem model until a formal HRA can be done (URE).
RRS-XHE-FO-SDRSP	FAILURE OF THE OPER TO SHUTDOWN FROM REMOTE SDP	Rev 3.2 value is based on an HEP calculator.	The procedure used in the HEP evaluation, -EVAC-1 “Evacuation of MCR”, is no longer exists. The likely procedure that would cause a shutdown from outside the control room is S2.OP-AB.CR-0002. See URE SA-06-014 Set to 1.0E-01.

Operator Action	Description	Comments	Action Needed
SJS-XHE-FO-MANAC	This HRA is used to model opening a valve or closing a valve or other single action if the SSPS fails to automatically actuate it. It was originally used in an SJS fault tree, which is why the first part of the name is SJS, and the name was kept. MANAC means manual actuation. This HRA is not modeled in all systems, which 1-EOP-TRIP-1 may indicate can benefit from recovery, such as closure of the SW valves for the turbine area, CCW, FW isolation valves, the CS valves, 1CC17, 11 through 14 SJ54.	From the THERP handbook: No diagnosis error – action committed to memory, Moderate stress for all initiators, because the only stress causer is the SI signal. At this point in the event it is too soon to tell what type of event. THERP Table 2-12, Item 3, BHEP of 1.3E-3. Moderate stress multiplies by 2.0 = 2.6E-3.	Assume 5 minutes to diagnose action. Per ASEP lower bound curve at 5 minutes, Pcog = 4E-2. Therefore use HEP of 4.3E-2 (4E-2 + 2.6E-3)
SJS-XHE-FO-SAFLO	This HRA is used to model starting a pump or opening a valve or other single action if the SEC fails to automatically actuate it. It was originally used in an SJS fault tree, which is why the first part of the name is SJS, and the name was kept. SAFLO means safeguard or safeguards loading. This HRA is not modeled in all system, which 1-EOP-TRIP-1 could indicate can benefit from recovery, such as SW, FW pumps, EAC, Chillers, and AUX Bldg. Supply and exhaust fans, and 240/480v.	From the THERP handbook: No diagnosis error – action committed to memory, Moderate stress for all initiators, because the only stress causer is the SI signal. At this point in the event it is too soon to tell what type of event. THERP Table 212, Item 3, BHEP of 1.3E-3. Moderate stress multiplies by 2.0 = 2.6E-3.	Assume 5 minutes to diagnose action. Per ASEP lower bound curve at 5 minutes, Pcog = 4E-2. Therefore use HEP of 4.3E-2 (4E-2 + 2.6E-3)

Operator Action	Description	Comments	Action Needed
SWS-XHE-FO-OVER2	Failure to open the SW header cross-tie vales	Annunciator response model. Not considered a dominant event at the beginning of the HRA update. It's only purpose is to compensate for plugging of the 11SW22 and 12SW20 valves.	Assume 10 minute time frame (one of the scenarios is based on low SW flow to EDG). Use ASEP Median Curve Pcog = 0.1 Therefore, make HEP 0.1
U2-1-CTLPWRXTIE	Failure to perform Unit 2 to Unit 1 crosstie of 115VAC instrument power and 28VDC control power	A detailed HEP probability calculation has not been done yet.	Doesn't appear that there is any way to cross-tie these systems between units. Set to 1.0.
CVS-XHE-FO-BATPS	Failure to transfer charging suction to the Boric Acid System	A detailed HEP probability calculation has not been done yet.	CVS-XHE-FP-BATPS = 4.5E-2. This is for fire, so it's likely bounding (although the source of the value is not clear). Use 4.5E-2.
RECOV11	Lower HEP for ACP-XHE-FO-GTG if up to 4 hours are available (i.e., blackout, seal LOCA assumed)	No basis for the value. With RECOV11 = 0.219, ACP-XHE-FO-GTG is effectively lowered to 1.4E-2	Deleted recovery term. Because the gas turbine cannot be started in time to avert a seal LOCA only one HEP has been developed and no recovery is necessary.
CCS-XHE-FO-ISOLT	Isolate ccs prior to system drain	< 5 minutes for initial action, but Pcog = 1E-4	This is too short of a time period and unlikely this is practiced much. They only have a minute or two to diagnose, since it probably takes a couple minutes to do the action. Pcog from ASEP Median is 0.5 at 2 minutes, 1.0 on ASEP Upper bound. Assume = HEP = 1.0
MRI	OPERATOR MANUALLY INSERTS RODS	B F&O – value is too low for something that needs to be done in 1 minute.	1RT-RX-TWSHRBOA from B/B uses 0.15 from NUREG-5550. This would be a better value. Assume HEP = 0.15

- The operator action to establish condensate to the steam generators given that AFW has failed is modeled in the HEP MFW-XHE-FO-COND. This HEP has been moved and is now a child of G-MFWCNS. Gate G-MFWCNS models some fire scenarios under G-MFWCNS1, and the condensate flow path through feedwater to the SG via gate GHM1100. As a child to G-MFWCNS1, G-MFW models operator action MFW-XHE-FO-COND ANDed with HM2 (failure to recover MFW and condensate). This is unnecessary. The structure has been left, but the presence of MFW-XHE-FO-COND higher up in the structure makes the action HM2 under G-MFW moot.

- When there is only one train of CCS available, the CCS valve (CC71) to the letdown heat exchanger must close so that sufficient cooling is available to mitigate the accident. A new gate was created to model the requirement for closing CCS to the letdown heat exchanger (G1R1103). In addition, a new basic event was created (CCS-AOV-OO-CC71) for CC71 failing to close on demand. In addition, gate GCIA700 was added as a dependency for CC71, since CV7 needs to close before CC71 can. CC71 does not get an isolation signal, it only closes when CV7 closes (see paragraph 4 on page 30 of NOS05CCW000-06). CC71 fails to the closed position on loss of air, so it cannot fail to close on loss of air initiators. This logic was captured via a NAND gate G1R1104 so that when there is a loss of instrument air (%TCA) there are no cutsets with CC71 failing to close. CC71 will transfer to the failed position (closed) which is desired. On loss of DC CV7 will close but there is no power to generate a signal from the closed limit switch to signal CC71 to close. The condition where only one train of CCS is failed is capture via gate G1R1102 which is an OR gate under which each train of CCS is a child. New gates G1R1102 and G1R1103 are children to gate G1R1101 which has been placed under G1R1100 and G1R2100 which model RHR heat exchanger HX-11 and HX-12 faults, respectively.

- Miscellaneous changes:

    - For several basic events that are set to 1.0, they were added to the flag file and set to true. These include: ACP-XHE-FO-CTFOT, ACP-XHE-FO-TRUCK and CVS-MDP-TM-CVN21.

- Changed the description of RHS-XHE-FO-RECR1 to reflect it as a Unit 1 action, not Unit 2.
- The offsite distribution lines are undeveloped at this point and have probability 0.0E+00. In order to solve the model properly and not have trouble with NOT gates, the basic events ACP-OPL-LP-5024, ACP-OPL-LP-5021, ACP-OPL-LP-5037 are set to FALSE (0.00E+00) in the flag file. Problems manifested via gate G-3L-AVAIL.

- Addressed sequences that don't have adequate time to align the GTG, which were crediting GTG alignment. These sequences include SBO with failure of AFW (TDE Sequences S18-S19) and stuck open PORV (TDE Sequences S15-16)
- TDES18 - Sequences with failure of AFW and use of non-recovery event RBU4
- Under gate TDES18, replaced TES03 with new gate TE-RBU4. The difference between this new gate and the old, is that the children gates for onsite power are replaced with logic that does not credit the GTG.
- GT-RBU4 replaces GT-GGT1100: GT-GGT1100 becomes a child of GT-RBU4. It is OR'd with basic event RBU4-GTG, which represents the failure probability of loading the GTG in events with complete loss of AFW. This could be in cases where feed and bleed could be used to delay the onset of core damage, thus extending the time available to start the GTG (with complete loss of AFW at time-zero, the time available is about 2 hours). If the failure of onsite power is due to the failure of A and B EDGs, and the subsequent failure of C EDG due to loss of fuel oil, it is estimated that approximately 1-1/2 hours will be available to remove decay heat, in addition to the 2 hours for core damage.
- [NOTE: The event RBU4-GTG is set to 1.0, and the recovery RECOV14 includes both the improved offsite power non-recovery as well as the capability to load the GTG. Thus, the entire gate GT-RBU4 could be deleted without changing the model results.]

- DE-GDTRBU4 replaces DE-GDT1100: DE-GDTRBU4 is based on the logic in DE-GDT1100 – the difference is that the child logic for 4KV bus logic (G14A100, G14B100 and G14C100) does not credit the GTG for power. Each of the individual bus fault trees for this scenario are changed to end in RBU4 (e.g., G14A100 becomes G14A100RBU4). Gates below the parent gate for each bus that are changed are similarly suffixed with RBU4. At G14A110/G14A110RBU4, all three of the children gates are changed, since each one (power from the EDG, SPT #13, and SPT #14) ultimately take credit for the GTG (e.g., for power to support systems for the diesel or explicitly as a power source for the station power transformers). The logic used to break the AC circular logic is changed.

- Note that the gates discussed here have the suffix RBU4, but they are also used for the next logic discussed (RBU3)

- TDES15 - Sequences with stuck open PORV and use of non-recovery event RBU3

- Under gate TDES15, replaced TES03 with new gate TE-RBU3. The difference between this new gate and the old, is that the child gate for onsite power using the GTG (GT-GGT1100) is deleted, and the gate for onsite power (DE-GDT1100) is replaced with logic that does not credit the GTG.

- DE-GDTRBU4 replaces DE-GDT1100: This is described above for TDES18/RBU4 sequences.

- Set the GTG to fail during cases where depressurization fails and the largest Seal LOCA occurs (480 gpm / pump), because there isn't enough time to align the GTG. Added GTG-RBU2 to G1XM2A0. RBU2-GTG is 5E-3, which is the likelihood for the largest Seal LOCA for the unqualified seals (it's 2.5E-3 for the high temp seals). Thus, 5E-3 is bounding. Had to add a disallowed combination (MEX) to the model, since some RBU1 cases were showing up with RBU2-GTG. See gate GDAM-RBU.

- Changed the value for ACP-GTS-TE-GTG to 0.27 based on update to LOOPGridRecoverySalem.xls, which now includes 8 more weather events. Also changed description of the event to include weather.

- Changed value of SWS-XHE-FO-LOCAL to 1.0, since there is no procedural guidance to shut this valve, and it's not clear whether the operators will get to it in time.

- Changed CVS-XHE-FO-SOVCT to 1.4E-2 based on updated Loss of CCW procedure and draft HRA.

- Recovery for RBU1 and RBU4.

- Recover cutsets with failure of 1SW26 to close with B EDG fail to run (RECOV9).

- Modify model for stuck open PORV for SBO and VSLOCA sequences.

    - The model has a basic event (PC4) which has no apparent basis, but reduces the impact of a stuck open PORV during SBO sequences by a factor of 2 (PC4 = 0.5). Since there is no basis, the value of PC4 was set to 1.0. Note that the model does not take credit for isolating a stuck open PORV (prior to the SBO, if there is power to the correct bus). Perhaps that was what the 0.5 was supposed to represent. This action should be added to the model. See URE SA-06-018.

    - The VSLOCA stuck open PORV logic used a basic event (PC3) to represent the likelihood that after a PORV sticks open, it fails to reclose (value = 1.5E-3). However, the logic for the VSLOCA should be the same as for a general transient. Therefore, the gate PC3-G13P100 was deleted, so that the stuck open PORV logic for transients could be used for VSLOCA also (G11P110). It was noted that PC3 still exists in the fault tree in logic that prevents SEC actuation (i.e., if an induced LOCA does not exist: NOR-TSORV-TSLOCA). This does not appear to affect the results, but has been documented in URE SA-06-018.

- Revise model to require some form of recovery following loss of CCW and failure to swap CV pump suction to the RWST.

- There are 2 flags used to change the success criteria for service water, XHOS-SUMMER and XHOS-WINTER. In revision 3.2 XHOS-SUMMER was set to 1.0 and the winter version was set to 0.0 forcing the more restrictive service water pump alignment. This has been changed to require each alignment 50% of the time, i.e., XHOS-SUMMER and XHOS-WINTER are each set to 0.5 in the database.

E.2.1.7 PRA Model 4.0 Update (PSEG 2008a)

The following describes the changes made to create this new model from the previous model (3.2A). Changes made for this revision (PRA Model 4.0) affected only the CDF but the LERF models will be revised subsequently.

- The Salem PRA Human Reliability Analysis (HRA) was completely revised and updated to be consistent with current industry guidance for pre- and post-initiator actions. Significant changes in both upward and downward directions for individual failure probabilities occurred. Dependencies were reassessed.

- Failure and common-cause data were evaluated and updated using current industry generic information and Salem plant specific information.

- Generic industry experience was adopted from NUREG/CR5750. For rare events, this information was utilized directly. For common events, the NUREG/CR-5750 data was updated using recent Salem plant specific data. For several systems that perform both mitigating functions and which contribute to initiating events (e.g. service water, component cooling water) initiating event fault trees were quantified to estimate the likelihood of initiating events. For losses of offsite power, data on the likelihood of loss of offsite power (LOOP) and nonrecovery probabilities from those LOOPs as a function of time were taken from report INEEL/EXT-04-02326. These frequencies were split up in the model with separate initiators to represent weather-related LOOPs, grid-related LOOPs and site/switchyard related LOOPs.

- Salem procedures for small LOCA indicates that it is desirable to cooldown and depressurize the RCS such that the plant can be transitioned to shutdown cooling, in preference to maintaining the RCS at high pressure, injecting with high head safety injection pumps until the RWST is depleted, and then transitioning to sump recirculation. Actual industry experience also indicates that this will be the approach which operating crews will prefer to follow. Credit for this strategy was incorporated in the Salem model. If adequate AFW is available and if adequate steam release paths (MS10's or condenser steam dumps) are available and if the operators take appropriate actions, and if the shutdown cooling system functions correctly, this will prevent core damage.

- The available analyses, procedures and documentation regarding control area ventilation "CAV" were reviewed. The available analyses which are conservative and design based indicate that temperatures in the control area (control room, electrical equipment "rack" room, and relay room) can approach 160F within a few hours of a loss of cooling by the CAV system. Based on these analyses, it will not be possible to perform a normal control room shut down of a unit in event of a loss of all CAV / cooling to that unit. Accordingly the model was modified to reflect that upon a complete loss of CAV or cooling to the CAV system (due to failure of the chillers , chilled water pumps, service water cooling of the chillers, etc.) plant shutdown must be accomplished from outside the control room and if that is not successful then core damage will result. A recommendation has been made that more realistic and best-estimate analyses be performed , possibly in conjunction with some procedural changes to open doors, insert fans, etc., to mitigate this scenario. However to meet category 2 of the ASME standard it is important to have an analytical basis for success criteria and the PRA is now consistent with existing basis information.

- Several updates were made to the service water fault tree logic. An operator recovery action to crosstie unit 2's service water system to unit 1's was removed. The hardware and capability exist but current procedures do not support this action. Credit was improved for operator action to isolate the turbine building / nonessential

SW header. A limited set of equipment sufficient for safe shutdown of the unit can be supplied by a single service water pump. However a single service water pump will operate on the verge of "runout" unless the nonessential header is isolated. Salem has performed an analysis to show that a service water pump can operate in this condition for approximately 30 minute before sustaining damage and the station has prioritized actions in several relevant procedures to promptly manually close the nonessential header isolation valve. This permitted assignment of improved credit in the HRA assessment of the action. The service water initiating event tree was restructured. Previously a loss of service water to a unit was assumed to result in certain core damage. A close review of plant design and operation indicates that safe shutdown of the unit may be possible and the new event tree reflects that. After a loss of service water, decay heat can be removed via the AFW system, which is not dependent on SW for cooling or inventory. A connection does exist from the SW system to the AFW suction supply but sufficient inventory exists in the AFWST and demineralized water tanks that SW is not required for a 24 hour mission time. A loss of service water will result in a loss of cooling to the closed cooling water system, which in turn has the potential to fail the charging pumps. If CCW and charging /seal injection were lost, an RCP seal LOCA could result. However Salem has proceduralized a strategy to provide alternate demineralized water cooling to the centrifugal charging pumps and thereby maintain seal injection. With decay heat removal and RCS inventory assured, most of the required key safety functions are fulfilled. One issue remains; upon a loss of all service water to a unit, the chillers for that unit will fail. Without support via "maintenance mode" or "AB.CAV" mode from the adjacent unit, temperatures in the control area are assumed to become excessive within as little as 4 hours. This is based on current Salem design basis calculations. When temperatures become excessive the operators must shut down the plant from outside the control room.

- An instance was identified in the existing fault tree logic where EDG C was not failed even when EDGs A and B or their associated fuel oil transfer pumps were. Failure of EDGs A and B or the associated transfer pumps will prevent EDG C from receiving any fuel. This was corrected.

- The seal / AC power nonrecovery model was updated with nonrecovery probabilities based on information in INEEL/EXT-04-02326. In addition, RCP seal failure was assumed to be certain in event that a non-LOOP loss of thermal barrier cooling and seal injection occurs. The WOG2000 seal model requires depressurization of the RCS to < 1710 psig within 2 hours, for Westinghouse seals. Other vendors of seal components such as Jeumont/ Framatome have suggested that depressurization to even lower pressures, perhaps around 1400 psig could be required. During an SBO, procedural guidance exists to require prompt depressurization to 230 psig. However a simple loss of thermal barrier cooling and seal injection at Salem will result in entry into procedures for slow natural circulation cooldown, < 25 F per hour. It is not clear this will meet the requirements of the WOG2000 model. In that event, a likelihood of failure ~= 1.0 must be assumed.

- The gas turbine generator may be used during grid-related LOOPs but not site/switchyard or weather related LOOPs. Alignment of the GTG requires a series of complex actions so limited credit was given.

- Manual shutdown events provide less challenge to systems providing key safety functions than a reactor trip and only infrequently result in trip. Therefore manual shutdowns are considered to contribute negligibly to the transient frequency and will not be evaluated as an initiating event. Very small LOCA is defined as a LOCA with a leak rate within the makeup capability of a single charging pump. A leak of this magnitude would generally be isolated and no plant transient would result. Occasionally, a plant shutdown would be required but only rarely would a trip be required. Therefore the very small LOCA is considered to contribute negligibly to the transient frequency and it need not be maintained as an initiating event.

- Various DC dependencies were added, clarified, or corrected. Most seemed to have negligible impact but including the dependence of DR-6 on DC train A resulted in increase in risk associated with DC train A and causes an asymmetry between trains A and B.

- Top event RSX in the SBO event tree was rendered unnecessary by existing logic in the previous model version. RSX was removed.

- Top event DAMDG in the LOOP event tree was rendered unnecessary by the conversion to CAFTA. DAMDG was removed.

- Very small LOCA was removed. By definition, a VSLOCA was within the capability of a single charging pump. Therefore most VSLOCAs would be repaired and would not be an initiating event at all. In some cases, a plant shutdown might be required to effect repairs. In that case the event would look like a shutdown or at worst a transient. VSLOCA can thus be considered to contribute negligibly to the transient frequency.

- Manual shutdown was removed. Manual shutdowns generally are well-controlled and provide minimal challenge to plant systems. In some circumstances they could result in a transient. Therefore manual shutdowns may be considered to contribute negligibly to the transient frequency.

- The small LOCA event tree was slightly modified, to reflect the potential to depressurize and use shutdown cooling before the RWST is depleted, instead of requiring alignment of sump recirculation. This is consistent with plant procedures and industry experience.

- The loss of SW event tree was modified to reflect the ability to avoid core damage if AFW is available for decay heat removal, if operator actions to realign charging pumps (change suction source and cooling water source) are successful in order to protect RCP seals, and if steps are taken to deal with control area ventilation issues.

E.2.1.8 PRA Model 4.1 Update (PSEG 2008b)

As noted in the previous section, model 4.0 documents the results for CDF only. In this subsequent revision, CDF and LERF are both analyzed. A complete listing of changes made to revision 4.1 is provided below.

- The Salem internal flooding analysis was completely revised and updated to meet the current ASME Standard (ASME 2005).

- The Salem Level 2 model had been essentially abandoned, existing in documentation but not in a readily quantifiable model. It was recreated, incorporating current industry guidance.

- Previously only a random “transfers closed” event was incorporated in the model for the common in-series charging minimum flow valves, CV139 and CV40. Salem EOPs direct that centrifugal charging pump minimum flow valves be opened at RCS pressure of 1500 psig decreasing and that they be reopened at 2000 psig increasing. Exact impact of failure of either transfer is not clear but it was assumed that runout / dead-head concerns could lead to pump failure in the event that the transfers were not accomplished as required.

- During SGTR events, the EOPs direct operator actions to depressurize the RCS below the lowest SG safety valve setpoint and in most cases down to a level close to that of the secondary side of the ruptured generator. If this action is not performed successfully, inventory from the RCS will fill and pressurize the SG. Ultimately it will force open one or more SG safety valves. If SG safety valves pass two-phase flow, experience has shown that they may not reseat afterward. This results in an inability to stop leakage from the RCS except by depressurizing the RCS down to approximately atmospheric pressure. These actions (depressurizing the RCS below SG safety valve setpoints prior to opening of one or more SG safeties, depressurizing the RCS down to close to atmospheric pressure and transition to RHR) are important to minimizing the risk associated with SGTR scenarios. The HRA analyses for those actions were refined to give appropriate credit for the ability to identify and correct initial errors in order to ultimately accomplish the actions. This reduced the failure probabilities associated with the actions and therefore reduced the CDF associated with SGTR.

E.2.2 Current PRA Model of Record

The Salem PRA model of record (Rev. 4.1), which was completed in September 2008, was used for this SAMA analysis. The cutoff date for including new plant data and incorporation of plant modifications was December 2006. The changes that were incorporated into this model are discussed above. The risk insights from this model are discussed in the following section.

E.2.2.1 Model 4.1 Results

The core damage frequency (CDF) for the Salem PRA Model 4.1 is 4.77E-05.

The relative contributions to core damage due to initiating events can be seen in Figure E.2-1 and E.2-2. These figures show that a significant portion of CDF is caused by the transients resulting from loss of support systems, which dominates the core damage profile. Various support system failures contribute to this category, most notably loss of control area ventilation and to a lesser extent service water, control air, component cooling water, and switchgear ventilation. Loss of control area ventilation events are dominated by failure of the running chillers, inability to utilize the standby chillers, and difficulty in aligning for support from the adjacent unit.

Loss of offsite power is the next significant contributor group to CDF. LOOP scenarios are characterized by failure of both A and B diesels, either independently (including maintenance) or by common cause, failure of the gas turbine generator, and failure to restore offsite power. The lack of a third diesel fuel oil transfer pump reduces the effectiveness of three trains of diesel generators.

Loss of service water events are dominated by common cause such as strainer plugging and service water pump fail to start or run.

Steam Generator tube rupture events are dominated by the operator actions, such as identification and isolation of the ruptured generator, early depressurization, and late depressurization.

All other initiators together contribute less than one quarter of the risk.

E.2.2.2 Salem Level 2 PRA Model 4.1

The SAMA analysis is based upon the Salem Model of record (4.1) developed in September 2008. This revision includes the Level 2 PRA analysis and CDF due to internal flooding which was not included in the previous model (4.0). The overall CDF is also recalculated in the PRA model 4.1.

The large early release frequency (LERF) for the Salem PRA Model 4.1 is 5.06E-06 which is a decrease from the previous PRA model which calculated the LERF to be 7.61E-06 (NOTE: Model 4.0 did not calculate LERF, therefore the previous LERF value is calculated in model 3.2A). See Table E.2-1 for more details.

Figures E.2-3 and E,2-4 show initiator group contribution to LERF. Primary contributors are steam generator tube rupture, loss of offsite power and loss of control area ventilation.

<u>E.2.2.2.1 Previous Level 2 Analyses</u>

Previous versions of the Salem Level 2 PRA (PSEG 1998, PSEG 2004a, and PSEG 2005b) have included various release categories from the containment. However, starting with Revision 3 of the model, only LERF was calculated. For those analyses, the probabilistic aspects of the Level 2 analysis were quantified with a simplified containment event tree that interfaced with the Level 1 analysis through the appropriate definition of a set of plant damage states. The analysis approach for all the previous versions made use of the results of published Level 2 research and development programs performed for similar Westinghouse designed pressurized water reactors (PWR) with large, dry containments. Specifically, the analyses utilized core and containment response analyses for the Zion Unit 1 PRA reported in NUREG/CR 4551 (BNL 1993). Both the Zion Unit 1 and the SGS reactor plants are four loop, Westinghouse PWRs with large, dry concrete containments. Whereas the Zion Unit 1 containment is a prestressed / post-tensioned design, the SGS containments are reinforced concrete design. Because of these construction differences, a SGS specific pressure capacity analysis was performed and documented in the previous versions of the Level 2 PRA.

E.2.2.2.2 Areas of Focus for Update

This version of the Salem Level 2 PRA (Revision 4.1) utilizes the most up-to-date research and related analyses to update the Level 2 analysis to focus on the most important Level 2 phenomenological issues and provide a broad range of release categories. Areas of improvement include:

- Modeling of RCS hotleg or surge line failure during high-pressure core damage scenarios
- Credit for operator action to depressurize the RCS during high-pressure core damage scenarios
- Incorporation of recent modeling methods for pressure-induced and thermally-induced steam generator tube ruptures
- Updated failure probabilities for early containment failure due to steam explosion, hydrogen burn, and/or direct containment heating
- Updated MAAP containment performance modeling

E.2.2.2.3 Key Plant Characteristics

- Reactor Cavity and Instrument Tunnel Configuration. The communication between the reactor cavity and other areas of the containment at Salem is important in two regards. First, if the RWST inventory has been injected into containment, this water can freely flow into the reactor cavity. Second, for severe accidents involving vessel breach, core debris will be initially introduced into the reactor cavity area. If the reactor pressure is high at the time of vessel breach, the core debris can be swept out to other areas of the containment.

Walk-throughs performed during the previous Level 2 analysis confirmed the configuration of the reactor cavity and instrument tunnel. The reactor cavity extends from beneath the reactor vessel out to the instrument tunnel. The instrument tunnel then slopes upward into the incore instrumentation room (also referred to as the reactor sump room). The exit from this room is a 3 ft wide by 8 ft high opening through the crane wall to the containment annulus. The reactor sump room is normally closed off by a wire mesh door in this 3-ft × 8-ft opening. This wire door would allow free communication between the containment annulus and the reactor sump room, and ultimately, the reactor cavity. This design permits RWST water to drain to the reactor cavity, but also allows core debris to be swept out of the cavity during high-pressure vessel failures.

- Containment Sump. The containment walkdown verified that the containment sump is located on the lowest elevation of the containment annulus (outside the crane wall on Elevation 78'). It is 90° (110 ft) from the opening into the reactor sump room (the flow path from the annulus to the reactor cavity).

- Containment Fan Coolers. The containment fan coolers are located on the refueling deck (Elevation 130'). Under accident conditions, the fans intake air from the containment atmosphere. This air is then sent through a moisture separator, a high efficiency particle air (HEPA) filtering section, cooling coils, and then through the fan to a header to distribute the flow to various containment areas. Outlet ducts are located both below and above the refueling deck. Ducts below the refueling deck (and inside the crane wall) provide air circulation that will help cool this area. The air will then flow back up to the operating floor through the openings around the steam generators. Ducts located above the refueling deck extend well above the floor to ensure circulation in the containment dome area.

- Steam Generator Power Operated Relief Valves. The steam generator PORVs are used to depressurize the steam generators. There is one PORV for each of the four steam generators. When power is available, these air operated valves are controlled remotely from the control room. When power is not available, such as in an extended station blackout, these valves can be operated manually. A previous walkdown verified access to the valves and that the valve operators were not located next to the steam exit (which would endanger the individual).

A dedicated diesel generator driven air compressor was added as part of the SBO rulemaking, which allows for opening of the PORVs (MS10s) remotely.

- Modeling of SGS Containment. In the MAAP code, the containment is divided into four regions. These regions are the upper compartment, lower compartment, annular compartment, and the reactor cavity. The "upper compartment" is the containment volume above the refueling deck (Elevation 130'). The "lower compartment" is the volume below the refueling deck but above the reactor cavity and inside the crane wall. The "annular compartment" is the volume below the refueling deck outside of the crane wall (the containment annulus). The "reactor cavity" is the volume beneath the reactor vessel.

The upper compartment volume is 2.05 million cubic feet; the lower compartment volume is .31 million cubic feet. The annular compartment volume is .28 million cubic feet, and the cavity volume is 9,800 cubic feet, giving a total containment free volume of approximately 2.65 million cubic feet. The percentages of free volume in the upper, lower, and annular compartments and in the reactor cavity are 77.3, 11.7, 10.6, and 0.4%, respectively.

- General Observations. SGS Units 1 and 2 are very similar to one another for purposes of the Level 2 PRA. Upper containment in both units is very spacious and open. Natural convection mixing of any gases in the upper containment is expected to be thorough due to this openness. The two units have floor levels constructed at the same elevations, identical major concrete constructions, and all major pieces of equipment are essentially identical and located in the same place in each unit.

E.2.2.3 Containment Event Tree Structure

To assess the accident progression following a core damage event, the Level 2 analysis uses the containment event tree shown in Figure E.2-5. This event tree begins with each core damage sequence, then asks a number of questions to determine the type of release, if any. Each question represents a top event in the event tree and is based on previous work for Salem Level 2, recent accident progression research, and similar analyses for other nuclear plants. Each top event in the event tree is discussed below. Endstates on the event tree are discussed in E.2.2.5.

E.2.2.3.1 Core Damage Endstates

This first node of the containment event tree represents the collection of all core damage sequences from the Level 1 PRA. The assignment of each core damage sequences to a plant damage state is discussed in Section E.2.2.4.

E.2.2.3.2 Containment Bypass

Level 1 PRA sequences with an initiating steam generator tube rupture or an unisolated interfacing systems LOCA (ISLOCA) will bypass containment. The ISLOCA analysis (WAKE 1992) shows that the likely release path from ISLOCAs will not be submerged. No credit is taken for scrubbing by the auxiliary building. While it is possible that releases due to steam generator tube ruptures may be submerged, no credit is taken in this analysis for fission product scrubbing within the steam generator. For SGTR core damage scenarios, the analysis assumes that the steam generator PORV will stick open once it passes water, providing a direct path to the atmosphere.

E.2.2.3.3 Containment Isolation

For all other scenarios, the possibility of containment isolation failure exists to provide a fission product release path through containment. The Level 2 PRA models the containment isolation function through the use of fault tree YCI-GCI1100. Contributors to containment isolation failure include pre-existing containment faults, containment ventilation paths, reactor coolant pump seal injection and return paths, and fire protection supply paths.

E.2.2.3.4 Reactor Coolant System Pressure

The next two top events have similar effects on accident progression, though the method by which it is achieved is different. This top event, RCS pressure, represents core damage scenarios where the reactor coolant system is at low pressure due to a medium or large loss of coolant accident. Low pressure means that pressure is insufficient to challenge the steam generator tubes or result in direct containment heating later in the accident progression. The branch is determined by the initiating event from the Level 1 PRA.

E.2.2.3.5 Auxiliary Feedwater to Steam Generators

Another method for reducing reactor pressure is through use of the steam generators. If feedwater is available to a steam generator, decay heat is removed and the reactor can be reduced in pressure. This pressure reduction will eliminate the challenge to the steam generator tubes and reduce the effects of direct containment heating. The function of feedwater is modeled in the Level 1 PRA and identified by the plant damage state designation.

E.2.2.3.6 Pressure-Induced SGTR

Core damage sequences that continue on the high pressure branch are assumed to be at or near the PORV/SRV setpoint. Without water in the steam generators, there is a possibility of pressure-induced steam generator tube rupture. Because the pressure is high from the beginning of the scenario, this question is asked prior to any operator actions or other reactor coolant system failures that could depressurize the RCS. Details of this evaluation are based on NUREG-1570 (NRC 1998b).

E.2.2.3.7 RCS Depressurization

If the steam generator tubes survive the initial pressure differential, the operators may take action to depressurize the reactor coolant system in order to reduce the likelihood of tube rupture. To do so, the operators are directed to open the primary system PORVs per steps 24-25 of Reference (PSEG 2000). If successful, the scenario transfers to a low-pressure accident progression. If the RCS is not depressurized, either due to human error or equipment failure, additional high-pressure failures are considered.

E.2.2.3.8 Thermally-Induced SGTR

With the reactor coolant system remaining at high pressure and without feedwater to the steam generators, the likelihood of thermally-induced creep rupture of steam generator tubes is addressed. As with pressure-induced tube rupture, the age and condition of the steam generator tubes must be considered. Though the steam generators at Salem are relatively new, failure probabilities for moderately-damaged tubes are used to account for plant aging during the license renewal term. Details of this evaluation are based on NUREG-1570 (NRC 1998b).

E.2.2.3.9 Hot Leg Rupture

During high-pressure core damage scenarios, a "race" occurs to determine where the RCS will first fail. While the reactor vessel will eventually fail as the molten core degrades the lower vessel head, failures may also occur in the steam generator tubes (discussed above) or in the hot leg or surge line of the reactor coolant system. For high-pressure, station-blackout-like scenarios which tend to occur on this branch, the likelihood of hot leg failure is very high. Based on Appendix C of NUREG-1150 (NRC 1990a), this analysis uses a likelihood of 95% for hotleg failure.

E.2.2.3.10 Containment Failure at Vessel Breach

Three primary causes for containment failure (CF) at the time of reactor vessel breach have been identified – steam explosion, hydrogen burn, and direct containment heating. Low pressure sequences due to a LOCA are subject to steam explosion and hydrogen burn challenges. Low pressure sequences due to steam generator cooling should consider steam explosion, hydrogen burn, and direct containment heating. High pressure sequences with depressurization after core damage due to operator action or hotleg failure are primarily subject to hydrogen burn challenges. High pressure scenarios at the time of vessel breach are primarily subject to direct containment heating challenges. Therefore, different branches through the event tree may require different early containment failure probabilities. This model assigns probability CF1 to the combination of steam explosion and hydrogen burn, CF2 to hydrogen burn by itself, CF3 to direct containment heating, CF4 to the combination of all three effects. Recent research has provided an improved understanding of these phenomena and each is discussed below.

Steam explosions due to the pouring of the molten core into a pool of water can challenge the integrity of the containment via damage to the reactor cavity. Based on NUREG/CR-6338 (NRC 1996), this is only an issue for free-standing reactor cavities (as opposed to excavated cavities). Because Salem is an excavated cavity, steam explosions do not pose a failure mechanism for early containment failure.

Hydrogen burns can challenge the integrity of the containment by creating high pressure excursions. The amount of hydrogen released into containment depends upon the amount of core damage at the time of vessel failure. Scenarios that lead to hydrogen burns at plants like Salem are limited to about 50% zirconium oxidation.

NUREG/CR-5567 (NRC 1990c) provides a conservative approach to calculate the maximum pressure of an adiabatic hydrogen burn in a large, dry containment.

$$P_b = 0.22 + \frac{1.42 M_{Zr}}{V}$$

In this equation, P_b is the peak pressure in MPa, M_{Zr} is the total inventory of zirconium in the core in kg, and V is the containment free volume in cubic meters. Along with other conservative assumptions, this formula assumes 75% zirconium oxidation. Correcting for a maximum of 50% zirconium oxidation, we calculate the maximum hydrogen burn pressure at Salem. Containment volume at Salem is 2,620,000 ft3 (74146 m^3) per Section 3.8 of Reference (PSEG 2008d). The core contains 52541 lb of zirconium (23833 kg) per Table 4.4-1 of Reference (PSEG 2008d).

$$P_b = 0.2 + \frac{1.4 \times (23833\ kg)}{(74146\ m^3)} \times \frac{(0.5)}{(0.7)} = 0.5\ MPa$$

NUREG/CR-6338 provides a containment fragility curve for Salem which starts with its lowest failure probability of 0.001 at 0.591 MPa. Therefore, the probability of early containment failure at Salem due to hydrogen burn is less than 0.001.

Direct containment heating is also addressed by NUREG/CR-6338. Table 7.1 in the NUREG reports conditional containment failure probabilities due to direct containment heating for several plants, including Salem. The mean probability is reported as zero for all scenarios.

Based on the above assessments, the probability of early containment failure at Salem is negligible for any sequence. However, in order to maintain flexibility in the model for sensitivity analyses, all four early containment failure probabilities (CF1, CF2, CF3, & CF4) are maintained in the model and assigned a probability of 0.001.

E.2.2.3.11 Containment Heat Removal

Containment heat removal at Salem can be accomplished through either the containment fan cooler units (CFCUs) or through containment spray (CS) and recirculation. The Level 2 PRA models the containment heat removal function via gate CHR-L2, which includes gates YF-GCU1100 for the CFCUs, YSI-G1SI100 for CS injection, and YSR-G1YR100 for CS recirculation. Note that for some scenarios, CS and/or CFCU may not be available due to power or service water failure, and these sequences are modeled accordingly. Failure of containment heat removal will allow the containment to slowly pressurize until failure. The MAAP calculations use a median failure pressure of 107 psig based on Section 4.4.3 of the Salem Level 2, Revision 3 PRA.

E.2.2.3.12 Basemat Meltthrough

If no other containment failures occur during an accident scenario and containment heat removal exists, the last containment failure mode to examine is basemat meltthrough. If not cooled by an overlying water pool, the molten corium will begin to attack and erode the concrete basemat. Several beneficial factors at Salem make basemat meltthrough less severe than other plants. First, Salem has a "wet" containment design. If the RWST is injected into the primary system or containment via ECCS or containment spray, the water will drain to the reactor cavity and provide cooling of the molten corium, thus preventing basemat meltthrough. Second, the Salem containment has a very thick basemat – 18 feet thick. Even without cooling of the molten corium, basemat meltthrough will require many hours to erode through this thickness of concrete. Third, Salem has a relatively large cavity floor area, meaning the molten corium will have more space to spread, resulting in a shallow layer of corium which can be more easily cooled by overlying water. For the containment event trees, sequences including injection of the RWST avoid basemat meltthrough, while sequences without injection are subject to eventual basemat meltthrough.

E.2.2.4 Plant Damage State Groupings

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

Plant damage state bins are the entry states to the containment event tree quantification (similar to initiating events for the Level 1 PRA). The PDS bins are characterized by reactor coolant system pressure at the onset of core damage and the availability of plant systems to terminate the accident or mitigate the release of radioactive materials to the environment. To maintain consistency with previous Salem analyses, the same basic PDS structure is used in this revision. The updated analysis includes a review of all Level 1 core damage sequences to ensure proper PDS assignments relative to the new containment event tree.

E.2.2.4.1 Selection of Plant Damage State Parameters

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

All of the plant model information on the operational status of active systems that are important to the timing and magnitude of the release of radioactive materials must be passed into the CET via the definition of the PDS. This requires that, in addition to representing the systems and functions that are important to preventing core damage, the Level 1 analysis must also address active systems and functions that are important to consequence mitigation, such as containment isolation, containment heat removal, and the removal of radioactivity from the containment atmosphere. The containment fan coolers and containment spray systems are good examples of such systems.

The modeling approach for the current revision of the PRA uses the CAFTA software package, which allows the incorporation of complete Level 1 information into the Level 2 PRA model. This permits the somewhat artificial boundary between the Level 1 event trees and the containment event tree (i.e., the PDS) to be eliminated from this analysis. That is, active systems such as containment fan coolers and containment spray are modeled in the Level 2 analysis alongside the Level 1 systems in order to accurately capture system dependencies such as actuation signals, electrical power, and cooling water.

Along with containment systems performance, the CET considers the influence that physical and chemical processes have on the integrity of the containment and on the release of fission products once core damage has occurred. The important physical conditions in the RCS and the containment include the pressure inside the reactor vessel at the onset of core damage, whether the reactor cavity is flooded, and the availability of cooling on the secondary side of the steam generators to assess the potential for induced steam generator tube rupture (ISGTR) in high pressure accident sequences.

In this study, the RCS pressure identified in the definition of PDSs is that which occurs at the onset of core damage. Events that could influence the change in pressure after the onset of core damage but prior to vessel breach are addressed in the CET. The two most important effects of high pressure for a Level 2 PRA are challenges to the steam generator tubes and direct containment heating. As discussed later in this analysis, direct containment heating is a relatively minor issue for Salem. Because of this, only two RCS pressure level categories have been considered in the PRA: high or low. Pressure level assignment was based on the accident initiators (e.g., medium and large LOCAs result in low pressure) and the availability of feedwater (which results in pressure low enough to alleviate steam generator tube challenges, but not DCH). Because the primary concern in high-pressure scenarios is a challenge to the steam generator tubes which requires pressures near the primary PORV/SRV setpoints, accident sequences wherein the expected RCS pressure is below these setpoints are categorized as low pressure; otherwise, they are categorized as high pressure. In general, either a medium/large LOCA or steam generator cooling is required to reach low pressure. Small LOCAs (including those due to RCP seal LOCAs) are insufficient to maintain low pressure at and beyond the time of core damage.

The presence of water in the reactor cavity is important to containment response because the interaction of this water with hot core debris can affect the immediate containment response at the time of vessel breach and the long-term cooling of core debris. Water in the reactor cavity at the time of vessel breach has been an important historic issue for containment response due to the possibility of steam explosion and direct containment heating and their effects on containment integrity. However, recent research has concluded that these phenomena are negligible for Salem. Therefore, the presence of water in the reactor cavity is more important for Salem for the purposes of cooling molten core debris and preventing basemat meltthrough.

The availability considerations of the containment safeguards systems included in the PDS classifications are the state of the containment itself at the time when severe core damage starts (whether it is isolated and intact, unisolated, or bypassed) and the availability of containment engineered safeguards systems to cool the containment atmosphere (containment sprays and containment fan coolers).

E.2.2.4.2 Plant Damage State Classifications for SGS

The following specific items are included for the plant damage state definition:

- RCS Pressure. RCS pressure at the onset of core damage can affect the in-vessel accident progression, the challenge to the steam generator tubes, and the degree of direct containment heating at the time of vessel breach. Two RCS pressure levels have been considered in the Level 1 study: high pressure (near the PORV/SRV setpoints) and low pressure (below these setpoints). For high pressure cases, induced hot leg, surge line, or steam generator tube failures could occur and high pressure melt ejection effects (e.g., direct containment heating) must be considered. For low pressure cases, no further RCS pressure boundary challenges would be expected prior to vessel breach and DCH effects would be reduced (if pressure is reduced via steam generator cooling) or eliminated (if the RCS is fully depressurized due to a LOCA).
- Containment Isolation Status.
  - Containment isolated and not bypassed.
  - Containment not isolated, or failed prior to core damage.
- Containment Bypass Status.
- Containment bypass via an unisolated SGTR.
- Containment bypass via an unisolated, large interfacing systems LOCA.
- Containment Spray Operation. There are two modes of containment spray operation at the SGS:
  - Containment spray injection (from the RWST), which initiates on a high-high containment pressure (25.3 psig).

    - Containment spray recirculation (from the RHR system taking suction from the containment sump and passing the water through heat exchanger before directing it to the spray ring headers).

    - Containment spray injection is one method for filling the reactor cavity with RWST water, while containment spray in recirculation mode can provide containment heat removal to prevent long-term overpressurization.

- Containment Fan Cooler Operation. SGS has five containment fan cooler units that would start automatically in a severe accident. The fan coolers are located at Elevation 130' in containment and deliver cooled, filtered air to all levels of the containment. During accident operation, the air passes through moisture separators, HEPA filters, and a cooling coil; the cooling coils reject heat to the SWS. Operation of the fan coolers can provide containment heat removal to prevent long-term overpressurization.

- RWST Injection. Whether the RWST has been injected into containment can have an effect on the containment response following vessel breach because RWST injection will flood the reactor cavity. The RWST will be injected if either (1) the containment spray system operates in the injection mode or (2) the ECCS system operates in the injection mode.

The SGS PDS matrix, shown in Table E.2-4 addresses the RCS pressure at the time of core uncovery (high or low pressure), the status of the ECCS (injection, injection and recirculation, or none), the status of containment isolation, and the status of containment safeguards (fan coolers or containment spray injection). Each PDS is signified by a three-character designator; e.g., C6D. The first character is always a "C" and has no special significance. The second character is a number between 1 and 7: numbers 1, 2, and 3 are for high pressure; numbers 4, 5, and 6 are for low pressure; and the number 7 indicates an unisolated interfacing system LOCA. The third character is a letter, A through H, signifying whether the containment is isolated (A through D) or unisolated (E through H), along with containment heat removal operation. Steam generator tube rupture initiating events (not ISGTR events) are denoted with a prime (') after the three-character designator.

E.2.2.5 Level 2 Sequences

Twenty-three distinct paths are formed through the containment event tree. Each path represents a Level 2 sequence defined by a specific set of containment response characteristics. Core damage sequences within a particular plant damage state will only occur within Level 2 sequences which match those characteristics. Each Level 2 sequence is labeled based on the expected outcome for containment – Intact, Late Release, or Large/Early Release. A brief discussion of each Level 2 sequence follows. See Table E.2-5 for the Level 2 Sequences plant damage state interface.

INTACT01

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS will be at low pressure due to a LOCA or an open pressurizer PORV. With the LOCA or open PORV, feedwater is unimportant and assumed to not exist. Questions related to induced primary system failures are not applicable. Containment failure due to CF1 does not occur, containment heat removal functions to prevent containment overpressure, and water in the reactor cavity prevents basemat meltthrough.

INTACT02

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS will be at low pressure due to feedwater cooling in at least one steam generator. Questions related to induced primary system failures are not applicable. Containment failure due to CF4 does not occur, containment heat removal functions to prevent containment overpressure, and water in the reactor cavity prevents basemat meltthrough.

INTACT03

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, and operators take action to depressurize the RCS by opening a PORV. The sequence then continues along a low-pressure path, with successful containment performance during hydrogen burn (CF2), successful containment heat removal, and water in the reactor cavity to prevent basemat meltthrough.

<u>INTACT04</u>

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, post-core damage depressurization via the PORVs fails due to operator error or equipment malfunction. A thermally-induced steam generator tube rupture does not occur, but the hotleg does fail prior to vessel breach. The sequence then continues along a low-pressure path, with successful containment performance during hydrogen burn (CF2), successful containment heat removal, and water in the reactor cavity to prevent basemat meltthrough.

<u>INTACT05</u>

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, post-core damage depressurization via the PORVs fails due to operator error or equipment malfunction. A thermally-induced steam generator tube rupture does not occur, and the hotleg does not fail prior to vessel breach. Vessel breach is at high pressure, but containment survives direct containment heating (CF3). Due to the high pressure melt ejection, sufficient core debris is dispersed out of the reactor cavity to avoid basemat meltthrough. If containment heat removal succeeds, the containment remains intact.

LATE01

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS will be at low pressure due to a LOCA or an open pressurizer PORV. With the LOCA or open PORV, feedwater is unimportant and assumed to not exist. Questions related to induced primary system failures are not applicable. Containment failure due to CF1 does not occur, containment heat removal functions to prevent containment overpressure, but there is insufficient water in the reactor cavity to prevent basemat meltthrough. A late release occurs via basemat meltthrough.

LATE02

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS will be at low pressure due to a LOCA or an open pressurizer PORV. With the LOCA or open PORV, feedwater is unimportant and assumed to not exist. Questions related to induced primary system failures are not applicable. Containment failure due to CF1 does not occur, but containment heat removal does not function, leading to containment failure due to overpressure. A late release occurs due to containment failure.

LATE03

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS will be at low pressure due to feedwater cooling in at least one steam generator. Questions related to induced primary system failures are not applicable. Containment failure due to CF4 does not occur and containment heat removal functions to prevent containment overpressure, but there is insufficient water in the reactor cavity to prevent basemat meltthrough. A late release occurs via basemat meltthrough.

LATE04

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS will be at low pressure due to feedwater cooling in at least one steam generator. Questions related to induced primary system failures are not applicable. Containment failure due to CF4 does not occur, but containment heat removal does not function, leading to containment failure due to overpressure. A late release occurs due to containment failure.

LATE05

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, and operators take action to depressurize the RCS by opening a PORV. The sequence then continues along a low-pressure path, with successful containment performance during hydrogen burn (CF2) and successful containment heat removal, but there is insufficient water in the reactor cavity to prevent basemat meltthrough. A late release occurs via basemat meltthrough.

LATE06

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, and operators take action to depressurize the RCS by opening a PORV. The sequence then continues along a low-pressure path, with successful containment performance during hydrogen burn (CF2), but containment heat removal does not function, leading to containment failure due to overpressure. A late release occurs due to containment failure.

LATE07

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, and post-core damage depressurization via the PORVs fails due to operator error or equipment malfunction. A thermally-induced steam generator tube rupture does not occur, but the hotleg does fail prior to vessel breach. The sequence then continues along a low-pressure path, with successful containment performance during hydrogen burn (CF2) and successful containment heat removal, but there is insufficient water in the reactor cavity to prevent basemat meltthrough. A late release occurs via basemat meltthrough.

LATE08

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, and post-core damage depressurization via the PORVs fails due to operator error or equipment malfunction. A thermally-induced steam generator tube rupture does not occur, but the hotleg does fail prior to vessel breach. The sequence then continues along a low-pressure path, with successful containment performance during hydrogen burn (CF2), but containment heat removal does not function, leading to containment failure due to overpressure. A late release occurs due to containment failure.

LATE09

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, and post-core damage depressurization via the PORVs fails due to operator error or equipment malfunction. A thermally-induced steam generator tube rupture does not occur, and the hotleg does not fail prior to vessel breach. Vessel breach is at high pressure and containment survives direct containment heating (CF3), but containment heat removal does not function, leading to containment failure due to overpressure. A late release occurs due to containment failure.

LERF01

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS will be at low pressure due to a LOCA or an open pressurizer

PORV. With the LOCA or open PORV, feedwater is unimportant and assumed to not exist. Questions related to induced primary system failures are not applicable. Early containment failure due to CF1 occurs, and a large, early release occurs due to containment failure.

LERF02

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS will be at low pressure due to feedwater cooling in at least one steam generator. Questions related to induced primary system failures are not applicable. Early containment failure due to CF4 occurs, and a large, early release occurs due to containment failure.

LERF03

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, and operators take action to depressurize the RCS by opening a PORV. The sequence then continues along a low-pressure path, but containment fails early during hydrogen burn (CF2), and a large, early release occurs due to containment failure.

LERF04

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, and post-core damage depressurization via the PORVs fails due to operator error or equipment malfunction. A thermally-induced steam generator tube rupture does not occur, but the hotleg does fail prior to vessel breach. The sequence then continues along a low-pressure path, but containment fails early during hydrogen burn (CF2), and a large, early release occurs due to containment failure.

LERF05

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, and post-core damage depressurization via the PORVs fails due to operator error or equipment malfunction. A thermally-induced steam generator tube rupture does not occur, and the hotleg does not fail prior to vessel breach. Vessel breach is at high pressure and containment fails early due to direct containment heating (CF3), causing a large, early release to occur due to containment failure.

LERF06

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture does not occur, and post-core damage depressurization via the PORVs fails due to operator error or equipment malfunction. A thermally-induced steam generator tube rupture then occurs, providing a direct release path to the environment through the steam generator relief valves which are not designed to handle primary system temperatures and pressures. A large, early release occurs due to induced steam generator tube rupture.

LERF07

Sequences within this path are non-bypass scenarios with successful containment isolation. The RCS was initially at high pressure due to the loss of feedwater in the steam generators. A pressure-induced steam generator tube rupture then occurs, providing a direct release path to the environment through the steam generator relief valves which are not designed to handle primary system temperatures and pressures. A large, early release occurs due to induced steam generator tube rupture.

LERF08

Sequences within this path are non-bypass scenarios, but containment isolation fails due to valve failure or pre-existing excess containment leakage. A large, early release occurs due to containment isolation failure.

LERF09

Sequences within this path bypass containment either via an unisolated interfacing system LOCA or a steam generator tube rupture. An unisolated ISLOCA creates a release path into the auxiliary building, then into the environment. With a steam generator tube rupture, the steam generator relief valves are expected to fail open either due to water egress or excessive temperatures or pressures following core damage.

E.2.2.6 Release Categories

E.2.2.6.1 General Release Categories

As indicated in the previous section, the Level 2 PRA event tree sequences are categorized into three general release categories, which are described below.

INTACT

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

LATE

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

LERF

Containment failure occurs early in the scenario. Early releases are defined as those releases that occur within a short time following core damage, such that adequate evacuation time is not available to protect the public from prompt health effects. While releases could be considered small if scrubbing or other fission product reduction techniques are used, these are not credited in this analysis.

E.2.2.6.2 Detailed Release Categories

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

INTACT

This release category captures all of the INTACT sequences. Because the containment is essentially intact, sequence variations have a negligible impact on the release characteristics. INTACT01, INTACT02, INTACT03, INTACT04, and INTACT05 contribute to this category. Releases to the environment are via normal containment leakage.

LATE-BMMT-AFW

This release category captures sequences that result in basemat meltthrough with feedwater available to the steam generators. Because basemat meltthrough takes many days to erode the thick basemat at Salem, containment failure is assumed at 100hr. LATE03 contributes to this category.

LATE-BMMT-NOAFW

This release category captures sequences that result in basemat meltthrough without feedwater available to the steam generators. Because basemat meltthrough takes many days to erode the thick basemat at Salem, containment failure is assumed at 100hr. LATE01, LATE05, and LATE07 contribute to this category.

LATE-CHR-AFW

This release category captures sequences that result in containment failure due to late overpressure with feedwater available to the steam generators. LATE04 contributes to this category.

LATE-CHR-NOAFW

This release category captures sequences that result in containment failure due to late overpressure without feedwater available to the steam generators. LATE02, LATE06, LATE08, & LATE09 contribute to this category.

LERF-ISLOCA

This release category captures sequences caused by an unisolated ISLOCA. Those sequences from LERF09 with ISLOCA initiating events contribute to this category.

LERF-CI

This release category captures sequences that result in containment isolation failure due to either valve failure or excessive pre-existing containment leakage. Containment failure due to pre-existing leakage is assumed at the start time of the scenario for the release calculations. LERF08 contributes to this release category.

LERF-CFE

This release category captures sequences that result in early containment failure due to steam explosion, hydrogen burn, and/or direct containment heating at the time of vessel breach. LERF01, LERF02, LERF03, LERF04, and LERF05 contribute to this category.

LERF-SGTR-AFW

This release category captures sequences caused by a steam generator tube rupture that have successful operation of auxiliary feedwater. With or without isolation of the ruptured steam generator, SGTR sequences with core damage provide a direct release path to the environment through the steam generator relief valves. Those sequences from LERF09 with SGTR initiating events and successful AFW contribute to this category.

LERF-SGTR-NOAFW

This release category captures sequences caused by a steam generator tube rupture that also have failed auxiliary feedwater. With or without isolation of the ruptured steam generator, SGTR sequences with core damage provide a direct release path to the environment through the steam generator relief valves. Those sequences from LERF09 with SGTR initiating events and failure of AFW contribute to this category.

LERF-ISGTR

This release category captures sequences that result in either a pressure-induced or thermally-induced steam generator tube rupture that bypasses containment. LERF06 and LERF07 contribute to this category.

E.2.2.7 Source Term Calculations

E.2.2.7.1 Representative Sequence Selection

For each detailed release category defined above, accident progression calculations predict the timing and amount of release. But because each release category can contain a high number of sequences, representative sequences must be defined for each category. For the INTACT and LATE categories, the most likely initiators and sequences are chosen to represent the category. For the LERF categories, both the likelihood of the scenario and its potential offsite effect is considered. Because the LERF release categories have the highest potential offsite consequences, the representative scenarios are generally chosen conservatively in order to bound the effects. Table E.2-3 describes the representative sequences for each detailed release category.

For INTACT sequences, containment structure and function succeed and prevent a large or late release of fission products. Source term calculations assume normal plant leakage to determine offsite consequences.

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

For LERF sequences, containment failure occurs early in the scenario. Early releases are defined as those releases that occur within a short time following core damage, such that adequate evacuation time is not available to protect the public from prompt health effects. While releases could be considered small if scrubbing or other fission product reduction techniques are used, these are not credited in this analysis.

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

E.2.2.7.2 MAAP Results

The timing of important events and the timing and magnitude of fission product releases for each representative sequence is documented in Tables 7-2 and 7-3 of Reference (PSEG 2008c).

E.2.2.8 Results

Endstate Frequency Totals

Table E.2-6 and Figure E.2-6 show the calculated results for the three general release categories. The calculation used a truncation of 1.0E-11 to match the Level 1 quantification. Calculations with a truncation of 1.0E-12 showed an acceptably small change in the results. The sum of these three endstates is approximately equal to the core damage frequency (4.77E-5), allowing for slight differences due to truncation of low probability sequences and inclusion of non-minimal Level 1 sequences.

Release Category Frequencies

Table E.2-2 shows the calculated results for the detailed release categories. The associated figures (Figures E.2-7 through E.2-9) show the composition of each release category.

Contribution to LERF/LATE/INTACT by Level 2 Sequence

Figures E.2-10 through E.2-12 show the contribution to each main endstate by Level 2 sequences.

Contribution to LERF/LATE/INTACT by Initiator

Figures E.2-13 through E.2-15 show the contribution to each main endstate by Level 2 initiator.

E.2.3 SGS Peer Review Summary

As stated previously, the Salem PRA model used for this SAMA evaluation was revision 4.1, issued September 30, 2008. This model is a full-power internal events model capable of assessing level 1 (core damage) and level 2 / large early release risk. Revision 4.1 incorporated the updated internal flooding results developed in the summer of 2008 into the revision 4.0 model, which was released on March 31, 2008. Revision 4.0 was created by making improvements to the previous PRA model (version 3.2a) in order to more closely track the requirements of the ASME PRA standard and NRC Regulatory Guide 1.200, Revision 1.

Revision 3.2a of the SGS PRA model represented an improved version of the Salem model that was peer reviewed by a Westinghouse Owners Group team in February 2002. All “A” and “B” findings from that review have since been addressed.

In November 2008, a PWR Owners Group team provided a peer review of the revision 4.1 Salem PRA model using the NEI process for performing follow-on PRA peer reviews (NEI 2007) to determine compliance with Addendum B of the ASME PRA Standard (ASME 2005) and Regulatory Guide 1.200, Revision 1. The final report for that peer review has not yet been received as of this analysis.

In addition to peer reviews, other measures to ensure, validate, and maintain the quality of the Salem PRA include a formal qualification program for PRA staff, use of procedural guidance to perform PRA tasks, and a program to control PRA models and software. Therefore, the use of revision 4.1 of the Salem PRA model for this SAMA evaluation is deemed appropriate.

E.3 LEVEL 3 RISK ANALYSIS

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

E.3.1 Analysis

The MACCS2 code (NRC 1998a) was used to perform the Level 3 probabilistic risk assessment (PRA) for Salem Nuclear Generating Station (SGS). The input parameters given with the MACCS2 "Sample Problem A," formed the basis for the present analysis. These generic values were supplemented with parameters specific to SGS and the surrounding area. Site-specific data included population distribution, economic parameters, and meteorological data. Generic economic parameters for the costs of evacuation, relocation and decontamination were escalated from the time of their formulation (1986) to more recent (April 2008) costs. Plant-specific release data included release frequencies and the time-dependent distribution of nuclide releases from 11 accident sequences at SGS. The behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points (i.e., declaration of a General Emergency) and evacuation time estimates (KLD 2004). These data were used in combination with site specific meteorology to calculate risk impacts (exposure and economic) to the surrounding (within 50 miles) population.

E.3.2 Population

The population surrounding the SGS site is estimated for the year 2040.

The population distribution projection was based on census data available via SECPOP2000 (NRC 2003). The baseline population was determined for each of 160 sectors, consisting of sixteen directions (i.e., N, NNE, NE,…NNW) for each of ten concentric distance rings with outer radii at 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles surrounding the site. SECPOP2000 census data from 1990 and 2000 were used to determine a ten year population growth factor for each of the concentric rings. The ten year population growth factor for each ring was applied successively and uniformly to all sectors in the ring to calculate the 2040 population distribution.

The total year 2040 population for the 160 sectors in the region is estimated at 6,415,055. The distribution of the population is given for the 10-mile radius and the 50-mile radius from SGS in Tables E.3-1 and E.3-2, respectively.

E.3.3 Economy and Agriculture

MACCS2 requires certain agricultural based 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) for each of the 160 sectors. This data can be generated by SECPOP2000 (NRC 2003), but due to recent errors discovered with the economic parameter processing of the SECPOP2000 code, SECPOP2000 was not utilized to develop the economic parameters for the SGS analysis. Instead, the economic parameters were developed manually using data in the 2002 National Census of Agriculture (USDA 2004) and from the Bureau of Economic Analysis (BEA 2008) for each of the 23 counties surrounding the plant, to a distance of 50 miles. The values used for each of the 160 sectors were the data from each of the surrounding counties multiplied by the fraction of that county's area that lies within that sector. Region-wide wealth data (i.e., farm wealth and non-farm wealth) were based on county-weighted averages for the region within 50-miles of the site using data in the 2002 National Census of Agriculture (USDA 2004) and the Bureau of Economic Analysis (BEA 2008). The portion of each county within 50-miles of the site was accounted for in the calculation.

In addition, generic economic data that is 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 1.96, representing cost escalation from 1986 to April 2008 was applied to parameters describing cost of evacuating and relocating people, land decontamination, and property condemnation.

MACCS2 economic parameters utilized in the SGS analysis include the following:

SGS MACCS2 Economic Parameters

Variable	Description	SGS Value
DPRATE[1]	Property depreciation rate (per yr)	0.20
DSRATE[2]	Investment rate of return (per yr)	0.07
EVACST[3]	Daily cost for a person who has been evacuated ($/person-day)	52.92
POPCST[3]	Population relocation cost ($/person)	9799
RELCST[3]	Daily cost for a person who is relocated ($/person-day)	52.92
CDFRM0[3]	Cost of farm decontamination for various levels of decontamination ($/hectare)	1102 2450
CDNFRM[3]	Cost of non-farm decontamination per resident person for various levels of decontamination ($/person)	5880 15679
DLBCST[3]	Average cost of decontamination labor ($/man-year)	68595
VALWF0[4]	Value of farm wealth ($/hectare)	16636
VALWNF[4]	Value of non-farm wealth ($/person)	275924

(1) DPRATE uses NUREG/CR-4551 value (NRC 1990b).
(2) DSRATE based on NUREG/BR-0058 (NRC 2004).
(3) These parameters for SGS use the NUREG/CR-4551 values (NRC 1990b), updated to April 2008 using the consumer price index. For CDFRM0 and CDNFRM, two values are utilized, one for each of two levels of modeled decontamination.
(4) VALWF0 and VALWNF are based on 2002 National Agriculture Census (USDA 2004) and Bureau of Economic Analysis data (BEA 2008), updated to the April 2008 using the consumer price index.

E.3.4 Food and Agriculture

Food ingestion is modeled using the new MACCS2 ingestion pathway model COMIDA2 (NRC 1998a), consistent with Sample Problem A. The COMIDA2 model utilizes national based food production parameters derived from the annual food consumption of an average individual such that site specific food production values are not utilized. The fraction of population dose due to food ingestion is typically small compared to other population dose sources. For SGS, less than one percent of the total population dose is due to food ingestion.

E.3.5 Nuclide Release

The core inventory at the time of the accident is based on a plant specific calculation (PSEG 2005a). The core inventory corresponds to the end-of-cycle values for SGS operating at 3632 MWt, five percent above the current licensed value of 3468 MWt. Table E.3-3 summarizes the estimated SGS core inventory used in the MACCS2 analysis.

SGS nuclide release categories, as determined by the MAAP computer code, are related to the MACCS2 categories as shown in Table E.3-4. Releases were modeled as occurring at the top of containment (59 meters). 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 E.7.3.

Release frequencies, nuclide release fractions (of the core inventory), shown in Table E.3-6, and the time distribution of the release were analyzed to determine the sum of the exposure (50-mile dose) and economic (50-mile economic costs) risks from 11 accident sequences (also given in Table E.3-6). Each accident sequence was chosen to represent a set of similar accidents. 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 E.3-5, and a summary of the release magnitude and timing for those cases is provided in Table E.3-6. Multiple release duration periods (i.e., plume segments) were defined which represented the time distribution of each category's releases.

E.3.6 Evacuation

Reactor trip for each sequence was taken as time zero relative to the core containment response times. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. For the SGS analysis it was assumed that the declaration would coincide with the onset of core damage. The declaration times are presented in Table E.3-6.

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 are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the EPZ (NRC 1990a).

The evacuees are assumed to begin evacuation 65 minutes after a general emergency has been declared at a base evacuation radial speed of 2.8 m/sec. This time to begin evacuation and the base speed is derived from the site specific evacuation study (KLD 2004). The evacuation speed is a time-weighted average value accounting for season, day of week, time of day, and weather conditions. It is noted that the longest evacuation time presented in the study (i.e., full 10 mile EPZ, winter snow conditions, 99^{th} percentile evacuation) is 4 hours (from the issuance of the advisory to evacuate). The evacuation parameters were considered further in the sensitivity analyses presented in Section E.7.3.

E.3.7 Meteorology

Annual hourly meteorology SGS data sets from 2004 through 2007 were investigated for use in MACCS2. Of the hourly data of interest (10-meter wind speed, 10-meter wind direction, multi-level temperatures used to calculate stability class, and precipitation), less than 1% of the data were missing for 2004, and less than 4% for 2005 and 2007. Approximately 8.3 % of year 2006 precipitation data was missing. Traditionally, up to 10% of missing data is considered acceptable. MACCS2 requires complete sequential hourly data, therefore missing data must be estimated. Data gaps were filled by (in order of preference): using data from the backup met pole instruments (10-meter), using corresponding data from another level of the main met tower, interpolation (if the data gap was less than 6 hours), or using data from the same hour and a nearby day (substitution technique). The 10-meter wind speed and direction were combined with precipitation and atmospheric stability (derived from the vertical temperature gradient) to create the hourly data file for use by MACCS2.

The 2004 and 2006 data sets were found to result (see Section E.7.3 for discussion of sensitivity analysis) in the larger economic cost risk and dose risk compared to the 2005 and 2007 data sets. Given that the 2004 data set was the most complete and the 2006 data set was missing the most data, the 2004 hourly meteorology was selected as the base case.

Atmospheric mixing heights were specified for AM and PM hours for each season of the year. These values ranged from 600 meters to 1700 meters (EPA 1972).

E.3.8 MACCS2 Results

Table E.3-7 shows the mean off-site doses and economic impacts to the region within 50 miles of SGS for each of 11 release categories calculated using MACCS2. The mean off-site dose impacts are multiplied by the annual frequency for each release category and then summed to obtain the dose-risk and offsite economic cost-risk (OECR) for each unit. Table E.3-7 provides these results.

E.4 BASELINE RISK MONETIZATION

This section explains how SGS calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). SGS also used this analysis to establish the maximum benefit that could be achieved if all on-line SGS risk were eliminated, which is referred to as the Maximum Averted Cost-Risk (MACR). It should be noted that the sum of the release category frequencies for the base SAMA case (4.95E-05 /yr) was chosen as the base CDF value for the below cost-risk calculations instead of the nominal Level 1 CDF value of 4.77E-05. This was done in order to be consistent with the estimated MMACR results for each of the modeled SAMAs in Section E.6, which were based on summing all of the individual release category frequencies from the PRA cases.

Section E.4.6 summarizes the results for these cases.

E.4.1 Off-Site Exposure Cost

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

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

Where:

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

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

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

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

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

The Level 3 analysis showed an annual off-site population dose risk of 78.22 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 $2,352,694.

E.4.2 Off-Site Economic Cost Risk

The Level 3 analysis showed an annual off-site economic risk of $305,718. 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 $4,597,886.

E.4.3 On-Site Exposure Cost Risk

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

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

Equation 1:

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

Where:

W_{IO}	=	monetary value of accident risk avoided due to immediate doses, after discounting
R	=	monetary equivalent of unit dose ($2,000 per person-rem)
F	=	accident frequency (events per year) (4.95E-05 (total CDF))
D_{IO}	=	immediate occupational dose [3,300 person-rem per accident (NRC estimate)]
$_S$	=	subscript denoting status quo (current conditions)

$_A$ = subscript denoting after implementation of proposed action

r = real discount rate (0.03 per year)

t_f = years remaining until end of facility life (20 years).

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

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

= $2{,}000*4.95E\text{-}05\ *3{,}300*\{[1 – \exp(-0.03*20)]/0.03\}$

= $4,913

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

Equation 2:

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

Where:

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

D_{LTO} = long-term dose [20,000 person-rem per accident (NRC estimate)]

m = years over which long-term doses accrue (as long as 10 years)

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

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

= $2{,}000*4.95E\text{-}05*20{,}000*\{\ [1 – \exp(-0.03*20)]/0.03\}\ \{[1 –\exp(-0.03*10)]/0.03*10\}$

= $25,726

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:

$$W_O = W_{IO} + W_{LTO} = (\$4,913 + \$25,726) = \$30,639 \text{ person-rem}$$

E.4.4 On-Site Cleanup and Decontamination Cost

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

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

Where:

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

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

r = real discount rate (0.03)

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

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

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

Where:

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

r = real discount rate (0.03)

t_f = 20 years (license renewal period)

The resulting net present value of cleanup integrated over the license renewal term, \$1.95E+10, must be multiplied by the total CDF (4.95E-05) to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is \$964,735.

E.4.5 Replacement Power Cost

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

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

Where:

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

r = 0.03

t_f = 20 years (license renewal period)

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

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

Where:

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

After applying a correction factor to account for SGS’s size relative to the “generic” reactor described in NUREG/BR-0184 (NRC 1997) (i.e., 1115 megawatt electric / 910 megawatt electric, the replacement power costs are determined to be 6.77E+09 (\$-year). Multiplying 6.77E+09 (\$-year) by the CDF (4.95E-05) results in a replacement power cost of \$335,120.

E.4.6 Maximum Averted Cost-Risk

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

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

As described in Section E.5.1, the MACR is used in the SAMA identification process to determine the depth of the importance list review. In addition, the MACR is used in the Phase 1 analysis as a means of screening SAMAs.

The following subsections provide a description of how each of these components are calculated and used together to obtain the SGS MACR.

E.4.6.1 Internal Events Maximum Averted Cost-Risk

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

Maximum Averted Internal Events Cost-Risk

Off-site exposure cost	=	$2,352,694
Off-site economic cost	=	$4,597,886
On-site exposure cost	=	$30,639
On-site cleanup cost	=	$964,735
Replacement Power cost	=	$335,120
Total cost	=	$8,281,074

This total represents the monetary equivalent of the risk that could be eliminated if all on-line internal events based events could be eliminated for a single SGS unit. The internal events MACR is rounded to next highest thousand ($8,282,000) for SAMA calculations. It should be noted that the Phase 2 cost benefit calculations account for the difference between the rounded MACR and the actual MACR by adding the difference to the averted cost-risk calculated for each SAMA.

E.4.6.2 External Events Maximum Averted Cost-Risk

The maximum averted cost-risk for external events must be quantified for the cost benefit calculations; however, this cost-risk must be estimated based on information in the IPEEE given that complete, current, quantifiable external events models are not available. As described in Sections E.5.1.5 and E.5.1.6, these models have not been officially updated to reflect recent plant changes or current PRA techniques. Therefore, the absolute CDF values that are included in the IPEEE are not considered to be directly comparable to the results of the internal events PRA model. As a result, an alternate method of accounting for the external events contributions must be established.

Before this can be done for SGS, however, it is necessary to account for changes that have been made to the fire suppression system and some fire wrap changes at the site since completion of the IPEEE.

E.4.6.2.1 Impact of SGS Fire Suppression System and Cable Wrap Changes

After completion of the IPEEE, SGS replaced the CO2 suppression systems in the following rooms with water sprinkler systems:

- 460V AC Switchgear Rooms
- 4160V AC Switchgear Rooms
- Lower Electrical Penetration Area

In addition, the results of PSE&G cable wrap tests suggested that the cable wrap that was in place is some plant areas would not perform as expected. This was a potential issue for the 460V AC Switchgear room and the changes that were made to the wrap in that area were not captured by the IPEEE fire analysis.

With regard to the changes made to the fire suppression systems, the water sprinkler design has characteristics that are both beneficial and detrimental to the CDF compared with the CO2 systems, but the overall impact of these characteristics depends on which factor dominate the important fire scenarios. In general, the suppression failure probability for a water sprinkler system is lower than a CO2 system (2.0E-02 versus 4.0E-02) (NRC 2005), which would suggest a CDF reduction. In addition, the configuration of the rooms containing the CO2 systems raised questions about the system's viability and safety due to CO2 migration. Installation of the water sprinkler systems addressed these issues, which would also suggest a CDF reduction. However, the actuation systems are not exactly the same. The original SGS CO2 fire suppression system was actuated on a combination of smoke detection and area thermal detectors while the new water based system is actuated on as similar combination of thermal and smoke detectors with the additional requirement that the fusible links in the sprinkler heads melt. The smoke and area thermal detectors allow water to enter the fire suppression piping in the corresponding fire area, but water does not spray from the sprinkler header until the heat of the fire melts the fusible link. The presence of the fusible links may result in delayed actuation compared to the CO2 system depending on the positions of the sprinkler headers and the fire, which could result in a CDF increase. A detailed analysis would be required to assess the impact of the transition to the water sprinkler system, which is not within the scope of the SAMA analysis.

The determination that the cable wrap in the 460V Switchgear Room (1FA-AB-84A) would not perform as expected and its subsequent removal/replacement raised questions about how fire propagation was treated in the IPEEE for this area. Because the conditional core damage probability (CCDP) can change substantially based on propagation details, an interim SGS fire model that did not credit the fire wrap was reviewed to gain insights related to how the CDF was impacted by fire propagation assumptions (SCIENTECH 2003). Because propagation issues are also a potential concern for the other two fire areas in which the fire suppression systems were changed, they have been reviewed as well. As summarized below, the CDF went up for areas 1FA-AB-84A and 1FA-EP-78C and down for 1FA-AB-64A:

Comparison of IPEEE and Interim SGS Fire Model Results for Selected Areas

FIRE AREA	DESCRIPTION	IPEEE CDF	INTERIM SGS FIRE MODEL CDF (SCIENTECH 2003)
1FA-AB-84A	460V Switchgear Room	1.70E-06	6.43E-06
1FA-AB-64A	4160 Switchgear Room	1.70E-06	7.10E-07
1FA-EP-78C	Lower Electrical Penetration Area	1.40E-06	1.60E-06

Additional CDF information is available for other fire areas, but because the SGS Interim Fire Model (SCIENTECH 2003) was neither implemented at the site nor reviewed by any external entities, the use of the model has been limited to the areas for which the IPEEE is considered to be invalid due to plant changes.

In order quantitatively account for the impacts of the fire wrap and suppression system changes to the 460V Switchgear Room, the 4160 Switchgear Room, and the Lower Electrical Penetration Area, two major assumptions have been made:

- The fire propagation/cable wrap issue for these rooms is addressed by the SGS Interim Fire Model (SCIENTECH 2003) given that cable wrap was not credited in that model. Fire propagation and the corresponding CCDPs are appropriately accounted for in the SGS Interim Fire Model and the resulting CDFs are more "realistic" estimates than those included in the IPEEE. If the CDF from the interim SGS fire analysis is larger than the IPEEE CDF (1FA-AB-84A, 1FA-EP-78C), it is used for the SAMA analysis; otherwise, the IPEEE CDF is used (1FA-AB-64A).

- Replacement of the CO2 system with the water sprinkler systems may result in a CDF reduction based on improved reliability and elimination of CO2 migration issues, but because the impact of potential actuation delay has not been quantified, the CDFs for the areas with the new water sprinkler systems have been multiplied by a factor of two.

The following table summarizes the changes made to the fire CDFs for the areas with the new water sprinkler systems:

Revised CDFs for Fire Areas with New Water Sprinkler Systems

FIRE AREA	DESCRIPTION	ORIGINAL CDF	NEW CDF	COMMENTS
1FA-AB-84A	460V Switchgear Room	1.70E-06	1.29E-05	The SGS Interim Fire Model (SCIENTECH 2003) CDF of 6.43E-06 has been multiplied by a factor of 2 and used as the CDF for this fire area.
1FA-AB-64A	4160V Switchgear Room	1.70E-06	3.40E-06	The IPEEE CDF is larger than the CDF from the SGS Interim Fire Model (SCIENTECH 2003). The IPEEE CDF has been multiplied by 2 and used as the CDF for this fire area.
1FA-EP-78C	Lower Electrical Penetration Area	1.40E-06	3.20E-06	The SGS Interim Fire Model (SCIENTECH 2003) CDF of 1.60E-06 has been multiplied by a factor of 2 and used as the CDF for this fire area.

Based on the information in the table, the total SGS fire CDF has been changed from 2.3E-05/yr to 3.8E-05/yr.

E.4.6.2.2 External Events Multiplier

The method chosen to account for external events contributions in the SAMA analysis is to use a multiplier on the internal events results. In previous SAMA analyses, it has been assumed that the risk posed by external events and internal events is approximately equal. This assumption is not unreasonable unless available analyses indicate that there are external events contributors that present a disproportionate risk to the site. Based on a review of the SGS external events results, no such contributors have been identified.

The contributions of the external events from the original IPEEE analysis are summarized in the following table:

Original IPEEE Contributor Summary

External Event Initiator Group	CDF
Seismic	9.5E-06 per yr
Internal Fire	2.3E-05 per yr
High Winds	Not Applicable (progressive screening method used)

Original IPEEE Contributor Summary

External Event Initiator Group	CDF
External Floods	3E-7 per yr: A progressive screening method used and an overall CDF was not calculated, but three potential water ingress paths were estimated to contribute CDFs of about 1E-07 each.
Transportation and Nearby Facility Accidents	6.7E-08 per yr (PSEG 1996a)
Detritus	5.2E-07 per yr to 9.2E-07 per yr (PSEG 1996a)
Chemical Release	Not Applicable (progressive screening method used)
Total (for initiators with CDF available)	3.4E-05 per yr

The lack of detailed quantitative analyses makes it difficult to establish a meaningful CDF for many of these initiator groups; however, some assumptions can be made about the non-quantified initiator groups that could be used to further develop a total external events CDF.

The SGS IPEEE methodology implies that if the plant licensing bases are met, the plant and facilities design meets the 1975 Standard Review Plan (SRP) criteria, and the site walkdown does not reveal any potential vulnerability not already considered in the design basis analysis, then the CDF posed by an initiator is less than the 1.0E-06 per yr screening criterion. As described in section E.5.1.6, these conditions are met for SGS and no contributions of greater than 1.0E-06 per yr are expected for any of the external events excluding seismic and internal fire initiators. Given that, a CDF of 1.0E-06 per yr could be assumed for each of the contributors for which no complete quantitative basis exists to obtain a more detailed estimate of the external events CDF. If this is done, the external events contributions could be summarized as follows:

Modified IPEEE Contributor Summary

External Event Initiator Group	CDF Per Year
Seismic (LLNL hazard curves)	9.5E-06
Internal Fire (accounting for suppression and cable wrap changes)	3.8E-05
High Winds	1.0E-06
External Floods	1.0E-06
Transportation and Nearby Facility Accidents (including accidental aircraft impact)	1.0E-06
Detritus	1.0E-06

Modified IPEEE Contributor Summary

External Event Initiator Group	CDF Per Year
Chemical Release	1.0E-06
Total	5.25E-05

Even when the screening threshold of 1.0E-06 is used for the non-quantified external event initiator groups, the total is 5.25E-05 per yr, which is approximately equal to the current internal events CDF of 4.95E-05 per yr. No conditions exist that would indicate an external events multiplier of greater than two should be used.

While it is possible to assume larger external events multipliers to compensate for the uncertainty associated with undeveloped external events models, overemphasizing external events contributions can be detrimental to the SAMA process in that:

- Over predicting the averted cost-risk of internal events based SAMAs through the use of an inflated multiplier could divert site resources to issues that are not important to the plant.

- Over predicting the averted cost-risk of an external events based SAMA could change the prioritization of addressing cost effective SAMAs away from important issues identified by the internal events model to highly uncertain issues identified by the external events analyses.

For these reasons, a multiplier of two has been chosen to account for the SGS external events contributions. This implies that the contribution to the MACR from the external events is the same as the contribution from the internal events model ($8,282,000).

E.4.6.3 SGS Maximum Averted Cost-Risk

As stated in Section E.4.6, the MACR is the total of these two components:

Internal Events	=	$8,282,000
External Events	=	$8,282,000
Single Unit Maximum Averted Cost-Risk	=	$16,564,000

The single unit MACR was sufficient in determining cost-effective SAMAs, since Unit 1 and Unit 2 were assumed to be identical. However, SAMA implementation costs were developed at the site level to capture “economy of scale” between the two units, which were then divided by two to obtain the equivalent values for a single unit.

E.5 PHASE 1 SAMA ANALYSIS

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

E.5.1 SAMA Identification

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

- Salem PRA results and PRA Group Insights
- Industry Phase 2 SAMAs (review of the potentially cost effective Phase 2 SAMAs for selected plants)
- Salem Individual Plant Examination IPE (Salem IPE) (PSEG 1993)
- Salem IPEEE (PSEG 1996a)

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 Salem.

In addition to the "Industry Phase 2 SAMA" review identified above, an industry based SAMA list was used in a different way to aid in the development of the Salem plant specific SAMA list. While the industry Phase 2 SAMA review cited above was used to identify SAMAs that might have been overlooked in the development of the Salem SAMA list due to PRA modeling issues, a generic SAMA list was used to help identify the types of changes that could be used to address the areas of concern identified through the Salem importance list review. For example, if Instrument Air availability was determined to be an important issue for Salem, the industry list would be reviewed to determine if a plant enhancement had already been conceived that would address Salem's needs. If an appropriate SAMA was found to exist, it would be used in the

Salem list to address the Instrument Air issue; otherwise, a new SAMA would be developed that would meet the site's needs. This generic list was compiled as part of the development of several industry SAMA analyses and is available in NEI 05-01 (NEI 2005).

E.5.1.1 Level 1 Salem Importance List Review

The Salem 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 Salem CDF if the failure probability were set to zero. The events were reviewed down to the risk significant threshold of 1.01, which addresses all events that could reduce the CDF by 1 percent or more if they were assumed to never fail.

The review threshold could be correlated to the minimum expected SAMA implementation cost, but for SGS, the large MACR would result in a very low review threshold. For example, if the minimum expected SAMA implementation cost is assumed to be a procedure change at $50,000 to $100,000 for the site (CPL 2004), the CDF, dose-risk and offsite economic cost-risk would have to be reduced by a factor of 1.003 to achieve a unit-based averted cost-risk of about $50,000 (including external events), or $100,000 for the site. Performing a review to this level would likely generate additional unique SAMAs, some of which could be cost beneficial, but because the impact on risk is so low and because they would be competing for resources with SAMAs that will likely address larger areas of risk that impact daily plant functions (e.g., MSPI), their potential for implementation is extremely limited. Even if the implementation cost is low, as in the case of a procedure change, justifying the need to modify how the plant is operated to achieve less than a 1 percent reduction in CDF is difficult. As a result, the review to the 1.01 RRW threshold is considered reasonable to identify those SAMAs that are most likely to be cost effective and have some potential for implementation.

At the RRW review threshold of 1.01, the corresponding single unit averted cost-risk would be about $164,000.

Table E.5-1 documents the disposition of each event in the Level 1 SGS RRW list with RRW values of 1.010 or greater. Note that the review of each event involves a detailed evaluation of the cutsets including the event to identify the factors that make the event important.

E.5.1.2 Level 2 Salem Importance List Review

A similar review was performed on the importance listings from the Level 2 results. In this case, a composite importance file based on the following release categories was used to identify potential SAMAs:

- LATE-CHR-NOAFW
- LERF-SGTR-AFW
- LERF-ISGTR

This method was chosen to prevent high frequency-low consequence events from biasing the importance listing. While the remaining release categories contribute about 5.5% of the dose-risk, that small contribution depends on about 22% of the Level 2 frequency. For SGS, this is not a highly important factor because the consequences are largely driven by the LATE-CHR-NOAFW release category, but this strategy was implemented for completeness.

As with the Level 1 review, the Level 2 review included those events with a Risk Reduction Worth (RRW) greater than 1.01. Table E.5-2 lists those events and the corresponding comments.

E.5.1.3 Industry SAMA Analysis Review

The SAMA identification process for SGS 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 2 SAMAs that were determined to be potentially cost beneficial at other plants. These SAMAs were further analyzed and included in the SGS SAMA list if they were considered to address potential risks not identified by the SGS importance list review.

While many of the industry SAMAs reviewed are ultimately shown not to be cost beneficial, some are close contenders and a small number have been estimated to be cost beneficial at other plants. Use of the SGS importance ranking should identify the types of changes that would most likely be cost beneficial for SGS, but review of selected industry Phase 2 SAMAs may capture potentially important changes not identified for SGS 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 2 SAMAs in the SGS SAMA identification process.

Phase 2 SAMAs from the following United States nuclear power sites have been reviewed:

- Susquehanna (PPL 2006)
- Shearon Harris (CPL 2006)
- H.B. Robinson (CPL 2002)
- Point Beach (NMC 2004)
- Prairie Island (NMC 2008)
- Wolf Creek (WCNOC 2006)

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

E.5.1.3.1 Susquehanna Steam Electric Station

Review of SSES Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for SGS	Disposition for SGS SAMA List
2a	Improve Cross-Tie Capability Between 4kV AC Emergency Buses (A-D, B-C)	SSES did not credit cross-tie between EDG trains and relied on the swing EDG to mitigate EDG failures. For SGS, this type of enhancement was identified based on the plant specific PRA results review (SAMAs 3 and 4).	Already included
6	Procure Spare 480V AC Portable Station Generator	This SAMA was developed to address the hardware failure contribution from their existing portable 480V generator, which does not currently exist at SGS. Also, the situation at SGS is different than at some sites given that the positive displacement pump, which is required for primary side makeup, requires cooling from the CCW system, which is powered by 4kV power, so a 460V AC generator alone at SGS would not be address the required SBO issues. A form of the portable generator SAMA is included on the SGS list (SAMA 5), but the SAMA is expanded to meet the site specific needs for SBO mitigation.	Already included
2b	Improve Cross-Tie Capability Between 4kV AC Emergency Buses (A-BC-D)	This SAMA is an enhancement over SSES SAMA 2a and allows cross-tie between any EDG division. All cross-tie options will be reviewed for SGS as part of SGS SAMAs 3 and 4.	Already included
3	Proceduralize Staggered RPV Depressurization When Fire Protection System Injection is the Only Available Makeup Source	This SAMA is specific to the SSES site and is based on the need to split flow from a single injection system between units. It is not applicable to the SGS design.	Not required for the SAMA list

Review of SSES Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for SGS	Disposition for SGS SAMA List
5	Auto Align 480V AC Portable Station Generator	This SAMA was designed for a plant that already had a portable generator, but the impacts of auto generator alignment can be considered for Salem. In this case, auto alignment would primarily be important to ensure power could be available for RCP seal injection before the 13 minute time window that is set for seal cooling restoration. SGS SAMA 5 takes an alternate approach that includes replacing the positive displacement CVCS pump with a larger size pump that can make up for all but the largest seal LOCAs. Using this approach, manual alignment of the portable generator can be successful given that the new pump could make up for the higher flow leaks that could accompany failure to restore seal cooling. This is considered to be a more cost effective approach for SGS given that the positive displacement pump would have to be replaced anyway given its cooling dependence on the 4kV CCW system.	Addressed through different means

E.5.1.3.2 Shearon Harris

Review of Shearon Harris Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for SGS	Disposition for SGS SAMA List
9	Proceduralize Actions to Open EDG Room Doors on Loss of HVAC and Implement Portable Fans	This action was identified for SGS as part of the PRA importance list review and is included as SAMA 17.	Already included
6	Flood Mitigation for Scenarios 6 and 7	This is a plant specific internal flooding issue related to valve qualification in flooding conditions. The internal flooding issues at SGS are identified in the SAMA list and treated as appropriate for the site, including SAMAs 6, 8, 12, 19.	Already included
8	Alternate Seal Cooling and Direct Feed to Transformer 1B3-SB	This SAMA was developed to address loss of 4kV bus events where power is available to the opposite 4kV bus, but vital equipment has failed on the powered bus. Loss of bus events are not important for SGS.	Not required for the SAMA list

E.5.1.3.3 H.B. Robinson

The H.B. Robinson SAMA analysis used a generic SAMA list as its starting point and few plant specific insights were available that might pertain specifically to Westinghouse PWRs. One of the SAMAs included in the Phase 2 list was, however, related to an important issue at SGS, which is discussed below

Review of H.B. Robinson Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for SGS	Disposition for SGS SAMA List
Phase 2 SAMA 8	Create automatic swap over to recirculation on RWT depletion	The swap to recirculation mode is a prominent operator action for most PWRs. The SGS importance list includes the event representing the failure to swap to recirculation mode, but based on cutset review, an effective and more desirable solution for SGS was considered to automate AFWST makeup and maintain secondary side cooling.	Not required for the SAMA list

E.5.1.3.4 Point Beach

As with H.B. Robinson, this analysis relied on a generic SAMA list and few plant specific insights were available that might pertain specifically to Westinghouse PWRs. The SAMAs identified in the Point Beach submittal as potentially cost effective appeared to be procedural updates to include checkoff provisions within the procedures. Some HRA methodologies credit placekeeping aids in procedures as a means of reducing the potential to skip a step in the cognitive portion of the HEP. While inclusion of such provisions is reflected quantitatively in the PRA, it would be difficult to justify changes to a large number of procedures based on a detail in a specific HRA methodology. This type of SAMA was not included in the SGS SAMA list

E.5.1.3.5 Prairie Island Nuclear Generating Plant

Review of Prairie Island Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for SGS	Disposition for SGS SAMA List
9	Analyze Room Heat-up for Natural/Forced Circulation (Screenhouse Ventilation)	This SAMA was developed to support the use of alternate room cooling in the plant's screenhouse when normal cooling fails. The SGS SAMA list includes SAMAs to implement alternate room cooling (opening doors) for those areas in which room cooling is important (SAMAs 1, 17)	Already included
22	Provide Compressed Air Backup for Instrument Air to Containment	The instrument air system is modeled for SGS, but as it is a robust design with inter-unit cross-tie capability, it is not an important contributor to plant risk.	Not required for the SAMA list

E.5.1.3.6 Wolf Creek Generating Station

Review of Wolf Creek Generating Station Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for SGS	Disposition for SGS SAMA List
2	Modify the Controls and Operating Procedures for Sharpe Station to Allow for Rapid Response	This is a site specific SAMA that was developed to allow the Wolf Creek operators to control a local diesel generating station from the Wolf Creek main control room. This SAMA is not applicable to SGS.	Not required for the SAMA list
4 (case 2)	Update emergency procedures to direct local, manual closure of the RHR EJHV8809A and EJHV8809B valves if they fail to close remotely	This SAMA was developed to address questions about the ability of MOVs to close against the differential pressure in a specific ISLOCA sequence for Wolf Creek. This SAMA is not applicable to SGS.	Not required for the SAMA list
5	Enhance procedures to direct operators to open EDG Room doors for alternate room cooling	This action was identified for SGS as part of the PRA importance list review and is included as SAMA 17.	Already included

Review of Wolf Creek Generating Station Cost Beneficial SAMAs

Industry Site SAMA ID	SAMA Description	Discussion for SGS	Disposition for SGS SAMA List
1	Permanent, Dedicated Generator for the NCP with Local Operation of TD AFW After 125V Battery Depletion	This was designed to assist in an SBO that included a seal LOCA. The design includes a 4kV, 500kW EDG to power a charging pump and transformer to support the 125V battery chargers. This type of change, modified to meet the needs of SGS, was identified as part of the PRA importance list review (SAMA 5).	Already included
3	AC Cross-tie Capability	This SAMA is designed to improve AC crosstie capability. For SGS, this type of enhancement was identified based on the plant specific PRA results review (SAMA 3).	Already included
13	Alternate Fuel Oil Tank with Gravity Feed Capability	For Wolf Creek, fuel oil failures contributed significantly to the CDF and an alternate method to transfer fuel to the EDG day tank was determined to be cost effective. The diesel fuel oil system is modeled for SGS, but the most important issue for SGS is that the “C” EDG does not have its own fuel oil transfer pump. This is addressed by SAMA 4.	Not required for the SAMA list
14	Permanent, Dedicated Generator for the NCP, one Motor Driven AFW Pump, and a Battery Charger	This was designed to assist in an SBO that included a seal LOCA. The design includes a 4kV, 500kW EDG to power a charging pump, an AFW pump, and a transformer to support the 125V battery chargers. This type of change, modified to meet the needs of SGS, was identified as part of the PRA importance list review (SAMA 5).	Not required for the SAMA list

E.5.1.3.7 Industry SAMA Identification Summary

The important issues for SGS are generally considered to be addressed by the SAMAs developed through the PRA importance list review. The plant changes suggested as part of that review were developed to meet the specific needs of the plant such that those SAMAs are more likely to provide effective means of risk reduction than SAMAs taken from other sites. However, effort was made to review other industry SAMA analyses to determine if other sites identified plant changes that could be cost beneficial for SGS based on modeling differences or other factors. For SGS, no additional SAMA candidates were identified based on a review of selected industry analyses.

E.5.1.4 SGS IPE

The SGS IPE 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.

The following table summarizes the status of the potential plant enhancements resulting from the IPE processes and their treatment in the SAMA analysis:

Status of IPE Plant Enhancements

Description of Potential Enhancement	Status of Implementation	Disposition
Install an isolation valve in the Demineralized Water line on the 84 foot elevation of the Aux Building	Implemented	No further review required
Revise SGS procedures to ensure that ISLOCA events in the RHR system are correctly diagnosed and treated as ISOLCA events	Implemented	No further review required
Initiated general improvements to ISLOCA procedures	Implemented	No further review required

All of the plant changes suggested in the IPE have been implemented at SGS and no further review of these items is required.

E.5.1.5 SGS IPEEE

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

The following table summarizes the status of the potential plant enhancements resulting from the IPEEE processes and their treatment in the SAMA analysis.

Status of IPEEE Plant Enhancements

Description of Potential Enhancement	Status of Implementation	Disposition
Control transient combustibles in the turbine and service building areas near redundant OSP cables and employ compensatory measures during periods of fire suppression system unavailability	Implemented	No further review required
Address water ingress pathways for external flooding events: 1) conduit penetrations, 2) inadvertent open door between service building and aux building, 3) leakage through seal between the containment and inner penetration area.	Partially implemented (item 1 only)	Improvement of the remaining ingress pathways has been correlated to PACRs of only $16,000 each in section E.5.1.6.4. Excluded from further review
Increase the seismic capacity of the masonry wall in the 4kv switchgear room at elevation 64 ft.	Subsequent analysis determined that the wall did not to represent a credible seismic interaction source to the switchgear. Not implemented	The determination that the wall does not represent a credible seismic interaction source is considered to be adequate justification to exclude this from further review.

E.5.1.5.1 Post IPEEE Site Changes

In addition to performing a review of the IPEEE results, it was necessary to review the changes to the site and surrounding area that were implemented after the completion of the IPEEE to determine if the changes could impact the conclusions of the external events analyses. The approach taken is to identify changes that could have a net increase on site risk and develop SAMAs to address those risks, if necessary. No credit is taken for changes that would reduce risk.

The SGS PRA group identified several changes that have been made to the site since the completion of the IPEEE, but the only changes with the potential to impact risk ina negative manner include:

- Installation of security enhancements.

- Installation of additional bullet resistant enclosures
- Installation of additional fencing

- Addition of the spent fuel storage facility
- Replacement of CO2 fire protection with water sprinkler systems

These changes are discussed in further detail below.

E.5.1.5.1.1 Security Changes

The security changes would not impact the fire, seismic, external flooding, transportation and fixed facility risk, or “other” external events. The only external event initiator relevant to SGS that could potentially be impacted is the high winds risk. However, the bullet resistant enclosures are judged to be secure structures that would not introduce wind generated missiles. Also, failure of the enclosures, themselves, would not impact plant operations.

There is a potential for the material in the security fences to become wind generated missiles, but these materials are bounded by a design basis wind generated missile (utility pole, 13.5 inch diameter, 35 feet long, 1490 lb., traveling at 0.4 of tornado speed) and do not pose a threat to the site’s safety structures. It is possible that the fences could be displaced by a high wind event and impede access to areas that require entry by the operators, but the security fences are not unlike existing fences in the switchyard and they would not pose a unique challenge to the site.

In conclusion, the addition of the security enhancements did not impact the results of the IPEEE and no SAMAs are required to address the security related changes.

E.5.1.5.1.2 Spent Fuel Storage Facility

The spent fuel storage facility is a large concrete pad that is separated from the site’s safety structures. The addition of the spent fuel storage facility would not impact the on-line plant risk for fire, seismic, external flooding, transportation and fixed facility risk, or “other” external events. It is possible an event could occur with one of these initiators that would result in a leaking storage cask, but NUREG 1864 (NRC 2007a) estimates the probability of a latent cancer fatality from a fuel storage site to be 1.8E10-12 during the first year of service, and 3.2E10-14 per year during subsequent years of storage. The NUREG 1864 analysis is not an SGS specific study, but it is a good indicator that the risk associated with a leak of one of the casks is low compared with the on-line power generation risk. With respect to the potential for the cask to become a wind generated missile that could impact the plant, NUREG 1864 estimates that wind speeds of 400 mph would be required to slide the cask on the storage pad and over 600 mph to even tip the case over, which excludes this type of event from further consideration.

No SAMAs are suggested to address any risk associated with the spent fuel storage facility.

E.5.1.5.1.3 Replacement of CO2 Fire Suppression with Water Sprinkler Systems

SGS replaced the CO2 suppression systems in the following rooms with water sprinkler systems:

- 460V AC Switchgear Rooms
- 4160V AC Switchgear Rooms
- Lower Electrical Penetration Area

The differences between the CO2 suppression system and the water sprinkler systems are both beneficial and detrimental to the CDF, depending on which factor dominates the fire scenarios. As discussed in Section E.4.6.2.1, the CDFs for the fire areas identified above were reviewed and updated to reflect the impact of the new fire suppression system (new fire CDF = 3.8E-05/yr).

E.5.1.6 Use of External Events in the SGS SAMA analysis

An effort was also made to use the IPEEE to develop new SAMAs based on a review of the original results. However, the SGS 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 cannot be "quantified" 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. Therefore, the external events models are considered to be useful tools for identifying important accident sequences and mitigating equipment, but any quantitative results should not be directly combined with those from the internal events models due to the differences in the modeling characteristics. In this analysis, external events contributions are estimated for the reasons described above.

The IPEEE was used in the SGS 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 SGS external events analysis were identified by Supplement 4 of Generic Letter 88-20 (NRC 1991) and included:

- Internal Fires
- Seismic Events
- High Wind Events
- External Flooding and Probable Maximum Precipitation
- Transportation and Nearby Facility Accidents

The generic letter also required that a review be performed to identify other types of potential hazards that could impact the plant to confirm that no plant specific issues were excluded by the IPEEE that could initiate severe accidents at SGS. The SGS IPEEE indicates that the guidance in NUREG-1407, NUREG/CR-5042, and NUREG/CR-2300 was used to identify other potential IE types that could impact safe operation of site, which were organized into the following categories for evaluation:

- Transportation and Nearby Facility Accidents

- External Floods (e.g., wind, precipitation, tide, and wave effects)
- Reduction of Secondary Heat Sink (e.g., low river level, ice blockage, detritus)
- High Winds and Tornadoes (e.g., wind and missile effects)
- Internal Fires
- Severe Weather Storms
- Severe Temperature Transients
- Internal Flooding
- Avalanche, Landslide, and Volcanoes
- Lightning
- External Fires
- Release of On-site Chemicals
- Seismic Events
- Soil Failure
- Turbine Missiles
- Extraterrestrial Activity

These potential contributors were evaluated using a progressive screening approach, per NUREG-1407, which resulted in the designation of seven initiators for more detailed analysis:

- Internal Fires (Section E.5.1.6.1)
- Seismic Events (Section E.5.1.6.2)

- High Wind Events (Section E.5.1.6.3)
- External Flooding and Probable Maximum Precipitation (Section E.5.1.6.4)
- Transportation and Nearby Facility Accidents (Section E.5.1.6.5)
- Release of On-site Chemicals (E.5.1.6.6)
- Detritus (E.5.1.6.7)

The type of information available for the initiators that were evaluated by SGS varied due to the manner in which they were addressed in the IPEEE. For instance, the fire analysis used an approach that combined the deterministic evaluation techniques from the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology with classical PRA techniques. A full seismic PRA was performed, but a progressive screening approach was employed to address the other external events contributors that were considered to be applicable to the site. While CDF results are available for the fire and seismic PRAs, the results of these 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.

E.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 SGS Fire Model shares many of the same characteristics as the IPE internal events model and for SGS, CDF results are available for the unscreened fire compartments. While this is true, limitations on the state of technology produce results that are potentially 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.

The SGS modeling strategy makes use of PRA techniques, but the plant response model is not up to date nor is the fire modeling methodology. As a result, there are some factors that make it undesirable to use the CDF results directly with the internal events results. The following table summarizes these issues. In addition, the fire model is not integrated with a Level 2 or a Level 3 analysis, which prevents the evaluation of accident consequences in a manner consistent with the process used for the internal events models.

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. The SGS IPEEE was developed prior to the release of these updated IE frequencies.
System Response:	Many IPEEE fire models assume balance of plant systems are not available in fires due to lack of cable tracing information for those systems. For SGS, this information was available for the fire analysis and these systems were credited when not damaged by fire.
Sequences:	Sequences in the SGS fire model are defined in detail. The consequences of any sequence collapsing is likely minor.
Fire Modeling:	There are several assumptions that were made in the IPEEE that could be considered to be conservative, including the following: • All equipment in a cabinet is damaged for any fire within a cabinet, regardless of whether it is suppressed. • Compressor fires are assumed to be like pump fires, and pump fires are modeled as liquid spill fires. • If any ambiguity existed about equipment damaged by a fire, the worst case was assumed. • An entire 4kV electrical division was assumed to be unavailable for the quantification of some fire damage states when in fact only a portion of components relying on that division were disable by the fire. • Relay room fires involving fixed ignition sources were modeled with two conservatively selected fire damage stated based on conservative modeling of fire propagation from electrical cabinets.

PRA Topic	Comment
HRA:	There is little industry experience with crew actions under conditions of the types of fires modeled in fire PRAs. This has generally led to conservative characterization of crew actions in fire PRAs. For SGS, the assumptions used in the HRA are similar to some of the methods being employed in current screening methodologies. However, the IPEEE did assume that fires did not impact the HEPs for actions taken in the MCR when all instrumentation/indication was available to make the appropriate EOP decisions.
Level of Detail:	Many fire PRAs may have reduced level of detail in the mitigation of the initiating event and consequential system damage; however, the SGS model includes a detailed assessment of the impacts of the initiating events, consequential fire damage, and the subsequent response of the plant.
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.

While there are both conservative and potentially non-conservative factors included in the IPEEE Fire model, the IPEEE is still judged to include more conservative bias than an internal events model. In addition, an attempt has been made to eliminate the potentially non-conservative assumptions that were made in the IPEEE related to cable wrap effectiveness, as described in section E.4.6.2.1. Even with this treatment, the total External Events CDF is comparable to the current internal events CDF. As a result, no additional effort has been expended to justify a reduced Fire CDF to support a lower External Events multiplier.

The approach taken to identify potential fire-related SAMAs using the IPEEE (and some of the Interim SGS Fire Model results) was to review the fire compartments with potential averted cost-risks (PACRs) greater than the minimum expected SAMA implementation cost of $50,000. The fire area PACRs were estimated by distributing the External Events PACR among the fire areas based on their CDF contribution to the total External Events CDF. Review of additional fire scenarios is possible, but it is unlikely that any potentially cost beneficial SAMAs would be identified. Even if a cost beneficial SAMA were to be identified for scenarios with PACRs below $50,000, the averted cost-risk would be small (below $50,000) by definition and would not be a priority for implementation at the site. Consequently, the review effort for this analysis is limited to the fire scenarios with PACRs greater than $50,000.

The fire CDFs used to develop the fire scenario PACRs are based on the IPEEE CDF estimates, updated to address the replacement of the CO2 suppression systems with water sprinkler systems, as described in Section E.4.6.2.1. These results are presented below for the top 10 contributors, the top 9 of which have PACRs greater than $50,000.

Fire Area	DESCRIPTION	CDF (/yr)	% of Fire CDF	Compartment Fire PACR
1FA-AB-84A	460V Switchgear Rooms	1.29E-05	33.9%	$2,035,006
1FA-AB-100A	Relay Room	7.20E-06	18.9%	$1,135,817
12FA-AB-122A	Control Rooms, Peripheral Room, and Ventilation Rooms	7.00E-06	18.4%	$1,104,267
1FA-AB-64A	4160 Switchgear Room	3.40E-06	8.9%	$536,358
1FA-EP-78C	Lower Electrical Penetration Area	3.20E-06	8.4%	$504,808
1FA-EP-100G/1F1-PP-100H	Upper Electrical and Piping Penetration Areas	1.30E-06	3.4%	$205,078
1FA-AB-84B	Reactor Plant Aux Equip Area	1.10E-06	2.9%	$173,528
12FA-SB-100/1FA-TGA-88	Turbine and Service Buildings	6.40E-07	1.7%	$100,962
12FA-SW-90A/90B	Service Water Intake	4.20E-07	1.1%	$66,256
1FA-AB-100C	Reactor Plant Aux Equip Area	2.90E-07	0.8%	$45,748

For each fire compartment with a PACR greater than $50,000, the contributing risk factors were reviewed determine what measures could be taken to mitigate the fire event and the corresponding core damage sequences. Further discussion is provided for each of these fire compartments below.

1FA-AB-84A: 460V Switchgear Rooms

The important fires in this room disable equipment from all three divisions, which complicates mitigation. Specifically, the fire induced loss 125V DC buses 1A and 1B in conjunction with damage to AOVs in the turbine driven AFW pump train force difficult local control actions. Procedures have been developed at SGS to provide RCP seal cooling using the PDP from the opposite unit in conjunction with electrical cross-ties and local operation of the turbine driven AFW pump, which is considered to be helpful in many scenarios. However, large contributors to the fire risk for the area also include random hardware faults of the turbine driven AFW train, which implies that an alternate means of providing SG makeup could further reduce risk. In order to address these types of scenarios where damage cuts across multiple divisions and systems, a “fire safe” system is suggested. A potential option would be to install two engine driven pumps that can be controlled locally to provide makeup to the RCS and steam generators. The RCS makeup pump would require a suction connection to the RWST and an injection connection through the safety injection lines (outside containment, but downstream of the MOVs). For the secondary side makeup pump, suction would be required from the fire water system and injection through the turbine driven pump line (SAMA 20).

<u>1FA-AB-100A: Relay Room</u>

Based on the IPEEE analysis, Relay Room fires are dominated by two fire damage states, 1RE1 and 1RE2.

The CDF for 1RE1 is 1.7E-6 and it is comprised of fires occurring in cabinets that are designed such that propagation is not credible (20 out of 68 cabinets, called Category I cabinets) and from fires in other cabinets (Category II and III cabinets) that are suppressed either by automatic or manual suppression actions or by self suppression. Cat III cabinets are open racks and the only suppression credit taken is for auto suppression.

1RE1 is a cabinet fire that does not propagate from the initiating cabinet and is assumed to result in the loss of a division of control power. The possibility of a hot short causing a spurious PORV opening is also considered and that introduces a Small LOCA for those scenarios, but the fraction of the CDF associated with the SLOCA scenario is small and not addressed further.

Based on the IPEEE fire modeling rules, auto suppression enhancements can not be assumed to prevent the damage that the initiating fire is assumed to cause. It may be possible to reduce the failure probability of the auto suppression system by locating the spray headers and detectors within the relay cabinets, but the CDF would not be impacted given that the equipment in the cabinet would still be damaged. Likewise, sealing the cabinets would not prevent damage to the equipment in the cabinet where the fire initiated.

The only potential means of reducing the 1RE1 CDF appears to preventing the fire from occurring, which could be addressed by the installation of incipient fire detectors. However, credit for these types of systems has not been accepted within the industry and there is no quantitative basis for reducing the CDF based on the use of incipient fire detectors.

Credit for the “fire safe” system would be difficult to justify given that 1RE1 already credits use of the Remote Shutdown Panel (RSP). If the operators fail to control the plant from the RSP where the controls and instrumentation are reasonably robust, human dependence issues would suggest that controlling the plant with locally operated diesel injection pumps would also be unsuccessful. No SAMAs are suggested to address the 1RE1 contributors.

1RE2 consists of fires in Cat II or III cabinets that are not suppressed; they are assumed to grow to the point where damage is extensive enough to force shutdown from the RSP (environmental issues are not the primary concern for these scenarios). The reliability of plant shutdown after MCR evacuation dominates the risk for these scenarios given that the failure probability used in the IPEEE is very high (8.7E-2). The IPEEE already credits multiple fire suppression options for the Cat II and III cabinets: self suppression for Cat II cabinets (0.69 probability that self suppression fails), manual suppression for Cat II cabinets (0.1 failure probability), and auto suppression for Cat II and III cabinets (5.0E-02 failure probability).

Sealing the Cat II and III cabinets appears to be a potential means of preventing most of the MCR abandonment cases for the Relay Room. Installation of automatic, within cabinet suppression is also a potential enhancement, but most of the credit would be obtained by sealing the cabinets to prevent fire propagation. Since sealing the cabinets would be required for within cabinet suppression, simply sealing the Cat II and III cabinets is considered to be the more cost effective solution (SAMA 21).

12FA-AB-122A: Control Rooms, Peripheral Room, and Ventilation Rooms

In the IPEEE, fire damage state CR1 contributed about 35 percent of the area's CDF and was driven by failure to restore switchgear room cooling after the fire. Procedures are available to open the switchgear room doors to provide alternate cooling and this scenario is no longer considered to be a major concern for this fire area.

Two other fire damage states, CR13 and CR 16, contribute an additional 46 percent of the CDF for this fire area. Both of these scenarios require abandonment of the MCR due to damage in the 1CC1, 1CC2, or 1CC3 consoles and are dominated by human errors at the remote shutdown panel.

As with the fires in the relay room cabinets, no potentially cost effective enhancements have been identified that could be credited to prevent damage to the equipment within the cabinet where the fire originates. As a result, no SAMAs are suggested to address the single panel fires, which include fire damage state CR13 (fire in 1CC3 with a CDF of 1.1E-06).

For fire damage state CR16, which includes the fires that propagate from any one of the three identified consoles to the other two, installation of fire barriers between the consoles could reduce the CDF by preventing propagation to the other panels (SAMA 22).

1FA-AB-64A: 4160 Switchgear Room

The largest contributors to the CDF for this area are scenarios originating in the 1A, 1B, and 1C 4kV switchgear. When the fire propagates, damage is assumed to occur to all three power divisions rather than just one and SBO conditions result. Separation should be maintained between the power divisions; cables and equipment should be protected by installing barriers or wrap to prevent the spread of a fire between the divisions (SAMA 23).

1FA-EP-78C: Lower Electrical Penetration Area

The most significant risk contributors arise from scenarios originating in the 1GP cabinet. This scenario represents a severe fire which damages overhead cable raceways carrying cables associated with steam generator level instruments (which auto actuate the AFS and are required for the operator to successfully initiate feed and bleed) and the PORVs. The specific combination of fire damage and random failures/operator errors leads to core damage. This type of scenario could be mitigated by installing a “Fire Safe” system with procedures that address plant operations when fires damage critical instrumentation (SAMA 20).

1FA-EP-100G/1F1-PP-100H: Upper Electrical and Piping Penetration Areas

Over 60 percent of all risk from this fire area is estimated to be related to fires in the 1B Ventilation 230V VCC, which fails the Unit 1 Chilled water system in addition to causing closure of multiple MSIVs and failing SG level indication for the 11(21) and 13(23) SGs. The primary concern with this fire is that if fails the CRE cooling source, which is assumed to force the operators to control the plant from the RSP after high room temperature causes to operators to abandon the CRE. This scenario is address by proceduralizing an alternate CRE cooling method (SAMA 1).

1FA-AB-84B: Reactor Plant Aux Equip Area

Fires in this area is dominated by fires in the AFW pumps themselves (over 66 percent of the CDF). These failures could be mitigates by providing an engine driven, high pressure makeup pump for the steam generators (located outside the AFW equipment area) (SAMA8).

12FA-SB-100/1FA-TGA-88: Turbine and Service Buildings

The largest contributor for this fire area does not represent any particular undue hazard or failure. The initiator is the ignition of a fixed combustible source with a failure of the PCS, which is not unlike a normal transient event. Given the loss of the PCS, AFW would have an elevated importance and SAMAs that improve AFW reliability would be helpful. For cases where initial AFW operation is successful, SAMA 7 would improve the reliability of providing a long term suction source for the pumps. In the event that the AFW pumps fail, SAMA 8 would provide an alternate pumping source for steam generator makeup.

12FA-SW-90A/90B: Service Water Intake

The fires in the Service Water Bays are driven by the fire induced and random Service Water pumps failures. If at least 2 Service Water pumps are not available for a unit (1 if non-essential loads are isolated), then the IPEEE assumed core damage would ensue. This did not account for currently proceduralized actions to mitigate loss of SW initiators.

Currently, at least two different proceduralized paths are available to SGS operators to mitigate loss of SW events in a fire:

1. Align a centrifugal charging pump to the demineralized water system for alternate pump cooling and align alternate Control Room Envelope cooling from the opposite unit (for any initiator).

2. Cross-tie SW to the opposite unit (only directed for fire initiators).

If these actions are credited for the fire analysis, the PACR for fire area 12FA-SW-90A/90B would be reduced to below the $50,000 review threshold and no SAMAs would be required to address the fire based risk. For example, even if the failure probability of the operator action to perform the SW cross-tie were as high as 0.1, the PACR would be reduced to $6,626 and further efforts to reduce the fire area 12FA-SW-90A/90B would not be cost beneficial.

E.5.1.6.2 Fire SAMA Identification Summary

Based on the review of the SGS fire area results, four unique SAMAs have been identified as potentially cost beneficial methods of reducing fire risk:

- Fire Safe System (SAMA 20)
- Seal the Category II and III Cabinets in the Relay Room (SAMA 21)

- Install Fire Barriers between the 1CC1, 1CC2, and 1CC3 Consoles in the CRE (SAMA 22)

- Install Fire Barriers and Cable Wrap to Maintain Divisional Separation in the 4160V AC Switchgear Room (SAMA 23)

These SAMAs have been added to the SGS SAMA list.

E.5.1.6.3 Seismic Events

In response to Generic Letter 88-20, Supplement 4 (NRC 1991), PSE&G prepared a seismic PRA (SPRA) to asses seismic risk at the site. The SPRA considered site specific seismic event frequencies in conjunction with the plant specific response that is based on the SGS IPE risk model. The IPEEE quantified results using the seismic hazard curves developed by both Lawrence Livermore National Labs (NRC 1994) and EPRI (EPRI 1989), but while the SGS IPEEE indicated that the EPRI results were believed to be more realistic, the SGS SAMA analysis uses the results based on the LLNL curves.

The approach taken by SGS to identify potential seismic-related SAMAs was to review the seismic contributors with PACRs greater than the minimum expected SAMA implementation cost of $50,000. The seismic PACRs were estimated by taking the external events PACR and distributing it among the seismic sequences based on the seismic sequence CDFs relative to the total External Events CDF. Review of additional seismic sequences is possible, but it is unlikely that any potentially cost beneficial SAMAs would be identified. Even if a cost beneficial SAMA were to be identified for SDS with PACRs below $50,000, the averted cost-risk would be small (below $50,000) by definition and would not be a priority for implementation at the site. Consequently, the review effort for this analysis is limited to those SDS PACRs that are $50,000 or greater.

The CDFs used to develop the seismic PACRs are based on the LLNL seismic hazard curves used in the IPEEE. The CDF results from that analysis are presented below for the top 7 seismic contributors; the top 6 have PACRs that are greater than $50,000 and the last has a PACR of about $46,000, which was considered to be close enough to the $50,000 review threshold to be included.

SGS Seismic Sequence Summary

Sequence	DESCRIPTION	CDF (/yr) (LLNL Curves)	% of Seismic CDF	Seismic Sequence PACR
17	OP	2.90E-06	30.6%	$457,482
33	OP-DAB	2.00E-06	21.1%	$315,505
31	OP-SW	1.30E-06	13.7%	$205,078
35	OPIC	1.20E-06	12.6%	$189,303
34	OP-DAB-DG	7.70E-07	8.1%	$121,469
17F	OP	5.40E-07	5.7%	$85,186
21F	OP-FW-FC	2.90E-07	3.1%	$45,748

For each of the top seismic sequences, the contributing risk factors were reviewed to determine what measures could be taken to mitigate the seismic event and the corresponding core damage evolution. Further discussion is provided for each of these sequences below.

<u>17 OP: Offsite Power</u>

Seismic sequence 17 OP results in a seismically induced loss of offsite power generally caused by failure of the switchyard ceramic insulators, combined with non-seismic failure of the diesels and associated support systems.

The ceramic insulators could potentially be replaced with more durable insulator designs, but the switchyard would probably remain a weak point even after upgrades. More effective solutions would include changes to improve the on-site AC supply or to improve the site's ability to cope with a long term loss of power.

- Seismic Safe System: Providing a pair of engine driven injection pumps that would be available in a seismic event is a potential means of mitigating seismically induced

SBO conditions. The RCS makeup pump would require a suction connection to the RWST and an injection connection through the safety injection lines (outside containment, but downstream of the MOVs). For the secondary side makeup pump, suction would be required from the fire water system and injection through the turbine driven pump line. This SAMA was identified for the Fire contributors and has been combined with the requirement that the pumps be seismically qualified and stored in a seismically qualified area so that it can address both types of initiating events (SAMA 20).

- Portable Generator: For long term SBO scenarios, AFW operation can be extended by powering the station battery charger with a 460V AC generator. Primary side makeup could be provided by a PDP if it was replaced with an air cooled model that is capable of a flow rate of about 300-350 gpm (addresses most of RCP seal LOCA risk). It is necessary to replace the PDP because it relies on CCW for cooling (a 4kV load) and the flow rate is not large enough to provide makeup for the larger seal LOCAs. Requiring the new equipment to be seismically qualified (enhancement over characteristic used for identification in the Level 1 model) would improve the probability that would be available for seismic events (SAMA 5).

33 OP-DAB

Seismic sequence 17 OP results in a loss of offsite power and failure of battery trains A&B (caused by failure of the masonry block walls around the batteries), leading to failure to start of DG “A” and “B”, and of the fuel oil transfer pumps. This results in the eventual loss of DG “C” leading to SBO.

These sequences can be mitigated by providing a means of allowing the plant to operate in SBO conditions. As identified for sequence 17 OP, SAMAs 5 and 20 would provide some benefit for these scenarios.

In addition, the IPEEE identifies that the fuel oil transfer pumps would be unavailable due to failure of the “A” and “B” power sources. Adding a new, alternate method of supplying fuel to the “C” EDG day tank could reduce the risk associated with these failures. The most cost effective option would likely be to obtain a portable, engine driven fuel transfer pump that could be used to fill the "C" day tank in the event that the normal pumps are unavailable (SAMA 4).

The battery failures could also be addressed directly by replacing or strengthening the masonry block walls around the "A" and "B" station batteries (SAMA 25).

31 OP-SW

Seismic sequence 31 OP-SW results in a loss of offsite power and seismically induced failure of the SW system, which leads to a loss of diesel generator jacket cooling water and SBO.

These sequences can be mitigated by providing a means of allowing the plant to operate in SBO conditions. As identified for sequence 17 OP, SAMAs 5 and 20 would provide benefit for the loss of power conditions, but just as importantly, the loss of SW conditions.

For non-seismic loss of SW events, the inter-unit cross-tie is considered to be a viable means of providing alternate SW flow; however, for a seismic event, the similarity of the SW systems for the two units would force an assumption of failure correlation, which would imply that the opposite unit's SW systems is also failed.

SAMAs 5 and 20 are considered to be the most appropriate to address the challenges posed by this sequence.

35 OP-IC

Seismic sequence 35 OP-IC results in a loss of offsite power and seismic failure of instrumentation and control capability and equipment (ceiling grid collapse) in the main control room.

Failure of the MCR ceiling grid is assumed to injure the plant operators, so while the RSP is available for plant control, it is not credited due to the lack of capable operators. Strengthening the MCR ceiling is considered to be the most effective means of reducing the risk posed by these scenarios (SAMA 26).

34 OP-DAB-DG

Seismic sequence 17 OP results in a loss of offsite power and failure of battery trains A&B (caused by failure of the masonry block walls around the batteries), leading to failure to start of DG “A” and “B”, and of the fuel oil transfer pumps. Battery train “C” is more seismically durable than the “A” and “B” trains, but in this sequence, the “C” train fails as well. This results in an SBO.

These sequences can be mitigated by providing a means of allowing the plant to operate in SBO conditions. As identified for sequence 17 OP, SAMAs 5 and 20 would provide some benefit for these scenarios.

SAMA 25 may provide some benefit, but even if the block walls are strengthened around the “A” and “B” batteries, if the “C” battery is failed, then the “A” and “B” batteries may be failed for reasons other than interaction with the block walls and the changes may not mitigate this sequence.

17F OP: Offsite Power

Seismic sequence 17F OP is the same as 17 OP, but the containment fan coolers also fail. This sequence results in a seismically induced loss of offsite power generally caused by failure of the switchyard ceramic insulators, combined with non-seismic failure of the diesels and associated support systems. Failure of the containment fan coolers removes the ability to remove containment heat such that containment overpressurization would occur if other means were not used to provide containment cooling.

The same SAMAs applicable to sequence 17 OP are considered to be applicable here to reduce the risk of CDF. Providing a means of removing primary side heat through the secondary side is considered to be the best way to keep containment pressure down.

21F OP-FW-FC: Offsite Power

Seismic sequence 21F OP results in a seismically induced loss of offsite power. This is generally caused by failure of the switchyard ceramic insulators combined with non-seismic failure of the diesels and associated support systems. Failure of AFW is also a contributor for this sequence and is dominated by the seismically induced failure of the AFWST. Finally, failure of the containment fan coolers removes the ability to remove containment heat such that containment overpressurization would occur if other means were not used to provide containment cooling.

This sequence is similar to 17F OP with the additional failure of the AFWST, which forces alignment of AFW to the Fire Water header for continued success. A new SAMA, which is the combination of SAMAs 5 and a simplified alignment design for alternate AFW pump suction, has been added to the SAMA list to address this contributor (SAMA 27).

Seismic SAMA Identification Summary

Based on the review of the SGS SDS results, three unique SAMAs have been identified as potentially cost beneficial methods of reducing seismic risk:

- Strengthen masonry block walls around the “A” and “B” Station Batteries (SAMA 25)
- Strengthen the MCR Ceiling (SAMA 26)
- Use of 460V AC Generator for AFW and OSP Recovery Support with Air Cooled PDP and Simplified Connection of AFW to Alt Suction Header (SAMA 27)

E.5.1.6.4 High Wind Events

The approach taken to analyze the high wind, flood, and “other” external event risk in the SGS IPEEE was to implement a progressive screening approach. The process included a review of SGS specific hazard data and licensing basis and verification that the SGS design met the 1975 SRP criteria. An affirmative determination that the 1975 SRP screening criteria were met resulted in the screening of the hazard on the basis that conformance to the SRP met the IPEEE screening criterion. Those hazards that could not be screened based on conformance to the 1975 SRP criteria were analyzed in more detail.

For the SAMA analysis, this process is considered adequate for screening events that do not pose a credible threat to plant operations. However, any issues that could impact plant safety are reconsidered to determine if the development of a SAMA is appropriate to address the risk.

Based on the review performed at the site, it was determined that the plant safety equipment was not vulnerable to the effects of high winds; however, some issues were noted during the analysis:

- The control room has dampers that will close on negative pressure, but they are not tornado proofed. Should the dampers fail to re-open, the IPEEE indicates that alternate room cooling procedures would be used.
- It was determined that the lightning mast on the Reactor Building could fail on the Auxiliary Building in a high wind event, but the lightning mast was bounded by a design basis tornado missile and it was considered to no pose a threat to the structure.
- The Unit 2 hydrogen tank racks were of a design that would not always secure the tanks when one or more of the tanks were removed from the rack, which could introduce a wind generated missile threat. This issue was resolved by changing the design to be consistent with the Unit 1 racks, which secure each tank individually.
- The Unit 1 EDG ventilation intake and exhaust penthouse were determined not to be protected by missile barriers. Given that the frequency of missile impact (not CDF) was determined to be only 3.0E-07 per year, the issue was screened from further review. Even if the conditional core damage probability for this missile strike was 1.0, the corresponding PACR would only be about $50,000. The Unit 2 EDG exhaust penthouse is protected by missile barriers.
- The RWST and AFST are not surrounded by dikes and could be susceptible to wind generated missiles. The IPEEE calculated “bounding” CDFs for these scenarios and determined that they were below the IPEEE screening criterion of 1.0E-06 per year

and were eliminated from further review. While the CDFs were not provided explicitly, the missile strike frequency is expected to be similar to what was documented for the EDG exhaust penthouse (3.0E-07 per year). The size of the tanks would make the strike frequency larger, but even if it was estimated that the size of the tanks increased the strike probability by a factor of 10, consideration of the conditional probability of critical tank damage on a strike and the conditional core damage probability given tank damage would likely reduce the CDF below 3.0E-07 (the IPEEE indicates that the CCDP for RWST failure is only 8.0E-03). No SAMAs are suggested to address this issue.

- The IPEEE identified a potential scenario in which an EDG fuel oil storage tank, which is located outside and within a dike, could be damaged by a wind generated missile. However, the IPEEE indicates that procedures exist to provide continuous resupply of the EDG day tanks by outside sources in the event that the fuel oil storage tank is damaged and that the scenario is screened from further review. Even if the procedures to resupply the EDG fuel oil supply are neglected, the frequency of a missile strike and tank damage appear to be similar to what is described above for the RWST and AFST. Given that procedures exist to resupply the EDG day tanks and the frequency of a strike and consequential critical tank damage appears to be in the range of 3.0E-07 per year (corresponds to a PACR of about $50,000), no SAMAs are suggested for this scenario.

In conclusion, no high wind related SAMAs are required for SGS.

E.5.1.6.5 External Flooding and Probable Maximum Precipitation

Site flooding at SGS is addressed by the probable maximum hurricane surge coincident with wave run-up, tide, hurricane location, and wind direction. The IPEEE indicates that the external flooding risk assessment consisted of the following:

- A walkdown for the purposes of discovering paths of significant water ingress into safety related structures owing to severe storm induced floods.

- A hazard analysis that estimated the frequencies of various flood levels at the site.

- An analysis to bound core damage frequency using event trees to develop and quantify flood induced scenarios that could lead to core melt.
- An analysis that shows the risk reduction effect of the PSE&G program to improve penetration plugging material for penetrations leading into the Auxiliary Building from the Service Building.

The walkdown identified four types of water ingress paths into the Auxiliary Building:

1. Through conduit and penetrations that are unplugged, have plugs that leak, or have plugs that blow out owing to hydrostatic pressure.
2. Through inadvertently left open flood doors separating the Service Building from the Auxiliary Building.
3. Through the rubberized fabric membrane that seals the gap between the containment and inner penetration areas.
4. Direct in-leakage through wall and floor cracks.

Ingress path 1 was estimated to have a corresponding CDF of about 1.0E-04 per year until the PSE&G penetration improvement program was implemented to address the issue. After seal improvements, the IPEEE indicates the CDF was estimated to be about 1.0E-07 per year, which corresponds to a PACR about $16,000. No SAMAs are required to address this flooding pathway.

The CDF for ingress path 2 was evaluated in the IPEEE and screened from further review given that the estimated CDF of 1.0E-07 per year was below the IPEEE CDF screening criterion of 1.0E-06 per year. As described for ingress path 1, a CDF of 1.0E-07 per year correlates to a PACR of about $16,000. As a result, this flood pathway is screened from further review.

The CDF for ingress path 3 was evaluated in the IPEEE and screened from further review given that the estimated CDF of 1.0E-07 per year was below the IPEEE CDF screening criterion of 1.0E-06 per year. As described for ingress path 1, a CDF of 1.0E-

07 per year correlates to a PACR of about $16,000. As a result, this flood pathway is screened from further review.

The CDF for ingress path 4 was evaluated in the IPEEE and screened from further review given that the CDF was considered to be negligible. For the SAMA analysis, the same assumption is made.

In addition, probable maximum precipitation events were examined for the site and the safety structures were determined not to be vulnerable to stresses related to “ponding” or snow accumulation.

Given the low potential for identifying cost beneficial SAMAs to mitigate risk posed by external flooding, no further efforts were made in the SAMA analysis to develop SAMAs related to external flooding events.

E.5.1.6.6 Transportation and Nearby Facility Accidents

Transportation and nearby facility accidents were included in the SGS IPEEE to account for human errors or equipment failures that may occur in events not directly related to the power generation process at the plant. The types of hazards considered for analysis included:

- Transportation Accidents
    - Accidental Aircraft Strike
    - Road and Rail
    - River shipping
- Fixed Facility Accidents
    - Industrial Facilities
    - Military Facilities

- Pipeline Accidents

It is recognized that the types of credible threats to nuclear facilities by aircraft have changed since the time the IPEEE was published. While this is true, efforts are underway within the industry to address this issue in conjunction with other forms of sabotage. Based on the fact that this topic is currently being analyzed in another forum and due to the complexity of the issue, intentional aircraft impact events are considered to be out of the scope of the SAMA analysis. Accidental aircraft impact was reviewed in the IPEEE and a previous analysis was cited that estimated the frequency of a strike with a potential for causing radiological consequences in excess of the exposure guidelines of 10CFR100 was 6.7E-08 per year. Even if the conditional CDF is assumed to be 1.0 after an aircraft impact, the CDF is 567 times less than the modified internal fire CDF of 3.8E-05 per yr and over 738 times less than the current internal events CDF (4.95E-05 per yr). If the same process used in Section E.5.1.6.1 to estimate the fire area PACRs is used for the accidental aircraft impact PACR, an aircraft strike CDF of 6.7E-08/yr can be correlated to a cost-risk of about $11,000 (assuming a 1.0 conditional core damage probability). Given the relatively low risk of aircraft impact compared with fire risk, no further efforts were made in the SAMA analysis to develop plant enhancements related to accidental aircraft protection.

The road and railway loading around SGS was analyzed for the IPEEE and it was determined that because no major highway or rail line was located with a 5 mile radius of the plant, the impact of any transportation accidents on those types of routes was negligible. No SAMAs are required to address these types of events.

Accidents from river traffic, including detonation of explosives and impacts with the Service Water intake structure, were examined in the IPEEE. While subsequent changes to the shipping procedures and exclusion zones have reduced the potential for these types of events to occur, the IPEEE concluded that the detonation of explosives related to river shipping would not threaten the integrity of the safety structures even under the conditions present during the performance of the IPEEE. In addition, the potential for an impact on the Service Water intake structure was estimated to be on the order of 1E-07 per yr and it was excluded from further review in the IPEEE. Given that the PACR associated with an event with a frequency of 1E-07 per yr is only about $16,000 (assuming core damage occurs at that frequency), no SAMAs are suggested to address river shipping hazards.

The fixed facility accidents, including pipeline breaks, industrial accidents, and accidents from nearby military bases, were reviewed in the IPEEE and it was determined that none of these elements posed credible threats to safe plant operation. There were no such facilities located within a 5-mile-radius of the site and the threats from these types of accidents were considered to be negligible. Given the low potential for identifying cost beneficial SAMAs to mitigate risk posed by the fixed facility accidents, no further efforts were made in the SAMA analysis to develop SAMAs related to these hazards.

E.5.1.6.7 Detritus

Detritus was also examined for SGS in the IPEEE given that the site had experienced problems due to mud and grass buildup on the Circulating Water system travelling screens. The IPEEE indicates that PSE&G has already made the following changes to protect the Circulating Water intake against detritus:

- Installation of blowdown fittings on screen wash headers.
- Installation of new screen wash pumps capable of digesting detritus. Replacement of stilling tubes and base plates.
- Upgrading screen wash pump motors and cables.
- Refurbishment of screen wash control panels to allow automatic screen wash operation.

In addition to these changes, the design of the Circ Water Travelling Screens has been changed and implemented for evaluation for some of the travelling screens (PSEG 2004b). The intent of this design change is to reduce the possibility that debris can bypass the travelling screens and enter the suction of the Circ Water pumps. Plant procedures have also been updated to monitor the pressure differential in the Circ

Water system water boxes and to initiate cleaning on high differential pressure (PSEG 2004b). Finally, additional pump vibration monitoring instrumentation has been installed for evaluation on the 13B Circ Water pump to determine if the data can be used to help identify conditions where water box clogging challenges safe pump operation (PSEG 2004b).

No additional, potentially cost beneficial changes to the Circ Water system have been identified for SGS.

The Service Water system also uses water from the Delaware River, but the low intake rates at the Service Water Intake Structure do not present the same challenges that exist for the Circ Water system. The IPEEE indicates that detritus had never affected the Service Water pumps nor was it expected to do so in the future.

The IPEEE indicates that a seismically induced detritus event, which could simultaneously clog the entire intake structure, was evaluated for the Salem site. The CDF for this type of event was estimated to range from about 5E-07/yr to about 9E-07/yr (PSEG 1996a). These CDFs correlate to a range of PACRs from about $82,000 to $142,000. Based on the information available in the IPEEE related to detritus events, no additional procedure enhancements that would significantly reduce risk have been identified, which would imply only hardware changes would be available to further reduce detritus risk. However, no credible, potentially cost beneficial SAMAs have been identified that would significantly reduce the risk of seismically induced detritus events.

E.5.1.6.8 "Other" Events

Because numerous hazardous chemicals are stored at, delivered to, and used at the SGS site, it was necessary to examine the impact of chemical releases on plant operations. The IPEEE indicates that SGS conforms to Regulatory Guide 1.78 and that control room habitability would not be impacted by any postulated accidents. No SAMAs are suggested.

E.5.2 Phase 1 Screening

The initial list of SAMA candidates is presented in Table E.5-3. The process used to develop the initial list is described in Section E.5.1.

The purpose of the Phase 1 analysis is to use high-level knowledge of the plant and SAMAs to preclude the need to perform detailed cost-benefit analyses on them. The following screening criteria were used:

- Applicability to the Plant: If a proposed SAMA does not apply to the SGS design, it is not retained. Similarly, any SAMAs that have already been implemented by PSE&G or achieve results that PSE&G has achieved by other means can be screened as they are not applicable to the current plant design. The use of these criteria is not often explicitly used in the Phase 1 analysis because the SAMA methodology generally precludes inclusion of such SAMAs; however, they are listed as a possible screening methods given that there may be circumstances in which a SAMA would be included in the list even if it is not relevant to the site. An example may be the inclusion of a high profile SAMA that is well known in the industry, but not applicable to the specific site design. Such a SAMA may be included for documentation purposes. Another example may be an unimplemented SAMA from the IPE that has been superseded by another plant enhancement.

- Implementation Cost Greater than Screening Cost: If the estimated cost of implementation is greater than the modified MACR (refer to Section E.4.6), the SAMA cannot be cost beneficial and is screened from further analysis.

Table E.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 passed to the Phase 2 analysis and evaluated in Section E.6. Table E.6-1 contains the Phase 2 SAMAs.

E.6 PHASE 2 SAMA ANALYSIS

The SAMA candidates identified as part of the Phase 2 analysis are listed in Table E.6-1. The base PRA model was manipulated to simulate implementation of each of the proposed SAMAs and then quantified to determine the risk benefit. In general, in order to maximize the potential risk benefit due to implementation of each of the SAMAs, the failure probabilities assigned to new basic events, such as HEPs, were optimistically chosen so as not to inadvertently screen out any potential cost-beneficial SAMAs. Also, any new model logic that was added to the PRA model in order to simulate SAMA implementation was also simplified and optimistically configured to achieve the same effect.

Determination of the cost-risk benefit for each of the Phase 2 SAMAs involved calculating what was known as the averted cost-risk, which was obtained by comparing the SAMA results with the base case MMACR value. This value is then compared with the cost of implementation to determine the overall net benefit. That is, the net value is determined by the following equation:

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

If the net value of the SAMA is negative, the cost of implementation is larger than the benefit associated with the SAMA and the SAMA is not considered cost beneficial. The baseline cost-risk of plant operation was derived using the methodology presented in Section E.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 1 and 2 analyses consist of SGS specific estimates developed by plant personnel. It should be noted that SGS specific implementation costs <u>do</u> include contingency costs for unforeseen difficulties, but do <u>not</u> account for any replacement power costs that may be incurred due to consequential shutdown time. Table E.5-3 provides implementation costs for each Phase 1 and Phase 2 SAMA.

The following sections describe the simplified cost-benefit analysis that was used for each of the Phase 2 SAMA candidates. It should be noted that the sum of the release category frequencies for the base SAMA case (4.95E-05 /yr) was chosen as the base CDF value against which all other modeled SAMAs were compared instead of the nominal Level 1 CDF value of 4.77E-05. This was due to the fact that all of the estimated MMACR results for each of the modeled SAMAs were based on summing all of the individual release category frequencies from the PRA cases. Therefore, this approach was viewed as more appropriate in obtaining the averted cost risk for each of the SAMAs.

It should be noted that Salem units 1 and 2 are essentially identical in design and operation. Such differences that do exist are not believed to be significant from a risk perspective. As such, the Unit 1 PRA model that was employed to evaluate each of the risk benefits and averted costs for each of the SAMAs was viewed as also being applicable to Unit 2. That is, if a particular SAMA proves cost beneficial for Unit 1, it will also likewise be cost beneficial for Unit 2.

E.6.1 SAMA 1: Enhance Procedures and Provide Additional Equipment to Respond to Loss of Control Area Ventilation

In the event that cooling to the control area is lost (including use of “maintenance mode” and “AB.CAV” modes of alternate control area cooling), the doors in the CRE, Rack Room, and Relay Room could be opened to establish a vent path and portable fans could be used to provide additional circulation. Portable duct connections could also be included in the design if necessary.

This SAMA proposes development of the analytical basis and creation of procedures to allow the use of existing fans or temporary fans as well as opening doors and/or using preinstalled connections to create a vent path between the control area and the outside which would be sufficient to limit control area temperatures, so that one or both units could be safely shut down upon a loss of control area cooling. The changes associated with this SAMA were simplistically modeled to maximize the possible risk benefit. The details are provided below.

Assumptions:

- It is assumed that the changes proposed would either be unsuccessful or would be significantly more difficult to implement during other initiating events such as LOCAs, SGTRs, etc. Therefore the changes are only evaluated for use in responding to initiating events which directly cause a loss of control area cooling.

E.6.1.1 Non-Fire Averted Cost-Risk

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA a new operator action, CAV_XHE_IMPROVE, was added below gate TVCS03. This represents a new proposed action to open doors and align fans as required to provide "open loop" ventilation of the control area. This action would require a number of steps to be taken outside of the main control room. A typical failure likelihood for an action described in those terms might be in the range of 1E-2. In this case a value of 2E-2 was used to allow for some amount of dependency with other operator actions which sometimes can occur in cutsets with CAV_XHE_IMPROVE.

Results of SAMA Quantification:

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	3.26E-05	54.59	$230,803
Percent Change	34.1%	30.2%	24.5%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	1.80E-05	2.97E-08	1.40E-07	2.01E-08	2.55E-06	1.98E-07	1.43E-06	**3.26E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.06	22.51	0.62	1.46	0.22	23.18	0.78	5.58	**54.59**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$292	$60,143	$2,393	$5,567	$732	$115,152	$6,385	$40,104	**$230,803**

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

SAMA 1 Non-Fire Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$11,980,724	$4,583,276

The results of the SAMA 1 quantification show a large reduction in the CDF risk metrics for SGS, and a corresponding decrease in the frequencies for certain release categories. The release categories that showed the largest decrease in frequency relative to CDF were those categories in which containment failure due to overpressurization resulted due to failure of the SGs to remove heat from the reactor coolant system.

E.6.1.2 Fire Averted Cost-Risk

This SAMA was specifically identified as an appropriate means of addressing the risk for fire area 1FA-EP-100G/1F1-PP-100H. Typically, a SAMA will provide some benefit for more than one fire area; however, this SAMA is focused on a specific scenario in which the fire damages components required for CRE cooling. No other fire areas have been identified for which this SAMA would be helpful.

It is assumed that if the portion of the SGS CDF related to the relevant SGS fire areas can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total PACR attributable to external events

- Determine the component of the external events PACR attributable to fire
- Determine the component of the fire PACR attributable to fire area 1FA-EP-100G/1F1-PP-100H
- Calculate the percent reduction in the fire area CDFs that would result if the SAMA is implemented and reduce the PACR for the fire area by the same percent. The reduction in the PACRs is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the SGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $8,282,000 for a single unit, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF can be estimated in several ways, but the distribution established in Section 4.6 to calculate the total External Events CDF is considered to be appropriate for SGS and is used here. Using that distribution, the fire CDF of 3.8E-05 per yr is estimated to be 72.4 percent of the total External Events CDF. The single unit fire contribution, therefore, corresponds to a PACR of $5,994,590.

The cost-risk associated with each fire area can then be determined based on their relative contributions to the total fire CDF and the assumption that the CDF is proportional to cost-risk (Fire CDFs are provided in Section E.5.1.6.1):

Fire Area	Percent of Fire Risk	Corresponding PACR (single unit)
1FA-EP-100G/1F1-PP-100H	3.4	$205,078

The risk reduction possible for this area is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. In this case, the SAMA is assumed to have a failure probability of 2.0E-02, as described for the internal events evaluation. This implies that the SAMA eliminates 98 percent of the risk from these sequences and correlates to a single unit averted cost-risk of $200,976.

E.6.1.3 Cost of Implementation

SGS estimated an implementation cost of $475,000 for a single unit.

E.6.1.4 Net Value

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation, where the total averted cost risk is the sum of the Non-Fire averted cost-risk and the fire averted cost-risk, or $4,784,252 ($4,583,276 + $200,976 = $4,784,252):

SAMA 1 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$4,784,252	$475,000	$4,684,252

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive, which implies that this SAMA is cost beneficial.

E.6.2 SAMA 2: Re-configure Salem 3 to Provide a More Expedient Backup AC Power Source for Salem 1 and 2

Currently the Gas Turbine Generator is only credited in the PRA model for use during grid LOOPs, losses of offsite power originating in the grid supplying Salem. This is because current design and procedures for use of the GTG (Salem Unit 3) direct a complicated series of alignments in the switchyard in order to route power back into the plant. If a loss of offsite power occurs because of problems in the switchyard, it may not be possible to route power back into the plant via the switchyard. During severe weather events it may be difficult or unsafe to undertake the local actions in the switchyard, of which there are several, required to route power back into the plant, so use of the GTG is not credited for those events. A SAMA is proposed to provide a more direct connection to the ESF buses, and enhanced procedures for its use, such that the gas turbine generator may be used during switchyard and weather related LOOPs.

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA, event G-PC-TE-GTG ("Plant-centered or severe weather LOOP prevents use of GTG") was deleted as an input into G1XM450 ("Other failure of GTG A and B engines"). Also %TEW (weather related loop) and %TES (switchyard loop) were removed as inputs into G1XM430 (GTG common or dependent failure). The effect was to allow the gas turbine to be credited for weather-related LOOPs and switchyard LOOPs the same as it is currently credited for grid LOOPs.

Results of SAMA Quantification:

Implementation of this SAMA yielded a slight reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.45E-05	70.54	$276,691
Percent Change	10.0%	9.8%	9.5%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	1.80E-05	2.97E-08	1.40E-07	2.01E-08	2.55E-06	1.98E-07	1.43E-06	**3.26E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.06	22.51	0.62	1.46	0.22	23.18	0.78	5.58	**54.59**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$292	$60,143	$2,393	$5,567	$732	$115,152	$6,385	$40,104	**$230,803**

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

SAMA 2 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$14,963,210	$1,600,790

The SAMA 2 results show about a 10% reduction in CDF, dose-risk and offsite economic consequences. With a unit implementation cost estimated at $875,000, the net value for this SAMA is $725,790 ($1,600,790 - $875,000), which implies that this SAMA is cost beneficial.

E.6.3 SAMA 3: Install Limited EDG Cross-Tie Capability Between Salem 1 and 2

For loss of offsite power scenarios with failure of all EDGs on a given unit, the EDGs on the opposite unit may be available but there is not currently a means of performing a cross-tie between the units in useful timeframe. Enhancing the plant so that a cross-tie can be made between the ESF buses on one unit and the adjacent unit would reduce the risk associated with LOOP scenarios. Ideally this crosstie would be implementable from the control room.

This SAMA proposes development of a plant modification which would allow an ESF bus on a healthy “donor” unit to be crosstied to supply a dead bus on an SBO unit. The changes associated with this SAMA were simplistically modeled to maximize the possible risk benefit. The details are provided below.

Assumptions:

- Since this proposed modification includes the capability to operate the crosstie from the control room, it was assumed that successful alignment of the crosstie could occur in time to allow restoration of RCP seal cooling or injection.

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA a new undeveloped basic event, "NEW_AC_SOURCE" was added below gates g01x110, g14a110, g14a110rbu4, g1ag110, g1ax110, and G4AS110. Each of these gates represents "Loss of all power to 1A 4KV vital bus" under slightly different conditions.

Adding NEW_AC_SOURCE represents the potential to crosstie a 4kV vital bus on one unit to the adjacent unit. This action would be relatively quickly and under conditions of some stress. In addition, there is some likelihood of a common-cause concern. If multiple EDGs on (for instance) unit 1 were to fail, it should be considered that a similar problem could occur simultaneously on unit 2. Therefore a probability of failure to crosstie, incorporating both hardware and operator action failures, of 0.05 was employed.

Results of SAMA Quantification:

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.18E-05	66.63	$262,968
Percent Change	15.5%	14.8%	14.0%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.21E-06	1.81E-10	9.89E-07	1.66E-08	2.72E-05	2.97E-08	1.94E-07	3.11E-08	2.55E-06	1.98E-07	1.39E-06	**4.18E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.04	34.05	0.62	2.02	0.34	23.18	0.78	5.43	**66.63**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$193	$90,988	$2,393	$7,703	$1,136	$115,147	$6,385	$38,989	**$262,968**

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

SAMA 3 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$14,169,520	$2,394,480

The SAMA 3 results indicate a relatively large reduction in CDF, dose-risk and offsite economic consequences. With the cost of implementation per unit being $4,175,000, the net value for this SAMA is -$1,780,520 ($2,394,480 - $4,175,000), which implies that this SAMA is <u>not</u> cost beneficial.

E.6.4 SAMA 4: Install Fuel Oil Transfer Pump on “C” EDG & Provide Procedural Guidance for Using “C” EDG to Power Selected “A” and “B” Loads

There are risk contributions from scenarios where the ability to crosstie power between ESF buses within a unit would be helpful. In addition, there are scenarios involving failures of A and B EDG fuel oil transfer pumps which result in loss of all power and core damage. Addition of a C EDG fuel oil transfer pump would reduce risk. This SAMA considers the addition of a C EDG fuel oil transfer pump and also the ability to crosstie any ESF bus to any other ESF bus within the same unit. An operator action failure probability of 0.1 is used to account for dependency with other actions and to recognize the fact that management of EDG loading would be demanding.

E.6.4.1 Non-Seismic Averted Cost-Risk

<u>PRA Model Changes to Model SAMA:</u>

Common-cause failure to start of fuel oil transfer pumps dominates failure of the fuel oil transfer system. Therefore the addition of a new “C” FOTP was approximated by adding a new common-cause failure to start of the A, B and proposed C FOTPs. ACP-MDP-FS-1DF99 was added below gates g14c232, g4cs232, g48x102, gfot102 such that failure of pumps A, B and C is required to fail fuel oil supply to the EDGs. A failure probability of 1E-2 was used to approximate both the failure to start and other failure modes such as failure-to-run of all three pumps. Note that failures to run can be expected to occur after the passage of time, thereby reducing their significance.

<u>Crosstie between ESF buses on same unit was modeled as follows:</u>

A simplified model of EDG A was constructed under gate DG_A_XTIE, which ORed ESF_XHE_XTIE (0.1) and G14A200, G14A160, DGS-DGN-TM-DG1A. Similar logic was constructed for B and C EDGs. DG_B_XTIE was constructed using ESF_XHE_XTIE G14B200, G14B160, DGS-DGN-TM-DG1B. DG_C_XTIE was constructed using ESF_XHE_XTIE, G14C200, G14C160 and DGS-DGN-TM-DG1C. Appropriate combinations of A, B and C crosstie logic were appended below relevant ESF buses. For instance, power to C ESF bus was modeled using DG_A_XTIE and DG_B_XTIE as inputs to gate G06X110, G14C110, G14C110RBU4, G1CX110, G1CX110RBU4 (was EQU made into AND), G48X950 (was EQU made into AND), G4CS110, and GF0T950 (was EQU made into AND). Power to A ESF bus was modeled using DG_B_XTIE and DG_C_XTIE as inputs to gates G01X110, G14A110, G14A110RBU4, G1AX110, G1AX110RBU4 (equ becomes and), G48X640 (EQU becomes AND), G4AS110, GFOT640 (EQU becomes and). Power to B ESF bus was modeled using DG_A_XTIE and DG_C_XTIE as inputs to G05X110, G14B110, G14C110RBU4, G1BX110, G1BX110RBU4, G48X320, G4BS110, and GFOT320.

<u>Results of SAMA Quantification:</u>

Implementation of this SAMA yielded a slight reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.18E-05	66.67	$263,240
Percent Change	15.5%	14.8%	13.9%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.21E-06	1.81E-10	9.89E-07	1.66E-08	2.72E-05	2.97E-08	1.94E-07	3.11E-08	2.55E-06	1.98E-07	1.39E-06	**4.18E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.04	34.05	0.62	2.02	0.34	23.18	0.78	5.43	**66.63**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$193	$90,988	$2,393	$7,703	$1,136	$115,147	$6,385	$38,989	**$262,968**

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

SAMA 4 Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
Salem Unit 1	$16,564,000	$14,179,592	$2,384,408

SAMA 4 results indicate a relatively large reduction in CDF, dose-risk and offsite economic consequences.

E.6.4.2 Seismic Averted Cost-Risk

This SAMA was specifically identified as a potential means of addressing the risk associated with seismic sequence 33 OP-DAB in section E.5.1.6.2, however, as described in Table E.5-3 for SAMA 25, further investigation at the plant revealed that the walls around the “A” and “B” station batteries are surrounded by poured concrete walls rather than the masonry block walls documented in the IPEEE. Consequently, the postulated interaction between the “A” and “B” station batteries does not exist and this type of contributor is considered to be negligible. The standard external events multiplier of two is considered to address any seismic based benefit for this SAMA.

E.6.4.3 Cost of Implementation

SGS estimated an implementation cost of $585,000 for a single unit.

E.6.4.4 Net value

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation, where the total averted cost risk is the sum of the Non-Seismic averted cost-risk and the Seismic averted cost-risk, or $2,384,408 ($2,384,408 + $0 = $2,384,408):

SAMA 4 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$2,384,408	$585,000	$1,799,408

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive, which implies that this SAMA is cost beneficial.

E.6.5 SAMA 5: Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries and Replace PDP with Air-Cooled Pump

For loss of offsite power scenarios with failure of all EDGs on a given unit, there are two mitigating functions which must be maintained: decay heat must be removed and, if seal injection or cooling is not maintained, RCS makeup may be required in event of a possible RCP seal LOCA. In addition the capability should be maintained to restore offsite power once it becomes available.

This SAMA proposes development of plant modifications which would allow decay heat removal to operate indefinitely via the secondary side using the TDAFWP; it would provide for adequate RCS makeup in event of an RCP seal LOCA; and it would provide for restoration of offsite power. The details are provided below.

E.6.5.1 Non-Seismic Averted Cost-Risk

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA a new charging pump was added to the model. Gate G1RP320, "#11 CCP faults" was changed to an "AND" of G1RP320X and NEW_CVS_PUMP and the logic for the #11 CCP was moved under G1RP320X. A failure probability of 0.1 was assigned to NEW_CVS_PUMP to allow for equipment and operator failures and to ensure that excessive credit was not given for the necessary actions in conjunction with other actions which could be required. In addition the impact of the battery charger generators was modeled by adjusting offsite power nonrecovery probabilities: the likelihood of offsite power nonrecovery was changed to 0.01 for grid and site/switchyard related causes and to 0.03 for weather related causes. This represents both the likelihood that offsite power would not be available for restoration at extended times of around 24 hours and the likelihood that requisite actions would not be completed successfully.

Results of SAMA Quantification:

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.15E-05	69.33	$271,515
Percent Change	16.1%	11.4%	11.2%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
Frequency_{BASE}	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
Frequency_{SAMA}	6.79E-06	1.81E-10	9.88E-07	2.32E-08	2.93E-05	2.97E-08	1.86E-07	2.87E-08	2.54E-06	1.96E-07	1.47E-06	**4.15E-05**
Dose-Risk_{BASE}	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
Dose-Risk_{SAMA}	0.11	0.00	0.02	0.06	36.61	0.62	1.93	0.31	23.15	0.78	5.74	**69.33**
OECR_{BASE}	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
OECR_{SAMA}	$22	$0	$5	$270	$97,812	$2,393	$7,369	$1,048	$114,989	$6,320	$41,287	**$271,515**

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

SAMA 5 Averted Cost-Risk Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$14,572,690	$1,991,310

SAMA 5 results indicate a relatively large reduction in CDF, dose-risk and offsite economic consequences.

E.6.5.2 Seismic Averted Cost-Risk

This SAMA was identified as an appropriate means of addressing the risk for several seismic sequences, including:

- 17 OP
- 33 OP-DAB
- 31 OP-SW
- 34 OP-DAB-DG
- 17F OP

It is assumed that if the portion of the SGS CDF related to the relevant SGS seismic sequences can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total PACR attributable to external events
- Determine the component of the external events PACR attributable to seismic events
- Determine the component of the seismic PACR attributable to the seismic sequences identified above

- Calculate the percent reduction in the sequence CDFs that would result if the SAMA is implemented and reduce the PACR for the sequences by the same percent. The reduction in the PACRs is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the SGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $8,282,000 for a single unit, the same value is assigned to external events.

The relative contribution of seismic events to the total external events CDF can be estimated in several ways, but the distribution established in Section 4.6 to calculate the total External Events CDF is considered to be appropriate for SGS and is used here. Using that distribution, the seismic CDF of 9.5E-06 per yr is estimated to be 18.1 percent of the total External Events CDF. The single unit seismic contribution, therefore, corresponds to a PACR of $1,498,648.

The cost-risk associated with each seismic sequence can then be determined based on their relative contributions to the total seismic CDF and the assumption that the CDFs are proportional to cost-risk (Seismic CDFs are provided in Section E.5.1.6.2):

Seismic Sequence	Percent of Seismic Risk	Corresponding PACR (single unit)
17 OP	30.6	$457,482
33 OP-DAB	21.1	$315,505
31 OP-SW	13.7	$205,078
34 OP-DAB-DG	8.1	$121,469
17F OP	5.7	$85,186

The risk reduction possible for this area is a fraction of the total ($1,184,720) based on the potential capabilities of the changes proposed in this SAMA. In this case, the SAMA is assumed to have a failure probability of 0.1 to account for the potentially difficult task of aligning the portable generator and other local tasks in time to prevent core damage. This implies that the SAMA eliminates 90 percent of the risk from these sequences and correlates to an averted cost-risk of $1,066,248.

E.6.5.3 Cost of Implementation

SGS estimated an implementation cost of $3,320,000 for a single unit.

E.6.5.4 Net Value

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation, where the total averted cost risk is the sum of the non-seismic averted cost-risk and the seismic averted cost-risk, or $3,057,558 ($1,991,310 + $1,066,248 = $3,057,558):

SAMA 5 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$3,057,558	$3,320,000	-$262,442

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative, which implies that this SAMA is not cost beneficial.

E.6.6 SAMA 6: Enhance Flood Detection for 84′ Aux Building and enhance procedural guidance for responding to service water flooding

Internal floods can occur in two general sections of the 84' elevation of the Auxiliary Building, the non-radiologically controlled area including the switchgear rooms and the corridor between them ("84B"), and the radiologically controlled area of the Aux Building which contains the AFW pumps, the charging pumps, etc. ("84C"). The significant flood concern in the 84B area involves a flood from the fire protection system. This flood is readily detected and isolated. Significant floods in the 84C area, with the greatest contribution coming from failures in the service water system, are less easily identified, diagnosed, and resolved. If steps were taken to make it easier to identify and resolve floods in the 84C area, this would reduce the risk associated with those floods.

This SAMA proposes development of detection and procedural mitigation steps for floods in the 84C area of the auxiliary building. The details are provided below.

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA, the failure probabilities of existing operator actions to detect and isolate floods successfully were multiplied by a factor of 0.1 (FL_XHE_AB084C_G set to 1.1E-3 and FL_XHE_AB084C_M set to 1.4E-3).

Results of SAMA Quantification:

Implementation of this SAMA yielded a slight reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.68E-05	77.43	$302,138
Percent Change	5.5%	1.0%	1.2%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	6.82E-06	1.81E-10	9.87E-07	2.52E-08	3.40E-05	2.97E-08	2.10E-07	3.16E-08	2.55E-06	1.98E-07	1.95E-06	**4.68E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.11	0.00	0.02	0.06	42.49	0.62	2.19	0.34	23.18	0.78	7.63	**77.43**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$22	$0	$5	$292	$113,533	$2,393	$8,347	$1,152	$115,152	$6,385	$54,857	**$302,138**

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

SAMA 6 Net Value			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
Salem Unit 1	$16,564,000	$16,263,874	$300,126

The SAMA 6 results indicate a relatively small reduction in CDF, dose-risk and offsite economic consequences. However, with the cost of implementation per unit being

$250,000, the net value for this SAMA is $50,126 ($300,126 - $250,000), which implies that this SAMA is cost beneficial.

E.6.7 SAMA 7: Install "B" Train AFWST Makeup Including Alternate Water Source

Auxiliary feedwater is required for decay heat removal in many scenarios. The AFW storage tank only contains enough inventory for approximately 8-12 hours of operation however normal PRA success criteria are that key functions required to maintain a stable state out to 24 hours. Accordingly a requirement to make up to the AFWST is modeled. Currently this involves opening valve DR-6 using train A DC to allow transfer of water from the demineralized water storage tanks. If a modification was made to automate makeup from a different source and using a different train of DC for control power, this would reduce the risk of loss of decay heat removal due to loss of supply to the AFW system.

This SAMA proposes development and implementation of a new train-B AFWST makeup. Details are provided below.

<u>PRA Model Changes to Model SAMA:</u>

To calculate the consequences of implementation of this SAMA, the logic beneath gate GAN1584, "Normal source from AFWST fails" was modified. The existing logic was placed under GAN1584X and this was ANDed with logic for the alternate makeup beneath gate G1060, consisting of gate G1B1100 to capture train B dependencies correctly and undeveloped event AFWST_AUTO_MU. This represents both the likelihood that the control circuit might fail and the likelihood that the valve could fail. A probability of 1E-3 was assigned.

<u>Results of SAMA Quantification:</u>

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.62E-05	77.15	$300,042
Percent Change	6.6%	1.4%	1.9%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$\text{Frequency}_{\text{BASE}}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$\text{Frequency}_{\text{SAMA}}$	6.35E-06	1.81E-10	9.88E-07	2.52E-08	3.39E-05	2.97E-08	2.12E-07	3.21E-08	2.55E-06	1.21E-07	1.97E-06	**4.62E-05**
$\text{Dose-Risk}_{\text{BASE}}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$\text{Dose-Risk}_{\text{SAMA}}$	0.10	0.00	0.02	0.06	42.43	0.62	2.21	0.35	23.18	0.48	7.70	**77.15**
$\text{OECR}_{\text{BASE}}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$\text{OECR}_{\text{SAMA}}$	$20	$0	$5	$292	$113,373	$2,393	$8,432	$1,171	$115,152	$3,900	$55,304	**$300,042**

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

SAMA 7 Net Value			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
Salem Unit 1	$16,564,000	$16,152,556	$411,444

The SAMA 7 results indicate a relatively small reduction in CDF, dose-risk and offsite economic consequences. With the cost of implementation per unit being $470,000, the net value for this SAMA is -$58,556 ($411,444 - $470,000), which implies that this SAMA is <u>not</u> cost beneficial.

E.6.8 SAMA 8: Install High Pressure Pump Powered with Portable Diesel Generator and Long-term Suction Source to Supply the AFW Header

Auxiliary feedwater is required for decay heat removal in many scenarios. Addition of an engine-driven AFW pump with its own suction supply would provide a redundant source of an important function..

This SAMA proposes development and implementation of a new engine-driven AFW pump with its own suction supply connection. Details are provided below.

Assumptions:

- It is assumed that the pump would be installed such that it could be started and operated promptly and simply.

E.6.8.1 Non-Fire Averted Cost-Risk

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA, the logic beneath gate GAN1172 “Insuff flow from TDP” was moved below a new gate GAN1172X and this was “anded” with the likelihood that the proposed new pump would fail, “NEW_AFW.” A probability of 1E-2 was assigned that this new pump would fail or that it would not be aligned as required when needed.

Results of SAMA Quantification:

Implementation of this SAMA yielded a slight reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.20E-05	73.19	$283,512
Percent Change	15.3%	6.4%	7.3%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$\text{Frequency}_{\text{BASE}}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$\text{Frequency}_{\text{SAMA}}$	4.45E-06	1.81E-10	9.85E-07	2.52E-08	3.19E-05	2.97E-08	1.98E-07	2.92E-08	2.55E-06	4.31E-09	1.78E-06	**4.20E-05**
$\text{Dose-Risk}_{\text{BASE}}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$\text{Dose-Risk}_{\text{SAMA}}$	0.07	0.00	0.02	0.06	39.88	0.62	2.06	0.32	23.18	0.02	6.96	**73.19**
$\text{OECR}_{\text{BASE}}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$\text{OECR}_{\text{SAMA}}$	$14	$0	$5	$293	$106,549	$2,393	$7,846	$1,066	$115,152	$139	$50,055	**$283,512**

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

SAMA 8 Non-Fire Averted Cost-Risk			
Unit	**Base Case Cost-Risk**	**Revised Cost-Risk**	**Averted Cost-Risk**
Salem Unit 1	$16,564,000	$15,187,824	$1,376,176

E.6.8.2 Fire Averted Cost-Risk

This SAMA was identified as an appropriate means of addressing the risk for two fire areas:

- 12FA-SB-100/1FA-TGA-88
- 1FA-AB-84B

It is assumed that if the portion of the SGS CDF related to the relevant SGS fire areas can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total PACR attributable to external events
- Determine the component of the external events PACR attributable to fire
- Determine the component of the fire PACR attributable to fire areas 12FA-SB-100/1FA-TGA-88 and 1FA-AB-84B
- Calculate the percent reduction in the fire area CDFs that would result if the SAMA is implemented and reduce the PACRs for the fire areas by the same percent. The reduction in the PACRs is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the SGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $8,282,000 for a single unit, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF can be estimated in several ways, but the distribution established in Section 4.6 to calculate the total External Events CDF is considered to be appropriate for SGS and is used here. Using that distribution, the fire CDF of 3.8E-05 per yr is estimated to be 72.4 percent of the total External Events CDF. The single unit fire contribution, therefore, corresponds to a PACR of $5,994,590.

The cost-risk associated with each fire area can then be determined based on their relative contributions to the total fire CDF and the assumption that the CDF is proportional to cost-risk (Fire CDFs are provided in Section E.5.1.6.1):

Fire Area	Percent of Fire Risk	Corresponding PACR (single unit)
12FA-SB-100/1FA-TGA-88	1.7	$100,962
1FA-AB-84B	2.9	$173,528

The risk reduction possible for this area is a fraction of the total ($274,490) based on the potential capabilities of the changes proposed in this SAMA. In this case, the SAMA is assumed to have a failure probability of 1.0E-02, as described for the internal events evaluation. This implies that the SAMA eliminates 99 percent of the risk from these sequences and correlates to a single unit averted cost-risk of $271,745.

E.6.8.3 Cost of implementation

SGS estimated a unit implementation cost of $2,510,000.

E.6.8.4 Net value

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation, where the total averted cost-risk is the sum of the non-fire averted cost-risk and the fire averted cost-risk, or $1,647,921 ($1,376,176 + $271,745 = $1,647,921):

SAMA 8 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$1,647,921	$2,510,000	-$862,079

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative, which implies that this SAMA is not cost beneficial.

E.6.9 SAMA 9: Connect Hope Creek Cooling Tower Basin to Salem Service Water System as Alternate Service Water Supply

Salem SW is an open system drawing suction from the Delaware River. Debris or other material in the river could obstruct the service water system.

This SAMA proposes development and implementation of a new connection to the SGS SW system, supplying a SW pump from the close HC circulating water supply.

Assumptions :

- It is assumed that a supply to the SGS SW system could be returned to the HC circ water system without materially impacting volume or temperature of this large volume system.

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA, the probabilities for SW fouling events SWS-STR* and STS-TWS* were all multiplied by a factor of 0.1.

Results of SAMA Quantification:

Implementation of this SAMA yielded a slight reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.33E-05	69.46	$277,742
Percent Change	12.6%	11.2%	9.2%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.22E-06	1.81E-10	9.89E-07	2.00E-08	2.83E-05	2.97E-08	1.91E-07	2.80E-08	2.55E-06	1.97E-07	1.80E-06	**4.33E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.05	35.33	0.62	1.99	0.31	23.18	0.78	7.04	**69.46**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$231	$94,395	$2,393	$7,585	$1,023	$115,147	$6,333	$50,600	**$277,742**

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

SAMA 9 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$14,861,434	$1,702,566

The SAMA 9 results indicate a relatively large reduction in CDF, dose-risk and offsite economic consequences. With a unit implementation cost of $1,235,000, the net value for this SAMA is $467,566 ($1,702,566 - $1,235,000), which implies that this SAMA is cost beneficial.

E.6.10 SAMA 10: Provide Procedural Guidance for Faster Cooldown Loss of RCP Seal Cooling

Salem procedures for losses of CCW cooling will generally direct a slow (25 F per hour) natural circulation cooldown. In the event that CCW is lost and seal injection cannot be maintained, guidance indicates that the RCS should be depressurized more rapidly within 2 hours to prevent RCP seal LOCA.

This SAMA proposes development and implementation of new procedure steps to ensure that the RCS is sufficiently depressurized early during a loss of CCW event if seal injection cannot be maintained.

<u>PRA Model Changes to Model SAMA:</u>

To calculate the consequences of implementation of this SAMA, the probability that operators would fail to reduce RCS pressure as required (RCS-XHE-FO-CLDN) was adjusted from its current value of 1.0 to 0. 1. This relatively high screening value was appropriate because the resulting cutsets sometimes contain actions which could have a dependency with RCS-XHE-FO-CLDN..

Results of SAMA Quantification:

Implementation of this SAMA yielded a small reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.86E-05	77.90	$304,360
Percent Change	1.9%	0.4%	0.4%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
Frequency$_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
Frequency$_{SAMA}$	8.50E-06	1.81E-10	7.65E-07	2.51E-08	3.42E-05	2.03E-08	2.18E-07	3.30E-08	2.55E-06	1.98E-07	2.02E-06	**4.86E-05**
Dose-Risk$_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
Dose-Risk$_{SAMA}$	0.14	0.00	0.02	0.06	42.78	0.42	2.27	0.36	23.18	0.78	7.89	**77.90**
OECR$_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
OECR$_{SAMA}$	$27	$0	$4	$291	$114,308	$1,632	$8,661	$1,206	$115,152	$6,385	$56,695	**$304,360**

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

SAMA 10 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$16,453,436	$110,564

The SAMA 10 results indicate a relatively insignificant reduction in the CDF, dose-risk and offsite economic consequences. With a unit implementation cost of $100,000, the net value for this SAMA is $10,564 ($110,564 - $100,000), which implies that this SAMA is cost beneficial.

E.6.11 SAMA 11: Modify Plant Procedures to Make Use of Other Unit's PDP for RCP Seal Cooling

Salem fire response procedures in some cases direct that plant operators utilize a charging cross-tie between units so that unit 2 can provide seal injection to unit 1 or vice-versa. It could be beneficial if this crosstie could be used in other circumstances.

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA, operator actions "Operator fails to respond to short term / long term {seal injection} demand," XTI-XHE-U21-STM, -LTM were changed from 1.0 to 0.1. This value was chosen because the operator actions occurred in cutsets where there were additional dependency issues that were not evaluated. In addition a test and maintenance basic event, CVS-MDP-TM-CVN21 was being set to "true" and this was removed from the flag file.

Results of SAMA Quantification:

Implementation of this SAMA yielded a small reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	**Dose-Risk**	**OECR**
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.30E-05	68.56	$270,207
Percent Change	13.1%	12.4%	11.6%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	**INTACT**	**LATE-BMMT-AFW**	**LATE-BMMT-NOAFW**	**LATE-CHR-AFW**	**LATE-CHR-NOAFW**	**LERF-ISLOCA**	**LERF-CI**	**LERF-CFE**	**LERF-SGTR-AFW**	**LERF-SGTR-NOAFW**	**LERF-ISGTR**	**Total**
Frequency$_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
Frequency$_{SAMA}$	9.21E-06	1.81E-10	9.89E-07	3.66E-07	2.80E-05	2.97E-08	1.94E-07	3.09E-08	2.54E-06	1.96E-07	1.42E-06	**4.30E-05**
Dose-Risk$_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
Dose-Risk$_{SAMA}$	0.15	0.00	0.02	0.92	35.02	0.62	2.02	0.34	23.15	0.78	5.54	**68.56**
OECR$_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
OECR$_{SAMA}$	$29	$0	$5	$4,240	$93,583	$2,393	$7,713	$1,129	$114,984	$6,322	$39,806	**$270,207**

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

SAMA 11 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$14,565,076	$1,998,924

The SAMA 11 results indicate a relatively large reduction in CDF, dose-risk and offsite economic consequences. With a unit implementation cost of only $100,000, the net value for this SAMA is $1,898,924 ($1,998,924 - $100,000), which implies that this SAMA is cost beneficial.

E.6.12 SAMA 12: Improve Flood Barriers Outside of 220/440VAC Switchgear Rooms

It is proposed to add flood barriers to prevent or delay entry of water into the switchgear rooms in event that drains do not drain as designed.

<u>PRA Model Changes to Model SAMA:</u>

To calculate the consequences of implementation of this SAMA, the likelihood that the drains would fail to remove the volume of water assumed in the flooding analysis was reduced by a factor of 0.1 to 0.001 (RDW-STR-PG-FLOOD2). Additional head of water above the drains would drive higher flow through the drains. In addition this could permit additional time for operator action.

<u>Results of SAMA Quantification:</u>

Implementation of this SAMA yielded small reductions in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.79E-05	75.58	$295,646
Percent Change	3.3%	3.4%	3.3%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.27E-05	2.97E-08	2.10E-07	3.25E-08	2.55E-06	1.98E-07	1.87E-06	**4.79E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.06	40.91	0.62	2.18	0.35	23.18	0.78	7.31	**75.58**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$292	$109,318	$2,393	$8,322	$1,185	$115,152	$6,385	$52,564	**$295,646**

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

SAMA 12 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$16,013,844	$550,156

The SAMA 12 results show a moderate reduction in CDF, dose-risk and offsite economic consequences. With a unit implementation cost of $475,000, the net value for this SAMA is $75,156 ($550,156 - $475,000), which implies that this SAMA is cost beneficial.

E.6.13 SAMA 13: Install Primary Side Isolation Valves on the Steam Generators

The ability to isolate a ruptured steam generator would substantially reduce the risk associated with an SGTR.

<u>Assumptions:</u>

It is assumed that any installation of loop stop valves would be engineered such that the likelihood of the valves contributing to an event or accident (vs. mitigating) would be negligible.

<u>PRA Model Changes to Model SAMA:</u>

Typical MOV failure rates are in the range of 1E-3 and operator action failure probabilities would be likely to be in the range between 1E-3 and 1E-2 for important actions with some degree of dependency. To calculate the consequences of implementation of this SAMA, the likelihood of an SGTR itself was reduced by 1E-2 (each %S4-A/B/C/D reduced by 1E-2).

<u>Results of SAMA Quantification:</u>

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.68E-05	54.48	$185,241
Percent Change	5.5%	30.4%	39.4%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.42E-08	1.25E-09	2.03E-06	**4.68E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.06	42.78	0.62	2.32	0.37	0.22	0.00	7.93	**54.48**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$292	$114,308	$2,393	$8,857	$1,240	$1,095	$40	$56,981	**$185,241**

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

SAMA 13 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$11,366,786	$5,197,214

The results of the SAMA 13 sensitivity analysis showed a measurable drop in CDF with large reductions in dose-risk and offsite economic consequences. With an estimated unit implementation cost of $17,750,000, the net value for this SAMA was -$12,552,786 ($5,197,214 - $17,750,000), which implies that this SAMA is not cost beneficial.

E.6.14 SAMA 14: Expand AMSAC Function to Include Backup Breaker Trip on RPS Failure

AMSAC could be used to trip a power supply in the feed to the reactor trip breakers, thereby providing a backup electrical trip.

This SAMA proposes development of a plant modification which would allow AMSAC to provide a backup electrical trip.

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA a new undeveloped basic event, the current event for electrical trip fails “CE,” was ANDed with the top gate for AMSAC, AM-GAMF100, and this was placed below a new gate “CEX” which was substituted for the original locations for “CE.”

Results of SAMA Quantification:

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.01E-05	78.02	$305,358
Percent Change	19.1%	0.3%	0.1%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	0.00E+00	1.81E-10	7.52E-07	2.52E-08	3.42E-05	2.97E-08	2.22E-07	3.38E-08	2.55E-06	1.98E-07	2.02E-06	**4.01E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.00	0.00	0.02	0.06	42.78	0.62	2.31	0.37	23.18	0.78	7.90	**78.02**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$0	$0	$4	$292	$114,308	$2,393	$8,810	$1,232	$115,152	$6,385	$56,782	**$305,358**

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

SAMA 14 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$16,033,512	$530,488

The results of the SAMA 14 sensitivity analysis showed a measurable drop in the CDF, but showed a much smaller decrease in the dose risk and offsite consequence risk metrics. With a unit estimated implementation cost of $485,000, the net value for this SAMA was $45,488 ($530,488 - $485,000), which implies that this SAMA is cost beneficial.

E.6.15 SAMA 15: Automate RCP Seal Injection Realignment upon Loss of CCW

In event of a loss of CCW it is important to isolate letdown and to swap charging suction from the VCT to the RWST. Automating this response would make it more reliable and reduce risk.

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA, operator actions CVS-XHE-FO-SOVCT was adjusted. CVS-XHE-FO-SOVCT represents the actions which should be promptly taken to protect the centrifugal charging pumps and the reactor coolant pump seals. If these actions were automated, the likelihood of their failure would be reduced. This was modeled by reducing the probability of CVS-XHE-FO-SOVCT from 1E-2 to 1E-3.

Results of SAMA Quantification:

Implementation of this SAMA yielded a modest decrease in CDF, with substantial reductions in both Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.89E-05	78.17	$305,489
Percent Change	1.2%	0.1%	0.1%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	8.61E-06	1.11E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.20E-07	3.33E-08	2.55E-06	1.98E-07	2.03E-06	**4.89E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.14	0.00	0.02	0.06	42.78	0.62	2.29	0.36	23.18	0.78	7.93	**78.17**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$27	$0	$5	$292	$114,308	$2,393	$8,729	$1,217	$115,152	$6,385	$56,981	**$305,489**

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

SAMA 15 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$16,522,046	$41,954

The results of the SAMA 15 sensitivity analysis showed a minor reduction in the CDF, dose risk and offsite economic consequences. With a unit estimated implementation cost of $210,000, the net value for this SAMA was -$168,046 ($41,954 - $210,000), which implies that this SAMA is not cost beneficial.

E.6.16 SAMA 16: Install Additional Train of Switchgear Room Cooling

In event of a loss of the current trains of switchgear room cooling, an additional train of switchgear room cooling with auto-start capability is proposed.

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA, operator action RD4-XHE was adjusted. This action is the operator response to a loss of switchgear room cooling. It was reduced by a factor of 0.01, in effect ANDing the operator action with a failure of the proposed new train.

Results of SAMA Quantification:

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.88E-05	77.29	$302,729
Percent Change	1.3%	1.2%	1.0%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.36E-05	2.97E-08	2.20E-07	3.36E-08	2.55E-06	1.98E-07	2.01E-06	**4.88E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.06	41.97	0.62	2.29	0.37	23.18	0.78	7.84	**77.29**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$292	$112,137	$2,393	$8,748	$1,227	$115,152	$6,385	$56,360	**$302,729**

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

SAMA 16 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$16,382,914	$181,086

The results of the SAMA 16 sensitivity analysis showed a relatively small reduction in the CDF, dose risk and offsite economic consequences. With a unit estimated implementation cost of $2,535,000, the net value for this SAMA was -$2,353,914 ($181,086 - $2,535,000), which implies that this SAMA is not cost beneficial.

E.6.17 SAMA 17: Enhance Procedures and Provide Additional Equipment to Respond to Loss of EDG Control Room Ventilation

Loss of HVAC cooling to the EDG control rooms is currently modeled as resulting in failure of the associated EDGs. If a procedure was developed to open and ventilate the rooms upon failure of the HVAC system, the risk associated with this failure mode might be reduced.

Assumptions:

It is assumed that HVAC to the EDG rooms themselves is required. This procedural modification applies only to the EDG control rooms.

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA, the failure probabilities for the diesel control room HVAC fans were adjusted. Failure probabilities for VDG-FNS-FS-VHE-28, 29, and 30 were reduced.

Results of SAMA Quantification:

As expected from the method described above, implementation of this SAMA yielded a uniform decrease in CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.79E-05	75.77	$296,671
Percent Change	3.3%	3.1%	3.0%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.22E-06	1.81E-10	9.89E-07	2.29E-08	3.27E-05	2.97E-08	2.17E-07	3.34E-08	2.55E-06	1.98E-07	1.90E-06	**4.79E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.06	40.92	0.62	2.26	0.36	23.18	0.78	7.41	**75.77**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$265	$109,342	$2,393	$8,617	$1,219	$115,152	$6,385	$53,264	**$296,671**

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

SAMA 17 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Crystal River 3	$16,564,000	$16,057,820	$506,180

The results of the SAMA 17 sensitivity analysis showed a moderate reduction in the CDF, dose risk and offsite economic consequences. With a unit estimated implementation cost of $200,000, the net value for this SAMA was $306,180 ($506,180 - $200,000), which implies that this SAMA is cost beneficial.

E.6.18 SAMA 18: Redundant SW Turbine Header Isolation Valve

During some scenarios involving loss of multiple SW pumps it is necessary to promptly isolate SW26 manually. It is proposed to add a redundant isolation for this valve including a power supply which would remain available (for instance, an air operated valve with DC control power).

<u>PRA Model Changes to Model SAMA:</u>

To calculate the consequences of implementation of this SAMA, the failure probabilities for the operator action to isolate SWS-XHE-FO-SWIXO was reduced to 1E-3, thus roughly bounding the likelihood of failure of an MOV..

Results of SAMA Quantification:

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.91E-05	77.54	$303,246
Percent Change	0.9%	0.9%	0.8%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	9.22E-06	1.81E-10	9.89E-07	2.00E-08	2.83E-05	2.97E-08	1.91E-07	2.80E-08	2.55E-06	1.97E-07	1.80E-06	**4.33E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.15	0.00	0.02	0.05	35.33	0.62	1.99	0.31	23.18	0.78	7.04	**69.46**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$29	$0	$5	$231	$94,395	$2,393	$7,585	$1,023	$115,147	$6,333	$50,600	**$277,742**

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

SAMA 18 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$16,424,896	$139,104

The results of the SAMA 18 sensitivity analysis showed a relatively minor reduction in the CDF, dose risk and offsite economic consequences. With a unit estimated implementation cost of $635,000, the net value for this SAMA was -$495,896 ($139,104 - $635,000), which implies that this SAMA is not cost beneficial.

E.6.19 SAMA 19: Install Spray Shields on RHR Pumps

There are risk contributions from flooding scenarios involving spray on the 45' elevation of the auxiliary building, particularly involving spray around the RHR pumps. If the pumps were fitted with a spray shield, the risk would be reduced

PRA Model Changes to Model SAMA:

To calculate the consequences of implementation of this SAMA, the initiating event frequency for the 45' AB spray scenario was reduced by a factor of 0.01.

Results of SAMA Quantification:

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.90E-05	78.18	$305,519
Percent Change	1.0%	0.0%	0.1%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
Frequency_{BASE}	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
Frequency_{SAMA}	8.50E-06	1.81E-10	7.65E-07	2.51E-08	3.42E-05	2.03E-08	2.18E-07	3.30E-08	2.55E-06	1.98E-07	2.02E-06	**4.86E-05**
Dose-Risk_{BASE}	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
Dose-Risk_{SAMA}	0.14	0.00	0.02	0.06	42.78	0.42	2.27	0.36	23.18	0.78	7.89	**77.90**
OECR_{BASE}	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
OECR_{SAMA}	$27	$0	$4	$291	$114,308	$1,632	$8,661	$1,206	$115,152	$6,385	$56,695	**$304,360**

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

SAMA 19 Net Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$16,530,228	$33,772

The results of the SAMA 19 sensitivity analysis showed a relatively minor reduction in the CDF, dose risk and offsite economic consequences. With a unit estimated implementation cost of $350,000, the net value for this SAMA was -$316,228 ($33,772 - $350,000), which implies that this SAMA is <u>not</u> cost beneficial.

E.6.20 SAMA 20: Fire Protection System to Provide Make-up to RCS and SGs

A potential option to mitigate fires that cause damage across multiple trains and systems would be to install two engine driven pumps that can be controlled locally to provide makeup to the RCS and steam generators. These systems would not rely on any other systems for success and while they may be relatively difficult to operate, they would provide a path for success when other makeup options are not available. The RCS makeup pump would require a suction connection to the RWST and an injection connection through the safety injection lines (outside containment, but downstream of the MOVs). For the secondary side makeup pump, suction would be required from the fire water system and injection through the turbine driven pump line. In order to make operation of these systems possible, the SAMA design must include a way to provide independent, supplemental level/pressure instrumentation (does not rely on existing A or DC systems) for the primary and secondary sides. Ensuring the equipment is seismically qualified and stored is a seismically qualified structure would also provide a means of mitigating seismic events that cause widespread system failures.

Because implementation of this SAMA would impact internal events risk as well as the specific seismic contributors that were used to identify the SAMA, the averted cost-risk is calculated as the sum of the internal and external events averted cost-risk components. In general, this type of system could be considered to be useful for nearly any accident scenario in which hardware failures are the dominate contributors; the limitations in applicability are those cases in which time constraints preclude alignment of the system (ATWS, LOCA, SGTR) or where there would be a significant dependence between use of the system and other operator actions that have failed.

For this quantification, the Fire and Seismic averted cost risk are quantified based on a review of the individual contributors for those initiator types. Given that fire and seismic events account for over 90 percent of the external events risk for SGS, the external events multiplier is changed to 1.1 for this specific evaluation.

E.6.20.1 Internal Events Averted Cost-Risk

A SAMA has been separately proposed to install an independently-powered AFW pump: "Auxiliary feedwater is required for decay heat removal in many scenarios. Addition of an engine-driven AFW pump with its own suction supply would provide a redundant source of an important function. This SAMA proposes development and implementation of a new engine-driven AFW pump with its own suction supply connection."

The model developed to support that SAMA evaluation was further adapted by adding an independently-powered charging pump.

With independent sources of primary and secondary side makeup and with sufficient independently-powered instrumentation to allow monitoring of conditions in the RCS and SGs, many initiating events could be mitigated. In effect, the proposed modifications represent an additional "safe shutdown" system.

As discussed in the related SAMA, the proposed AFW pump was modeled by altering logic beneath gate GAN1172: "Insuff flow from TDP" was moved below a new gate GAN1172X and this was anded with the likelihood that the proposed new pump would fail, "NEW_AFW." A probability of 1E-2 was assigned that this new pump would fail or that it would not be aligned as required when needed.

The additional proposed independently-powered and -controlled centrifugal charging pump was modeled by adding a new undeveloped basic event “NEW_CVS_PMP” below gate G1RP320.

In some applications this pump should be started and aligned relatively promptly so an operator error failure likelihood of 0.1 was assumed. This value dominates hardware failures so they were not modeled in detail.

The ability to use these pumps in combination with appropriate instrumentation was modeled by creating a new OR gate, AFW_CVS_MODS. Inputs to AFW_CVS_MODS are NEW_AFW and NEW_CVS_PMP. This gate, representing an additional safe shutdown capability, was ANDed with several initiators: @TT (turbine trip), @TP (LOFW), @SUPPORT / @TEC / @TES (loss of support systems such as CCW, service water, or HVAC), and @TE (loss of offsite power). In each case, even if the systems and components normally credited to address the relevant initiators fail, the new components should permit a safe shutdown.

Results of SAMA Quantification:

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	3.90E-05	72.08	$278,811
Percent Change	21.2%	7.8%	8.8%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	2.03E-06	1.81E-10	9.85E-07	2.33E-08	3.15E-05	2.97E-08	1.84E-07	2.66E-08	2.54E-06	2.30E-09	1.70E-06	**3.90E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.03	0.00	0.02	0.06	39.38	0.61	1.91	0.29	23.11	0.01	6.65	**72.08**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$6	$0	$5	$270	$105,210	$2,391	$7,305	$971	$114,808	$74	$47,770	**$278,811**

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

SAMA 20 Internal Events Averted Cost-Risk

Unit	Base Case Cost-Risk*	Revised Cost-Risk*	Averted Cost-Risk
SGS Unit 1	$9,110,200	$8,150,168	$960,032

*Using an External Events Multiplier of 1.1

E.6.20.2 External Events Averted Cost-Risk

SAMA 20 was developed to address fire and seismic initiators that cause widespread damage to critical functions. In these cases, the most effective type of enhancement is one that does not rely on existing systems and is maintained in areas that are protected from the effects of the important fire and seismic initiators. As a result, there are many sequences that would be addressed by this type of system.

Internal Fire Evaluation

This SAMA was specifically identified as an appropriate means of addressing the risk for fire areas 1FA-AB-84A and 1FA-EP-78C; however, the implementation of this SAMA would impact several other fire areas:

- 1FA-AB-64A
- 1FA-AB-84B
- 12FA-SB-100/1FA-TGA-88

No credit is taken for controlling the plant with this SAMA for the scenarios in which control of the reactor fails from the RSP given that the actions would essentially be completely dependent (1FA-AB-100A, 12FA-AB-122A, 1FA-EP-100G/1F1-PP-100H).

It is assumed that if the portion of the SGS CDF related to the relevant SGS fire areas can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total PACR attributable to external events
- Determine the component of the external events PACR attributable to fire
- Determine the component of the seismic PACR attributable to the fire areas identified above
- Calculate the percent reduction in the fire area CDFs that would result if the SAMA is implemented and reduce the PACR for the fire areas by the same percent. The reduction in the PACRs is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the SGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $8,282,000 for a single unit, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF can be estimated in several ways, but the distribution established in Section 4.6 to calculate the total External Events CDF is considered to be appropriate for SGS and is used here. Using that distribution, the fire CDF of 3.8E-05 per yr is estimated to be 72.4 percent of the total External Events CDF. The single unit fire contribution, therefore, corresponds to a PACR of $5,994,590.

The cost-risk associated with each fire area can then be determined based on their relative contributions to the total fire CDF and the assumption that the CDFs are proportional to cost-risk (Fire CDFs are provided in Section E.5.1.6.1):

Fire Area	Percent of Fire Risk	Corresponding PACR (single unit)
1FA-AB-84A	33.9	$2,035,006
1FA-EP-78C	8.4	$504,808
1FA-AB-64A	8.9	$536,358
1FA-AB-84B	2.9	$173,528
12FA-SB-100/1FA-TGA-88	1.7	$100,962

The risk reduction possible for this area is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. In this case, the SAMA is assumed to have a failure probability of 0.1, as described for the internal events evaluation. This implies that the SAMA eliminates 90 percent of the risk from these sequences and correlates to a single unit averted cost-risk of $3,015,596.

<u>Seismic Evaluation</u>

This SAMA was specifically identified to address the risk from seismic sequences 17 OP, 33 OP-DAB, 31 OP-SW, 34 OP-DAB-DG, and 17F OP; however, the implementation of this SAMA would also benefit sequence 21F OP-FW-FC.

It is assumed that if the portion of the SGS CDF related to the relevant SGS seismic sequences can be identified, and then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total PACR attributable to external events
- Determine the component of the external events PACR attributable to seismic events
- Determine the component of the seismic PACR attributable to the seismic sequences identified above
- Calculate the percent reduction in the sequence CDFs that would result if the SAMA is implemented and reduce the PACR for the sequences by the same percent. The reduction in the PACRs is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the SGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $8,282,000 for a single unit, the same value is assigned to external events.

The relative contribution of seismic events to the total external events CDF can be estimated in several ways, but the distribution established in Section 4.6 to calculate the total External Events CDF is considered to be appropriate for SGS and is used here. Using that distribution, the seismic CDF of 9.5E-06 per yr is estimated to be 18.1 percent of the total External Events CDF. The single unit seismic contribution, therefore, corresponds to a PACR of $1,498,648.

The cost-risk associated with each seismic sequence can then be determined based on their relative contributions to the total seismic CDF and the assumption that the CDFs are proportional to cost-risk (Seismic CDFs are provided in Section E.5.1.6.2):

Seismic Sequence	Percent of Seismic Risk	Corresponding PACR (single unit)
21F OP-FW-FC	12.6%	$45,748
17 OP	30.6	$457,482
33 OP-DAB	21.1	$315,505
31 OP-SW	13.7	$205,078
34 OP-DAB-DG	8.1	$121,469
17F OP	5.7	$85,186

The risk reduction possible for this area is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. In this case, the SAMA is assumed to have a failure probability of 0.1, as described for the internal events evaluation. This implies that the SAMA eliminates 90 percent of the risk from these sequences and correlates to a single unit averted cost-risk of $1,107,421.

E.6.20.3 Cost of implementation

SGS estimated an implementation cost of $13,100,000 for a single unit.

E.6.20.4 Net value

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation, where the total averted cost risk is the sum of the internal events averted cost-risk, the fire averted cost-risk, and the seismic averted cost-risk, or $5,083,049 ($960,032 + $3,015,596 + $1,107,421 = $5,083,049):

SAMA 20 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$5,083,049	$13,100,000	-$8,016,951

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative, which implies that this SAMA is <u>not</u> cost beneficial.

E.6.21 SAMA 21: Seal the Category II and III Cabinets in the Relay Room

The dominant fire scenario in the Relay Room (1FA-AB-100A) is a cabinet fire that is not suppressed and is able to propagate to the point where it is large enough to force main control room abandonment. The issue for this scenario is not necessarily the availability of the equipment itself, but more that the operators are forced to take control of the plant from the RSP. The most effective method identified to reduce the risk from this scenario is to prevent the propagation of the initiating fire so that it does not grow large enough to cause widespread damage in the relay room and fail the controls in the MCR. The cabinets classified as “Category II” and “Category III” cabinets are those that are not sealed and can potentially allow fires initiating within them to propagate. The sealed cabinets (Category I cabinets) do not allow propagation. If the Category II and III cabinets can be sealed so that they perform in a manner similar to the Category I cabinets, then the risk of large fires that can force MCR abandonment can be reduced.

It is assumed that if the portion of the SGS CDF related to the fire propagation cases in fire area 1FA-AB-100A can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total PACR attributable to external events
- Determine the component of the external events PACR attributable to fire events
- Determine the component of the fire based PACR attributable to fire area 1FA-AB-100A
- Determine the component of the 1FA-AB-100A PACR attributable to 1RE2 (fires that have propagated out of the Category II and III cabinets),
- Calculate the percent reduction in fire area CDF that would result if the SAMA is implemented and reduce the PACR for the fire areas by the same percent. The reduction in the PACR is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the SGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $8,282,000 for a single unit, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF can be estimated in several ways, but the distribution established in Section 4.6 to calculate the total External Events CDF is considered to be appropriate for SGS and is used here. Using that distribution, the fire CDF of 3.8E-05 per yr is estimated to be 72.4 percent of the total External Events CDF. The single unit fire contribution, therefore, corresponds to a PACR of $5,994,590.

The cost-risk associated with each fire area can then be determined based on their relative contributions to the total fire CDF and the assumption that the CDF is proportional to cost-risk (Fire CDFs are provided in Section E.5.1.6.1):

Fire Area	Percent of Fire Risk	Corresponding PACR (single unit)
1FA-AB-100A	18.9%	$1,135,817

The 1RE2 fire damage state comprises 76.4 percent of the total 1FA-AB-100A CDF (5.5E-06/yr out of 7.2E-06/yr). This corresponds to a PACR of $867,638 (5.5E-06 / 7.2E-06 * $1,135,817 = $867,638).

The risk reduction possible for this fire damage state is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. In this case, the cabinet enhancements are considered to be highly effective and they are assumed to eliminate all of the 1RE2 risk. This correlates to a single unit averted cost risk of $867,638.

E.6.21.1 Cost of implementation

SGS estimated an implementation cost of $3,230,000 for a single unit.

E.6.21.2 Net value

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation:

SAMA 21 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$867,638	$3,230,000	-$2,362,362

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative, which implies that this SAMA is not cost beneficial.

E.6.22 SAMA 22: Install Fire Barriers between the 1CC1, 1CC2, and 1CC3 Consoles in the Control Room Enclosure

The largest contributors to fires in the CRE are those that force abandonment of the CRE due to damage in the 1CC1, 1CC2, and 1CC3 consoles. The most effective means of reducing the CDF of these scenarios is considered to be preventing propagation of fires in any of these consoles to the other 2 consoles so that immediate MCR abandonment is not required. Preventing propagation so that the fire is contained in the originating console generally means that the operators will not have to abandon the MCR, although, a fire in 1CC3 is described as eventually requiring use of the auxiliary control panel to operate AFW. This is due to the damage that is assumed to occur to the electrical controls on console 1CC3. However, the failure probability used for this long term action is 4.0E-03 rather than the 8.7E-02 that is used in immediate MCR abandonment cases.

Implementation of this SAMA would require the installation of fire barriers between each of the 1CC1, 1CC2, and 1CC3 consoles. It should be noted that the barriers would not prevent damage to the equipment within the consoles where the fire originates; they only prevent propagation of the fire from the initiating console. Incipient fire detectors are a potential means of reducing the fire CDF for these scenarios, but they are not currently recognized as an acceptable means of reducing fire events and are not proposed as a SAMA in this analysis.

It is assumed that if the portion of the SGS CDF related to fire area 12FA-AB-122A can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total PACR attributable to external events.
- Determine the component of the external events PACR attributable to fire events.
- Determine the component of the fire based PACR attributable to fire area 12FA-AB-122A.
- Determine the component of the fire area 12FA-AB-122A PACR attributable to consoles 1CC1, 1CC2, and 1CC3.
- Calculate the percent reduction in fire area CDF that would result if the SAMA is implemented and reduce the PACR for the fire areas by the same percent. The reduction in the PACR is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the SGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $8,282,000 for a single unit, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF can be estimated in several ways, but the distribution established in Section 4.6 to calculate the total External Events CDF is considered to be appropriate for SGS and is used here. Using that distribution, the fire CDF of 3.8E-05 per yr is estimated to be 72.4 percent of the total External Events CDF. The single unit fire contribution, therefore, corresponds to a PACR of $5,994,590.

The cost-risk associated with each fire area can then be determined based on their relative contributions to the total fire CDF and the assumption that the CDF is proportional to cost-risk (Fire CDFs are provided in Section E.5.1.6.1):

Fire Area	Percent of Fire Risk	Corresponding PACR (single unit)
12FA-AB-122A	18.4%	$1,104,267

Fires that damage the 1CC1, 1CC2, and 1CC3 consoles (fire damage state CR16) contribute only a fraction of this fire area's risk. Based on the information in the IPEEE, the CR16 CDF is only 2.10E-06/yr out of the total fire area CDF of 7.00E-06/yr. The PACR associated with CR16 is, therefore, $331,280 (1,104,267 * 2.10E-06/7.0E-06 = $331,280).

The risk reduction possible for this area is a fraction of the CR16 PACR, but in this case, installation of the barriers is assumed to eliminate all of the CR16 risk and the entire PACR of $331,280 is assumed to be the averted cost-risk.

E.6.22.1 Cost of implementation

SGS estimated an implementation cost of $1,600,000 for a single unit.

E.6.22.2 Net value

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation:

SAMA 22 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$331,280	$1,600,000	-$1,268,720

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative, which implies that this SAMA is <u>not</u> cost beneficial.

E.6.23 SAMA 23: Install Fire Barriers and Cable Wrap to Maintain Divisional Separation in the 4160V AC Switchgear Room

Rooms that include cable or equipment for multiple divisions introduce the undesirable situation in which a single fire event can disable multiple divisions of equipment. Given the importance of the 4160V AC equipment, the cables and equipment in the 4160 Switchgear room should be protected to prevent the propagation of a fire from one division to another.

The main contributor to risk in this fire area is transient combustible that results in a fire that can propagate between buses; multiple division damage is not predicted for the other ignition sources in this area. Transient combustibles are controlled at SGS and while control of these potential ignition sources appears to be the cost appropriate means of controlling risk in this area, no additional reduction in risk is considered to be possible through further restrictions. In some cases, work is required in the room that necessitates the introduction of combustibles. As a result, ensuring there is adequate division between divisions with robust fire barriers is considered to be the best approach to reduce the fire contribution in the 4160V AC switchgear rooms.

It is assumed that if the portion of the SGS CDF related to fire area 1FA-AB-64A can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total PACR attributable to external events
- Determine the component of the external events PACR attributable to fire events

- Determine the component of the fire based PACR attributable to fire area 1FA-AB-64A

- Calculate the percent reduction in fire area CDF that would result if the SAMA is implemented and reduce the PACR for the fire areas by the same percent. The reduction in the PACR is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the SGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $8,282,000 for a single unit, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF can be estimated in several ways, but the distribution established in Section 4.6 to calculate the total External Events CDF is considered to be appropriate for SGS and is used here. Using that distribution, the fire CDF of 3.8E-05 per yr is estimated to be 72.4 percent of the total External Events CDF. The single unit fire contribution, therefore, corresponds to a PACR of $5,994,590.

The cost-risk associated with each fire area can then be determined based on their relative contributions to the total fire CDF and the assumption that the CDF is proportional to cost-risk (Fire CDFs are provided in Section E.5.1.6.1):

Fire Area	Percent of Fire Risk	Corresponding PACR (single unit)
1FA-AB-64A	8.9%	$536,358

The fires that propagate between divisions (transient combustible fires) contribute only a fraction of this fire area's risk. Based on the information in the IPEEE, the CDF associated with transient combustible fires totals about 1.0E-06 per yr; however, because the suppression system for this fire area was changed from a CO2 system to a water sprinkler system, this CDF must be multiplied by a factor of 2 to remain consistent with the treatment described in Section E.4.6.2.1 for the 1FA-AB-64A fire area. Therefore, transient combustible fires contribute a CDF of 2.0E-06 out of a total of 3.4E-

06 for this area and the corresponding PACR is $315,505 (536,358 * 2.0E-06/3.4E-06 = $315,505).

The risk reduction possible for this area is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. In this case, the fire barriers are assumed to be highly effective at preventing propagation between divisions and that preventing propagation essentially eliminates the risk for the fire scenario For the calculation, it is assumed that the new barriers will be 95 percent effective, which correlates to a single unit averted cost risk of $299,730 ($315,505 * 0.95 = $299,730).

E.6.23.1 Cost of implementation

SGS estimated an implementation cost of $975,000 for a single unit.

E.6.23.2 Net value

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation:

SAMA 23 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$299,730	$975,000	-$675,270

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative, which implies that this SAMA is <u>not</u> cost beneficial.

E.6.24 SAMA 24: Provide Procedural Guidance to Cross-tie Salem 1 and 2 Service Water Systems

An inter-unit SW cross-tie exists at SGS, but its use is only currently proceduralized for fire events. Ensuring that adequate procedures are developed to allow the use of the cross-tie for all initiator types would reduce the contribution of many loss of SW scenarios. The applicability of this change would be limited to cases where the CAV hardware is operational for the unit and when SW is functional on the opposite unit.

This SAMA proposes development and implementation of new EOP / AB procedures to direct use of the inter-unit service water crosstie as needed.

Assumptions:

- It is assumed that the procedures will direct use of the crosstie when needed. Current procedures restrict its use to times when the "donor" unit is in mode 5 or 6; however, this SAMA assumes no such restriction.
- The cues for the alignment of "AB-CAV" CRE cooling and the SW x-tie are based on different parameters (e.g. SW flow vs. CRE temperatures) such that the level of dependence between the actions is low.

E.6.24.1 Non-Fire Averted Cost-Risk

To calculate the consequences of implementation of this SAMA, the logic below GSWS1424 was moved to a new gate GSWS1424X which was ANDed with SW-XHE-UNITXTIE. SWS-XHE-UNITXTIE was also entered below AND gates G12S110 and G11S110. This models use of the crosstie to support either nuclear header on the recipient unit for mitigating functions and also to prevent a complete loss of service water event, for events which can affect service water supply to one unit only.

Results of SAMA Quantification:

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.53E-05	75.51	$295,976
Percent Change	8.6%	3.5%	3.2%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
$Frequency_{BASE}$	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
$Frequency_{SAMA}$	6.64E-06	1.81E-10	9.89E-07	1.98E-08	3.27E-05	2.97E-08	2.02E-07	3.01E-08	2.55E-06	1.97E-07	1.90E-06	**4.53E-05**
$Dose\text{-}Risk_{BASE}$	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
$Dose\text{-}Risk_{SAMA}$	0.11	0.00	0.02	0.05	40.88	0.61	2.10	0.33	23.21	0.78	7.43	**75.51**
$OECR_{BASE}$	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
$OECR_{SAMA}$	$21	$0	$5	$230	$109,218	$2,391	$8,019	$1,099	$115,260	$6,343	$53,390	**$295,976**

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

SAMA 24 Non-Fire Averted Cost-Risk

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
SGS Unit 1	$16,564,000	$15,862,568	$701,432

E.6.24.2 Internal Fires Averted Cost-Risk

The IPEEE fire analysis identified Service Water Pump Bay fires as one of the top 10 contributing fire areas; however, the IPEEE analysis does not reflect the plant as it is currently operated and the fire contributions from this area must be re-examined.

The fires in the Service Water Bays are driven by the fire induced and random Service Water pump failures. If at least 2 Service Water pumps are not available for a unit (1 if non-essential loads are isolated), then the IPEEE assumed core damage would ensue. This did not account for currently proceduralized actions to mitigate loss of SW initiators, which include the following two options:

1. Align a centrifugal charging pump to the demineralized water system for alternate pump cooling and align alternate Control Room Envelope cooling from the opposite unit (for any initiator).

2. Cross-tie SW to the opposite unit (only directed for fire initiators).

If these actions are credited for the fire analysis, the PACR for fire area 12FA-SW-90A/90B would be reduced to below the $50,000 review threshold and no SAMAs would be required to address the fire based risk. For example, even if the failure probability of the operator action to perform the SW cross-tie were as high as 0.1, the PACR would be reduced to $6,626 (based on the $66,256 PACR documented in Section E.5.6.1.2 for fire area 12FA-SW-90A/90B) and further efforts to reduce the fire area 12FA-SW-90A/90B would not be cost beneficial. Because procedures already exist to use the SW cross-tie for fire events, this SAMA would not result in any averted cost-risk for fire initiators. The external events multiplier of 2 is considered to address any averted cost-risk contributions from the other external events initiators.

E.6.24.3 Cost of implementation

SGS estimated an implementation cost of $175,000 for a single unit.

E.6.24.4 Net value

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation. The total averted cost-risk is based on the internal events evaluation multiplied by 2 to account for external events contributions. Procedures already exist to use the SW cross-tie for fire events and no additional benefit exists for this SAMA for those initiators.

SAMA 24 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$701,432	$175,000	$526,432

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive, which implies that this SAMA is cost beneficial.

E.6.25 SAMA 26: Strengthen Main Control Room Ceiling

Seismically induced failure of the MCR Ceiling Grid is assumed to cause injury to the plant operators and while it is possible to control the plant from the RSP, qualified personnel would not be available to operate the plant. Strengthening the MCR ceiling so that it is more seismically durable would help reduce the risk associated with MCR ceiling collapse.

Since the time of the IPEEE, the SGS main control room has been significantly modified. The changes included the installation of a new ceiling, which was designed to meet seismic requirements (PSEG 1996c).

While the HCLPF value for the SGS ceiling was estimated to be relatively high in the IPEEE (0.36g), the analysis assumed that failure of the ceiling grid supports could occur and that the ceiling could collapse into the MCR. Collapse of the ceiling was assumed to result in injury to the operators such that no personnel would be available to control the plant (conditional core damage probability = 1.0). Damage to the control panels is also assumed, but the remote shutdown panel would still be available for control.

Even if the revisions to the MCR ceiling are not credited to reduce the CDF, crediting the SGS field supervisor and/or the work control center supervisor (licensed SROs) as available operators would reduce the contribution from this sequence to the point where the PACR is below the minimum expected SAMA implementation cost. These SROs are not stationed in the MCR and would potentially be available to operate the plant in the postulated scenarios.

In the IPEEE, SGS used a 6.0E-02 failure probability for controlling the plant from the RSP. For this evaluation, assuming a failure probability as high as 0.5 for controlling the plant from the RSP is sufficient to reduce the relevant PACR below $100,000 and demonstrate that no further changes to the MCR ceiling would be cost beneficial for SGS.

It is assumed that if the portion of the SGS CDF related to seismic sequence 35 OP-IC can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total PACR attributable to external events.
- Determine the component of the external events PACR attributable to seismic events.

- Determine the component of the seismic PACR attributable to sequence 35 OP-IC assuming that the field supervisor and/or the work control center supervisor are available to recover the plant at the RSP (0.5 failure probability).
- Compare the PACR to the minimum expected implementation cost to demonstrate that further enhancements would not be cost beneficial.

The baseline assumption for external events contributions in the SGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $8,282,000 for a single unit, the same value is assigned to external events.

The relative contribution of seismic events to the total external events CDF can be estimated in several ways, but the distribution established in Section 4.6 to calculate the total External Events CDF is considered to be appropriate for SGS and is used here. Using that distribution, the seismic CDF of 9.5E-06 per yr is estimated to be 18.1 percent of the total External Events CDF. The single unit seismic contribution, therefore, corresponds to a PACR of $1,498,648.

The cost-risk associated with each seismic sequence can then be determined based on their relative contribution to the total seismic CDF and the assumption that the CDF is proportional to cost-risk (Seismic CDFs are provided in Section E.5.1.6.2). The baseline CDF for sequence 35 OP-IC is 1.20E-06, which corresponds to a PACR of 189,303:

Seismic Sequence	Percent of Seismic Risk	Corresponding PACR (single unit)
35 OP-IC	12.6%	$189,303

If the 0.5 multiplier is applied to this PACR to reflect the availability of non-MCR personnel to control the plant from the RSP after a seismic event with MCR ceiling failure, the PACR is reduced to $94,652, which is below the minimum expected SAMA implementation cost (Section E.5.1.1) and demonstrates that additional changes to the MCR ceiling would not be cost beneficial. It should also be noted that this SAMA does not include credit for the extensive changes that SGS has already implemented to modify and enhance the MCR ceiling subsequent to the IPEEE, which would tend to further reduce the PACR.

E.6.26 SAMA 27: In Addition to the Equipment Installed for SAMA 5, Install Permanently Piped Seismically Qualified Connections to Alternate AFW Water Sources

Seismically induced AFWST and AC power failures present the need to provide SBO mitigation capability (same as SAMA 5) and an alternate AFW suction source. SGS already has an alternate AFW suction alignment capability, but simplifying its alignment process through installation of a permanent, hard piped connection would improve reliability, especially after a seismic event where movement of the pipes could cause trouble with alignment of the "spool pieces" currently used in the suction path.

Because implementation of this SAMA would impact internal events risk as well as the specific seismic contributors that were used to identify the SAMA, the averted cost-risk is calculated as the sum of the internal and external events averted cost-risk components. For simplicity, the non-seismic external events contributions are considered to be treated by the use of the multiplier of 2 on the internal events result even though some portion of that result would normally be attributed to the seismic contributors. This approach could be considered to “double count” the seismic averted cost-risk.

E.6.26.1 Non-Seismic Averted Cost-Risk

This SAMA is essentially the same as SAMA 5; the exception is that failure of the AFST requires an alternate suction source for AFW. For internal events risk, failure of the AFST is a minor issue and the averted cost risk is estimated to be the same as what was calculated for SAMA 5 ($1,991,310).

E.6.26.2 Seismic Averted Cost-Risk

This SAMA was specifically identified to address the risk from seismic sequence 21F OP-FW-FC, which includes seismically induced failure of the AFST as a dominant contributor to AFW failure. However, the implementation of this SAMA would impact several other seismic sequences:

- 17 OP
- 33 OP-DAB
- 31 OP-SW
- 34 OP-DAB-DG
- 17F OP

Since the time of the IPEEE, some changes have been made to the MCR ceiling, but it is not clear that the changes would adequately address the failure mode identified in the IPEEE. As a result, seismic sequence 35 OP-IC is still considered to be a contributor and that further changes to the ceiling could be made to reduce the risk related to ceiling failure.

It is assumed that if the portion of the SGS CDF related to the relevant SGS seismic sequences can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total PACR attributable to external events
- Determine the component of the external events PACR attributable to seismic events
- Determine the component of the seismic PACR attributable to the seismic sequences identified above
- Calculate the percent reduction in the sequence CDFs that would result if the SAMA is implemented and reduce the PACR for the sequences by the same percent. The reduction in the PACRs is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the SGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $8,282,000 for a single unit, the same value is assigned to external events.

The relative contribution of seismic events to the total external events CDF can be estimated in several ways, but the distribution established in Section 4.6 to calculate the total External Events CDF is considered to be appropriate for SGS and is used here. Using that distribution, the seismic CDF of 9.5E-06 per yr is estimated to be 18.1 percent of the total External Events CDF. The single unit seismic contribution, therefore, corresponds to a PACR of $1,498,648.

The cost-risk associated with each seismic sequence can then be determined based on their relative contributions to the total seismic CDF and the assumption that the CDFs are proportional to cost-risk (Seismic CDFs are provided in Section E.5.1.6.2):

Seismic Sequence	Percent of Seismic Risk	Corresponding PACR (single unit)
21F OP-FW-FC	12.6%	$45,748
17 OP	30.6	$457,482
33 OP-DAB	21.1	$315,505
31 OP-SW	13.7	$205,078
34 OP-DAB-DG	8.1	$121,469
17F OP	5.7	$85,186

The risk reduction possible for this area is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. In this case, the SAMA is assumed to have a failure probability of 0.1 to account for the potentially difficult task of aligning the portable generator and other local tasks in time to prevent core damage. This implies that the SAMA eliminates 90 percent of the risk from these sequences and correlates to an averted cost-risk of $1,107,421.

E.6.26.3 Cost of implementation

SGS estimated an implementation cost of $4,230,000 for a single unit.

E.6.26.4 Net value

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation, where the total averted cost risk is the sum of the non-seismic averted cost-risk and the seismic averted cost-risk, or $3,098,731 ($1,991,310 + $1,107,421 = $3,098,731):

SAMA 27 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$3,098,731	$4,230,000	-$1,131,269

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative, which implies that this SAMA is not cost beneficial.

E.6.27 Summary

All of the SAMAs reviewed showed at least some benefit with respect to the traditional CDF and LERF risk metrics. However, since the CDF and MMACR for SGS is relatively high when compared with the rest of the industry, about half of the proposed SAMAs are nominally cost beneficial when comparing the averted cost-risk to their implementation costs.

Based on the given implementation costs, a list of those cost-beneficial SAMAs at the nominal level is given below that show the most likely candidates for proposed implementation. They are listed as follows:

SAMA 1: Enhance Procedures and Provide Additional Equipment to Respond to Loss of Control Area Ventilation

SAMA 2: Re-configure Salem 3 to Provide a More Expedient Backup AC Power Source for Salem 1 and 2

SAMA 4: Install Fuel Oil Transfer Pump on “C” EDG & Provide Procedural Guidance for Using “C” EDG to Power Selected “A” and “B” Loads

SAMA 6: Enhance Flood Detection for 84’ Aux Building and Enhance Procedural Guidance for Responding to Service Water Flooding

SAMA 9: Connect Hope Creek Cooling Tower Basin to Salem Service Water System as Alternate Service Water Supply

SAMA 10: Provide Procedural Guidance for Faster Cooldown on Loss of RCP Seal Cooling

SAMA 11: Modify Plant Procedures to Make Use of Other Unit's PDP for RCP Seal Cooling

SAMA 12: Improve Flood Barriers Outside of 220/440VAC Switchgear Rooms

SAMA 14: Expand AMSAC Function to Include Backup Breaker Trip on RPS Failure

SAMA 17: Enhance Procedures and Provide Additional Equipment to Respond to Loss of EDG Control Room Ventilation

SAMA 24: Provide Procedural Guidance to Cross-tie Salem 1 and 2 Service Water Systems

E.7 UNCERTAINTY ANALYSIS

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

- Use a discount rate of 7 percent, instead of 3 percent used in the base case analysis.
- Use the 95^{th} percentile PRA results in place of the mean PRA results.
- Selected MACCS2 input variables.

E.7.1 Real Discount Rate

A sensitivity study has been performed in order to identify how the conclusions of the SAMA analysis might change based on the value assigned to the real discount rate (RDR). The original RDR of 3 percent, which could be viewed as conservative, has been changed to 7 percent and the modified maximum averted cost-risk was re-calculated using the methodology outlined in Section E.4.

The Phase 2 analysis was re-performed using the 7 percent RDR. Implementation of the 7 percent RDR reduced the MMACR by 27 percent compared with the case where a 3 percent RDR was used. This corresponds to a decrease in the MMACR from $16,564,000 to $12,094,000.

The Phase 2 SAMAs are dispositioned based on a quantitative 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 further investigated.

The Phase 2 SAMAs were dispositioned based on a quantitative analysis using the PRA model and a specific cost-benefit analysis using the implementation costs estimated for each SAMA. 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 changed for three of the SAMAs (SAMA8, SAMA14, and SAMA22) when the 7 percent RDR was used in lieu of 3 percent. That is, these three SAMAs were no longer viewed as cost-beneficial when using the 7 percent real discount rate.

Summary of the Impact of the RDR Value on the Detailed SAMA Analyses

SAMA ID	Cost of Implementation (TBD)	Averted Cost Risk (3 percent RDR)	Net Value (3 percent RDR)	Averted Cost Risk (7 percent RDR)	Net Value (7 percent RDR)	Change in Cost Effectiveness?
SAMA1	$475,000	$4,784,252	$4,309,252	$3,508,584	$3,033,584	No
SAMA2	$875,000	$1,600,790	$725,790	$1,169,574	$294,574	No
SAMA3	$4,175,000	$2,394,480	($1,780,520)	$1,750,690	($2,424,310)	No
SAMA4	$585,000	$2,384,408	$1,799,408	$1,743,520	$1,158,520	No
SAMA5	$3,320,000	$3,057,558	($262,442)	$2,242,130	($1,077,870)	No
SAMA6	$250,000	$300,126	$50,126	$227,888	($22,112)	Yes
SAMA7	$470,000	$411,444	($58,556)	$310,370	($159,630)	No
SAMA8	$2,510,000	$1,647,921	($862,079)	$1,219,839	($1,290,161)	No
SAMA9	$1,235,000	$1,702,566	$467,566	$1,248,554	$13,554	No
SAMA10	$100,000	$110,564	$10,564	$83,716	($16,284)	Yes
SAMA11	$100,000	$1,998,924	$1,898,924	$1,462,022	$1,362,022	No
SAMA12	$475,000	$550,156	$75,156	$401,696	($73,304)	Yes
SAMA13	$17,750,000	$5,197,214	($12,552,786)	$3,732,412	($14,017,588)	No
SAMA14	$485,000	$530,488	$45,488	$425,414	($59,586)	Yes
SAMA15	$210,000	$41,954	($168,046)	$32,922	($177,078)	No
SAMA16	$2,535,000	$181,086	($2,353,914)	$132,776	($2,402,224)	No
SAMA17	$200,000	$506,180	$306,180	$370,060	$170,060	No
SAMA18	$635,000	$139,104	($495,896)	$101,726	($533,274)	No
SAMA19	$350,000	$33,772	($316,228)	$26,462	($323,538)	No
SAMA20	$13,100,000	$5,083,049	($8,016,951)	$3,725,430	($9,374,570)	No
SAMA21	$3,230,000	$867,638	($2,362,362)	$633,495	($2,596,505)	No
SAMA22	$1,600,000	$331,280	($1,268,720)	$241,880	($1,358,120)	No
SAMA23	$975,000	$299,730	($675,270)	$218,844	($756,156)	No
SAMA24	$175,000	$701,432	$526,432	$522,788	$347,788	No
SAMA27	$4,230,000	$3,098,731	($1,131,269)	$2,272,192	($1,957,808)	No

E.7.2 95th Percentile PRA Results

The results of the SAMA analysis can be impacted by implementing conservative values from the PRA's uncertainty distribution. If the best estimate failure probability values were consistently lower than the "actual" failure probabilities, the PRA model would underestimate plant risk and yield lower than "actual" averted cost-risk values for potential SAMAs. Re-assessing the cost-benefit calculations using the high end of the failure probability distributions is a means of identifying the impact of having consistently underestimated failure probabilities for plant equipment and operator actions included in the PRA model.

A Level 1 internal events model uncertainty analysis was performed for SGS. The availability and use of Level 2 uncertainties is unique since most plants incorporate only a Level 1 analysis in their SAMA reports. The reason a Level 2 analysis is not typically used is due to the differing degree of development and uncertainties between the two models. Specifically, the Level 1 model tends to represent the plant in a more thorough and comprehensive manner as opposed to the Level 2 model. Furthermore, there are more release contributors beyond those captured by LERF. As such, for the purposes of the 95^{th} percentile analysis, only Level 1 results are used in the uncertainty process.

In performing the sensitivity analysis, only the base case was used in determining the appropriate value for the 95^{th} percentile. For those SAMAs that required the addition of new basic events, no new uncertainty distributions were assigned since the design and implementation of each SAMA was arbitrary and was defined by the analysis assumptions. The results of this uncertainty analysis, therefore, show the expected statistical uncertainty of the CDF risk metrics under the assumption that each SAMA was designed and implemented as it was specified in this analysis. The analysis was run using the EPRI R&R Workstation UNCERT code (version 2.2) with the following simulation settings:

- Sample size – 25,000 trials
- Random seed – AUTO
- Sampling method – Monte Carlo

The calculational results of this uncertainty calculation is shown in the below table. The term CDF_{pe} refers to the nominal Level 1 CDF point estimate of 4.77E-05. The nominal

CDF value of 4.77E-5 was chosen as the mean point estimate instead of the base SAMA CDF (sum of all release category frequencies) value of 4.95E-5, since the Level 1 PRA model was what was used to generate the uncertainty distribution.

Summary of Uncertainty Distribution

Mean	5%	50%	95%	Ratio of 95% to CDFpe	Std Dev
4.77E-05	3.43E-05	4.46E-05	7.83E-05	1.64	1.52E-05

The above table reveals a factor that is 1.64 greater than the respective point estimate CDF used in the SAMA analysis. Therefore, for this analysis, the 95th percentile ratio of the base case is used to examine the change in the cost benefit for each SAMA.

E.7.2.1 Phase 1 Impact

Phase 1 SAMAs are not impacted by use of the 95th percentile PRA results. The Phase 1 screening process only eliminated one of the initial SAMAs due to no longer being applicable (see Table E.5-3), with all others being passed to the Phase 2 analysis. Hence, no separate sensitivity analysis was applicable to Phase 1.

E.7.2.2 Phase 2 Impact

As discussed above, a single factor based on the 95th percentile for the base case is used to determine the impact of the cost-benefit analysis for the proposed SAMA candidates. The uncertainty analyses that are available for the Level 1 model are not available (or not used) for the Level 2 and 3 PRA models. In order to simulate the use of the 95th percentile results for the Level 2 and 3 models, the same scaling factor calculated for the Level 1 results was implicitly applied to the Level 2 and 3 models.

The Phase 2 SAMA list was re-examined by multiplying the nominal averted cost risk by the ratio of the 95th percentile to the nominal CDF value (see Section 7.2) to identify SAMAs that would be re-characterized as cost beneficial, i.e., positive net value. Those SAMAs that were previously determined to not be cost beneficial due to implementation costs exceeding their associated nominal averted cost risk may be potentially cost beneficial at the revised 95th percentile averted cost risk.

E.7.2.3 95th Percentile Summary

The following table provides a summary of the impact of using the 95th percentile PRA results on the detailed cost-benefit calculations that have been performed. For display purposes, numbers enclosed within parentheses represent a negative value.

Summary of the Impact of Using the 95th Percentile PRA Results

SAMA ID	Cost of Implementation	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effectiveness?
SAMA1	$475,000	$4,784,252	$4,309,252	$7,853,396	$7,378,396	No
SAMA2	$875,000	$1,600,790	$725,790	$2,627,712	$1,752,712	No
SAMA3	$4,175,000	$2,394,480	($1,780,520)	$3,930,562	($244,438)	No
SAMA4	$585,000	$2,384,408	$1,799,408	$3,914,028	$3,329,028	No
SAMA5	$3,320,000	$3,057,558	($262,442)	$5,019,010	$1,699,010	Yes
SAMA6	$250,000	$300,126	$50,126	$492,660	$242,660	No
SAMA7	$470,000	$411,444	($58,556)	$675,389	$205,389	Yes
SAMA8	$2,510,000	$1,647,921	($862,079)	$2,705,078	$195,078	Yes
SAMA9	$1,235,000	$1,702,566	$467,566	$2,794,778	$1,559,778	No
SAMA10	$100,000	$110,564	$10,564	$181,492	$81,492	No
SAMA11	$100,000	$1,998,924	$1,898,924	$3,281,253	$3,181,253	No
SAMA12	$475,000	$550,156	$75,156	$903,086	$428,086	No
SAMA13	$17,750,000	$5,197,214	($12,552,786)	$8,531,276	($9,218,724)	No
SAMA14	$485,000	$530,488	$45,488	$870,801	$385,801	No
SAMA15	$210,000	$41,954	($168,046)	$68,868	($141,132)	No
SAMA16	$2,535,000	$181,086	($2,353,914)	$297,254	($2,237,746)	No
SAMA17	$200,000	$506,180	$306,180	$830,899	$630,899	No
SAMA18	$635,000	$139,104	($495,896)	$228,341	($406,659)	No
SAMA19	$350,000	$33,772	($316,228)	$55,437	($294,563)	No
SAMA20	$13,100,000	$5,083,049	($8,016,951)	$8,343,873	($4,756,127)	No
SAMA21	$3,230,000	$867,638	($2,362,362)	$1,424,236	($1,805,764)	No
SAMA22	$1,600,000	$331,280	($1,268,720)	$543,799	($1,056,201)	No
SAMA23	$975,000	$299,730	($675,270)	$492,010	($482,990)	No
SAMA24	$175,000	$701,432	$526,432	$1,151,407	$976,407	No
SAMA27	$4,230,000	$3,098,731	($1,131,269)	$5,086,596	$856,596	Yes

When the 95th percentile PRA results are used, four of the Phase 2 SAMAs (5, 7, 8, and 27) that were previously classified as not cost effective are now determined to be cost effective. The use of the 95th percentile PRA results is not considered to provide the most rational assessment of the cost effectiveness of a SAMA; however, these additional SAMAs should be considered for implementation to address the uncertainties inherent in the SAMA analysis.

E.7.2.4 Discussion of 95th Percentile Multiplier

The ratio of the 95th percentile to the nominal CDF value (see Section 7.2) to identify SAMAs that would be re-characterized as cost beneficial was based on an incomplete set of error factors. That is, the type code database for components such as pumps, valves, diesel generators, instrumentation, etc. was associated with the uncertainty distributions and parameters found in Reference (NRC 2007b). However, those basic events not associated with the standard type-code values, such as initiating events and human event probabilities, were not associated with any uncertainty distribution and associated error factor. As a result, it is expected that the generated ratio of the 95th percentile to the mean is somewhat underestimated, and to investigate this issue, a multiplier of 2.5, which is typical for most light water reactor CDF uncertainty analyses, was used to determine what the change in cost effectiveness is for those Phase 2 SAMAs evaluated in Section E.7.2.3. In effect, a similar table to that shown in Section E.7.2.3 is reproduced below, except that the multiplier was changed from a value of 1.64 to 2.5 in order to compensate for this additional component of uncertainty within the PRA model.

Summary of the Impact of Using the 95th Percentile PRA Results with a Multiplier of 2.5

SAMA ID	Cost of Implementation	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effectiveness?
SAMA1	$475,000	$4,784,252	$4,309,252	$11,960,631	$11,485,631	No
SAMA2	$875,000	$1,600,790	$725,790	$4,001,975	$3,126,975	No
SAMA3	$4,175,000	$2,394,480	($1,780,520)	$5,986,200	$1,811,200	Yes
SAMA4	$585,000	$2,384,408	$1,799,408	$5,961,020	$5,376,020	No
SAMA5	$3,320,000	$3,057,558	($262,442)	$7,643,895	$4,323,895	Yes
SAMA6	$250,000	$300,126	$50,126	$750,315	$500,315	No
SAMA7	$470,000	$411,444	($58,556)	$1,028,610	$558,610	Yes
SAMA8	$2,510,000	$1,647,921	($862,079)	$4,119,803	$1,609,803	Yes
SAMA9	$1,235,000	$1,702,566	$467,566	$4,256,415	$3,021,415	No
SAMA10	$100,000	$110,564	$10,564	$276,410	$176,410	No
SAMA11	$100,000	$1,998,924	$1,898,924	$4,997,310	$4,897,310	No
SAMA12	$475,000	$550,156	$75,156	$1,375,390	$900,390	No
SAMA13	$17,750,000	$5,197,214	($12,552,786)	$12,993,035	($4,756,965)	No
SAMA14	$485,000	$530,488	$45,488	$1,326,220	$841,220	No
SAMA15	$210,000	$41,954	($168,046)	$104,885	($105,115)	No
SAMA16	$2,535,000	$181,086	($2,353,914)	$452,715	($2,082,285)	No
SAMA17	$200,000	$506,180	$306,180	$1,265,450	$1,065,450	No
SAMA18	$635,000	$139,104	($495,896)	$347,760	($287,240)	No
SAMA19	$350,000	$33,772	($316,228)	$84,430	($265,570)	No
SAMA20	$13,100,000	$5,083,049	($8,016,951)	$12,707,623	($392,378)	No

Summary of the Impact of Using the 95th Percentile PRA Results with a Multiplier of 2.5

SAMA ID	Cost of Implementation	Averted Cost Risk (Base)	Net Value (Base)	Averted Cost Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effectiveness?
SAMA21	$3,230,000	$867,638	($2,362,362)	$2,169,095	($1,060,905)	No
SAMA22	$1,600,000	$331,280	($1,268,720)	$828,200	($771,800)	No
SAMA23	$975,000	$299,730	($675,270)	$749,325	($225,675)	No
SAMA24	$175,000	$701,432	$526,432	$1,753,580	$1,578,580	No
SAMA27	$4,230,000	$3,098,731	($1,131,269)	$7,746,828	$3,516,828	Yes

In using a 95th percentile multiplier of 2.5, there was only one change in the status of the cost effectiveness for the Phase 2 SAMAs previously evaluated using the original multiplier of 1.64, namely SAMA 3. As stated previously, the use of the 95th percentile PRA results is not considered to provide the most rational assessment of the cost effectiveness of a SAMA; however, in this instance, the use of a higher multiplier showed that there was one additional SAMA that warranted additional consideration for implementation.

E.7.3 MACCS2 Input Variations

The MACCS2 model was developed using the best information available for the SGS site; however, reasonable changes to modeling assumptions can lead to variations in the Level 3 results. In order to determine how certain assumptions could impact the SAMA results, a sensitivity analysis was performed on parameters that have previously been shown to impact the Level 3 results. These parameters include:

- Meteorological data
- Evacuation timing and speed
- Release height and heat
- Population estimates
- Population resettlement planning
- Economic rate of return

The risk metrics produced by MACCS2 that are evaluated in the sensitivity analyses are the 50 mile population dose and the 50 mile offsite economic cost. The subsections below discuss the changes in these results for each of the sensitivity parameters noted above. The final subsection, E.7.3.6, correlates the worst case changes identified in the sensitivity runs to a change in the site's averted cost-risk and discusses the implications of the sensitivity analysis on the SAMA analysis.

Sensitivity of SGS Baseline Risk to Parameter Changes

Parameter	Description	Pop. Dose Risk Δ Base (%)	Cost Risk Δ Base (%)
Meteorology	Year 2005 Meteorology	-4%	-4%
	Year 2006 Meteorology	+1%	+6%
	Year 2007 Meteorology	-8%	-11%
Evacuation Time	Evacuation delay time increased from 65 minutes to 130 minutes (factor of 2)	+3%	0%
Evacuation Speed	Average evacuation speed decreased 50% from 2.8 m/sec to 1.4 m/sec.	+4%	0%
Release Height	Release height set to ground level (in lieu of top of containment).	-8%	-7%
Release Heat	Buoyant plume assumed (10 MW for each plume segment, except for intact containment release).	-0.2%	-1%
Population	Year 2040 population uniformly increased 30%	+30%	+29%
Resettlement Planning	No "Intermediate Phase" resettlement planning (in lieu of 6 months)	+17%	-37%
	1 year "Intermediate Phase" resettlement planning (in lieu of 6 months)	-7%	+38%
Rate of Return	3% expected rate of return (in lieu of 7%)	+0.3%	-9%
	12% expected rate of return (in lieu of 7%)	-0.2%	+11%

E.7.3.1 Meteorological Sensitivities

In addition to the year 2004 base case meteorological data, years 2005 through 2007 were also analyzed. Analysis of year 2005 and 2007 data sets yielded population dose-risks and cost risks that were 4% to 11% less than 2004 results. The year 2006 data set showed higher dose risk and cost risk than the 2004 results, 1% and 6%

respectively. As previously discussed, the data gaps in the 2004 results were less than 1% while the precipitation data gaps in the 2006 data was 8.3%. As no particular criteria have been defined by the industry related to determining which meteorological data set should be used as a base case for a site, the year 2004 data is chosen for SGS given that it represents the most complete data set and results in higher results than most of the other data sets.

E.7.3.2 Evacuation Sensitivities

The sensitivity of two evacuation parameters was assessed. The delay time to evacuation (increased from 65 minutes to 130 minutes) was found to have a minor impact (approximately 3% increase) on population dose risk. The evacuation speed sensitivity which decreased the average radial evacuation speed by a factor of two (from 2.8 m/sec to 1.4 m/sec) demonstrates a similar impact. The population dose risk increased approximately 4% using the slower evacuation speed. An increase in population dose is the expected result for a slower evacuation speed since evacuees would be expected to be exposed to releases for a longer period of time. It is noted that while evacuation assumptions do impact the population dose-risk estimates, they do not impact MACCS2 offsite economic cost-risk estimates because MACCS2 calculated cost-risks are based on land contamination levels which remain unaffected by evacuation assumptions and the number of people evacuating.

E.7.3.3 Release Height & Heat Sensitivities

The release height sensitivity case quantifies the impact of the assumption related to the height of the release of the plumes. The baseline case assumes that the releases occur at the top of containment (59m) which tends to disperse material over a wider geographical region, generally impacting more people and creating larger cleanup costs. A ground level release height shows a decrease in dose risk and cost risk of 8% and 7%, respectively.

The release heat sensitivity case evaluates the impact of neglecting thermal plume effects. The base case assumed no thermal plume heat in the releases (e.g., no buoyant plumes). The sensitivity case assumed a heat content of 10 MW per plume segment, except for the intact containment release category. Increasing the plume heat contents resulted in differing results for individual releases (i.e., results of some release categories increased while others decreased.) The net result is a negligible dose-risk change and a small cost risk decrease of 1% when 10 MW plume heat content values are applied.

E.7.3.4 Population Sensitivity

A population sensitivity case assesses the impact of population assumptions. The base case year 2040 population is uniformly increased by 30% in all sectors of the 50-mile radius. This change has a significant impact on the dose risk and cost risk, increasing risk by 30% and 29%, respectively. This sensitivity case demonstrates a significant dependence upon population estimates. This dependence is expected given that population dose and offsite economic costs are primarily driven by the regional population.

E.7.3.5 Resettlement Planning Sensitivities

The MACCS2 consequence modeling incorporates an “intermediate phase” which depicts the time period following the release and immediate evacuation actions (termed the “early phase”) and extends to the time when recovery efforts such as decontamination and resettlement of people are begun (termed the “long term phase”). The intermediate phase thus models the time period when decontamination and resettlement plans are being developed. MACCS2 allows the habitation of land during the intermediate phase unless projected dose criteria is exceeded, in which case individuals are relocated. MACCS2 allows an intermediate phase ranging from no intermediate phase to one year. The intermediate phase sensitivities show significant impacts and are therefore discussed further:

- The no intermediate phase resettlement planning case is developed based on the NUREG-1150 modeling approach. The 37% reduction in cost risk seen in the sensitivity results, however, are judged too optimistic in that the land decontamination efforts are modeled as starting one week after the accident (i.e., directly after the early phase ends) such that a significant portion of population relocation costs are omitted. For instance, the costs associated with temporary housing while decontamination strategies are developed and decontamination teams are contracted are not accounted for without an intermediate phase. A competing factor is that the population dose increases (17% increase over the base case) because people are allowed to re-occupy the land sooner. It is believed that the NUREG-1150 studies omitted the intermediate phase because the intermediate phase coding was not validated at that time (NRC 1998a).

- The 1 year intermediate phase resettlement planning case is developed based on the maximum length of time allowed by MACCS2 for the intermediate phase. A long intermediate phase can be unrealistic in that re-occupation of contaminated land is not performed during this phase even if contamination levels decrease (by natural radioactive decay) to levels which would allow it (i.e., resettlement is evaluated as part of the long term phase, not the intermediate phase). Therefore population relocation costs may be over estimated using a long (i.e., one year) intermediate phase. An intermediate phase of one year shows a 38% increase in cost risk estimates compared with the base case selection of 6 months. The population dose decreased by 7% with a longer intermediate phase due to later resettlement on decontaminated land.

The six month intermediate phase (base case) is judged to be a best estimate approach in that it provides reasonable time for both decontamination and resettlement planning to be performed. The sensitivity cases demonstrate that the six month value used in the base case provides mid-range results for the modeling choices available.

E.7.3.6 Rate of Return Sensitivities

One of the economic cost components included in the MACCS2 calculated cost result is the financial loss associated with property and associated improvements (e.g., buildings) not achieving their expected annual rate of return during interdiction periods. A piece of land that is interdicted (i.e., not occupied) for a period of years will not achieve the historical rate of return or the rate of return achieved by other non-impacted properties during the interdiction period. This lack of expected return is an economic loss for the owner / society. The base case assumes a 7% expected rate of return, consistent with NRC guidance (NRC 2004). A sensitivity case using a 3% expected rate of return (NRC 2004) shows a decrease in the expected cost risk of approximately 9%. This decrease in cost risk associated with the lower rate or return is expected since there is a lower expectation associated with the land's return on investment. A sensitivity case using a 12% expected rate of return, the value used in NUREG-1150 MACCS2 analyses (NRC 1990a), shows an increase cost risk of approximately 11%. For both sensitivity cases the dose risk changes are essentially negligible.

E.7.3.7 Impact on SAMA Analysis

Several different Level 3 input parameters have been examined as part of the SGS 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 E.7.3 summarizes the changes (in percentage) to the dose-risk and OECR 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 resulted from increasing the 2040 population estimate by 30 percent while the largest increase in OECR (38 percent) resulted from increasing the length of the "Intermediate Phase" from 6 months to 12 months. The SGS MACR was recalculated using these results to determine the impact of using the worst case for each parameter simultaneously. The resulting MACR was $21,468,143, which is less than the MACR that correlates to the use of the 95th percentile PRA results. As implied in Section E.7.2, the MACR for the 95th percentile PRA results can be estimated by multiplying the base MACR of $16,564,000 by a factor of 1.64 to obtain $27,164,960. The 95th percentile PRA results sensitivity is considered to bound the worst case combination of the MACCS2 sensitivity cases and no SAMAs would be retained based on this sensitivity that were not already identified in Section E.7.2.

E.7.4 Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries (SAMA 5A)

SGS SAMA 5 was developed with the intent of providing a comprehensive, long term mitigation strategy for SBO scenarios. The design includes a means of providing both primary and secondary side makeup in addition to ensuring power is available to the switchyard so that offsite power can be re-aligned to the site in long term SBOs.

An alternate approach to mitigating SBOs would be to limit the scope of the SAMA to only address cases in which the RCP seals remain intact, which occurs in a majority of the SBO scenarios based on the assumptions used in the SGS PRA. Due to the uncertainty related to RCP seal performance, the original SAMA 5 design is considered to be the most appropriate for SBO scenarios, but the PRA model will show that most of the benefit for SBO sequences can be achieved by prolonging the availability of secondary side heat removal and recovering offsite power. Adopting this approach to the SAMA design, however, places a large amount of importance on the assumptions related to RCP seal performance,

In order to investigate the potential benefit of only prolonging secondary side heat removal and offsite power restoration capability, the air cooled PDP/CCP was removed from the SAMA 5 design and the size of the 460V AC generator was reduced to match the loads associated with turbine driven AFW operation (SAMA 5A). The details of the analysis are provided below.

E.7.4.1 Non-Seismic Averted Cost-Risk

<u>PRA Model Changes to Model SAMA:</u>

In order to simulate implementation of this SAMA, only minor database changes were required. Specifically, the installation of the battery charger generators was modeled by adjusting the offsite power nonrecovery probabilities: the likelihood of offsite power nonrecovery was changed to 0.01 for grid and site/switchyard related causes and to 0.03 for weather related causes. This represents both the likelihood that offsite power would not be available for restoration at extended times of about 24 hours and the likelihood that requisite actions would not be successful.

Results of SAMA Quantification:

Implementation of this SAMA yielded a reduction in the CDF, Dose-Risk, and Offsite Economic Cost-Risk. The results are summarized in the following table for SGS:

	CDF	Dose-Risk	OECR
Base Value	4.95E-05	78.22	$305,718
SAMA Value	4.48E-05	70.63	$276,851
Percent Change	9.5%	9.7%	9.4%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR	Total
Frequency_{BASE}	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06	**4.95E-05**
Frequency_{SAMA}	6.64E-06	1.81E-10	9.89E-07	1.98E-08	3.27E-05	2.97E-08	2.02E-07	3.01E-08	2.55E-06	1.97E-07	1.90E-06	**4.53E-05**
Dose-Risk_{BASE}	0.15	0.00	0.02	0.06	42.75	0.61	2.32	0.37	23.21	0.78	7.94	**78.22**
Dose-Risk_{SAMA}	0.11	0.00	0.02	0.05	40.88	0.61	2.10	0.33	23.21	0.78	7.43	**75.51**
OECR_{BASE}	$29	$0	$5	$292	$114,228	$2,391	$8,853	$1,241	$115,260	$6,376	$57,043	**$305,718**
OECR_{SAMA}	$21	$0	$5	$230	$109,218	$2,391	$8,019	$1,099	$115,260	$6,343	$53,390	**$295,976**

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

SAMA 5A Averted Cost-Risk Value

Unit	Base Case Cost-Risk	Revised Cost-Risk	Averted Cost-Risk
Salem Unit 1	$16,564,000	$14,987,254	$1,576,746

For the non-seismic contributors, the averted cost-risk of $1,576,746 is about 79 percent of the $1,991,310 averted cost-risk that was achieved by SAMA 5.

E.7.4.2 Seismic Averted Cost-Risk

SAMA 5A would address the same seismic sequences as SAMA 5, which are generally SBO scenarios and include the following:

- 17 OP

- 33 OP-DAB
- 31 OP-SW
- 34 OP-DAB-DG
- 17F OP

It is assumed that if the portion of the SGS CDF related to the relevant SGS seismic sequences can be identified, and then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total PACR attributable to external events
- Determine the component of the external events PACR attributable to seismic events
- Determine the component of the seismic PACR attributable to the seismic sequences identified above
- Calculate the percent reduction in the sequence CDFs that would result if the SAMA is implemented and reduce the PACR for the sequences by the same percent. The reduction in the PACRs is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the SGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $8,282,000 for a single unit, the same value is assigned to external events.

The relative contribution of seismic events to the total external events CDF can be estimated in several ways, but the distribution established in Section 4.6 to calculate the total External Events CDF is considered to be appropriate for SGS and is used here. Using that distribution, the seismic CDF of 9.5E-06 per yr is estimated to be 18.1 percent of the total External Events CDF. The single unit seismic contribution, therefore, corresponds to a PACR of $1,498,648.

The cost-risk associated with each seismic sequence can then be determined based on their relative contributions to the total seismic CDF and the assumption that the CDFs are proportional to cost-risk (Seismic CDFs are provided in Section E.5.1.6.2):

Seismic Sequence	Percent of Seismic Risk	Corresponding PACR (single unit)
17 OP	30.6	$457,482
33 OP-DAB	21.1	$315,505
31 OP-SW	13.7	$205,078
34 OP-DAB-DG	8.1	$121,469
17F OP	5.7	$85,186

The risk reduction possible for this area is a fraction of the total ($1,184,720) based on the potential capabilities of the changes proposed in this SAMA. In this case, the SAMA is assumed to have a failure probability of 0.1 to account for the potentially difficult task of aligning the portable generator and other local tasks in time to prevent core damage. This implies that the SAMA eliminates 90 percent of the risk from these sequences, which would correlates to an averted cost-risk of $1,066,248.

However, the reduced scope of SAMA 5A relative to SAMA 5 does indicate that the averted cost-risk should be less than what was estimated for SAMA 5. The internal events results demonstrated that SAMA 5A achieved only about 79 percent of the averted cost-risk for SAMA 5, which was primarily based on SBO mitigation. Given that the seismic sequences addressed by SAMA 5A are also SBO sequences, the same type of reduction is considered to be applicable to the seismic sequences. As a result, the $1,066,248 averted cost-risk is multiplied by 0.79 to account for the elimination of the primary side makeup capability of SAMA 5A. The seismic averted cost–risk for this SAMA is $842,336

E.7.4.3 Cost of implementation

SGS estimated an implementation cost of $770,000 for a single unit, which is based on the implementation cost for SAMA 5 minus the cost of a new PDP pump ($3,320,000 – $2,550,000).

E.7.4.4 Net value

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation, where the total averted cost risk is the sum of the non-seismic averted cost-risk and the seismic averted cost-risk, or $2,419,082 ($1,576,746 + $842,336 = $2,419,082):

SAMA 5A Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$2,419,082	$770,000	$1,649,082

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive, which implies that this SAMA is cost beneficial.

E.8 CONCLUSIONS

The benefits of revising the operational strategies in place at SGS and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. Use of the PRA in conjunction with cost-benefit analysis methodologies has, however, provided an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on a larger future population. The results of this study indicate that several potential improvements were identified that warrant further review for potential implementation at SGS.

It should be noted that Salem units 1 and 2 are essentially identical in design and operation. Such differences that do exist are not believed to be significant from a risk perspective. As such, the Unit 1 PRA model that was employed to evaluate each of the risk benefits and averted costs for each of the SAMAs was viewed as also being applicable to Unit 2. That is, if a particular SAMA proves cost beneficial for Unit 1, it will also likewise be cost beneficial for Unit 2.

In summary, based on the given implementation costs, a number of SAMAs have been identified as cost-beneficial at the 95th percentile and are suggested for potential implementation at SGS (see Section E.7.2.4). While these results are believed to accurately reflect potential areas for improvement at the plant, PSEG notes that this analysis should not necessarily be considered a formal disposition of these proposed changes as other engineering reviews are necessary to determine the ultimate resolution. For the identified cost-beneficial SAMAs listed below, PSEG will disposition them using existing action-tracking and design change processes.

SAMA 1: Enhance Procedures and Provide Additional Equipment to Respond to Loss of Control Area Ventilation

SAMA 2: Re-configure Salem 3 to Provide a More Expedient Backup AC Power Source for Salem 1 and 2

SAMA 3: Install Limited EDG Cross-tie Capability Between Salem 1 and 2

SAMA 4: Install Fuel Oil Transfer Pump on “C” EDG & Provide Procedural Guidance for Using “C” EDG to Power Selected “A” and “B” Loads

SAMA 5: Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries & Replace PDP with Air-Cooled Pump

SAMA 5A: Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries (Section E.7.4)

SAMA 6: Enhance Flood Detection for 84’ Aux Building and Enhance Procedural Guidance for Responding to Service Water Flooding

SAMA 7: Install “B” Train AFWST Makeup Including Alternate Water Source

SAMA 8: Install High Pressure Pump Powered with Portable Diesel Generator and Long-term Suction Source to Supply the AFW Header

SAMA 9: Connect Hope Creek Cooling Tower Basin to Salem Service Water System as Alternate Service Water Supply

SAMA 10: Provide Procedural Guidance for Faster Cooldown on Loss of RCP Seal Cooling

SAMA 11: Modify Plant Procedures to Make Use of Other Unit’s PDP for RCP Seal Cooling

SAMA 12: Improve Flood Barriers Outside of 220/440VAC Switchgear Rooms

SAMA 14: Expand AMSAC Function to Include Backup Breaker Trip on RPS Failure

SAMA 17: Enhance Procedures and Provide Additional Equipment to Respond to Loss of EDG Control Room Ventilation

SAMA 24: Provide Procedural Guidance to Cross-tie Salem 1 and 2 Service Water Systems

SAMA 27: In Addition to the Equipment Installed for SAMA 5, Install Permanently Piped Seismically Qualified Connections to Alternate AFW Water Sources

E.9 TABLES

Table E.2-1
Summary Table

Model Revision Date	Model Name	Int. Events Excluding Internal Flooding (1/yr)	Internal Flooding (1/yr)	Total CDF (1/yr)	Total LERF (1/yr)	Trunc. Limit (1/yr)	Reference (See Section E.11)	Note
July 1993	IPE	4.80E-05	1.6E-05	6.40E-05	5.23E-06	NR	PSEG 1993	1
Aug. 1996	Model 1.0	4.40E-05	7.3E-06	5.13E-05	4.75E-06	NR	PSEG 1996b	2
Aug. 1998	Model 2.0	4.50E-05	7.3E-06	5.23E-05	4.75E-06	1E-10	PSEG 1998	3
Jun. 2002	Model 3.0	4.47E-05	7.3E-06	5.20E-05	5.74E-06	1E-10	PSEG 2002	4
July 2003	Model 3.1	3.37E-05	7.3E-06	4.10E-05	3.97E-06	1E-09	PSEG 2004a	5
March 2005	Model 3.2	1.49E-05	9.9E-06	2.48E-05	1.01E-06	1E-11	PSEG 2005b	6
March 2006	Model 3.2A	6.21E-05	NR	NR	7.61E-06	1E-11	PSEG 2006	7
March 2008	Model 4.0	4.54E-05	NR	NR	NR	1E-11	PSEG 2008a	8
Sept. 2008	Model 4.1	4.29E-05	4.84E-06	4.77E-05	5.06E-06	1E-11	PSEG 2008b	9

Notes:

1. The IPE provides unit-specific values for CDF and LERF. For total CDF (not including internal flooding), the Unit 2 value of 4.8E-05/yr is provided because it is more conservative than the Unit 1 value of 4.4E-05/yr. The Unit 2 LERF value of 5.23E-06/yr is used because it is more conservative than the Unit 1 value of 3.95E-06/yr. The truncation limit is not reported (NR).
2. The PRA Model 1.0 CDF values provided above correspond to those calculated for Unit 1. The Unit 2 internal flooding CDF and CDF not including flooding are 7.2E-06/yr and 4.3E-05/yr, respectively. The LERF value provided in the table above is that of Unit 2 because it is more conservative than the Unit 1 value of 3.95E-06/yr. This revision incorporates changes to the PRA Model as of July 1996. The truncation limit is not reported.
3. The PRA Model 2.0 CDF value (not including internal flooding) provided is the Unit 2 value (Unit 1 value is 3.42E-05/yr) but the internal flooding CDF value is conservatively taken from Unit 1 (Unit 2 is 7.2E-06/yr). The LERF provided above is conservatively taken from Unit 2 (Unit 1 LERF is 3.95E-06/yr). This revision incorporates changes in the PRA model as of March 1997.
4. This revision was first released in November 2001 as an interim report to accommodate the Westinghouse Owner's Group (WOG) certification process. After receiving the WOG certification comments in December 2001, the model was delayed issuance until all Grade "A" and certain Grade "B" comments were resolved. It was not until June 2002 that Revision 3 of the PRA model became quantified and documented. The internal flood analysis, which was first performed in 1988, is reviewed; however, no new CDF due to internal flooding is calculated. The LERF value without the estimate internal flooding contribution is 4.89E-06/yr. These results have been obtained at the truncation probabilities of 1E-8 (for top events) and 1E-10 (for sequences).
5. This revision incorporates changes in the PRA model as of July 2003. The internal flooding contribution to CDF and LERF are not calculated in this revision but instead are taken from the previous revision (3.0). The above values reflect the internal flooding contribution from the previous revision. The CDF and LERF values without the contribution of internal flooding are 3.37E-05/yr and 3.12E-06/yr, respectively. For this update, a cutoff frequency of 1.0E-08 is usually used at the equation level (i.e., in the .IN file). The event tree cutoff value for merge steps in the .OCL file is 1E-09, and was used rather than the default value of 1E-10 because the cutset limit of 60,000 could easily be exceeded depending what equipment is unavailable.
6. As noted later in Section E.2.1.4, this revision documents the conversion of the Salem PRA model from WinNUPRA software platform to CAFTA. It is also important to note that this revision was never used by Salem but is being documented in this report because it was used as design input to the following revision of the PRA model 3.2A. The PRA 3.2A update is based off of data accumulated until August 2004. It is important to note that the internal flooding contributions to CDF and LERF were not calculated in this revision. Although this revision estimates that the LERF contribution from internal flooding is 1.15E-07/yr. When this value is added to the LERF value calculated without internal flooding (8.97E-07/yr), a total LERF value of 1.01E-06/yr is calculated.

7. The total internal flooding CDF and LERF were not provided by this model revision. The LERF value provided is that without the internal flooding contribution included.
8. Revision 4.0 of the PRA model does not provide the internal flooding CDF or the total LERF values. These values are provided in Model Revision 4.1.
9. Revision 4.1 of the PRA model includes both LERF and the CDF contribution frominternal flooding scenarios. Although the nominal CDF value is 4.77E-05/yr, the sum of the Level 2 release categories (4.95E-05/yr) was used for the base MMACR (see Sections E.2.2.8 and E.4).

Table E.2-2
Sequence Results

Endstate	Frequency	Percent
INTACT	9.22E-6	19%
LATE-BMMT-AFW	1.81E-10	<0.1%
LATE-BMMT-NOAFW	9.89E-7	2%
LATE-CHR-AFW	2.52E-8	<0.1%
LATE-CHR-NOAFW	3.42E-5	70%
LERF-ISLOCA	2.97E-8	<0.1%
LERF-CI	2.23E-7	0.5%
LERF-CFE	3.40E-8	<0.1%
LERF-SGTR-AFW	2.55E-6	5%
LERF-SGTR-NOAFW	1.98E-7	0.4%
LERF-ISGTR	2.03E-6	4%

Table E.2-3
Selection of Representative Release Scenarios

Release Category	Initiator	Sequence Definition
INTACT	TT	AFW fails, F&B fails, hotleg rupture, CHR
LATE-BMMT-AFW	TCC	Seal LOCA, AFW, SI fails, CHR
LATE-BMMT-NOAFW	TA	AFW fails
LATE-CHR-AFW	S2	AFW, SI, recirc fails, POX fails, CHR fails
LATE-CHR-NOAFW	TVC	AFW fails, POX, CHR fails
LERF-ISLOCA	VS	Isolation fails, SI fails
LERF-CI	TVC	AFW fails, pre-existing containment leak
LERF-CFE	TVC	AFW fails, containment failure @ vessel breach
LERF-SGTR-AFW	SGTR	SG isolation, SI, AFW, F&B fails, SOSGRV
LERF-SGTR-NOAFW	SGTR	SI, AFW, F&B fails, SOSGRV
LERF-ISGTR	TVC	AFW fails, induced SGTR @ core damage

Table E.2-4
Salem Plant Damage State Matrix

		CI	Isolated				Not Isolated			
		CHR	FC&CS	FC	CS	None	FC&CS	FC	CS	None
RCS Press	ECCS	PDS	A	B	C	D	E	F	G	H
High	Injection	1								
	Inj & Recirc	2								
	None	3								
Low	Injection	4								
	Inj & Recirc	5								
	None	6								
Unisolated ISLOCA		7								
SGTR		'								

Notes: CI = Containment Isolation
CHR = Containment Heat Removal
FC = Containment Fan Coolers
CS = Containment Spray
RCS = Reactor Coolant System
ECCS = Emergency Core Cooling System
PDS = Plant Damage State
ISLOCA = Interfacing System LOCA
SGTR = Steam Generator Tube Rupture
' = Appended to PDS designation to indicate SGTR

Table E.2-5
Level 2 Sequences – Plant Damage State Interface

Level 2 Sequence	Plant Damage States							
	12/ABC	**3/ABC**	**123/D**	**45/ABC**	**6/ABC**	**456/D**	**123456/EFGH**	**7 or '**
INTACT01				X[1]				
INTACT02				X[2]				
INTACT03	X							
INTACT04	X							
INTACT05	X	X						
LATE01					X[1]			
LATE02						X[2]		
LATE03					X[1]			
LATE04						X[2]		
LATE05		X						
LATE06			X					
LATE07		X						
LATE08			X					
LATE09			X					
LERF01				X[1]	X[1]	X[1]		
LERF02				X[2]	X[2]	X[2]		
LERF03	X	X	X					
LERF04	X	X	X					
LERF05	X	X	X					
LERF06	X	X	X					
LERF07	X	X	X					
LERF08							X	
LERF09								X

1. With LOCA or open PORV (no AFW)
2. With steam generator cooling

Table E.2-6
Salem Level 2 Overall Results

Endstate	Frequency	Percent
INTACT	9.22E-6	19%
LATE	3.52E-5	71%
LERF	5.06E-6	10%
Total (LEVEL2)	4.89E-5	100%

Table E.3-1
Estimated Population Distribution within a 10-Mile Radius of SGS, Year 2040

Sector	0-1 mile (1.00) [(1)]	1-2 miles (1.00) [(1)]	2-3 miles (1.00) [(1)]	3-4 miles (1.19) [(1)]	4-5 miles (1.38) [(1)]	5-10 miles (1.17) [(1)]	10-mile total
N	0	0	0	0	0	1659	1659
NNE	0	0	0	0	86	14370	14456
NE	0	0	0	0	143	4090	4233
ENE	0	0	0	168	466	3173	3806
E	0	0	0	0	179	1572	1751
ESE	0	0	0	0	0	1517	1517
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	117	117
S	0	0	0	81	0	1081	1162
SSW	0	0	0	0	0	1178	1178
SW	0	0	0	24	0	4265	4290
WSW	0	0	15	0	738	4697	5451
W	0	0	0	20	462	15468	15951
WNW	0	0	0	272	1745	5594	7611
NW	0	0	75	0	767	5154	5996
NNW	0	0	145	143	129	40405	40822
Total	0	0	235	708	4715	104341	109999

[(1)]Radial ten year population growth factor applied successively to year 2000 census data to develop year 2040 estimate. Radial growth factor is based upon radial population growth from 1990 to year 2000.

Table E.3-2
Estimated Population Distribution within a 50-Mile Radius of SGS, Year 2040

Sector	0-10 miles	10-20 miles (1.16) [(1)]	20-30 miles (1.09) [(1)]	30-40 miles (1.01) [(1)]	40-50 miles (1.04) [(1)]	50-mile total
N	1659	225283	195325	161195	198883	782344
NNE	14456	24411	161621	962962	1294039	2457489
NE	4233	15236	93545	415783	517857	1046653
ENE	3806	7877	45183	79722	44380	180967
E	1751	60180	103670	22181	50533	238315
ESE	1517	16167	21389	9929	28145	77147
SE	0	129	794	0	47423	48347
SSE	117	99	1755	1404	7628	11002
S	1162	25582	84655	27585	18460	157444
SSW	1178	29753	15392	9817	16803	72943
SW	4290	6526	7362	6301	12385	36864
WSW	5451	6525	4886	11132	35401	63394
W	15951	8781	5629	55514	206764	292639
WNW	7611	38758	35044	30374	27568	139356
NW	5996	176706	40620	28231	51267	302821
NNW	40822	218055	108203	75879	64369	507329

Table E.3-2
Estimated Population Distribution within a 50-Mile Radius of SGS, Year 2040

Sector	0-10 miles	10-20 miles (1.16) [(1)]	20-30 miles (1.09) [(1)]	30-40 miles (1.01) [(1)]	40-50 miles (1.04) [(1)]	50-mile total
Total	109999	860069	925072	1898009	2621906	6415055

(1) Radial ten year population growth factor applied successively to year 2000 census data to develop year 2040 estimate. Radial growth factor is based upon radial population growth from 1990 to year 2000.

Table E.3-3
SGS MACCS2 End of Cycle Core Inventory

Entry	Nuclide	Activity (Bq)	Entry	Nuclide	Activity (Bq)
1	Co-58	3.43E+16	31	Te-131m	5.48E+17
2	Co-60	2.62E+16	32	Te-132	5.45E+18
3	Kr-85	4.11E+16	33	I-131	3.70E+18
4	Kr-85m	9.71E+17	34	I-132	5.23E+18
5	Kr-87	1.76E+18	35	I-133	7.47E+18
6	Kr-88	2.50E+18	36	I-134	8.21E+18
7	Rb-86	2.21E+15	37	I-135	7.09E+18
8	Sr-89	4.20E+18	38	Xe-133	7.47E+18
9	Sr-90	2.27E+17	39	Xe-135	1.87E+18
10	Sr-91	5.40E+18	40	Cs-134	5.06E+17
11	Sr-92	5.63E+18	41	Cs-136	1.54E+17
12	Y-90	2.44E+17	42	Cs-137	2.83E+17
13	Y-91	5.12E+18	43	Ba-139	7.36E+18
14	Y-92	5.65E+18	44	Ba-140	7.28E+18
15	Y-93	6.39E+18	45	La-140	7.44E+18
16	Zr-95	6.47E+18	46	La-141	6.82E+18
17	Zr-97	6.74E+18	47	La-142	6.58E+18
18	Nb-95	6.12E+18	48	Ce-141	6.62E+18
19	Mo-99	7.14E+18	49	Ce-143	6.43E+18
20	Tc-99m	6.16E+18	50	Ce-144	3.99E+18
21	Ru-103	5.32E+18	51	Pr-143	6.32E+18
22	Ru-105	3.46E+18	52	Nd-147	2.82E+18
23	Ru-106	1.21E+18	53	Np-239	7.57E+19
24	Rh-105	2.40E+18	54	Pu-238	4.29E+15
25	Sb-127	3.26E+17	55	Pu-239	9.68E+14
26	Sb-129	1.16E+18	56	Pu-240	1.22E+15
27	Te-127	3.15E+17	57	Pu-241	2.05E+17
28	Te-127m	4.17E+16	58	Am-241	1.36E+14
29	Te-129	1.09E+18	59	Cm-242	5.19E+16
30	Te-129m	2.86E+17	60	Cm-244	3.04E+15

Table E.3-4
MACCS2 Release Categories vs. SGS Release Categories

MACCS2 Release Categories	SGS Release Categories
Xe/Kr	1 – noble gases
I	2 – CsI
Cs	6 & 2 – CsOH and CsI(3)
Te	3 & 11- TeO_2, Sb(2) & Te_2 (1)
Sr	4 – SrO
Ru	5 – MoO_2 (Mo is in Ru MACCS category)
La	8 – La_2O_3
Ce	9 – CeO_2 & UO_2 (1)
Ba	7 – BaO

(1) These release fractions are typically negligible compared to others in the group.

(2) The mass of Sb in the core is typically much less than the mass of Te.

(3) The mass of Cs contained in CsI is typically much less than the mass of Cs contained in CsOH.

Table E.3-5
Representative MAAP Level 2 Case Descriptions and Key Event Timings

Case	MAAP run	Sequence Definition	Tcd	Tvf	Tcf	Tend	NG fraction	CsI fraction
INTACT	2b	AFW fails, F&B fails, hotleg rupture, CHR	2.6	7.2	--	24	1.1E-3	5.1E-5
LATE-BMMT-AFW	28	Seal LOCA, AFW, SI fails, CHR	29	32	100	136	0.96	3.3E-5
LATE-BMT-NOAFW	22b	AFW fails	0.58	2.0	100	136	0.82	6.6E-5
LATE-CHR-AFW	16a	AFW, SI, recirculation fails, POX fails, CHR fails	20	25	27	72	1.0	4.1E-2
LATE-CHR-NOAFW	2e	AFW fails, POX, CHR fails	2.6	4.7	11	48	0.99	8.7E-2
LERF-ISLOCA	27	Isolation fails, SI fails	0.32	1.6	NA	8	1.0	0.97
LERF-CI	2f	AFW fails, pre-existing containment leak	2.6	4.1	0	24	0.98	4.8E-2
LERF-CFE	2g	AFW fails, containment failure at vessel breach	2.6	4.1	4.1	24	0.99	4.2E-2
LERF-SGTR-AFW	18e	SG isolation, SI, AFW, F&B fails, SOSGRV	11	14	NA	24	0.97	0.53
LERF-SGTR-NOAFW	19e	SI, AFW, F&B fails, SOSGRV	6.2	11	NA	48	0.33	8.1E-2
LERF-ISGTR	2d	AFW fails, induced SGTR at core damage	3.8	5.4	NA	24	0.86	0.15

All times are in hours
Tcd – Time of core damge
Tcf-Time of containment failure
Tend – End of time calculation
NG – Noble gas
CsI fraction – CsI release fraction

Table E.3-6
SGS Source Term Summary

	Release Category										
	INTACT	**LATE-BMMT-AFW**	**LATE-BMMT-NOAFW**	**LATE-CHR-AFW**	**LATE-CHR-NOAFW**	**LERF-ISLOCA**	**LERF-CI**	**LERF-CFE**	**LERF-SGTR-AFW**	**LERF-SGTR-NOAFW**	**LERF-ISGTR**
Bin Frequency	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06
MAAP Case	2b	28	22b	16a	2e	27	2f	2g	18e	19e	2d
Run Duration	24 hr	136 hr	136 hr	72 hr	48 hr	8 hr	24 hr	24 hr	24 hr	48 hr	24 hr
Time after Scram when GE is declared (1)	2.6 hr	29 hr	0.58 hr	20 hr	2.6 hr	0.37 hr	2.6 hr	2.6 hr	11 hr	6.2 hr	3.8 hr
Fission Product Group:											
1) Noble											
Total Release Fraction	1.10E-03	9.60E-01	8.20E-01	1.00E+00	9.90E-01	1.00E+00	9.80E-01	9.80E-01	9.70E-01	3.30E-01	8.60E-01
Total Plume 1 Release Fraction	2.00E-04	0.00E+00	0.00E+00	9.30E-01	0.00E+00	1.00E+00	1.00E-01	8.10E-01	9.10E-01	1.90E-01	8.60E-01
Start of Plume 1 Release (hr)	3.00			27.00		0.33	3.00	4.00	11.00	6.50	4.00
End of Plume 1 Release (hr)	7.00			30.00		1.00	4.00	6.00	12.75	7.00	5.50
Total Plume 2 Release Fraction	2.00E-04	7.10E-01	0.00E+00	7.00E-02	9.10E-01	0.00E+00	6.50E-01	1.40E-01	6.00E-02	5.00E-02	0.00E+00
Start of Plume 2 Release (hr)	7.00	86.00		30.00	19.00		4.00	6.00	12.75	8.50	
End of Plume 2 Release (hr)	11.00	95.00		40.00	22.00		5.50	9.00	22.75	10.00	
Total Plume 3 Release Fraction	7.00E-04	2.50E-01	8.20E-01	0.00E+00	8.00E-02	0.00E+00	2.30E-01	3.00E-02	0.00E+00	9.00E-02	0.00E+00
Start of Plume 3 Release (hr)	11.00	95.00	95.00		22.00		5.50	9.00		12.00	
End of Plume 3 Release (hr)	21.00	105.00	97.00		32.00		15.50	15.00		22.00	
2) CsI											
Total Release Fraction	5.10E-05	3.30E-03	6.60E-05	4.10E-02	8.70E-02	9.70E-01	4.80E-02	4.20E-02	5.30E-01	8.10E-02	1.50E-01
Total Plume 1 Release Fraction	3.80E-05	0.00E+00	3.40E-05	1.30E-02	0.00E+00	9.30E-01	1.20E-02	3.30E-02	5.00E-01	4.90E-02	1.50E-01
Start of Plume 1 Release (hr)	3.00		0.75	27.00		0.33	3.00	4.00	11.00	6.50	4.00
End of Plume 1 Release (hr)	7.00		2.50	30.00		1.00	4.00	6.00	12.75	7.00	5.50
Total Plume 2 Release Fraction	4.00E-06	2.50E-03	2.20E-05	2.70E-02	8.20E-02	4.00E-02	2.60E-02	5.00E-03	3.00E-02	2.10E-02	0.00E+00
Start of Plume 2 Release (hr)	7.00	86.00	2.50	30.00	19.00	1.67	4.00	6.00	12.75	8.50	
End of Plume 2 Release (hr)	11.00	95.00	12.50	40.00	22.00	3.00	5.50	9.00	22.75	10.00	
Total Plume 3 Release Fraction	9.00E-06	8.00E-04	1.00E-05	1.00E-03	5.00E-03	0.00E+00	1.00E-02	4.00E-03	0.00E+00	1.10E-02	0.00E+00
Start of Plume 3 Release (hr)	11.00	95.00	95.00	62.00	22.00		5.50	9.00		12.00	
End of Plume 3 Release (hr)	21.00	105.00	97.00	65.00	32.00		15.50	15.00		22.00	
3) TeO2											
Total Release Fraction	5.30E-05	9.20E-05	3.20E-05	1.70E-02	4.80E-03	9.30E-01	2.70E-02	2.50E-02	2.10E-01	5.80E-02	8.30E-02

Table E.3-6
SGS Source Term Summary

	Release Category										
	INTACT	**LATE-BMMT-AFW**	**LATE-BMMT-NOAFW**	**LATE-CHR-AFW**	**LATE-CHR-NOAFW**	**LERF-ISLOCA**	**LERF-CI**	**LERF-CFE**	**LERF-SGTR-AFW**	**LERF-SGTR-NOAFW**	**LERF-ISGTR**
Bin Frequency	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06
MAAP Case	2b	28	22b	16a	2e	27	2f	2g	18e	19e	2d
Run Duration	24 hr	136 hr	136 hr	72 hr	48 hr	8 hr	24 hr	24 hr	24 hr	48 hr	24 hr
Time after Scram when GE is declared (1)	2.6 hr	29 hr	0.58 hr	20 hr	2.6 hr	0.37 hr	2.6 hr	2.6 hr	11 hr	6.2 hr	3.8 hr
Fission Product Group:											
Total Plume 1 Release Fraction	4.00E-05	5.00E-06	3.20E-05	1.70E-02	0.00E+00	8.90E-01	4.00E-03	2.10E-02	2.00E-01	2.00E-03	8.30E-02
Start of Plume 1 Release (hr)	3.00	32.00	0.75	27.00		0.33	3.00	4.00	11.00	6.50	4.00
End of Plume 1 Release (hr)	7.00	38.00	2.50	30.00		1.00	4.00	6.00	12.75	7.00	5.50
Total Plume 2 Release Fraction	1.30E-05	6.80E-05	0.00E+00	0.00E+00	4.20E-03	4.00E-02	1.80E-02	4.00E-03	1.00E-02	5.50E-02	0.00E+00
Start of Plume 2 Release (hr)	7.00	86.00			19.00	1.67	4.00	6.00	12.75	8.50	
End of Plume 2 Release (hr)	11.00	95.00			22.00	3.00	5.50	9.00	22.75	10.00	
Total Plume 3 Release Fraction	0.00E+00	1.90E-05	0.00E+00	0.00E+00	6.00E-04	0.00E+00	5.00E-03	0.00E+00	0.00E+00	1.00E-03	0.00E+00
Start of Plume 3 Release (hr)		95.00			22.00		5.50			12.00	
End of Plume 3 Release (hr)		105.00			32.00		15.50			22.00	
4) SrO											
Total Release Fraction	2.40E-06	4.50E-06	2.30E-06	1.50E-03	1.50E-04	4.20E-02	4.30E-02	4.80E-02	1.90E-03	1.20E-03	1.70E-04
Total Plume 1 Release Fraction	5.00E-07	4.30E-06	2.30E-06	7.00E-04	1.00E-05	2.30E-02	0.00E+00	4.50E-02	1.80E-03	0.00E+00	1.60E-04
Start of Plume 1 Release (hr)	3.00	32.00	0.75	27.00	4.00	0.33		4.00	11.00		4.00
End of Plume 1 Release (hr)	7.00	38.00	2.50	30.00	6.00	1.00		6.00	12.75		5.50
Total Plume 2 Release Fraction	1.70E-06	2.00E-07	0.00E+00	0.00E+00	1.40E-04	1.90E-02	3.90E-02	2.00E-03	1.00E-04	1.10E-03	1.00E-05
Start of Plume 2 Release (hr)	7.00	86.00			19.00	1.67	4.00	6.00	12.75	8.50	5.50
End of Plume 2 Release (hr)	11.00	95.00			22.00	3.00	5.50	9.00	22.75	10.00	8.00
Total Plume 3 Release Fraction	2.00E-07	0.00E+00	0.00E+00	8.00E-04	0.00E+00	0.00E+00	4.00E-03	1.00E-03	0.00E+00	1.00E-04	0.00E+00
Start of Plume 3 Release (hr)	11.00			62.00			5.50	9.00		12.00	
End of Plume 3 Release (hr)	21.00			65.00			15.50	15.00		22.00	
5) MoO2											
Total Release Fraction	1.00E-05	3.00E-06	2.50E-06	8.40E-03	1.20E-04	7.70E-02	2.70E-02	3.20E-02	1.10E-01	2.60E-02	5.20E-02
Total Plume 1 Release Fraction	9.00E-06	2.90E-06	2.50E-06	8.20E-03	1.00E-05	7.60E-02	0.00E+00	3.00E-02	1.10E-01	0.00E+00	5.20E-02
Start of Plume 1 Release (hr)	3.00	32.00	0.75	27.00	4.00	0.33		4.00	11.00		4.00

Table E.3-6
SGS Source Term Summary

	Release Category										
	INTACT	**LATE-BMMT-AFW**	**LATE-BMMT-NOAFW**	**LATE-CHR-AFW**	**LATE-CHR-NOAFW**	**LERF-ISLOCA**	**LERF-CI**	**LERF-CFE**	**LERF-SGTR-AFW**	**LERF-SGTR-NOAFW**	**LERF-ISGTR**
Bin Frequency	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06
MAAP Case	2b	28	22b	16a	2e	27	2f	2g	18e	19e	2d
Run Duration	24 hr	136 hr	136 hr	72 hr	48 hr	8 hr	24 hr	24 hr	24 hr	48 hr	24 hr
Time after Scram when GE is declared (1)	2.6 hr	29 hr	0.58 hr	20 hr	2.6 hr	0.37 hr	2.6 hr	2.6 hr	11 hr	6.2 hr	3.8 hr
Fission Product Group:											
End of Plume 1 Release (hr)	7.00	38.00	2.50	30.00	6.00	1.00		6.00	12.75		5.50
Total Plume 2 Release Fraction	1.00E-06	1.00E-07	0.00E+00	2.00E-04	1.10E-04	1.00E-03	2.50E-02	2.00E-03	0.00E+00	2.60E-02	0.00E+00
Start of Plume 2 Release (hr)	7.00	86.00		30.00	19.00	1.67	4.00	6.00		8.50	
End of Plume 2 Release (hr)	11.00	95.00		40.00	22.00	3.00	5.50	9.00		10.00	
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.00E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)							5.50				
End of Plume 3 Release (hr)							15.50				
6) CsOH											
Total Release Fraction	3.40E-05	2.10E-04	5.50E-05	1.40E-02	5.70E-03	9.40E-01	2.40E-02	1.90E-02	1.70E-01	5.70E-02	5.50E-02
Total Plume 1 Release Fraction	2.50E-05	0.00E+00	3.40E-05	1.10E-02	0.00E+00	9.30E-01	7.00E-03	1.60E-02	1.60E-01	3.60E-02	5.50E-02
Start of Plume 1 Release (hr)	3.00		0.75	27.00		0.33	3.00	4.00	11.00	6.50	4.00
End of Plume 1 Release (hr)	7.00		2.50	30.00		1.00	4.00	6.00	12.75	7.00	5.50
Total Plume 2 Release Fraction	4.00E-06	1.50E-04	6.00E-06	2.00E-03	4.00E-03	1.00E-02	1.40E-02	3.00E-03	1.00E-02	1.90E-02	0.00E+00
Start of Plume 2 Release (hr)	7.00	86.00	2.50	30.00	19.00	1.67	4.00	6.00	12.75	8.50	
End of Plume 2 Release (hr)	11.00	95.00	12.50	40.00	22.00	3.00	5.50	9.00	22.75	10.00	
Total Plume 3 Release Fraction	5.00E-06	6.00E-05	1.50E-05	1.00E-03	1.70E-03	0.00E+00	3.00E-03	0.00E+00	0.00E+00	2.00E-03	0.00E+00
Start of Plume 3 Release (hr)	11.00	95.00	95.00	62.00	22.00		5.50			12.00	
End of Plume 3 Release (hr)	21.00	105.00	97.00	65.00	32.00		15.50			22.00	
7) BaO											
Total Release Fraction	3.60E-06	4.80E-06	2.30E-06	5.60E-03	1.40E-04	4.70E-02	3.80E-02	4.20E-02	2.50E-02	4.30E-03	3.00E-03
Total Plume 1 Release Fraction	2.50E-06	3.60E-06	1.20E-06	5.20E-03	1.00E-05	3.80E-02	0.00E+00	4.00E-02	2.40E-02	2.00E-04	3.00E-03
Start of Plume 1 Release (hr)	3.00	32.00	0.75	27.00	4.00	0.33		4.00	11.00	6.50	4.00
End of Plume 1 Release (hr)	7.00	38.00	2.50	30.00	6.00	1.00		6.00	12.75	7.00	5.50
Total Plume 2 Release Fraction	1.00E-06	7.00E-07	7.00E-07	1.00E-04	1.30E-04	9.00E-03	3.40E-02	2.00E-03	1.00E-03	4.10E-03	0.00E+00

Table E.3-6
SGS Source Term Summary

	Release Category										
	INTACT	**LATE-BMMT-AFW**	**LATE-BMMT-NOAFW**	**LATE-CHR-AFW**	**LATE-CHR-NOAFW**	**LERF-ISLOCA**	**LERF-CI**	**LERF-CFE**	**LERF-SGTR-AFW**	**LERF-SGTR-NOAFW**	**LERF-ISGTR**
Bin Frequency	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06
MAAP Case	2b	28	22b	16a	2e	27	2f	2g	18e	19e	2d
Run Duration	24 hr	136 hr	136 hr	72 hr	48 hr	8 hr	24 hr	24 hr	24 hr	48 hr	24 hr
Time after Scram when GE is declared (1)	2.6 hr	29 hr	0.58 hr	20 hr	2.6 hr	0.37 hr	2.6 hr	2.6 hr	11 hr	6.2 hr	3.8 hr
Fission Product Group:											
Start of Plume 2 Release (hr)	7.00	86.00	2.50	30.00	19.00	1.67	4.00	6.00	12.75	8.50	
End of Plume 2 Release (hr)	11.00	95.00	12.50	40.00	22.00	3.00	5.50	9.00	22.75	10.00	
Total Plume 3 Release Fraction	1.00E-07	5.00E-07	4.00E-07	3.00E-04	0.00E+00	0.00E+00	4.00E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)	11.00	95.00	95.00	62.00			5.50				
End of Plume 3 Release (hr)	21.00	105.00	97.00	65.00			15.50				
8) La2O3											
Total Release Fraction	4.50E-07	4.20E-06	2.50E-07	1.80E-04	1.10E-04	3.50E-03	4.20E-02	4.70E-02	4.50E-04	7.90E-05	2.40E-05
Total Plume 1 Release Fraction	2.00E-08	4.20E-06	4.00E-08	1.50E-04	1.00E-05	5.00E-04	0.00E+00	4.50E-02	4.20E-04	5.00E-06	1.90E-05
Start of Plume 1 Release (hr)	3.00	32.00	0.75	27.00	4.00	0.33		4.00	11.00	6.50	4.00
End of Plume 1 Release (hr)	7.00	38.00	2.50	30.00	6.00	1.00		6.00	12.75	7.00	5.50
Total Plume 2 Release Fraction	3.70E-07	0.00E+00	2.10E-07	1.00E-05	1.00E-04	3.00E-03	3.90E-02	2.00E-03	3.00E-05	6.50E-05	5.00E-06
Start of Plume 2 Release (hr)	7.00		2.50	30.00	19.00	1.67	4.00	6.00	12.75	8.50	5.50
End of Plume 2 Release (hr)	11.00		12.50	40.00	22.00	3.00	5.50	9.00	22.75	10.00	8.00
Total Plume 3 Release Fraction	6.00E-08	0.00E+00	0.00E+00	2.00E-05	0.00E+00	0.00E+00	3.00E-03	0.00E+00	0.00E+00	9.00E-06	0.00E+00
Start of Plume 3 Release (hr)	11.00			62.00			5.50			12.00	
End of Plume 3 Release (hr)	21.00			65.00			15.50			22.00	

Table E.3-6
SGS Source Term Summary

	Release Category										
	INTACT	**LATE-BMMT-AFW**	**LATE-BMMT-NOAFW**	**LATE-CHR-AFW**	**LATE-CHR-NOAFW**	**LERF-ISLOCA**	**LERF-CI**	**LERF-CFE**	**LERF-SGTR-AFW**	**LERF-SGTR-NOAFW**	**LERF-ISGTR**
Bin Frequency	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06
MAAP Case	2b	28	22b	16a	2e	27	2f	2g	18e	19e	2d
Run Duration	24 hr	136 hr	136 hr	72 hr	48 hr	8 hr	24 hr	24 hr	24 hr	48 hr	24 hr
Time after Scram when GE is declared (1)	2.6 hr	29 hr	0.58 hr	20 hr	2.6 hr	0.37 hr	2.6 hr	2.6 hr	11 hr	6.2 hr	3.8 hr
Fission Product Group:											
9) CeO2											
Total Release Fraction	3.70E-06	4.40E-06	1.90E-06	8.90E-04	1.50E-04	2.20E-02	4.30E-02	4.80E-02	1.20E-03	5.60E-04	4.10E-05
Total Plume 1 Release Fraction	1.00E-07	4.10E-06	2.00E-07	2.50E-04	1.00E-05	3.00E-03	0.00E+00	4.50E-02	1.10E-03	1.00E-05	3.60E-05
Start of Plume 1 Release (hr)	3.00	32.00	0.75	27.00	4.00	0.33		4.00	11.00	6.50	4.00
End of Plume 1 Release (hr)	7.00	38.00	2.50	30.00	6.00	1.00		6.00	12.75	7.00	5.50
Total Plume 2 Release Fraction	3.00E-06	3.00E-07	1.70E-06	1.00E-05	1.40E-04	1.90E-02	3.90E-02	2.00E-03	1.00E-04	4.70E-04	5.00E-06
Start of Plume 2 Release (hr)	7.00	86.00	2.50	30.00	19.00	1.67	4.00	6.00	12.75	8.50	5.50
End of Plume 2 Release (hr)	11.00	95.00	12.50	40.00	22.00	3.00	5.50	9.00	22.75	10.00	8.00
Total Plume 3 Release Fraction	6.00E-07	0.00E+00	0.00E+00	6.30E-04	0.00E+00	0.00E+00	4.00E-03	1.00E-03	0.00E+00	8.00E-05	0.00E+00
Start of Plume 3 Release (hr)	11.00			62.00			5.50	9.00		12.00	
End of Plume 3 Release (hr)	21.00			65.00			15.50	15.00		22.00	
10) Sb											
Total Release Fraction	4.40E-05	1.30E-03	9.80E-05	7.80E-02	6.00E-02	4.70E-01	1.40E-01	1.60E-01	3.90E-01	1.40E-01	2.00E-01
Total Plume 1 Release Fraction	2.70E-05	0.00E+00	1.10E-05	4.10E-02	0.00E+00	3.80E-01	0.00E+00	1.10E-01	3.10E-01	0.00E+00	2.00E-01
Start of Plume 1 Release (hr)	3.00		0.75	27.00		0.33		4.00	11.00		4.00
End of Plume 1 Release (hr)	7.00		2.50	30.00		1.00		6.00	12.75		5.50
Total Plume 2 Release Fraction	1.50E-05	1.00E-04	2.90E-05	4.00E-03	3.40E-02	9.00E-02	1.00E-01	2.00E-02	8.00E-02	1.20E-01	0.00E+00
Start of Plume 2 Release (hr)	7.00	86.00	2.50	30.00	19.00	1.67	4.00	6.00	12.75	8.50	
End of Plume 2 Release (hr)	11.00	95.00	12.50	40.00	22.00	3.00	5.50	9.00	22.75	10.00	
Total Plume 3 Release Fraction	2.00E-06	1.20E-03	5.80E-05	3.30E-02	2.60E-02	0.00E+00	4.00E-02	3.00E-02	0.00E+00	2.00E-02	0.00E+00
Start of Plume 3 Release (hr)	11.00	95.00	95.00	62.00	22.00		5.50	9.00		12.00	
End of Plume 3 Release (hr)	21.00	105.00	97.00	65.00	32.00		15.50	15.00		22.00	

Table E.3-6
SGS Source Term Summary

	Release Category										
	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-CHR-AFW	LATE-CHR-NOAFW	LERF-ISLOCA	LERF-CI	LERF-CFE	LERF-SGTR-AFW	LERF-SGTR-NOAFW	LERF-ISGTR
Bin Frequency	9.22E-06	1.81E-10	9.89E-07	2.52E-08	3.42E-05	2.97E-08	2.23E-07	3.40E-08	2.55E-06	1.98E-07	2.03E-06
MAAP Case	2b	28	22b	16a	2e	27	2f	2g	18e	19e	2d
Run Duration	24 hr	136 hr	136 hr	72 hr	48 hr	8 hr	24 hr	24 hr	24 hr	48 hr	24 hr
Time after Scram when GE is declared (1)	2.6 hr	29 hr	0.58 hr	20 hr	2.6 hr	0.37 hr	2.6 hr	2.6 hr	11 hr	6.2 hr	3.8 hr
Fission Product Group:											
11) Te2											
Total Release Fraction	1.50E-07	2.20E-05	2.30E-06	1.20E-03	4.20E-04	2.60E-03	2.70E-04	4.20E-04	1.60E-06	6.80E-05	5.00E-07
Total Plume 1 Release Fraction	0.00E+00	0.00E+00	1.00E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.30E-04	0.00E+00	0.00E+00	0.00E+00
Start of Plume 1 Release (hr)			0.75					4.00			
End of Plume 1 Release (hr)			2.50					6.00			
Total Plume 2 Release Fraction	1.40E-07	2.00E-06	3.00E-07	0.00E+00	2.10E-04	2.60E-03	2.20E-04	2.00E-05	1.60E-06	0.00E+00	5.00E-07
Start of Plume 2 Release (hr)	7.00	86.00	2.50		19.00	1.67	4.00	6.00	12.75		5.50
End of Plume 2 Release (hr)	11.00	95.00	12.50		22.00	3.00	5.50	9.00	22.75		8.00
Total Plume 3 Release Fraction	1.00E-08	2.00E-05	1.90E-06	1.20E-03	2.10E-04	0.00E+00	5.00E-05	7.00E-05	0.00E+00	6.80E-05	0.00E+00
Start of Plume 3 Release (hr)	11.00	95.00	95.00	62.00	22.00		5.50	9.00		12.00	
End of Plume 3 Release (hr)	21.00	105.00	97.00	65.00	32.00		15.50	15.00		22.00	
12) UO2											
Total Release Fraction	2.00E-08	2.10E-08	1.70E-08	1.90E-06	2.20E-07	1.20E-04	2.50E-06	3.00E-06	0.00E+00	3.50E-07	0.00E+00
Total Plume 1 Release Fraction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Plume 1 Release (hr)											
End of Plume 1 Release (hr)											
Total Plume 2 Release Fraction	1.60E-08	1.10E-08	1.10E-08	0.00E+00	1.60E-07	1.20E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Start of Plume 2 Release (hr)	7.00	86.00	2.50		19.00	1.67					
End of Plume 2 Release (hr)	11.00	95.00	12.50		22.00	3.00					
Total Plume 3 Release Fraction	4.00E-09	1.00E-08	6.00E-09	1.90E-06	6.00E-08	0.00E+00	2.50E-06	3.00E-06	0.00E+00	3.50E-07	0.00E+00
Start of Plume 3 Release (hr)	11.00	95.00	95.00	62.00	22.00		5.50	9.00		12.00	
End of Plume 3 Release (hr)	21.00	105.00	97.00	65.00	32.00		15.50	15.00		22.00	

Table E.3-7
MACCS2 Base Case Mean Results

Source Term	Release Category	Dose (p-rem)	Offsite Economic Cost ($)	Freq. (/yr)	Dose-Risk (p-rem/yr)	OECR ($/yr)
1	INTACT	1.64E+04	3.17E+06	9.22E-06	1.51E-01	2.92E+01
2	LATE-BMMT-AFW	8.33E+04	1.12E+08	1.81E-10	1.51E-05	2.03E-02
3	LATE-BMMT-NOAFW	2.31E+04	5.33E+06	9.89E-07	2.28E-02	5.27E+00
4	LATE-CHR-AFW	2.52E+06	1.16E+10	2.52E-08	6.35E-02	2.92E+02
5	LATE-CHR-NOAFW	1.25E+06	3.34E+09	3.42E-05	4.28E+01	1.14E+05
6	LERF-ISLOCA	2.07E+07	8.05E+10	2.97E-08	6.15E-01	2.39E+03
7	LERF-CI	1.04E+07	3.97E+10	2.23E-07	2.32E+00	8.85E+03
8	LERF-CFE	1.09E+07	3.65E+10	3.40E-08	3.71E-01	1.24E+03
9	LERF-SGTR-AFW	9.10E+06	4.52E+10	2.55E-06	2.32E+01	1.15E+05
10	LERF-SGTR-NOAFW	3.95E+06	3.22E+10	1.98E-07	7.82E-01	6.38E+03
11	LERF-ISGTR	3.91E+06	2.81E+10	2.03E-06	7.94E+00	5.70E+04
FREQUENCY WEIGHTED TOTALS				**4.95E-05**	**7.82E+01**	**3.06E+05**

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RRS-XHE-FO-SDRSP	1.00E-01	1.94	FAILURE OF THE OPER TO SHUTDOWN FROM REMOTE SDP	The action to shutdown and control the reactor from the remote shutdown panel (RSP) is required on loss of Control Area Ventilation (CAV) due to room heat up. This challenge can be averted by developing procedures to open the doors and use portable fans for alternate room cooling in the MCR, Rack Room/Electrical Equipment Room, and Relay Room. If temporary duct work is required to achieve the appropriate flow, then this should be added to the design (SAMA 1). Alternatively, the existing fire procedures that provide guidance for inter-unit Service Water cross-tie could be expanded to address non-fire scenarios (SAMA 24). The applicability of this change would be limited to cases where the CAV hardware is operational for the unit and when SW is functional on the opposite unit.
%TVC	1.00E+00	1.554	INITIATOR FLAG FOR LOSS OF CONTROL AREA HVAC IE-TVC	This initiating event is closely linked to action to shutdown and control the reactor from the RSP. This challenge can be averted by developing procedures to open the doors and use portable fans for alternate room cooling in the MCR, Rack Room/Electrical Equipment Room, and Relay Room. If temporary duct work is required to achieve the appropriate flow, then this should be added to the design (SAMA 1).

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
CHS-CHL-FR-NO11A	8.25E-01	1.371	CHILLER FAILS TO CONTINUE OPERATING annual	This event is closely linked to action to shutdown and control the reactor from the RSP. This challenge can be averted by developing procedures to open the doors and use portable fans for alternate room cooling in the MCR, Rack Room/Electrical Equipment Room, and Relay Room. If temporary duct work is required to achieve the appropriate flow, then this should be added to the design (SAMA 1).
G2SW22	2.00E-03	1.274	INSUFF FLOW FROM SW HDR 22	This event is closely linked to action to shutdown and control the reactor from the RSP. This challenge can be averted by developing procedures to open the doors and use portable fans for alternate room cooling in the MCR, Rack Room/Electrical Equipment Room, and Relay Room. If temporary duct work is required to achieve the appropriate flow, then this should be added to the design (SAMA 1).
CHS-CHL-TM-NO13	3.08E-02	1.226	CHILLER NO 13 UNAVAILABLE DUE TO TM	This event is closely linked to action to shutdown and control the reactor from the RSP. This challenge can be averted by developing procedures to open the doors and use portable fans for alternate room cooling in the MCR, Rack Room/Electrical Equipment Room, and Relay Room. If temporary duct work is required to achieve the appropriate flow, then this should be added to the design (SAMA 1).

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RBU1	1.00E+00	1.175	AC nrec SBO w afw success cd success	The cutsets including this flag appear are non-recovered SBO sequences, which include successful AFW operation and cooldown. Several approaches should be examined for addressing SBO at Salem. One approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). A second option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A third option is to provide a unique fuel oil transfer pump for EDG C and provide the capability to tie to the A and B 4kV buses (SAMA 4). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.
%TSW	1.00E+00	1.16	INITIATOR FLAG FOR LOSS OF SERVICE WATER IE-TSW	Over 88 percent of the contributors including this event are related to loss of CAV and failure to operate the plant from the RSP. SAMA 1 addressed these contributors. Alternatively, the existing fire procedures that provide guidance for inter-unit Service Water cross-tie could be expanded to address non-fire scenarios (SAMA 24). The applicability of this change would be limited to cases where the CAV hardware is operational for the unit and when SW is functional on the opposite unit.

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SWS-STR-PG-DF00	5.24E-05	1.124	CCF OF ALL SWS STRAINERS (BOTH UNITS) ON ANNUAL BASIS	Over 99 percent of the contributors including this event are related to loss of CAV and failure to operate the plant from the RSP. SAMA 1 addressed these contributors.
RCS-SLOCA-SPLIT	1.00E+00	1.091	SPLIT FRACTION FOR SEAL LOCA AFTER LOSS COOLING	The SW floods, which impact all of the equipment required to mitigate the event, carry most of the risk associated with this event. The SW flood event represents general flooding in the areas of the Aux. Building 84' el. from the Service Water system < 2000 gpm. The ability to rapidly detect and isolate the flooding source would greatly reduce the severity of this event. An option to install pressure indication and flow sensors in the Service Water lines with remote alarm indication in the control room with the capability to quickly identify the specific location of a break would greatly help mitigate this scenario (SAMA 6).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RD3-XHE-ABCAV	5.10E-03	1.085	FAIL TO ALIGN CAV FOR AB-CAV MODE	This event is 100% tied to the event "RRS-XHE-FO-SDRSP" and implies that failures to align alternate control area cooling have failed and an evacuation of the MCR is required. While using portable fans to cool the MCR, Rack Room/Electrical Equipment Room, and Relay Room addresses the same function as the actions to align alternate CAV, the dependence between the two actions is considered to be minimal and that opening the doors and staging portable fans in the control room envelope would provide some benefit. The cognitive component of aligning alternate cooling is considered to be negligible and the execution portion of the two actions would be completely different. SAMA 1 is judged to be applicable. Alternatively, the existing fire procedures that provide guidance for inter-unit Service Water cross-tie could be expanded to address non-fire scenarios (SAMA 24). The applicability of this change would be limited to cases where the CAV hardware is operational for the unit and when SW is functional on the opposite unit.

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Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%TES	1.03E-02	1.074	LOOP Initiator - switchyard / plant	For Salem, a large portion of the LOOP risk could be addressed by providing EDG "C" with its own diesel fuel oil transfer pump powered from the "C" division and enabling the "C" EDG to power the "A" and "B" 4kV buses (SAMA 4). Another approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). An additional option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.
AFS-XHE-FO-H2OLT	5.60E-02	1.073	Failure to provide alternate suction source for AFW	Automate makeup from the Demineralized Water Storage Tank or automate an AFW pump suction swap to an alternate water source on low suction pressure and/or a low Demineralized Water Storage Tank level signal (SAMA 7). Providing a parallel makeup valve with a "B" division power supply would help mitigate valve DR6 failures and loss of DC bus scenarios.

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%TEW	5.20E-03	1.069	LOOP initiator - weather	This event represents a weather related LOOP. Almost 80 percent on the contributors include EDG "A" and "B" failures (with consequential EDG "C" failure) and the most effective plant improvement is considered to be providing EDG "C" with its own diesel fuel oil transfer pump powered from the "C" division and enabling the "C" EDG to power the "A" and "B" 4kV buses (SAMA 4). Another approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). An additional option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.
CHS-CHL-FS-NO13	9.83E-03	1.063	CHILLER NO 13 FAILS TO START	This event is related to the loss of CAV, which subsequently forces MCR abandonment. Over 99 percent of the contributors including the failure to properly shut the reactor down from the RSP (RRS-XHE-FO-SDRSP). SAMA 1 addressed these contributors.

Table E.5-1
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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%FL_AB084C_G_SW	2.22E-04	1.06	General Flood Aux Bldg 84C Service Water	This event represents general flooding in the areas of the Aux. Building 84' el. from the Service Water system < 2000 gpm. The ability to rapidly detect and isolate the flooding source would greatly reduce the severity of this event. An option to install pressure indication and flow sensors in the Service Water lines with remote alarm indication in the control room with the capability to quickly identify the specific location of a break would greatly help mitigate this scenario (SAMA 6).
FL_XHE_AB084C_G	1.10E-02	1.055	Operator fails to isolate flood source	About 99 percent of the contributors including this event are linked to the event %FL_AB084C_G_SW, which is addressed by SAMA 6.

Table E.5-1
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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RECRBU1W	2.40E-01	1.053	AC pwr nrec AFW and cooldn success, wx LOOP	This event is the failure to recover offsite AC power by the time the station batteries deplete given successful AFW operation and cooldown. The most effective plant improvement is considered to be providing EDG "C" with its own diesel fuel oil transfer pump powered from the "C" division and enabling the "C" EDG to power the "A" and "B" 4kV buses (SAMA 4). Another approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). An additional option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
AFS-MDP-FS-DF04	4.25E-04	1.051	DEPEN FAILURE OF 3 AFW PUMPS (STEAM BINDING)	This event is important for initiators that disable MFW given that these failures result in the loss of all secondary side heat removal. This specific CCF mechanism is caused by steam leakage back through the AFW injection lines that ultimately causes pump failure. The contribution from this particular failure could potentially be reduced by operating with the "AF11/21" valves closed, but a more comprehensive enhancement would be to provide a portable diesel driven pump that can provide high pressure makeup to the steam generators from the AFWST or fire water header. Injection through the steam driven AFW header should provide adequate flexibility. (SAMA 8).

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RD3-XHE-MM	8.30E-03	1.051	FAIL TO ALIGN CAV FOR MAINTENANCE MODE	This event is 100% tied to the event "RRS-XHE-FO-SDRSP" and implies that failures to align alternate CAV have failed and an evacuation of the MCR is required. While using portable fans to cool the MCR, Rack Room/Electrical Equipment Room, and Relay Room, addresses the same function as the actions to align alternate control area cooling, the dependence between the two actions is considered to be minimal and that opening the doors and staging portable fans would provide some benefit. The cognitive component of aligning alternate cooling is considered to be negligible and the execution portion of the two actions would be completely different. SAMA 1 is judged to be applicable. Alternatively, the existing fire procedures that provide guidance for inter-unit Service Water cross-tie could be expanded to address non-fire scenarios (SAMA 24). The applicability of this change would be limited to cases where the CAV hardware is operational for the unit and when SW is functional on the opposite unit.
RECOV15	1.10E+01	1.051	Dependency adjust	This event is part of the HRA dependency analysis and is used to ensure that cutsets including the events RRS-XHE-FO-SDRSP, RD3-XHE-MM, and RD3-XHE-ABCAV are adjusted to the appropriate value. Those events are treated independently in this list and the event RECOV15 does not require additional treatment or the development of any unique SAMAs.

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
AFS-XHE-FO-REFIL	1.50E-03	1.05	FAILURE TO REFILL AFWST via DR6	Automate makeup from the Demineralized Water Storage Tank or automate an AFW pump suction swap to an alternate water source on low suction pressure and/or a low Demineralized Water Storage Tank level signal (SAMA 7).
%TP	3.75E-01	1.046	TRANSIENT WITH PCS UNAVAILABLE INITIATOR	For these initiators, AFW is important given that MFW is not available for secondary side heat removal. About 50 percent of the contributors including the %TP initiator are related to failures to align a long term suction source for AFW. Automating AFWST refill is a means of reducing this risk (SAMA 7). Providing a parallel makeup valve with a "B" division power supply would help mitigate DR6 valve failures and loss of DC bus scenarios. Steam binding of the AFW pumps (AFS-MDP-FS-DF04) is another large contributor for %TP initiators, which could be addressed by installing an portable, engine driven, high pressure AFW pump with a long term suction source (SAMA 8).

Table E.5-1
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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RECRBU1S	1.00E-01	1.043	AC pwr nrec AFW and cooldn success, swyd & plt LOOP	This event is the failure to recover offsite AC power by the time the station batteries deplete given successful AFW operation and cooldown. The most effective plant improvement is considered to be providing EDG "C" with its own diesel fuel oil transfer pump powered from the "C" division and enabling the "C" EDG to power the "A" and "B" 4kV buses (SAMA 4). Another approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). An additional option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%TT	6.02E-01	1.041	TRANSIENT WITH PCS AVAILABLE INITIATOR	For these initiators, MFW/Condensate is available for secondary side heat removal, but failure to align MFW for heat removal is a significant contributor (over 73 percent). The action to align MFW/Condensate for heat removal is required based on the assumption that the MFW pumps are unavailable after a trip and that the Condensate pumps must be used (requires depressurization). While this is a conservative assumption, the event is often paired with failure to secure a long term AFW suction source. A majority of the risk associated with this initiating event can be eliminated by automating AFWST refill (SAMA 7). Providing a parallel makeup valve with a "B" division power supply would help mitigate DR6 valve failures and loss of DC bus scenarios.

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%TEG	1.42E-02	1.039	LOOP initiator - Grid	This event represents a grid related LOOP. Over 63 percent on the contributors include EDG "A" and "B" failures (with consequential EDG "C" failure) and the most effective plant improvement is considered to be providing EDG "C" with its own diesel fuel oil transfer pump powered from the "C" division and enabling the "C" EDG to power the "A" and "B" 4kV buses (SAMA 4). Another approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). An additional option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
SRV-XHE-FO-FANDB	1.90E-03	1.038	OPERATOR FAILS TO INITIATE FEED AND BLEED	The action to initiate feed and bleed is relatively reliable and not one that can easily be automated. As a result, the focus for reducing the contribution of scenarios including feed and bleed failure is to prevent the conditions that require the action to be taken. Over 47 percent of the contributors including SRV-XHE-FO-FANDB include failure to refill the AFWST, which could be addressed by automating the refill function (SAMA 7). Providing a parallel makeup valve with a "B" division power supply would help mitigate DR6 valve failures and loss of DC bus scenarios. Finally, 43 percent of the contributors including SRV-XHE-FO-FANDB include CCF of the AFW pumps (steam binding), which may be mitigated with a portable diesel driven SG makeup pump (SAMA 8).
RHS-XHE-FO-RECIR	1.20E-03	1.03	U1 OPERATOR FAILS TO REALIGN FOR RECIRC	About 80 percent of the contributors including this event are related to failures to align a long term suction source for AFW. Automating AFWST refill is a means of reducing this risk (SAMA 7). Providing a parallel makeup valve with a "B" division power supply would help mitigate DR6 valve failures and loss of DC bus scenarios.

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
MFW-XHE-FO-COND	1.10E-02	1.029	OPERATOR FAILS TO ESTABLISH FW OR CONDENSATE TO SG'S	The action to align MFW/Condensate for heat removal is required based on the assumption that the MFW pumps are unavailable after a trip and that the Condensate pumps must be used (requires depressurization). While this is a conservative assumption, the event is paired with failure to secure a long term AFW suction source nearly 70 percent of the time. A majority of the risk associated with this action can be eliminated by automating AFWST refill (SAMA 7). Providing a parallel makeup valve with a "B" division power supply would help mitigate DR6 valve failures and loss of DC bus scenarios.
SWS-STR-PG-DF06	1.05E-03	1.028	COMMON CAUSE FAILURE 6 OF 6 STRAINERS ON ANNUAL BASIS	Common cause blockage of the strainers could be mitigated by using the Circ Water canal as an alternate suction and discharge path (SAMA 9). Alternatively, 43 percent of the contributors including this event lead to MCR evac on loss of cooling and subsequent failure to control the plant from the RSP. Installation of portable fans for alternate control envelope cooling could prevent the evacuation (SAMA 1).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RCS-XHE-FO-CLDWN	1.00E+00	1.026	OPER FAILS TO COOLDOWN AND DEPRESSURIZE	This HFE is assigned a 1.0 in the Salem PRA model because the current procedural guidance directs primary side cooldown at a rate of only 25 degrees per hour, which is not fast enough to reach the suggested safe range for the RCP seals within 2 hours after loss of all seal cooling. Procedure changes could be introduced that would increase the primary side cooldown rate for loss of RCP seal cooling cases to reduce the probability of incurring a seal LOCA. The target cooldown and depressurization rate would be about 1400 psi within 2 hours (SAMA 10).

Table E.5-1
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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RECRBU1G	2.40E-01	1.025	AC pwr nrec AFW and cooldown success, grid LOOP	This event is the failure to recover offsite AC power by the time the station batteries deplete given successful AFW operation and cooldown. The most effective plant improvement is considered to be providing EDG "C" with its own diesel fuel oil transfer pump powered from the "C" division and enabling the "C" EDG to power the "A" and "B" 4kV buses (SAMA 4). Another approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). An additional option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.
CHS-CHL-TM-NO23	3.08E-02	1.023	CHILLER 23 UNAVAILABLE DUE TO TEST AND MAINT	This event is related to the loss of Control Area Ventilation, which subsequently forces MCR abandonment. All of the contributors including this event also include the failure to properly shut the reactor down from the RSP (RRS-XHE-FO-SDRSP). SAMA 1 addressed these contributors.

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%TCC	1.00E+00	1.021	INITIATOR FLAG FOR LOSS OF COMPONENT COOLING WATER IE-TCC	About 95 percent of the contributors including this event include a failure to cool the reactor down to protect the RCP seals. This is primarily driven by the 25 degree per hour cooldown rate specified by plant procedures, which could be changed to include a more aggressive cooldown process for loss of RCP seal cooling cases (SAMA 10). Alternatively, the procedures could be modified to direct the use of the opposite unit's PDP through the cross tie line when normal cooling is lost. Currently, it is only directed in fire scenarios (SAMA 11).
RDW-STR-PG-FLOOD2	1.00E-02	1.02	Failure of drains (limited number)	This event represents failure of drains in the non-RCA corridor area of the Aux. Building 84' el. outside the 220/440 VAC switchgear rooms to convey flood waters away from the area. The equipment susceptible to damage is the switchgear components with electrical contacts only 2" above the floor surface. Although 4" curbs exist on the doorways between the switchgear area and corridor, a large volume of water due to flooding could quickly overflow the barriers and damage electrical equipment before operators are able to isolate the source of flooding. One means of mitigating this scenario would be to install larger flood barriers in front of the switchgear doors, similar to what was done at Kewaunee to alleviate flooding concerns for a similar area (SAMA 12).

Table E.5-1
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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
DGS-DGN-FR-DG1A	6.52E-03	1.019	DGN-1A FAILURE TO RUN	This event is the failure to run of the "A" EDG, which generally occurs with successful operation of AFW. The most effective plant improvement is considered to be providing EDG "C" with its own diesel fuel oil transfer pump powered from the "C" division and enabling the "C" EDG to power the "A" and "B" 4kV buses (SAMA 4). Another approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). An additional option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.
RCS-XHE-FO-LDEP	9.70E-03	1.019	OPER FAILS TO DEPRESSUR RCS LATE	Over 97 percent of the contributors including this event are SGTR scenarios that require primary side depressurization to discontinue leakage out of the ruptured SG. Installing primary side isolation valves on the SGs would provide a means of terminating flow to the break without the need to depressurize and cooldown (SAMA 13).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
DGS-DGN-FR-DG1B	6.52E-03	1.018	DGN-1B FAILURE TO RUN 6.52e-3 calc 3 6h 1.09e-3/h	This event is the failure to run of the "B" EDG, which generally occurs with successful operation of AFW. The most effective plant improvement is considered to be providing EDG "C" with its own diesel fuel oil transfer pump powered from the "C" division and enabling the "C" EDG to power the "A" and "B" 4kV buses (SAMA 4). Another approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). An additional option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.
CHS-CHL-FR-NO12	2.26E-03	1.016	CHILLER 12 - 1CHE8 FAILS TO RUN	This event is related to the loss of Control Area Ventilation, which subsequently forces MCR abandonment. Nearly all of the contributors including this event also include the failure to properly shut the reactor down from the RSP (RRS-XHE-FO-SDRSP). SAMA 1 addressed these contributors.

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%TA	1.00E+00	1.016	ATWS INITIATOR	About 80 percent of the ATWS contributors include electrical RPS failures, which could be bypassed by removing power from the control rods. A manual action from the MCR is available to do this, but a potential improvement would be to use AMSAC to trip the control rod power breakers given failure of RPS. The benefit of the change would be greatly improved if on-line AMSAC maintenance were eliminated (SAMA 14).
CVS-XHE-FO-SOVCT	1.00E-02	1.016	OP FAILS TO ISOLATE LETDOWN, TRANSFER CHG SUCTION, AND USE CCPS	Automating the isolation of the letdown line, the swap to a CCP, and the suction source alignment to the RWST could reduce the risk of seal LOCAs for loss of CCW cases (SAMA 15). Currently, these actions are performed manually and while the Salem procedures have been modified to direct these actions early in a loss of CCW scenario, an automated function would potentially improve reliability.
%S4-C	1.75E-03	1.015	STEAM GENERATOR 13 TUBE RUPTURE INITIATOR	Providing primary side steam generator isolation valves would greatly reduce the complexity of the response required in SGTR scenarios, including the elimination of rapid cooldown and depressurization to prevent and mitigate leaks to the secondary side (SAMA 13).

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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%FL_AB084B_M_FP	4.71E-05	1.015	Flood AB 084 B Major, fire protection source	Most of the contribution from this flooding event is related to floor drain clogging and subsequent flooding of the 220/440 VAC switchgear rooms. The equipment susceptible to damage is the switchgear components with electrical contacts only 2" above the floor surface. Although 4" curbs exist on the doorways between the switchgear area and corridor, a large volume of water due to flooding could quickly overflow the barriers and damage electrical equipment before operators are able to isolate the source of flooding. One means of mitigating this scenario would be to install larger flood barriers in front of the switchgear doors, similar to what was done at Kewaunee to alleviate flooding concerns for a similar area (SAMA 12).

Table E.5-1
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Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%TDCA	3.90E-04	1.015	LOSS OF 125V DC BUS A INITIATOR	Over 97 percent of the contributors including this initiating event also include failure to swap AFW to an alternate suction source after initial AFW success. The normal makeup path to the AFWST is failed due to the DC power dependence and that is why the alternate makeup action is required. Local valve actions are not credited to open the normal supply path, but given that an action already exists to open the alternate path, dependence issues would limit the credit available for locally opening the normal makeup valve (or other manual actions). Automating the alignment of the alternate makeup path would reduce the contribution of these contributors assuming the alternate alignment equipment can be powered from the "B" division (SAMA 7). Providing a parallel makeup valve with a "B" division power supply would help mitigate DR6 valve failures and loss of DC bus scenarios.
%S4-D	1.75E-03	1.015	STEAM GENERATOR 14 TUBE RUPTURE INITIATOR	Providing primary side steam generator isolation valves would greatly reduce the complexity of the response required in SGTR scenarios, including the elimination of rapid cooldown and depressurization to prevent and mitigate leaks to the secondary side (SAMA 13).
%S4-A	1.75E-03	1.015	STEAM GENERATOR 11 TUBE RUPTURE INITIATOR	Providing primary side steam generator isolation valves would greatly reduce the complexity of the response required in SGTR scenarios, including the elimination of rapid cooldown and depressurization to prevent and mitigate leaks to the secondary side (SAMA 13).

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
ACP-XHE-FO-GTG	6.70E-02	1.014	GTG UNAVAILABLE DUE TO OPERATOR FAILURE	This event is the failure to align Unit 3 to the Salem emergency buses, which generally occurs with successful operation of AFW. The most effective plant improvement is considered to be providing EDG "C" with its own diesel fuel oil transfer pump powered from the "C" division and enabling the "C" EDG to power the "A" and "B" 4kV buses (SAMA 4). Another approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). An additional option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
DGS-DGN-FS-DG1A	4.95E-03	1.014	DGN-1A FAILURE TO START	This event is the failure to start of the "A" EDG, which generally occurs with successful operation of AFW. The most effective plant improvement is considered to be providing EDG "C" with its own diesel fuel oil transfer pump powered from the "C" division and enabling the "C" EDG to power the "A" and "B" 4kV buses (SAMA 4). Another approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). An additional option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RD4-XHE	5.90E-03	1.014	FAIL TO OPEN DOORS /USE FANS FOR LOSS OF SWGR HVAC	This action is used to supply alternate cooling to the switchgear areas on loss of normal cooling. The HEP for the action is driven by the operators forgetting to open the switchgear room doors and the assumption that the switchgear room temperature indicators are difficult to locate, which is considered to be conservative. Reasonable measures are considered to have been taken for establishing alternate switchgear room cooling and no changes to the procedure or action are suggested. Further reducing the probability of the loss of switchgear room cooling scenarios would likely require the installation of a redundant train of cooling equipment (SAMA 16).
%VSW	1.00E+00	1.014	Initiator Flag for Loss of VSW IE	This initiating event is addressed by a proceduralized action to supply alternate cooling to the switchgear areas on loss of normal cooling. The HEP for the action is driven by the operators forgetting to open the switchgear room doors and the assumption that the switchgear room temperature indicators are difficult to locate, which is considered to be conservative. Reasonable measures are considered to have been taken for establishing alternate switchgear room cooling and no changes to the procedure or action are suggested. Further reducing the contribution from loss of switchgear room cooling scenarios would likely require the installation of a redundant train of cooling equipment (SAMA 16).

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
VDG-FNS-FS-VHE25	4.80E-03	1.014	DG 1A ROOM SUPPLY FAN 1VHE25 FAILS TO START	This event is mainly paired with other hardware failures of the "B" EDG division that would not impact the "C" division apart from its fuel oil transfer pump dependence. Adding a "C" fuel oil transfer pump that it is power from the "C" division and providing a means for the "C" EDG to power the "A" and/or "B" buses will eliminate most of the risk associate with these HVAC failures (SAMA 4). Alternatively, the EDG room doors could be opened and portable fans could be used, if necessary, to provide backup cooling (SAMA 17).
VDG-FNS-FS-VHE28	4.80E-03	1.014	DG 1A CONTROL ROOM SUPPLY FAN 1VHE28 FAILS TO START	This event is mainly paired with other hardware failures of the "B" EDG division that would not impact the "C" division apart from its fuel oil transfer pump dependence. Adding a "C" fuel oil transfer pump that it is power from the "C" division and providing a means for the "C" EDG to power the "A" and/or "B" buses will eliminate most of the risk associate with these HVAC failures (SAMA 4). Alternatively, the EDG room doors could be opened and portable fans could be used, if necessary, to provide backup cooling (SAMA 17).

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
DGS-DGN-FS-DG1B	4.95E-03	1.014	DGN-1B FAILURE TO START	This event is the failure to start of the "B" EDG, which generally occurs with successful operation of AFW. The most effective plant improvement is considered to be providing EDG "C" with its own diesel fuel oil transfer pump powered from the "C" division and enabling the "C" EDG to power the "A" and "B" 4kV buses (SAMA 4). Another approach is to provide the ability to align Unit 3 to the Salem 4kV buses from the MCR (SAMA 2). An additional option is to add an inter-unit 4kV cross-tie capability (SAMA 3). A 460V generator can be used to energize the battery chargers to support long term AFW operation, but this change would need to be accompanied by the replacement of the PDP pump with an air cooled model to eliminate the CCW dependence (requires 4kV power) (SAMA 5). This change should also include provisions to supply the Circ Water batteries with charging power so that offsite power can be restored to the switchyard when the grid is restored.
%S4-B	1.75E-03	1.014	STEAM GENERATOR 12 TUBE RUPTURE INITIATOR	Providing primary side steam generator isolation valves would greatly reduce the complexity of the response required in SGTR scenarios, including the elimination of rapid cooldown and depressurization to prevent and mitigate leaks to the secondary side (SAMA 13).

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
CHS-CHL-FR-NO13	2.26E-03	1.014	CHILLER 13 - 1CHE9 FAILS TO RUN	This event is related to the loss of Control Area Ventilation, which subsequently forces MCR abandonment. Nearly all of the contributors including this event also include the failure to properly shut the reactor down from the RSP (RRS-XHE-FO-SDRSP). SAMA 1 addressed these contributors.
EAC-FNS-FS-DF03	1.48E-04	1.014	COMM CAUSE FTS OF U2 CREACS SUP FANS 2VHE64/65	This event is related to the loss of Control Area Ventilation, which subsequently forces MCR abandonment. Nearly all of the contributors including this event also include the failure to properly shut the reactor down from the RSP (RRS-XHE-FO-SDRSP). SAMA 1 addressed these contributors.
VDG-FNS-FS-VHE26	4.80E-03	1.013	DG 1B ROOM SUPPLY FAN 1VHE26 FAILS TO START	This event is mainly paired with other hardware failures of the "A" EDG division that would not impact the "C" division apart from its fuel oil transfer pump dependence. Adding a "C" fuel oil transfer pump that it is power from the "C" division and providing a means for the "C" EDG to power the "A" and/or "B" buses will eliminate most of the risk associate with these HVAC failures (SAMA 4).

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
VDG-FNS-FS-VHE29	4.80E-03	1.013	DG 1B CONTROL ROOM SUPPLY FAN 1VHE29 FAILS TO START	This event is mainly paired with other hardware failures of the "A" EDG division that would not impact the "C" division apart from its fuel oil transfer pump dependence. Adding a "C" fuel oil transfer pump that it is power from the "C" division and providing a means for the "C" EDG to power the "A" and/or "B" buses will eliminate most of the risk associate with these HVAC failures (SAMA 4). Alternatively, the EDG room doors could be opened and portable fans could be used, if necessary, to provide backup cooling (SAMA 17).
CCS-HTX-PG-1YEAR	5.63E-03	1.013	HEAT EXCHANGER 11/12 TUBE PLUGGING	The loss of CCW is often paired with a consequential RCP seal LOCA due to procedure limitations that restrain the primary side cooldown rate to only 25 degrees per hour, which is not fast enough to reach the suggested safe range for the RCP seals within 2 hours after loss of all seal cooling. Procedure changes could be introduced that would increase the primary side cooldown rate for loss of RCP seal cooling cases to reduce the probability of incurring a seal LOCA. The target cooldown and depressurization rate would be about 1400 psi within 2 hours (SAMA 10). Automating the isolation of the letdown line, the swap to a CCP, and the suction source alignment to the RWST could reduce the risk of seal LOCAs for loss of CCW cases (SAMA 15). Currently, these actions are performed manually and while the Salem procedures have been modified to direct these actions early in a loss of CCW scenario, an automated function would potentially improve reliability.

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RECOV0AB	9.09E+02	1.013	Dependency adjust	This event is used as part of the HRA dependence analysis to set the appropriate value for the combination of the following events: AFS-XHE-FO-H2OLT, AFS-XHE-FO-REFIL, MFW-XHE-FO-COND, and RHS-XHE-FO-RECIR. In this case, the event RECOV0AB is applied to a single cutset and the only elements in the cutset apart from the initiating event are the HEPs identified. Each of these HEPs is addressed independently in this list and the SAMAs suggested for those events are also applicable to this combination.
CE	2.10E-05	1.013	ELECTRICAL RPS FAILURE (ATWS)	Electrical RPS failures could be bypassed by removing power from the control rods. A manual action from the MCR is available to do this, but a potential improvement would be to use AMSAC to trip the control rod power breakers given failure of RPS. The benefit of the change would be greatly improved if on-line AMSAC maintenance were eliminated (SAMA 14).

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%FL_AB084B_G_FP	4.47E-05	1.012	Flood AB 084 B General, fire protection source	Most of the contribution from this flooding event is related to floor drain clogging and subsequent flooding of the 220/44 VAC switchgear rooms. The equipment susceptible to damage is the switchgear components with electrical contacts only 2" above the floor surface. Although 4" curbs exist on the doorways between the switchgear area and corridor, a large volume of water due to flooding could quickly overflow the barriers and damage electrical equipment before operators are able to isolate the source of flooding. One means of mitigating this scenario would be to install larger flood barriers in front of the switchgear doors, similar to what was done at Kewaunee to alleviate flooding concerns for a similar area (SAMA 12).
CHS-CHL-FR-NO21	2.26E-03	1.012	CHILLER 21 FAILS TO RUN	This event is related to the loss of Control Area Ventilation, which subsequently forces MCR abandonment. Nearly all of the contributors including this event also include the failure to properly shut the reactor down from the RSP (RRS-XHE-FO-SDRSP). SAMA 1 addressed these contributors.
CHS-CHL-FR-NO22	2.26E-03	1.012	CHILLER 22 FAILS TO RUN	This event is related to the loss of Control Area Ventilation, which subsequently forces MCR abandonment. Nearly all of the contributors including this event also include the failure to properly shut the reactor down from the RSP (RRS-XHE-FO-SDRSP). SAMA 1 addressed these contributors.

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RHR-XHE-FO-SHDCL	6.40E-03	1.012	FAILURE OF OPERATOR TO ALIGN SHUTDOWN COOLING AFTER DEPRESS	This action is taken after the reactor is successfully cooled down and there are a limited number of strategies available for reducing the risk of these scenarios short of automating SDC initiation, which is impractical and not suggested. However, the scenarios do include some type of failure that results in continued leakage from the primary side (isolation failure or valve failures). A means of reducing the probability of these types of breaks would be to install primary side isolation valves on the steam generators (SAMA 13).
MFI-UNAVAILABLE	3.00E-01	1.012	Split Fraction for MFW Unavailable	Over 60 percent of the contributors including this event also include an AMSAC maintenance event. AMSAC could be used to provide a trip signal to the control rod breakers, but to benefit many of the ATWS cases where MFW is unavailable, on-line AMSAC maintenance would have to be eliminated (SAMA 14).
RECOV10	2.00E+00	1.011	Dependency adjust	This event is used as part of the HRA dependence analysis to set the appropriate value for the combination of the following events: AFS-XHE-FO-H2OLT, AFS-XHE-FO-REFIL. Each of these HEPs is addressed independently in this list and the SAMAs suggested for those events are also applicable to this combination.

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
ISG-XHE-SG-ISOL	3.70E-03	1.011	SGTR ISOLATE AFFECTED STEAM GENERATOR	This action has an estimated failure probability of 3.7E-03, which is dominated by execution error. Without a formality of the HRA methodology, this HEP could be 25 percent of the current value, but providing primary side steam generator isolation valves would still simplify the isolation process and improve the reliability of isolation and subsequent plant control actions (SAMA 13).
SWS-XHE-FO-SWIXO	2.20E-02	1.011	FAILURE TO MANUALLY CLOSE SW TURBINE HEADER VALVES	This action is required to reserve available SW flow for critical loads. Automating the turbine header isolation on low SW pump discharge pressure or return flow temperature could improve the reliability of the isolation function (SAMA 18).
MSS-PRV-CC-DF01	7.08E-05	1.01	COMMON CAUSE FAILURE TO OPEN OF ALL MS10 VALVES	For these cases, failure of the MS10 valves precludes the use of AFW to depressurize the RCS early and late to stop leakage to the secondary side. Providing primary side isolation valves would eliminate issues related to continued leakage to the secondary side (SAMA 13).

Table E.5-1
Level 1 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%FL_AB045_SP	7.60E-04	1.01	Flood AB045 spray all sources	Due to the nature of spray scenarios, equipment is assumed to fail once a water source has breached its piping boundary and wetted susceptible equipment. The installation of spray shields for the RHR pumps in this area of the Aux. Building 45' el. would provide the necessary protection against any damaging spray scenario, and thus would allow functionality of these pumps. Spray scenarios, by virtue of their flow rate being < 100 gpm, would not likely threaten the operability and functionality of the ruptured water system providing the source of spray (SAMA 19). One of the large contributors to this scenario is common cause steam binding of the AFW pumps (forces use of feed and bleed, which is disable due to the spray event). Providing an alternate, engine driven SG makeup pump could reduce the contribution from these scenarios (SAMA 8).

Table E.5-2
Level 2 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RRS-XHE-FO-SDRSP	1.00E-01	2.506	FAILURE OF THE OPER TO SHUTDOWN FROM REMOTE SDP	Addressed in the Level 1 importance list.
%TVC	1.00E+00	1.792	INITIATOR FLAG FOR LOSS OF CONTROL AREA HVAC IE-TVC	Addressed in the Level 1 importance list.
CHS-CHL-FR-NO11A	8.25E-01	1.506	CHILLER FAILS TO CONTINUE OPERATING annual	Addressed in the Level 1 importance list.
G2SW22	2.00E-03	1.364	INSUFF FLOW FROM SW HDR 22	Addressed in the Level 1 importance list.
CHS-CHL-TM-NO13	3.08E-02	1.297	CHILLER NO 13 UNAVAILABLE DUE TO TM	Addressed in the Level 1 importance list.
RBU1	1.00E+00	1.220	AC nrec SBO w afw success cd success	Addressed in the Level 1 importance list.
%TSW	1.00E+00	1.207	INITIATOR FLAG FOR LOSS OF SERVICE WATER IE-TSW	Addressed in the Level 1 importance list.
SWS-STR-PG-DF00	5.24E-05	1.159	CCF OF ALL SWS STRAINERS (BOTH UNITS) ON ANNUAL BASIS	Addressed in the Level 1 importance list.

Table E.5-2
Level 2 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
RD3-XHE-ABCAV	5.10E-03	1.107	FAIL TO ALIGN CAV FOR AB-CAV MODE	Addressed in the Level 1 importance list.
%TES	1.03E-02	1.088	LOOP Initiator - switchyard / plant	Addressed in the Level 1 importance list.
%TEW	5.20E-03	1.083	LOOP initiator - weather	Addressed in the Level 1 importance list.
CHS-CHL-FS-NO13	9.83E-03	1.079	CHILLER NO 13 FAILS TO START	Addressed in the Level 1 importance list.
RECRBU1W	2.40E-01	1.066	AC pwr nrec AFW and cooldn success, wx LOOP	Addressed in the Level 1 importance list.
RD3-XHE-MM	8.30E-03	1.064	FAIL TO ALIGN CAV FOR MAINTENANCE MODE	Addressed in the Level 1 importance list.
RECOV15	1.10E+01	1.064	Dependency adjust	Addressed in the Level 1 importance list.
RECRBU1S	1.00E-01	1.054	AC pwr nrec AFW and cooldn success, swyd & plt LOOP	Addressed in the Level 1 importance list.
RCS-SLOCA-SPLIT	1.00E+00	1.052	SPLIT FRACTION FOR SEAL LOCA AFTER LOSS COOLING	Addressed in the Level 1 importance list.
RDW-STR-PG-FLOOD2	1.00E-02	1.050	Failure of drains (limited number)	Addressed in the Level 1 importance list.

Table E.5-2
Level 2 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%TEG	1.42E-02	1.044	LOOP initiator - Grid	Addressed in the Level 1 importance list.
%FL_AB084B_M_FP	4.71E-05	1.037	Flood AB 084 B Major, fire protection source	Addressed in the Level 1 importance list.
SWS-STR-PG-DF06	1.05E-03	1.035	COMMON CAUSE FAILURE 6 OF 6 STRAINERS ON ANNUAL BASIS	Addressed in the Level 1 importance list.
%FL_AB084B_G_FP	4.47E-05	1.031	Flood AB 084 B General, fire protection source	Addressed in the Level 1 importance list.
RECRBU1G	2.40E-01	1.030	AC pwr nrec AFW and cooldown success, grid LOOP	Addressed in the Level 1 importance list.
CHS-CHL-TM-NO23	3.08E-02	1.028	CHILLER 23 UNAVAILABLE DUE TO TEST AND MAINT	Addressed in the Level 1 importance list.
DGS-DGN-FR-DG1A	6.52E-03	1.023	DGN-1A FAILURE TO RUN	Addressed in the Level 1 importance list.
DGS-DGN-FR-DG1B	6.52E-03	1.022	DGN-1B FAILURE TO RUN 6.52e-3 calc 3 6h 1.09e-3/h	Addressed in the Level 1 importance list.
RCS-XHE-FO-LDEP	9.70E-03	1.022	OPER FAILS TO DEPRESSUR RCS LATE	Addressed in the Level 1 importance list.

Table E.5-2
Level 2 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
CHS-CHL-FR-NO12	2.26E-03	1.020	CHILLER 12 - 1CHE8 FAILS TO RUN	Addressed in the Level 1 importance list.
RD4-XHE	5.90E-03	1.018	FAIL TO OPEN DOORS /USE FANS FOR LOSS OF SWGR HVAC	Addressed in the Level 1 importance list.
%S4-C	1.75E-03	1.018	STEAM GENERATOR 13 TUBE RUPTURE INITIATOR	Addressed in the Level 1 importance list.
DGS-DGN-FS-DG1A	4.95E-03	1.018	DGN-1A FAILURE TO START	Addressed in the Level 1 importance list.
ACP-XHE-FO-GTG	6.70E-02	1.017	GTG UNAVAILABLE DUE TO OPERATOR FAILURE	Addressed in the Level 1 importance list.
%VSW	1.00E+00	1.017	Initiator Flag for Loss of VSW IE	Addressed in the Level 1 importance list.
VDG-FNS-FS-VHE25	4.80E-03	1.017	DG 1A ROOM SUPPLY FAN 1VHE25 FAILS TO START	Addressed in the Level 1 importance list.
VDG-FNS-FS-VHE28	4.80E-03	1.017	DG 1A CONTROL ROOM SUPPLY FAN 1VHE28 FAILS TO START	Addressed in the Level 1 importance list.
CHS-CHL-FR-NO13	2.26E-03	1.017	CHILLER 13 - 1CHE9 FAILS TO RUN	Addressed in the Level 1 importance list.
EAC-FNS-FS-DF03	1.48E-04	1.017	COMM CAUSE FTS OF U2 CREACS SUP FANS 2VHE64/65	Addressed in the Level 1 importance list.

Table E.5-2
Level 2 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
%S4-D	1.75E-03	1.017	STEAM GENERATOR 14 TUBE RUPTURE INITIATOR	Addressed in the Level 1 importance list.
DGS-DGN-FS-DG1B	4.95E-03	1.017	DGN-1B FAILURE TO START	Addressed in the Level 1 importance list.
%S4-A	1.75E-03	1.017	STEAM GENERATOR 11 TUBE RUPTURE INITIATOR	Addressed in the Level 1 importance list.
VDG-FNS-FS-VHE26	4.80E-03	1.016	DG 1B ROOM SUPPLY FAN 1VHE26 FAILS TO START	Addressed in the Level 1 importance list.
VDG-FNS-FS-VHE29	4.80E-03	1.016	DG 1B CONTROL ROOM SUPPLY FAN 1VHE29 FAILS TO START	Addressed in the Level 1 importance list.
%S4-B	1.75E-03	1.016	STEAM GENERATOR 12 TUBE RUPTURE INITIATOR	Addressed in the Level 1 importance list.
CHS-CHL-FR-NO21	2.26E-03	1.015	CHILLER 21 FAILS TO RUN	Addressed in the Level 1 importance list.
CHS-CHL-FR-NO22	2.26E-03	1.015	CHILLER 22 FAILS TO RUN	Addressed in the Level 1 importance list.
RHR-XHE-FO-SHDCL	6.40E-03	1.015	FAILURE OF OPERATOR TO ALIGN SHUTDOWN COOLING AFTER DEPRESS	Addressed in the Level 1 importance list.
AFS-MDP-FS-DF04	4.25E-04	1.014	DEPEN FAILURE OF 3 AFW PUMPS (STEAM BINDING)	Addressed in the Level 1 importance list.

Table E.5-2
Level 2 Importance List Review

Event Name	Probability	Risk Reduction Worth	Description	Potential SAMAs
ISG-XHE-SG-ISOL	3.70E-03	1.013	SGTR ISOLATE AFFECTED STEAM GENERATOR	Addressed in the Level 1 importance list.
MSS-PRV-CC-DF01	7.08E-05	1.013	COMMON CAUSE FAILURE TO OPEN OF ALL MS10 VALVES	Addressed in the Level 1 importance list.
SWS-XHE-FO-SWIXO	2.20E-02	1.013	FAILURE TO MANUALLY CLOSE SW TURBINE HEADER VALVES	Addressed in the Level 1 importance list.
FL_XHE_AB084B_M	4.83E-03	1.012	Failure to isolate major flood in AB 084 B	All of these events result in temperature or pressure induced tube ruptures. Providing primary side steam generator isolation valves would provide a means of preventing hot core gases from entering the steam generators (SAMA 13).
RD-ABV	1.00E+00	1.011	Fail to Provide Alternate Cooling by Opening Door/Using Portable Fan	RCP seal LOCAs resulting from flood based system damage are large contributors to the pressure induced tube rupture scenarios. Proceduralizing the PDP seal injection cross-tie would provide an alternate means of seal injection thus preventing core damage (SAMA 11).
%TT	6.02E-01	1.010	TRANSIENT WITH PCS AVAILABLE INITIATOR	Addressed in the Level 1 importance list.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
1	Enhance Procedures and Provide Additional Equipment to Respond to Loss of Control Area Ventilation	In the event that cooling to the CAV is lost (including CAVA-B mode and maintenance mode), the doors in the CRE, Rack Room/Electrical Equipment room, and Relay Room could be opened and portable fans could be used to provide additional circulation. Portable ducts could also be included in the design, if necessary.	Level 1 Importance list, IPEEE (FIRE)	$475,000	Retained for Phase 2.
2	Re-configure Salem 3 to Provide a More Expedient Backup AC Power Source for Salem 1 and 2	For LOOP scenarios with failure of all EDGs, Unit 3 may be available to provide power to the Salem emergency 4kV buses, but the current configuration requires local manipulations in the switchyard that preclude success in AFW failure cases. Enhancing the site so that the alignment could be performed form the CRE would provide a reliable, rapid connection to Unit 3. Installing a direct line with a dedicated transformer would bypass potential switchyard problems and simplify the alignment process.	Level 1 Importance list	$875,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
3	Install Limited EDG Cross-tie Capability Between Salem 1 and 2	For LOOP scenarios with failure of all EDGs on a given unit, the EDGs from the opposite may be available, but currently, there is no means of performing a cross-tie to that unit in a useful timeframe. Enhancing the plant so that the cross-tie could be performed from the CRE is a means of reducing the risk from LOOP scenarios.	Level 1 Importance list	$525,000	Retained for Phase 2.
4	Install Fuel Oil Transfer Pump on “C” EDG & Provide Procedural Guidance for Using “C” EDG to Power Selected “A” and “B” Loads	Currently, LOOP events with failure of the "A" and "B" EDGs also results in failure of the "C" EDG because the "C" diesel does not have its own fuel oil transfer pump. If the "C" EDG is provided with its own fuel oil transfer pump and procedures are written to allow the "C" bus to power the important loads on the "A" and "B" buses, it would provide an additional means of coping with SBO conditions.	Level 1 Importance list, IPEEE (FIRE), IPEEE (Seismic)	$585,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
5	Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries & Replace PDP with Air-Cooled Pump	For long term SBO scenarios, AFW operation can be extended by powering the station battery charger with a 460V AC generator. Primary side makeup could be provided by a PDP if it was replaced with an air cooled model that is capable of a flow rate of about 300-350 gpm (addresses most of RCP seal LCOA risk). It is necessary to replace the PDP because it relies on CCW for cooling (a 4kV load) and the flow rate is not large enough to provide makeup for the larger seal LOCAs. Finally, providing power to the Circ Water batteries would facilitate the restoration of off-site power once the grid becomes available. Currently, the Circ Water batteries are required to operate breakers that are required for offsite power alignment.	Level 1 Importance list	$3,320,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
6	Enhance Flood Detection for 84' Aux Building and Enhance Procedural Guidance for Responding to Service Water Flooding	Service Water system breaks on the 84' elevation of the Aux building can fail the Service Water system in addition to other required support equipment. The ability to rapidly detect and isolate the flooding source would greatly reduce the severity of this event. An option to install pressure indication and flow sensors in the Service Water lines with remote alarm indication in the control room with the capability to quickly identify the specific location of a break would greatly help mitigate this scenario.	Level 1 Importance list	$250,000	Retained for Phase 2.
7	Install "B" Train AFWST Makeup Including Alternate Water Source	Currently, manual action is required to establish a long term suction source to AFW (one that will meet the 24 hour mission time requirement). The benefit of this SAMA would be enhanced if both trains of DC power are made available to support the makeup function (logic and valve motive power). The installation of a valve in parallel with DR6 powered from a train B DC power source would enhance the availability for a long term suction source of AFW. The use of a different design for this parallel valve arrangement is also suggested so as to eliminate possible common cause failures.	Level 1 Importance list	$470,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
8	Install High Pressure Pump Powered with Portable Diesel Generator and Long-term Suction Source to Supply the AFW Header	For cases that include AFW and MFW failures, a engine driven high pressure diesel driven pump could be used to provide alternate makeup to the steam generators. A long term suction source would be required for the pump and the ability to inject through the turbine driven AFW header would maximize flexibility. The most benefit would be gained if the pump is permanently mounted to support early injection (given immediate failure of all SG makeup) and in an area away from the other AFW equipment (for fire reasons).	Level 1 Importance list, IPEEE (FIRE)	$2,510,000	Retained for Phase 2.
9	Connect Hope Creek Cooling Tower Basin to Salem Service Water System as Alternate Service Water Supply	In the event that the Service Water system becomes fouled, the Hope Creek Circ Water Canal could be used as an alternate suction and discharge path. This should provide a clean water source and a viable flow path for the Service Water loads.	Level 1 Importance list	$1,235,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
10	Provide Procedural Guidance for Faster Cooldown on Loss of RCP Seal Cooling	Currently, the procedures direct a cooldown rate of 25 degrees F. per hour, which would not reduce primary side temperature to a "safe" range for the RCP seals. For loss of RCP seal cooling scenarios, the procedures could be modified to direct a more rapid cooldown in order to reduce the probability that an RCP seal LOCA would occur. The target cooldown range would potentially be as low as 1400 psi by 2 hours.	Level 1 Importance list	$100,000	Retained for Phase 2.
11	Modify Plant Procedures to Make Use of Other Unit's PDP for RCP Seal Cooling	Currently, only the fire procedures allow the operators to take advantage of the opposite unit's PDP for RCP seal cooling. Modifying the plant procedures to allow the use of the PDP cross-tie for this purpose when normal RCP seal cooling is lost can provide an additional means of RCP seal cooling.	Level 1 and 2 Importance list	$100,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
12	Improve Flood Barriers Outside of 220/440VAC Switchgear Rooms	This event represents failure of drains in the non-RCA corridor area of the Aux. Building 84' el. outside the 220/440 VAC switchgear rooms to convey flood waters away from the area. The equipment susceptible to damage is the switchgear components with electrical contacts only 2" above the floor surface. Although 4" curbs exist on the doorways between the switchgear area and corridor, a large volume of water due to flooding could quickly overflow the barriers and damage electrical equipment before operators are able to isolate the source of flooding. One means of mitigating this scenario would be to install larger flood barriers in front of the switchgear doors, similar to what was done at Kewaunee to alleviate flooding concerns for a similar area.	Level 1 Importance list	$475,000	Retained for Phase 2.
13	Install Primary Side Isolation Valves on the Steam Generators	The availability of primary side steam generator isolation vales would provide a simple means of isolating ruptured SGs. While secondary side isolation capability exists, these valves would help avoid challenges to secondary side integrity due to failure to rapidly cooldown the primary side.	Level 1 and 2 Importance list	$17,750,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
14	Expand AMSAC Function to Include Backup Breaker Trip on RPS Failure	A large portion of the ATWS contribution includes electrical RPS failures. Using the AMSAC to provide a signal to trip the control rod power breakers on RPS failure would improve the reliability of the scram function.	Level 1 Importance list	$485,000	Retained for Phase 2.
15	Automate RCP Seal Injection Re-alignment on Loss of CCW	CCW cools the letdown and seal water return heat exchangers which will raise VCT temperature and ultimately result in overheated RCP seals if charging continues to take suction from the VCT. This HEP models the operator action to isolate letdown and transfer charging pump suction to the RWST. If Charging suction is not transferred prior to reaching 225 F, the sudden lowering of the seal water injection temperature from the RWST could cause the RCP seals to crack and fail. In addition, as CCW cools the positive displacement charging pump (13) which is normally in service, the Loss of CCW procedure directs that the 11 or 12 charging pump be placed in service as their oil coolers use SW. Automating the isolation of the letdown line, the swap to a CCP, and the suction source alignment to the RWST could reduce the risk of seal LOCAs.	Level 1 Importance list	$210,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
16	Install an Additional Train of Switchgear Room Cooling Equipment	While Salem already has a reasonably reliable action to provide alternate cooling to the switchgear rooms, loss of cooling is still a significant contributor to risk. Further reductions in loss of switchgear room cooling contributions would require the installation of an additional train of cooling that would operate automatically on loss of cooling.	Level 1 Importance list	$2,535,000	Retained for Phase 2.
17	Enhance Procedures and Provide Additional Equipment to Respond to Loss of EDG Control Room Ventilation	In the event that normal EDG control room HVAC fails, opening the doors could prevent the rooms from overheating. Portable fans could be used if natural circulation does not provide sufficient circulation.	Level 1 Importance list	$200,000	Retained for Phase 2.
18	Automate Turbine Header Isolation in the Service Water System on Low Pump Discharge Pressure	In cases where fewer Service Water pumps are available than required for cooling the safety related loads, the turbine header isolation function could be enhanced by installing another isolation valve, such as an MOV, in series that is powered by a different electrical train so as to ensure redundancy and reliability.	Level 1 Importance list	$635,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
19	Install Spray Shields on the RHR Pumps	The installation of spray shields for the RHR pumps in the Aux. Building 45' el. area would provide the necessary protection against any damaging spray scenario, and thus would allow functionality of these pumps. Spray scenarios, by virtue of their flow rate being < 100 gpm, would not likely threaten the operability and functionality of the ruptured water system providing the source of spray and the focus is protecting the equipment in the area.	Level 1 Importance list	$350,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
20	Fire/Seismic Safe System	A potential option to mitigate fires that cause damage across multiple trains and systems would be to install two engine driven pumps that can be controlled locally to provide makeup to the RCS and steam generators. These systems would not rely on any other systems for success and while they may be relatively difficult to operate, they would provide a path for success when other makeup options are not available. The RCS makeup pump would require a suction connection to the RWST and an injection connection through the safety injection lines (outside containment, but downstream of the MOVs). For the secondary side makeup pump, suction would be required from the fire water system and injection through the turbine driven pump line. Ensuring the equipment is seismically qualified and stored in a seismically qualified structure would also provide a means of mitigating seismic events that cause widespread system failures. Additionally, adequate instrumentation would need to be provided so the operator can have reliable pressure, temperature, and level indications in the absence of normal power supplies.	SGS IPEEE (Fire, Seismic)	$13,100,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
21	Seal the Category II and III Cabinets in the Relay Room	The dominant fire scenario in the Relay Room (1FA-AB-100A) is a cabinet fire that is not suppressed and is able to propagate to the point where it is large enough to force main control room abandonment. The issue for this scenario is not necessarily the availability of equipment, but more that the operators are forced to take control of the plant from the RSP. The most effective method identified to reduce the risk from this scenario is to provide better barrier separation for cabinet fires in this area in order to reduce the threat of fire propagation from one cabinet to another. What this would involve includes the means of providing fire barrier and adequate cabinet/train separation so as to minimize the unavailability of both safety related trains due to fire propagation. This would involve the modification of several cabinets within the relay room. It was estimated that 48 out of 68 cabinets in the room would require protection using an approved fire barrier material. This SAMA would not involve installation or modification of any new or existing fire detection or suppression equipment.	SGS IPEEE (Fire)	$3,230,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
22	Install Fire Barriers Between the 1CC1, 1CC2, and 1CC3 Consoles in the CRE	The largest contributors to fires in the CRE are those that force abandonment of the CRE due to damage in the 1CC1, 1CC2, and/or 1CC3 consoles. The most effective means of reducing the CDF of these scenarios is considered to be preventing the need to abandon the CRE. Using an approved fire barrier material within these cabinets is one method of reducing the likelihood of having a fire in one cabinet propagate to another cabinet. The prevention of a fire from causing damage to one of the other two cabinets will help to reduce the need to abandon the MCR. This SAMA would not involve installation or modification of any new or existing fire detection or suppression equipment.	SGS IPEEE (Fire)	$1,600,000	Retained for Phase 2.
23	Install Fire Barriers and Cable Wrap to Maintain Divisional Separation in the 4160V AC Switchgear Room	Rooms that include cable or equipment for multiple divisions introduce the undesirable situation in which a single fire event can disable multiple divisions of equipment. Given the importance of the 4160V AC equipment, the cables and equipment in the 4160V AC Switchgear room should be protected to prevent the propagation of a fire from one division to another.	SGS IPEEE (Fire)	$975,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
24	Provide Procedural Guidance to Cross-tie Salem 1 and 2 Service Water Systems	For fire events in the Service Water pump bays, the combination of fire induced SW pump failures with random SW pump failures is a relatively large contributor to CDF, especially since the SW system was ultimately assumed to be required to prevent core damage. An inter-unit SW cross-tie exists at SGS, but its use is not currently proceduralized while both units are at power. Ensuring that adequate procedures exist to govern the use of the cross-tie for these fire scenarios would greatly reduce their CDF contributions.	SGS IPEEE (Fire)	$175,000	Retained for Phase 2.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
25	Strengthen Masonry Block Walls Around "A" and "B" Station Batteries	The seismically induced failure of the block walls around the station batteries results in failure of the batteries. Replacing the walls or strengthening them so that they are more seismically durable would reduce the contribution from these sequences.	SGS IPEEE (Seismic)	Not Required	Further investigation identified that the walls around the "A" and "B" station batteries are poured concrete and that the risk associated with seismic interaction between the batteries and the wall are overestimated in the IPEEE. Station battery "C", which is not an important contributor, is surrounded by masonry block walls. It has been concluded that because information used in the IPEEE did not reflect actual plant conditions, this SAMA is not applicable to the SGS site and it has been screened from further review.
26	Strengthen MCR Ceiling	Seismically induced failure of the MCR Ceiling Grid is assumed to cause injury to the plant operators and while it is possible to control the plant from the RSP, qualified personnel would not be available to operate the plant. Strengthening the MCR ceiling so that it is more seismically durable would help reduce the risk associated with MCR ceiling collapse.	SGS IPEEE (Seismic)	Not Required	The Salem Control Room was re-designed and modified in 1996 (PSEG 1996c). The ceiling is "2 / 1" seismic so it is already strengthened. Therefore, this SAMA should be screened from the Phase 2 analysis.

Table E.5-3
SGS Phase 1 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Cost Estimate	Phase 1 Baseline Disposition
27	In Addition to the Equipment Installed for SAMA 5, Install Permanently Piped Seismically Qualified Connections to Alternate AFW Water Sources	Seismically induced AFWST and AC power failures present the need to provide SBO mitigation capability (same as SAMA 5) and an alternate AFW suction source. SGS already has an alternate AFW suction alignment capability, but simplifying its alignment process through installation of a permanent, hard piped connection would improve reliability, especially after a seismic event where movement of the pipes could cause trouble with alignment of the "spool pieces" currently used in the suction path.	SGS IPEEE (Seismic)	$4,230,000	Retained for Phase 2.

Table E.6-1
SGS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
1	Enhance Procedures and Provide Additional Equipment to Respond to Loss of Control Area Ventilation	In the event that cooling to the CAV is lost (including CAVA-B mode and maintenance mode), the doors in the CRE, Rack Room/Electrical Equipment room, and Relay Room could be opened and portable fans could be used to provide additional circulation. Portable ducts could also be included in the design, if necessary.	Level 1 Importance list, IPEEE (FIRE)	The nominal averted cost-risk for this SAMA is **greater** than the cost of implementation, which implies that this SAMA is **cost beneficial**.
2	Re-configure Salem 3 to Provide a More Expedient Backup AC Power Source as Dedicated Backup Generator for Salem 1 and 2	For LOOP scenarios with failure of all EDGs, Unit 3 may be available to provide power to the Salem emergency 4kV buses, but the current configuration requires local manipulations in the switchyard that preclude success in AFW failure cases. Enhancing the site so that the alignment could be performed form the CRE would provide a reliable, rapid connection to Unit 3. Installing a direct line with a dedicated transformer would bypass potential switchyard problems and simplify the alignment process.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is **greater** than the cost of implementation, which implies that this SAMA is **cost beneficial**.
3	Install Limited EDG Cross-tie Capability Between Salem 1 and 2	For LOOP scenarios with failure of all EDGs on a given unit, the EDGs from the opposite may be available, but currently, there is no means of performing a cross-tie to that unit in a useful timeframe. Enhancing the plant so that the cross-tie could be performed from the CRE is a means of reducing the risk from LOOP scenarios.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is <u>not</u> cost beneficial.

Table E.6-1
SGS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
4	Install Fuel Oil Transfer Pump on “C” EDG & Provide Procedural Guidance for Using “C” EDG to Power Selected “A” and “B” Loads	Currently, LOOP events with failure of the "A" and "B" EDGs also results in failure of the "C" EDG because the "C" diesel does not have its own fuel oil transfer pump. If the "C" EDG is provided with its own fuel oil transfer pump and procedures are written to allow the "C" bus to power the important loads on the "A" and "B" buses, it would provide an additional means of coping with SBO conditions.	Level 1 Importance list, IPEEE (FIRE), IPEEE (Seismic)	The nominal averted cost-risk for this SAMA is **greater** than the cost of implementation, which implies that this SAMA is **cost beneficial**.
5	Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries & Replace PDP with Air-Cooled Pump	For long term SBO scenarios, AFW operation can be extended by powering the station battery charger with a 460V AC generator. Primary side makeup could be provided by a PDP if it was replaced with an air cooled model that is capable of a flow rate of about 300-350 gpm (addresses most of RCP seal LCOA risk). It is necessary to replace the PDP because it relies on CCW for cooling (a 4kV load) and the flow rate is not large enough to provide makeup for the larger seal LOCAs. Finally, providing power to the Circ Water batteries would facilitate the restoration of off-site power once the grid becomes available. Currently, the Circ Water batteries are required to operate breakers that are required for offsite power alignment.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is <u>not</u> cost beneficial.

Table E.6-1
SGS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
6	Enhance Flood Detection for 84' Aux Building &and Enhance Procedural Guidance for Responding to Service Water Flooding	Service Water system breaks on the 84' elevation of the Aux building can fail the Service Water system in addition to other required support equipment. The ability to rapidly detect and isolate the flooding source would greatly reduce the severity of this event. An option to install pressure indication and flow sensors in the Service Water lines with remote alarm indication in the control room with the capability to quickly identify the specific location of a break would greatly help mitigate this scenario.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is **greater** than the cost of implementation, which implies that this SAMA is **cost beneficial**.
7	Install "B" Train AFWST Makeup Including Alternate Water Source	Currently, manual action is required to establish a long term suction source to AFW (one that will meet the 24 hour mission time requirement). The benefit of this SAMA would be enhanced if both trains of DC power are made available to support the makeup function (logic and valve motive power). The installation of a valve in parallel with DR6 powered from a train B DC power source would enhance the availability for a long term suction source of AFW. The use of a different design for this parallel valve arrangement is also suggested so as to eliminate possible common cause failures.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is <u>not</u> cost beneficial.

Table E.6-1
SGS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
8	Install High Pressure Pump Powered with Portable Diesel Generator and Long-term Suction Source to Supply the AFW Header	For cases that include AFW and MFW failures, a engine driven high pressure diesel driven pump could be used to provide alternate makeup to the steam generators. A long term suction source would be required for the pump and the ability to inject through the turbine driven AFW header would maximize flexibility. The most benefit would be gained if the pump is permanently mounted to support early injection (given immediate failure of all SG makeup) and in an area away from the other AFW equipment (for fire reasons).	Level 1 Importance list, IPEEE (FIRE)	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is not cost beneficial.
9	Connect Hope Creek Cooling Tower Basin to Salem Service Water System as Alternate Service Water Supply	In the event that the Service Water system becomes fouled, the Hope Creek Circ Water Canal could be used as an alternate suction and discharge path. This should provide a clean water source and a viable flow path for the Service Water loads.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is **greater** than the cost of implementation, which implies that this SAMA is **cost beneficial**.
10	Provide Procedural Guidance for Faster Cooldown on Loss of RCP Seal Cooling	Currently, the procedures direct a cooldown rate of 25 degrees F. per hour, which would not reduce primary side temperature to a "safe" range for the RCP seals. For loss of RCP seal cooling scenarios, the procedures could be modified to direct a more rapid cooldown in order to reduce the probability that an RCP seal LOCA would occur. The target cooldown range would potentially be as low as 1400 psi by 2 hours.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is **greater** than the cost of implementation, which implies that this SAMA is **cost beneficial**.

Table E.6-1
SGS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
11	Modify Plant Procedures to Direct Alignment of the Opposite Unit's PDP for RCP Seal Cooling	Currently, only the fire procedures allow the operators to take advantage of the opposite unit's PDP for RCP seal cooling. Modifying the plant procedures to allow the use of the PDP cross-tie for this purpose when normal RCP seal cooling is lost can provide an additional means of RCP seal cooling.	Level 1 and 2 Importance list	The nominal averted cost-risk for this SAMA is **greater** than the cost of implementation, which implies that this SAMA is **cost beneficial**.
12	Improve Flood Barriers Outside of 220/440VAC Switchgear Rooms	This event represents failure of drains in the non-RCA corridor area of the Aux. Building 84' el. outside the 220/440 VAC switchgear rooms to convey flood waters away from the area. The equipment susceptible to damage is the switchgear components with electrical contacts only 2" above the floor surface. Although 4" curbs exist on the doorways between the switchgear area and corridor, a large volume of water due to flooding could quickly overflow the barriers and damage electrical equipment before operators are able to isolate the source of flooding. One means of mitigating this scenario would be to install larger flood barriers in front of the switchgear doors, similar to what was done at Kewaunee to alleviate flooding concerns for a similar area.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is **greater** than the cost of implementation, which implies that this SAMA is **cost beneficial**.
13	Install Primary Side Isolation Valves on the Steam Generators	The availability of primary side steam generator isolation vales would provide a simple means of isolating ruptured SGs. While secondary side isolation capability exists, these valves would help avoid challenges to secondary side integrity due to failure to rapidly cooldown the primary side.	Level 1 and 2 Importance list	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is <u>not</u> cost beneficial.

Table E.6-1
SGS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
14	Expand AMSAC Function to Include Backup Breaker Trip on RPS Failure	A large portion of the ATWS contribution includes electrical RPS failures. Using the AMSAC to provide a signal to trip the control rod power breakers on RPS failure would improve the reliability of the scram function.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is **greater** than the cost of implementation, which implies that this SAMA is **cost beneficial**.
15	Automate RCP Seal Injection Re-alignment on Loss of CCW	CCW cools the letdown and seal water return heat exchangers which will raise VCT temperature and ultimately result in overheated RCP seals if charging continues to take suction from the VCT. This HEP models the operator action to isolate letdown and transfer charging pump suction to the RWST. If Charging suction is not transferred prior to reaching 225 F, the sudden lowering of the seal water injection temperature from the RWST could cause the RCP seals to crack and fail. In addition, as CCW cools the positive displacement charging pump (13) which is normally in service, the Loss of CCW procedure directs that the 11 or 12 charging pump be placed in service as their oil coolers use SW. Automating the isolation of the letdown line, the swap to a CCP, and the suction source alignment to the RWST could reduce the risk of seal LOCAs.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is <u>not</u> cost beneficial.
16	Install an Additional Train of Switchgear Room Cooling Equipment	While Salem already has a reasonably reliable action to provide alternate cooling to the switchgear rooms, loss of cooling is still a significant contributor to risk. Further reductions in loss of switchgear room cooling contributions would require the installation of an additional train of cooling that would operate automatically on loss of cooling.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is <u>not</u> cost beneficial.

Table E.6-1
SGS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
17	Enhance Procedures and Provide Additional Equipment to Respond to Loss of EDG Control Room Ventilation	In the event that normal EDG control room HVAC fails, opening the doors could prevent the rooms from overheating. Portable fans could be used if natural circulation does not provide sufficient circulation.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is **greater** than the cost of implementation, which implies that this SAMA is **cost beneficial**.
18	Automate Turbine Header Isolation in the Service Water System on Low Pump Discharge Pressure	In cases where fewer Service Water pumps are available than required for cooling the safety related loads, the turbine header isolation function could be enhanced by installing another isolation valve, such as an MOV, in series that is powered by a different electrical train so as to ensure redundancy and reliability.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is <u>not</u> cost beneficial.
19	Install Spray Shields on the RHR Pumps	The installation of spray shields for the RHR pumps in the Aux. Building 45' el. area would provide the necessary protection against any damaging spray scenario, and thus would allow functionality of these pumps. Spray scenarios, by virtue of their flow rate being < 100 gpm, would not likely threaten the operability and functionality of the ruptured water system providing the source of spray and the focus is protecting the equipment in the area.	Level 1 Importance list	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is <u>not</u> cost beneficial.

Table E.6-1
SGS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
20	Fire/Seismic Safe System	A potential option to mitigate fires that cause damage across multiple trains and systems would be to install two engine driven pumps that can be controlled locally to provide makeup to the RCS and steam generators. These systems would not rely on any other systems for success and while they may be relatively difficult to operate, they would provide a path for success when other makeup options are not available. The RCS makeup pump would require a suction connection to the RWST and an injection connection through the safety injection lines (outside containment, but downstream of the MOVs). For the secondary side makeup pump, suction would be required from the fire water system and injection through the turbine driven pump line. Ensuring the equipment is seismically qualified and stored in a seismically qualified structure would also provide a means of mitigating seismic events that cause widespread system failures. Additionally, adequate instrumentation would need to be provided so the operator can have reliable pressure, temperature, and level indications in the absence of normal power supplies.	SGS IPEEE (Fire, Seismic)	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is not cost beneficial.

Table E.6-1
SGS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
21	Seal the Category II and III Cabinets in the Relay Room	The dominant fire scenario in the Relay Room (1FA-AB-100A) is a cabinet fire that is not suppressed and is able to propagate to the point where it is large enough to force main control room abandonment. The issue for this scenario is not necessarily the availability of equipment, but more that the operators are forced to take control of the plant from the RSP. The most effective method identified to reduce the risk from this scenario is to provide better barrier separation for cabinet fires in this area in order to reduce the threat of fire propagation from one cabinet to another. What this would involve incluces the means of providing fire barrier and adequate cabinet/train separation so as to minimize the unavailability of both safety related trains due to fire propagation. This would involve the modification of several cabinets within the relay room. It was estimated that 48 out of 68 cabinets in the room would require protection using an approved fire barrier material. This SAMA would not involve installation or modification of any new or existing fire detection or suppression equipment.	SGS IPEEE (Fire)	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is not cost beneficial.

Table E.6-1
SGS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
22	Install Fire Barriers Between the 1CC1, 1CC2, and 1CC3 Consoles in the CRE	The largest contributors to fires in the CRE are those that force abandonment of the CRE due to damage in the 1CC1, 1CC2, and/or 1CC3 consoles. The most effective means of reducing the CDF of these scenarios is considered to be preventing the need to abandon the CRE. Using an approved fire barrier material within these cabinets is one method of reducing the likelihood of having a fire in one cabinet propagate to another cabinet. The prevention of a fire from causing damage to one of the other two cabinets will help to reduce the need to abandon the MCR. This SAMA would not involve installation or modification of any new or existing fire detection or suppression equipment.	SGS IPEEE (Fire)	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is not cost beneficial.
23	Install Fire Barriers and Cable Wrap to Maintain Divisional Separation in the 4160V AC Switchgear Room	Rooms that include cable or equipment for multiple divisions introduce the undesirable situation in which a single fire event can disable multiple divisions of equipment. Given the importance of the 4160V AC equipment, the cables and equipment in the 4160V AC Switchgear room should be protected to prevent the propagation of a fire from one division to another.	SGS IPEEE (Fire)	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is not cost beneficial.

Table E.6-1
SGS Phase 2 SAMA List Summary

SAMA Number	SAMA Title	SAMA Description	Source	Phase 2 Baseline Disposition
24	Provide Procedural Guidance to Cross-tie Salem 1 and 2 Service Water Systems	For fire events in the Service Water pump bays, the combination of fire induced SW pump failures with random SW pump failures is a relatively large contributor to CDF, especially since the SW system was ultimately assumed to be required to prevent core damage. An inter-unit SW cross-tie exists at SGS, but its use is not currently proceduralized while both units are at power. Ensuring that adequate procedures exist to govern the use of the cross-tie for these fire scenarios would greatly reduce their CDF contributions.	SGS IPEEE (Fire)	The nominal averted cost-risk for this SAMA is **greater** than the cost of implementation, which implies that this SAMA is **cost beneficial**.
27	In Addition to the Equipment Installed for SAMA 5, Install Permanently Piped Seismically Qualified Connections to Alternate AFW Water Sources	Seismically induced AFWST and AC power failures present the need to provide SBO mitigation capability (same as SAMA 5) and an alternate AFW suction source. SGS already has an alternate AFW suction alignment capability, but simplifying its alignment process through installation of a permanent, hard piped connection would improve reliability, especially after a seismic event where movement of the pipes could cause trouble with alignment of the "spool pieces" currently used in the suction path.	SGS IPEEE (Seismic)	The nominal averted cost-risk for this SAMA is less than the cost of implementation, which implies that this SAMA is <u>not</u> cost beneficial.

E.10 FIGURES

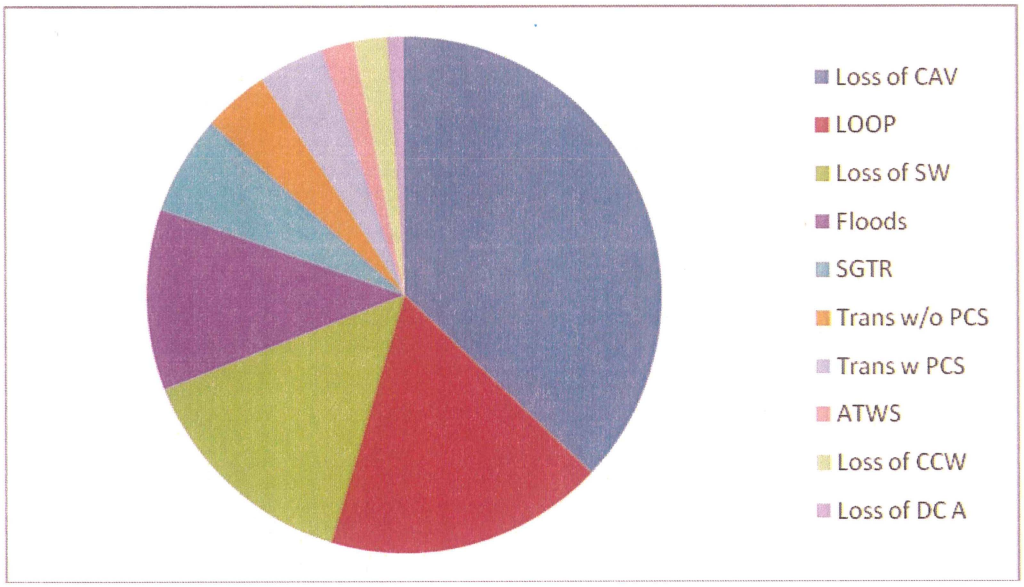


Figure E.2-1 Initiator Group Contribution to CDF

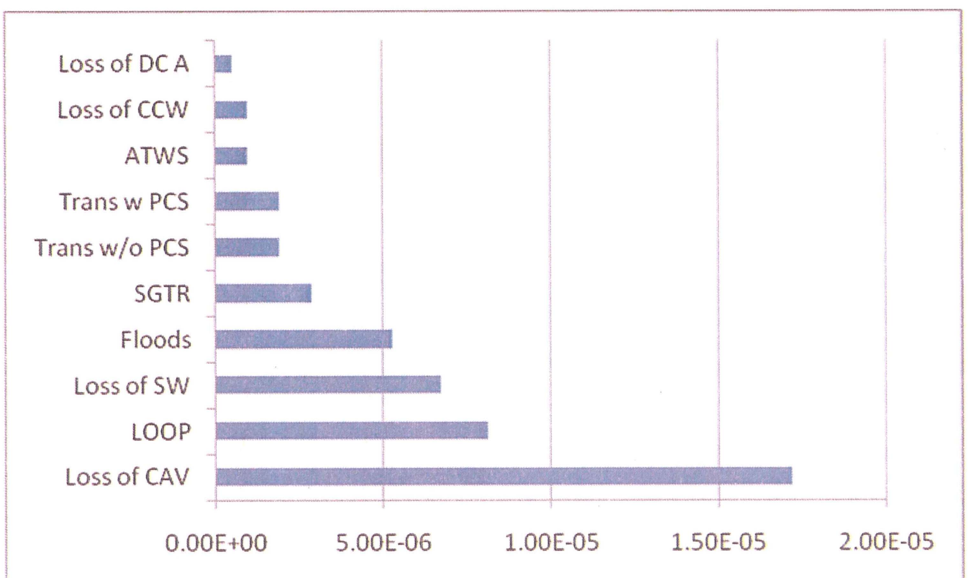


Figure E.2-2 Individual Initiator Contribution to CDF

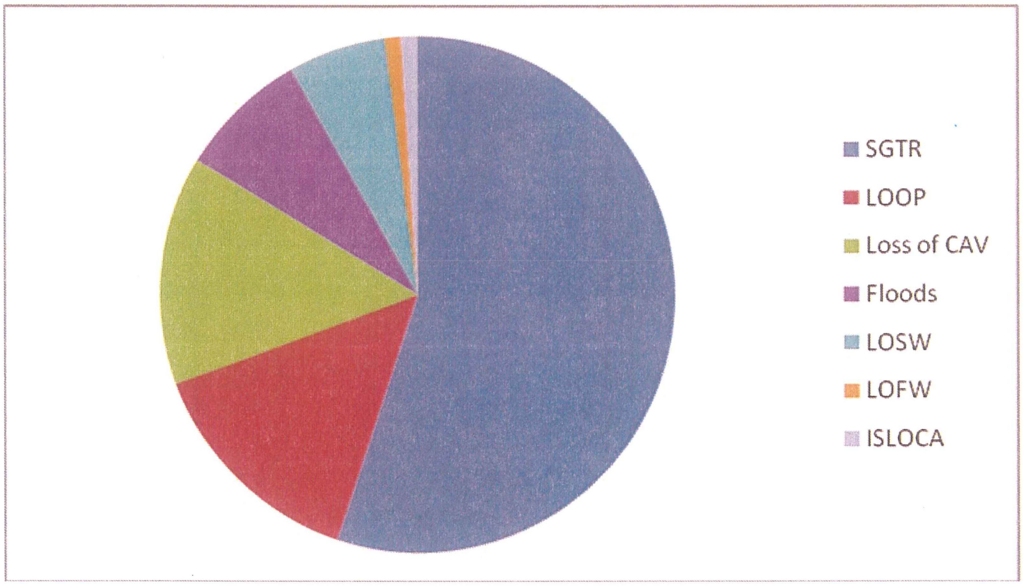


Figure E.2-3 Initiator Group Contribution to LERF

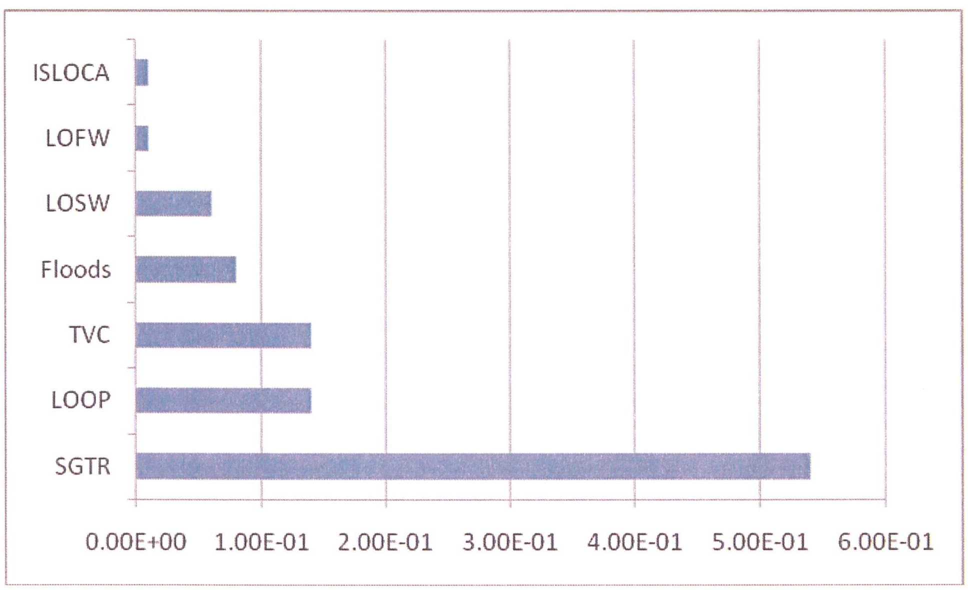


Figure E.2-4 Individual Initiator Contribution to LERF

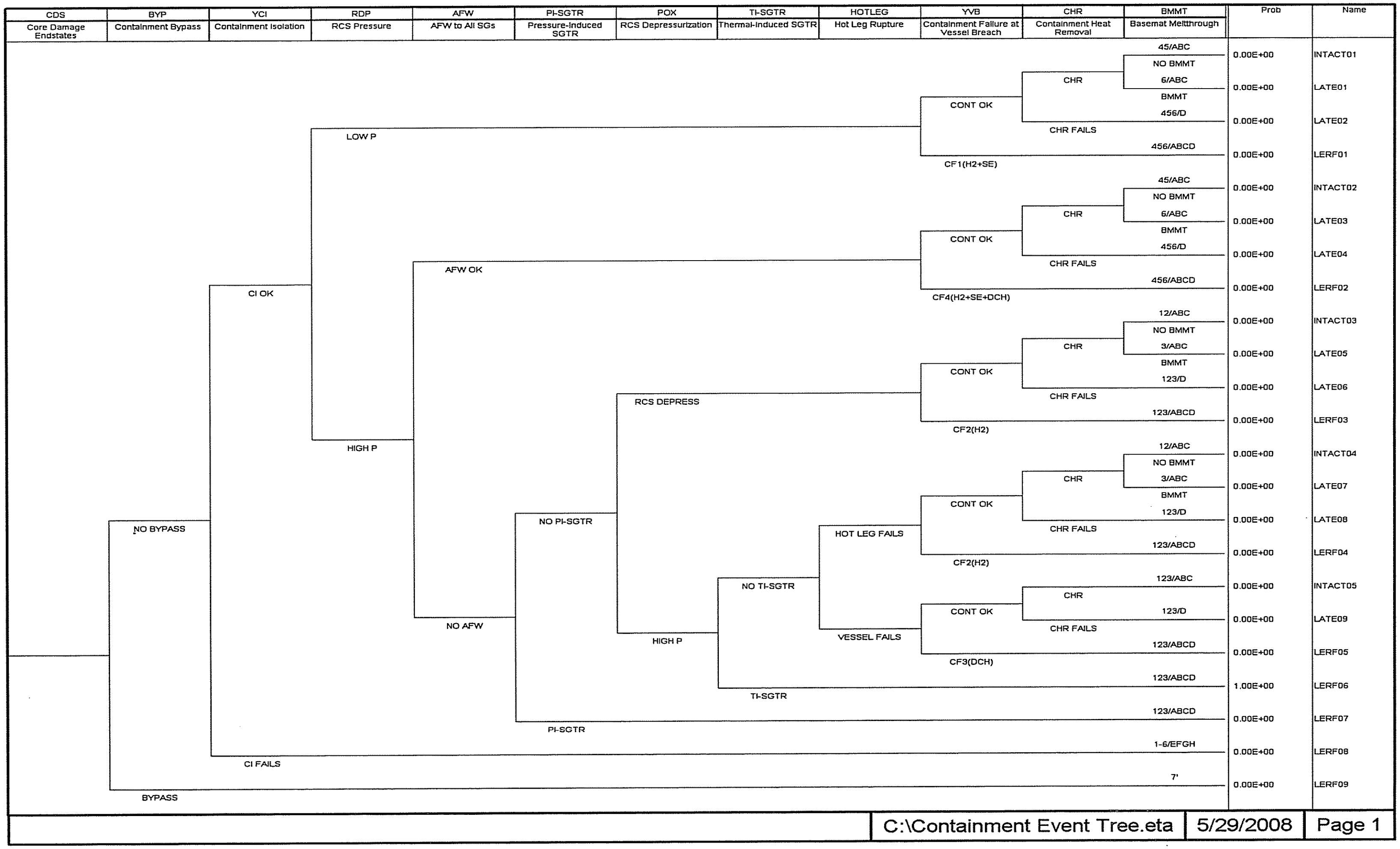


Figure E.2-5
Salem Level 2 Containment Event Tree

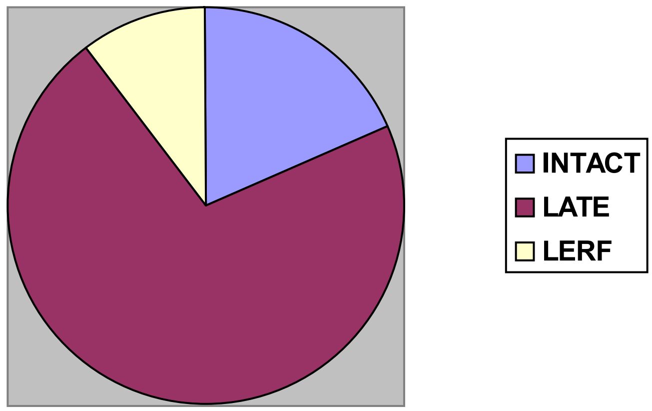


Figure E.2-6
Salem Level 2 Overall Results

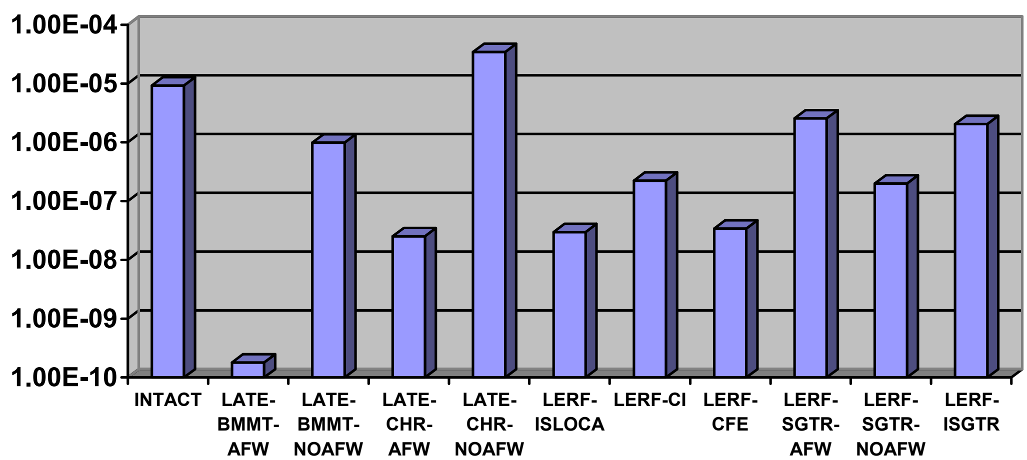


Figure E.2-7
Results for Detailed Release Categories

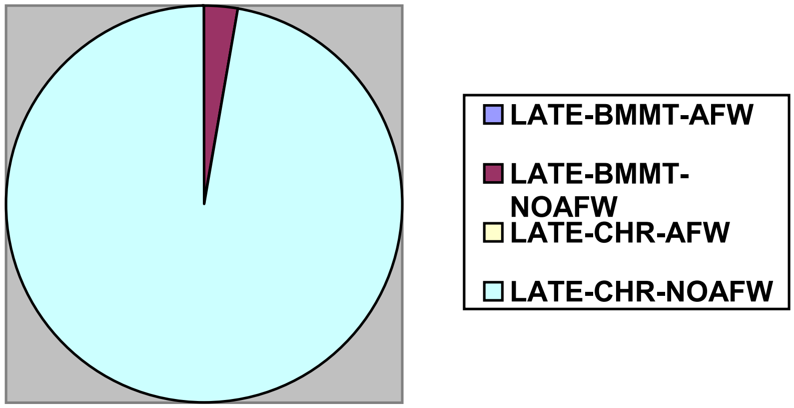
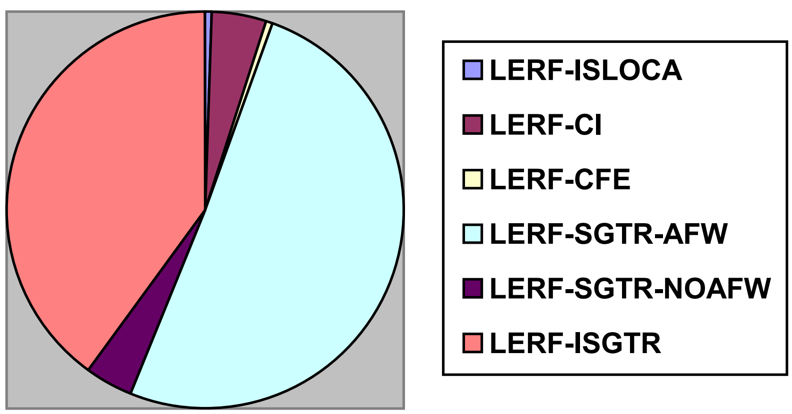


Figure E.2-8
LATE Contributors by Release Category



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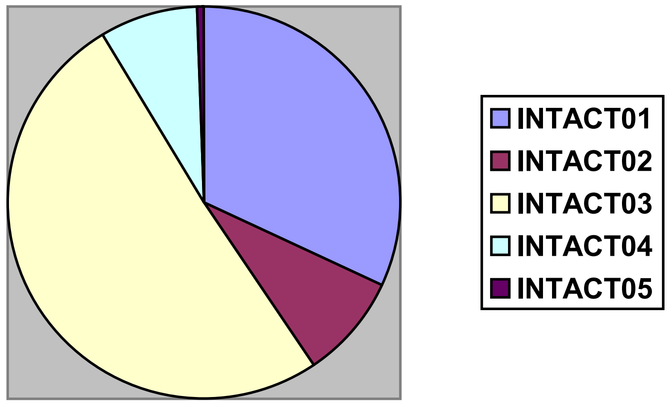

Figure E.2-10
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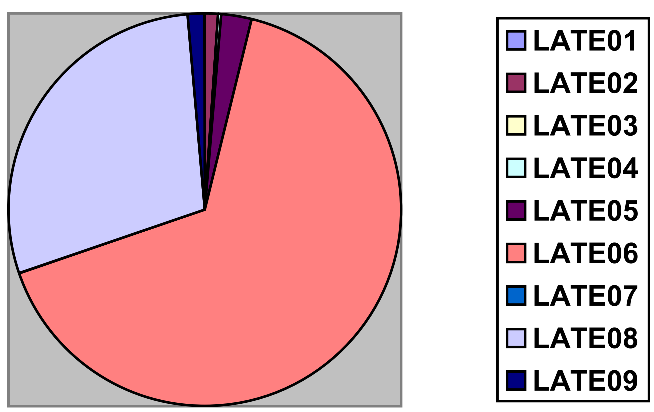

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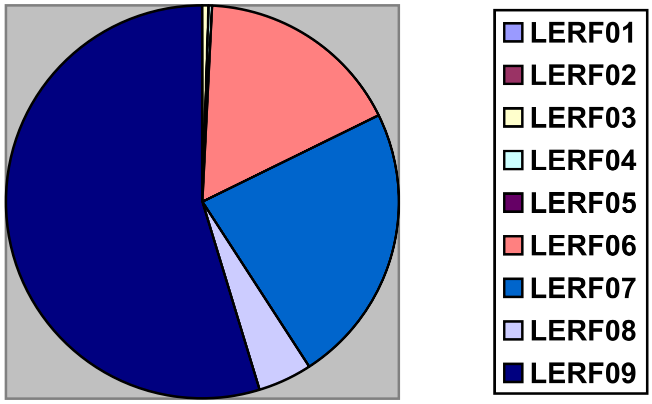

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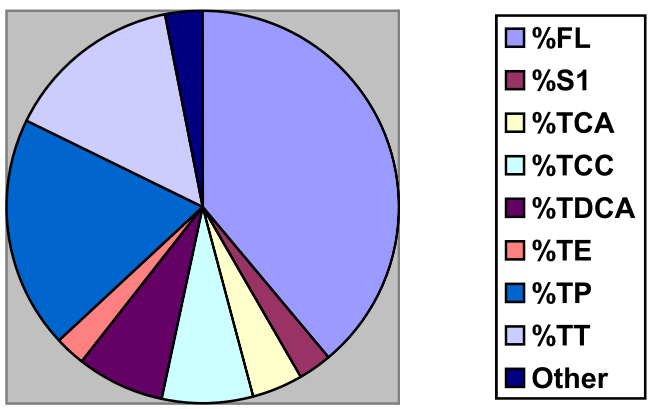

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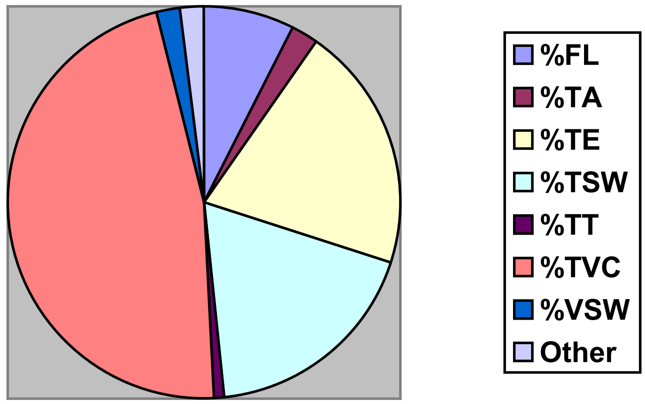

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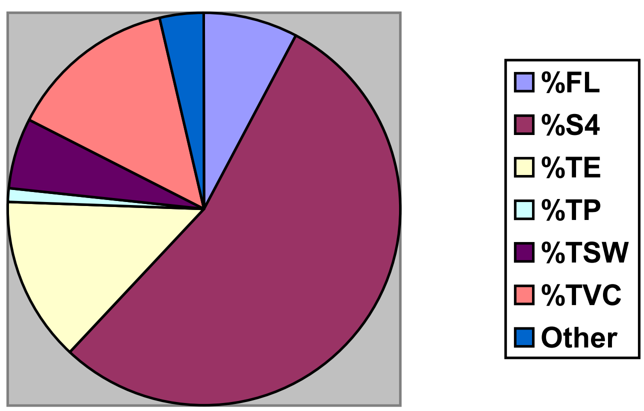

Figure E.2-15
LERF Contributors by Initiating Event

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Appendix F

Estuary Enhancement Program Description

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Description of the Estuary Enhancement Program and Summary of Recent Monitoring Results

ESTUARY ENHANCEMENT PROGRAM OVERVIEW

The tidal wetlands of the Delaware Estuary play a vital role in the health of the coastal ecosystem. They are spawning and breeding grounds for fish and wildlife, sources of food and shelter for migrating birds, valuable flood protection and filters for stormwater runoff from surrounding communities and agricultural areas. They form the base of the aquatic food web.

PSEG's Estuary Enhancement Program (EEP) has preserved and/or restored more than 20,000 acres, or approximately 32 square miles of Delaware Bay tidal wetlands and adjoining upland buffer areas. Created in 1994 as a condition of a New Jersey Pollutant Discharge Elimination System permit issued by the New Jersey Department of Environmental Protection (NJDEP), PSEG's innovative program is designed to actively enrich and protect the delicate coastal wetland systems of the Delaware Estuary.

With substantial regulatory, community and stakeholder input, PSEG has successfully restored the natural and productive structure and function to over 10,000 acres of degraded wetlands. Normal tidal inundation is present at all of the restored sites. The sites have been colonized by expanding stands of desirable vegetation. Productivity is comparable to that measured in nearby reference marshes. All of the restoration sites have either achieved or are on a trajectory to achieve success. The sites are used by a diverse fish population as feeding, reproduction, and nursery areas and by a bird and wildlife community typical of natural, un-disturbed wetlands. PSEG ensured the preservation of this land as open space through Deeds of Conservation Restriction or State ownership that will protect the restored lands from development in perpetuity. Public access improvements incorporated into the restoration designs offer unique access opportunities to natural areas of the Delaware River Bayshore at a scale and quality not found anywhere else. Public access is particularly valuable in a region recognized by The Nature Conservancy as one of the "Last Great Places" and by The Ramsar Convention as one of seventeen wetlands in the United States identified as a "Wetland of International Importance."

The restored marshes comprise approximately one half of the total lands PSEG has preserved as part of the EEP. In addition to the tidal wetland areas, PSEG has preserved more than 10,000 acres of adjoining uplands and transition areas including forested uplands and wetlands, agricultural fields, and properties and landscapes that have historic significance in New Jersey and Delaware. Preservation of these areas is as vital to the health of the Delaware Estuary as the preservation of restored wetlands themselves.

The EEP is not limited to tidal wetland restoration and land preservation. In addition to the thousands of acres that the EEP has successfully restored, thirteen fish ladders have been installed at impoundments in New Jersey and Delaware. As a result, more than 1,000 acres and over 130 miles of previously unreachable upstream habitat has been made available for the anadromous fish species of the Delaware Estuary. Anadromous fish species, including blueback herring and alewife, provide feedstock for other commercially and recreationally important species such as striped bass and weakfish.

While the EEP's primary purpose was to increase fish production in the Delaware Estuary through restoration of degraded marsh areas, preservation of environmentally sensitive lands, and installation of fish ladders, there have been numerous other ancillary benefits that have emanated from the Program.

EEP has provided funding initial restoration actions for restoration of three additional *Phragmites*-dominated areas in Delaware. While these areas are not included within the 10,000 acres of restoration credited to the EEP, they nonetheless provide important ecological benefits to the Delaware Estuary ecosystem. DNREC continues to manage the three sites with funding provided through the EEP.

Artificial reefs are manmade structures that increase habitat surface area for colonization by aquatic organisms and fish. The colonization produces a more diverse and productive forage base for predator fish, such as black sea bass. Artificial reefs improve water quality by enhancing the habitat for animals that filter algae, organic matter, and bacteria from the water column. The EEP has provided funds to NJDEP and the Delaware Department of Natural Resources and Environmental Control (DNREC) for their State-managed artificial reef programs which have successfully installed artificial reefs in Delaware Bay and the adjoining coastal areas. In early 2005, NJDEP used some of the PSEG funding to revitalize more than 150 acres of oyster habitat within the Bay as an extension of a 2003 pilot project, which enhanced an oyster seedbed in the Bay by planting approximately 30 million oysters.

DNREC used EEP funding to restore 964 acres of degraded wetlands at the Augustine Creek Impoundment. This wetland has historically been impounded by dikes that restrict flow to and from the Delaware River, resulting in increased upland flooding, *Phragmites* invasion, mosquito breeding, sedimentation and shoreline erosion. The restoration of the Augustine Creek Impoundment has been completed and functional tidal flow reestablished.

The EEP has funded and conducted numerous studies on the Estuary and its ecosystem. Studies conducted to date include investigations of marsh function, fish population abundance, trophic transfers (food habits), and movement and distribution of fish (young-of-year fishes and predator species).

More than 160 peer-reviewed papers have been published about the wetlands restoration process, the use of adaptive management as a tool for ensuring restoration success, and the overall success of EEP's restoration efforts. The October 2005 edition of the Journal of Ecological Engineering is dedicated entirely to the EEP's wetlands program.

The EEP provides opportunities for environmental education, promotes environmental stewardship, and supports ecotourism throughout southern New Jersey and the Delaware Estuary region. Environmental and student groups visit the sites regularly to learn more about ecosystems through tours and participation in hands-on activities. Public access improvements incorporated into the restoration designs provide the public with access to thousands of acres of vast, natural areas that were not previously available for a broad range of public uses including environmental education programs, nature study, bird watching, hunting, fishing, crabbing, trapping, and other recreational uses. Each year the EEP publishes an annual report, which provided additional details on the success of the restoration.

PSEG BIOLOGICAL MONITORING AND HABITAT RESTORATION PROGRAMS

Monitoring for the planned Salem Station began in 1968 and has been conducted almost continuously since that time, under various auspices. In many instances PSEG changed the program scope or gear deployment as the survey purposes changed in response to evolving regulatory requirements. For example, the pre-1979 finfish trawl program was conducted for the U.S. Nuclear Regulatory Commission (NRC) under the Environmental Technical Specification monitoring program. Its goals were very different from the bay-wide finfish sampling required by the U.S. Environmental Protection Agency (EPA) and the New Jersey Department of Environmental Protection (NJDEP) from 1977 through 1982 and from the finfish population monitoring performed for consistency with Delaware's Department of Natural Resources and Environmental Control (DNREC) program in the 1990s. Regardless, this long history of monitoring provides valuable data on the health of the Delaware Estuary.

As a requirement of the Salem 1994 New Jersey Pollutant Discharge Elimination System (NJPDES) permit, PSEG established the Estuary Enhancement Program (EEP). This program, one of the largest privately funded effort of its kind, has resulted in the restoration, enhancement, or preservation of more than 8,094 hectares (20,000 acres) of degraded wetlands and upland buffers in Delaware and New Jersey (PSEG 2007a). The restoration effort closest to the PSEG property is in the Alloway Creek Watershed, approximately 3 km (2 mi) to the north of Salem.

The restored and enhanced saltmarshes have increased the production of fish and shellfish within the estuary; these marshes provide food and habitat, including nursery and refuge areas. Intertidal marsh is the primary source of the productivity of any coastal system. In fact, more than half of the United States' fishery and two-thirds of the world's fishery are directly dependent on estuaries. (PSEG 2006a)

The EEP also supports bay-wide monitoring of biological resources, construction of fish ladders, and studies of technologies that may reduce the adverse impacts of the Salem CSW intakes on local fish populations. In fulfillment of requirements of the 1994 Salem NJPDES permit, PSEG developed and implemented an enhanced biological monitoring program for the Delaware Estuary, which has been conducted, with modifications and improvements, since 1995. Annual biological monitoring reports document data collection and results for seven separate focus areas: (1) impingement abundance monitoring, (2) entrainment abundance monitoring, (3) bay-wide trawl surveys, (4) beach seine surveys, (5) river herring run monitoring, (6) fish assemblages monitoring in restored saltmarsh, and (7) detrital production in restored marshes.

The annual biological monitoring reports (PSEG 1996, 1997, 1998, 1999a, 2000, 2001, 2002, 2003, 2004, 2005, 2006b, 2007b) contain thousands of data points concerning impingement and entrainment of target species at Salem, and bay-wide abundance and distribution data for more than 50 species of finfish, including species identified as Representative Important Species (RIS) or target species which were submitted annually to NJDEP. Age and length data were collected for most specimens. Data are presented both spatially and temporally, by gear type. In addition, each biological collection is associated with measurements of water temperature, salinity, and dissolved oxygen. The data presented in the monitoring reports were summarized and trends were reported in the NJPDES permit renewal applications, submitted in 1993, 1999, and 2006. In addition, a Comprehensive Demonstration Study, submitted in 2006 as part of the NJPDES permit renewal application (PSEG 2006a, Section 4), provides extensive trend analysis of fish abundance data.

Identification of Representative Important Species for Evaluating Effects of Salem's Intake on Aquatic Biota

EPA recognizes that site-specific factors such as biological assemblage, intake location, and type of waterbody can ameliorate or exacerbate the impacts of a specific cooling water technology. Evaluations and monitoring focus on RIS because it is not practical to investigate all species potentially affected by operations. RIS is a subset of possible species that are both representative of the other species and important in that they have important human use or ecological value. The list of RIS species evaluated for the 2006 NJPDES permit renewal application refines lists evaluated in previous approved permit applications, based on the NJDEP-approved Improved Biological Monitoring Work Plan. In 1978, PSEG proposed 11 species (alewife [*Alosa pseudoharengus*], American shad [*Alosa sapidissima*], Atlantic croaker [*Micropogonias undulates*], bay anchovy [*Anchoa mitchilli*], blueback herring [*Alosa aestivalis*], opossum shrimp [*Mysidacea*], scud [Anisogammaridae], spot [*Leiostomus xanthurus*], striped bass [*Morone saxatilis*], weakfish [*Cynoscion regalis*], and white perch [*Morone americana*]) as "target species" for its 316(b) plan of study, which was accepted by EPA and NJDEP in 1979. Subsequently, the Technical Advisory Group, which is comprised of representatives of relevant environmental resource agencies, was charged with identifying target species under the new 316(b) guidelines. They selected the same species for the 1984 Salem 316(b) demonstration. NJDEP hired a consultant, Versar, to review 1984 Salem 316(b) demonstration, including the selection of the RIS based on EPA's draft guidelines. Versar concluded that the RIS met all 316(b) guidelines. Versar also concluded that the Salem intake had the potential to affect only four finfish species (weakfish, spot, white perch and bay anchovy). Notwithstanding Versar's conclusion that only four finfish species were potentially affected by the Salem intake, the PSEG 1999 NJPDES renewal application (PSEG 1999b) addressed all 11 of the original RIS. In addition, PSEG reviewed the existing guidance on RIS selection to determine whether additional organisms should be identified as RIS. Blue crabs are relatively abundant in the vicinity of Salem and are impinged at the Salem CWS intake structure, and for these reason the blue crab (*Callinectes sapidus*) was included as an RIS.

The original finfish RIS were approved by the Technical Advisory Group, NJDEP, and EPA. The Estuary Enhancement Program Advisory Committee (EEPAC), established as part of the 2001 Salem NJPDES permit, reviewed the RIS. PSEG's monitoring programs continue to collect data for evaluating impacts on the following species: alewife, American shad, Atlantic menhaden (*Brevoortia tyrannus*), Atlantic silverside (*Menidia menidia*), bluefish (*Pomatomus saltatrix*), blueback herring, bay anchovy, Atlantic croaker, spot, weakfish, striped bass, white perch, and blue crab. Opossum shrimp (*Neomysis americana*) and scud (*Gammarus* spp.) were removed as RIS based on analyses which determined that Salem does not have the potential to impact these species due to their life histories (PSEG 2006a). PSEG also collects data on three non-RIS species, called "target species" because of NJDEP fisheries management concerns: Atlantic menhaden, bluefish, and Atlantic silverside..

Restoration and River Herring Run Monitoring

In compliance with a special condition of Salem's 1994 NJPDES permit and as part of a settlement agreement with DE Department of Natural Resources and Environmental Control, PSEG constructed a total of 13 fish ladders on Delaware River tributaries in an effort to restore spawning runs of river herring (alewife and blueback herring). Alaska Steeppass fish ladders have been constructed in New Jersey at Sunset Lake, Stewart Lake (2), Newton Lake, and Cooper River Lake, and in Delaware at Noxontown Pond, Silver Lake (Dover), Silver Lake

(Milford), McGinnis Pond, Coursey Pond, McColley Pond, Garrisons Lake, and Moore's Lake. NJDEP requires that PSEG monitor adult and juvenile river herring at several of the ladders during the annual spawning run.

Adult river herring use the ladders at highly variable rates (Table F-1). Generally, adult herring movement is associated with rising water temperature and sunny days. Adult herring are usually observed at the fish ladder sites only when spawning temperatures are appropriate. Very little activity is observed at the ladders at night or on overcast days. During years with relatively cooler temperatures and fewer warm sunny days, such as in 2005, smaller than average runs have been observed. Commercial fishermen in New Jersey and Delaware that collect herring for bait have confirmed that they observed a smaller run in the region in 2005. (PSEG 2005)

Adult river herring use the fish ladders at most of the ponds. Based on the consistently high use of the ladders by running adults, PSEG and NJDEP decided monitoring to determine the success of the ladders was no longer necessary and discontinued it, thus eliminating the unnecessary stress of capture on the adults. Sampling of adult passage was discontinued at Moore's Lake, McGinnis Pond, Coursey's Pond, and McColley Pond in 2005 or 2006. At other ladders, few or no adults were observed using the ladders during the 2005 and 2006 sampling periods (Table F-1).

In addition to monitoring passage of adult herring up the ladders, PSEG also monitored eggs, larvae, and juveniles in the impoundments above the ladders from 1996 through 2006 to track reproductive success of river herring. Egg viability, larval development, and juvenile growth are affected by water quality in the impoundments. Based on water sampling, the water quality of the impoundments is suitable to support young herring. Sampling ichthyoplankton for eggs was generally unsuccessful, likely because the demersal, adhesive eggs do not occur in the portion of the water column sampled by the plankton net. Some larvae were collected in ichthyoplankton tows; however, larvae are not particularly vulnerable to capture in plankton tows because they disperse among vegetation and small stones around the perimeter of the impoundment. Juveniles prefer open water from 1.2 to 1.8 m (4 to 6 ft) deep (PSEG 2005) and the presence of juveniles in the impoundments provides ample evidence of reproductive success of river herring, despite the absence of eggs and scarcity of larvae in the ichthyoplankton samples. For example, in Cooper River Lake, although no eggs and only 70 larvae were collected during spring and summer sampling, more than 7,800 juveniles were counted in the fall (PSEG 2000).

Juvenile blueback herring from the ponds were full-bodied and appeared to be well fed and in good condition. During 2005, these pond-reared herring attained a greater length (1½ times) than observed for herring juveniles taken in beach seine sampling in the mainstem Delaware River (PSEG 2006a). No growth anomalies or external parasites were noted on the collected herring. Juvenile monitoring is no longer performed as production has been documented in all twelve impoundments (PSEG 2007b).

The success of herring reproduction in the impoundments may be limited by the presence of other fish species that either compete with or prey upon herring at various life stages. No species lists from the impoundments are available, but many competitors and predators have been documented at the fish ladders, and are assumed to have access to the impoundments. Abundant species in at least one impoundment include several centrarchids (largemouth bass, bluegill, pumpkin seed), golden shiner, gizzard shad, white perch, and yellow perch (PSEG 2005).

FISH ASSEMBLAGES MONITORING IN SALTMARSH RESTORATIONS

Fish assemblages have been monitored since 1996 at three restored saltmarsh sites (and two reference sites) to evaluate the effectiveness of marsh restoration activities. In the lower Delaware Bay, where polyhaline (18-35 ppt saline) conditions prevail, the Commercial Township Restoration Site (CTRS) was compared with the Moores Beach reference site. Early reports (1996 and1997) also discuss the Dennis Township Restoration Site (DTRS). In the upper Bay, two restoration sites (Mill Creek and Alloways Creek) were compared with the Mad Horse Creek reference site; the upper Bay sites are in the Delaware River above Salem, where conditions are generally oligohaline (0.5-5 ppt saline). The Mad Horse Creek reference site includes both large and small creeks. The Mill Creek restoration site has large and small creeks. The Alloway Creek restoration site has only small creeks (PSEG 2007b).

Target species include weakfish, white perch, spot, and bay anchovy. Sampling was conducted monthly during summer and fall using otter trawls in large marsh creeks and weirs in small intertidal marsh creeks (PSEG 2007b).

CURRENT CONDITIONS

In 2007 in the lower Delaware Bay, abundance of all species collected in the large marsh creeks was greater at the CTRS than at the Moores Beach reference site. Bay anchovy were particularly abundant at the CTRS. Weakfish and white perch also were more abundant at the CTRS than at the reference site. In the small marsh creeks, species richness and abundance were similar between CTRS and the reference site. Mummichog and Atlantic silverside were co-dominant at both restored and reference sites. (PSEG 2007b)

In the lower Bay, species richness in trawl samples was similar between the restored and reference sites, with a total of 22 and 19 fish species collected, respectively, in 2007. Fifteen of those species were common to both restored and reference sites. At the CTRS, bay anchovy and Atlantic silverside were co-dominant in trawl samples. (PSEG 2007b)

In 2007 in the upper Bay (Delaware River), there were differences between the reference site (Mad Horse Creek) and restored sites (Mill Creek and Alloway Creek). Abundance of all species collected in small marsh creeks was higher at both restoration sites than at the Mad Horse Creek reference site. However, species richness was most similar between Mad Horse Creek and at Mill Creek, with 20 and 23 species, respectively. Abundance of all species collected from the large marsh creeks was 2.1 times greater at the Mill Creek site (CPUE = 17.80) than at the Mad Horse Creek reference site (CPUE = 8.33). White perch and bay anchovy were the dominant species at both sites (PSEG 2007b).

The Mad Horse Creek reference site and Mill Creek restored site are both in the transitional portion of the estuary where freshwater and saltwater fish assemblages intermingle at the boundaries of their ranges. During 2007, salinity differences at the two sites favored different fish assemblages. The fish assemblage at the Mad Horse Creek reference site consisted of 14 transient, 3 estuarine resident and 3 freshwater resident species. At the Mill Creek restored site, the fish assemblage consisted of 15 transient, 3 estuarine resident and 5 freshwater resident species. A total of 10 transient species were common to both sites; the same 3 estuarine residents occurred at both sites; and 2 freshwater resident species were common to both sites. However, silver perch, summer flounder, and smallmouth flounder, species which are typically associated with the higher salinity waters of the lower Bay, were taken exclusively at Mad Horse Creek. Similarly, carp and eastern silvery minnow, species which are typically associated with lower salinities, were taken exclusively at Mill Creek (PSEG 2007b).

Benthic invertebrates were monitored over a 4-year period following the restoration of the DTRS to natural tidal flows and compared to those at a nearby reference marsh (Moores Beach-West). The major invertebrate taxa responded to the restoration with 10 to 100-fold increases in abundance within the first few months, and continued to increase in abundance over the next three years, such that numbers were equal to or greater than those recorded from the reference marsh. (PSEG 2006a, Section 4)

Horseshoe crabs were absent from the Maurice River Township Restoration Site (MRTRS) and DRTS salt hay farms prior to restoration because there was no tidal flow except during the winter when these crabs are typically not found in estuaries. However, before the restoration of the MRTRS, thousands of horseshoe crabs had been stranded on-site on occasion as a result of breaching dikes by storms or erosion. Once the restoration restored normal daily tidal flow, horseshoe crabs were no longer stranded. After restoration in 1996, CPUE of horseshoe crabs at the restored sites has typically been equal to or greater than that at the reference site, with a few exceptions. (PSEG 2007b)

Target Species Accounts

Bay anchovy

In the lower Bay, bay anchovy were 2 and 75 percent of the total catch in large creeks at the reference and restoration sites, respectively. The mean CPUE was similarly skewed (0.11 at the reference site vs 26.21 at the restored site). Catches in the small creeks were negligible (PSEG 2007a). In the upper Bay, bay anchovy were 29 and 25 percent of the total catch in the large creeks at the reference site and restoration site, respectively. At the reference site, the mean CPUE was 2.42, compared with a mean CPUE of 4.51 at the restoration site. No bay anchovy were collected in the small marsh creeks dicussed here in 2007. Bay anchovy were 14 and 3 percent of the total catch at the Mad Horse Creek reference site, and at Mill Creek, respectively (PSEG 2007b).

Spot

In the large creeks of the lower Bay, spot were 24 percent and 3 percent of the total catch at the reference and restoration sites, respectively (PSEG 2007b). Notably, in 2006, spot was less than 1 percent of the total catch at both sites (PSEG 2006b). In 2007, numbers were still low, but increasing. At CTRS 18 spot were collected; 29 spot were collected at Moores Beach (PSEG 2007a). In the upper Bay, a total of less than 100 spot were collected in large creeks from all three sites. No spot were collected in small creeks (PSEG 2007b).

Weakfish

In the large creeks of the lower Bay, weakfish were less than 1 percent and 3 percent of the total catch at the reference and restoration sites, respectively. Mean CPUE was 0.02 and 1.21. No weakfish were collected in the small creeks. Large creeks in the upper Bay yielded 53 weakfish at all reference and restoration sites combined. No weakfish were collected from small creeks in the upper Bay. (PSEG 2007b)

White perch

In the large marsh creeks of the lower Bay, white perch were 9 and 2 percent of the total catch at the Moores Beach reference site and CTRS, respectively, occurring in 28 and 37 percent of the respective otter trawl collections. No white perch were taken in the small marsh creeks of the lower Bay. In the large marsh creeks of the upper Bay, white perch were 20 and 46 percent of the total catch at the reference and restoration sites, respectively. At the reference site, 210 individuals were collected, with a mean CPUE of 1.67. At the restoration site, 1,040 white perch were taken, with a mean CPUE of 8.25. Fewer than 30 individual white perch were taken from the small marsh creeks at all three sites. (PSEG 2007b)

Effects of Restoration on Fish Assemblages and Abundance

Effects of Restoration in the Lower Bay

In 2007, in the lower Bay, abundance of all species collected from large marsh creeks was 7.9 times greater at CTRS (CPUE = 34.97) than at the Moores Beach reference site (CPUE = 4.45). This difference was largely due to the predominance of bay anchovy at CTRS. If the bay anchovy contribution to total CPUE is ignored at both sites, then the CPUE's is more similar; 4.34 at Moores Beach and 8.76 at CTRS. The remaining difference in fish abundance is due to the higher abundance of two target species -- weakfish and white perch -- and four non-target species -- Atlantic silverside, black drum, hogchoker and American eel -- at CTRS. Weakfish were 60 times more common at CTRS (CPUE = 1.21) than at Moores Beach (CPUE = 0.02), and white perch were two times more common at CTRS (CPUE = 0.87), than at Moores Beach (CPUE = 0.42). Spot were equally abundant at both sites, with CPUE's of 1.07 and 1.13 at CTRS and Moores Beach, respectively. The abundance of the non-target species listed above ranged from 1.7 to 44.0 times higher at CTRS than at Moores Beach. (PSEG 2007b).

Abundances in the small marsh creeks of the lower Bay were similar; the Moores Beach reference site CPUE was 432.21 and the CTRS CPUE was 383.79. Nine speicies were collected from both sites. Five of the nine species were common to both sites, though the rank order of the common species differed between the sites. Mummichog and Atlantic silverside ranked first or second at both sites. Mummichogs were 70 percent of the total catch at Moores Beach and 18 percent of the total catch at CTRS. Atlantic silverside were 29 of the total catch at Moores Beach and 79 percent at CTRS. Other species included spot (third in abundance at Moores Beach and fourth at CTRS), Atlantic menhaden (fourth at Moores Beach and absent from CTRS samples), and black drum (third at CTRS and absent from Moores Beach samples). The catches of the other species were 13 or fewer individuals at each site, making their occurrences more or less incidental. (PSEG 2007b)

Fish species richness in trawl samples was similar at both sites with 19 species at Moores Beach and 22 at CTRS. There were 15 species common to both sites, though they differed in rank order. Species taken exclusively at one site or the other were incidental-to-infrequent captures represented by less than 10 individuals. The two sites had five of the seven most abundant species in common: Atlantic silverside, spot, white perch, bay anchovy, and hogchoker. Atlantic silverside was ranked first in abundance at Moores Beach and second at CTRS; spot was ranked second at Moores Beach and fourth at CTRS; white perch was third at Moores Beach and sixth at CTRS; bay anchovy ranked fifth at Moores Beach and first at CTRS; and hogchoker ranked sixth at Moores Beach and seventh at CTRS. Other species included striped bass (fourth at Moores Beach and nineth at CTRS) and weakfish (tenth at Moores Beach and third at CTRS). (PSEG 2007b)

Effects of Restoration at Upper Bay Phragmites-Dominated Marshes

In the large marsh creeks of the upper Bay in 2007, the aggregate abundance of all species collected was 2.1 times greater at the Mill Creek restoration site (CPUE = 17.80) than at the Mad Horse Creek reference site (CPUE = 8.33). White perch and bay anchovy were the predominant species at both sites. The difference in overall abundance was the result of those two species higher abundance at the Mill Creek site. If the combined contribution of white perch and bay anchovy to the total CPUE is ignored at either site, the resulting aggregate CPUEs are more similar (4.24 at Mad Horse Creek and 5.04 at Mill Creek). Weakfish was 1.4 times more abundant at Mill Creek than at Mad Horse Creek, and spot was 1.8 times more abundant at Mill Creek than at Mad Horse Creek. (PSEG 2007b)

In the small marsh creeks of the upper Bay in 2007, the aggregate abundance of all species collected was higher at both restoration sampling areas than at the Mad Horse Creek reference site. At Alloway Creek, the total CPUE (14.40) was 2.8 times greater than that at Mad Horse Creek (5.14), and at Mill Creek (219.00) it was 42.6 times greater. These differences were driven by the predominance of mummichogs at both restoration areas. Mummichog was dominant at all three sites. This was particularly notable at Mill Creek where mummichog abundance was two orders of magnitude higher than at Mad Horse Creek. Like abundance, species richness was higher at Mill Creek than at the Mad Horse Creek, with 15 and 7 species collected, respectively. Six species were collected at Alloways Creek. Five of seven species taken at Mad Horse Creek (mummichog, Atlantic silverside, American eel, white perch and naked goby) also were common to both Alloway and Mill Creeks, and all species taken at Alloway Creek were common to Mill Creek. The typically ubiquitous bay anchovy and Atlantic menhaden were taken at both Mad Horse and Mill Creek, but were absent from weir sets at Alloway Creek. There were seven species taken only at Mill Creek. (PSEG 2007b)

Historical Perspective of Marsh Restoration Success (1996 – 2006)

The restoration projects have been a success in providing suitable habitat for resident and transient fishes. When the first salt hay farm, at DTRS, was restored to marsh habitat by increasing tidal exchange, positive results were almost immediate. The 1996 monitoring report states, "[n]ewly constructed channels were quickly utilized by fish, including target species" (PSEG 1996). Monitoring results from the next decade continued to indicate extensive use of the restored habitats by fish typical in the region. PSEG's restoration program has increased primary production, thus increasing the food source for and productivity of fish and shellfish in the estuary (PSEG 2006a). In fact, two restoration sites met and the final criteria outlined in the NJPDES permit years in advance of the anticipated dates.

Within the restricted salinity zone of the upper Bay, fish growth, abundance, and diversity in restored sites were all greater than or similar to reference sites. Both large and small marsh creeks in the lower and upper Bay are functioning well as fish habitat. Differences in the specific assemblages, or in the size distribution of the collected fishes, can be attributed to salinity gradients among restoration and reference sites and localized mechanisms of larval access to creeks (PSEG 2007b). Results of 12 years of post-restoration monitoring of fish assemblages in restored and reference marsh creeks are summarized in Table F-2.

Table F-1 Interannual Variability in Adult Herring Abundance at Fish Ladders

Year	Total Adult River Herring Passing Ladder											
	NP	GL	SLD	ML	MGP	CP	MCP	SLM	CRL	NL	SL	SSL
1996	ND	ND	4	ND	1	ND	115	ND	ND	ND	ND	ND
1997	ND	ND	7	ND	2	30	177	ND	ND	ND	ND	0
1998	ND	ND	113	ND	25	488	559	ND	3	ND	ND	7
1999	ND	39	163	95	48	1102	1122	ND	1	ND	ND	60
2000	ND	70	65	78	33	884	1250	ND	4	ND	ND	32
2001	ND	4	151	690	99	1399	918	ND	2	ND	ND	195
2002	ND	3	139	682	764	1531	932	ND	11	ND	ND	366
2003	ND	31	32	678	25	346	228	ND	13	ND	ND	64
2004	ND	23	183	712	226	284	679	0	0	ND	ND	1
2005	5	2	76	ND	216	ND	ND	62	9	1	20	2
2006	0	21	115	ND	ND	ND	ND	3	3	0	5	63
2007	1	1	105	ND	ND	ND	ND	0	4	5	19	398

Source: PSEG (2005, Table 6-10); PSEG (2006b, Table 6-3) Missing SLM-SSL
ND = no data
NP = Noxontown Pond
GL = Garrison Lake
SLD = Silver Lake – Dover
ML = Moores Lake
MGP = McGinnis Pond
CP = Coursey Pond
MCP = McColley Pond
SLM = Silver Lake - Milford
CRL = Cooper River Lake
NL = Newton Lake
SL = Stewart Lake
SLL = Sunset Lake

Table F-2 Trends in Fish Assemblage Monitoring Results 1996-2005

Year	Total Number of Fish Species Collected	Percent Transient Species	Upper Bay Results (in terms of restoration site)	Lower Bay Results (in terms of restoration site)	Reference
1996	43	70	No restoration sites yet	Dennis Township: Newly constructed channels were quickly utilized by fish, including target species	PSEG (1996), page viii
1997	49	65	No restoration sites yet	Species richness in large and small creeks = reference Fish abundances > reference sites	PSEG (1997), page viii
1998	41	66	Herbicide treatment of *Phragmites* continuing, but species richness and abundance = reference	Dennis Township: Species richness in large and small creeks > reference. Fish abundances > reference sites. 2nd Restoration Site completed (Commercial Township): Abundance and richness > reference	PSEG (1998), page 9
1999	53	72	Fish assemblage similar between restored and reference sites.	Dominant species at restored and reference sites were similar. Dennis Township: richer fauna, higher catch rate	PSEG (1999a), page 7-12, 7-29, 7-28 through 7-28
2000	54	65	Species richness > reference at one site and = reference at other site	Species richness and abundance > reference "Fish utilization of restored marshes was similar to that in reference marshes."	PSEG (2000), page 9
2001	38	66	Species richness and abundance > reference at one site (Mill Creek) and = reference at other site	Species richness in large and small creeks = reference. Fish abundances ≥ reference sites.	PSEG (2001), page 7-16
2002	48	60	Fish utilization > reference	Fish utilization > reference	PSEG (2002), page 15
2003	47	68	Species abundance and richness > reference, but untreated *Phragmites* marsh is also functioning well as fish habitat (> reference)	Abundance > reference at one site and < reference at other site. Species richness ≥ reference. Both restoration sites function well as habitat; differences attributed to salinity gradient	PSEG (2003), page 7-19, 7-20, 7-132, 7-133, 7-134

Table F-2 Trends in Fish Assemblage Monitoring Results 1996-2005 (Continued)

Year	Total Number of Fish Species Collected	Percent Transient Species	Upper Bay Results (in terms of restoration site)	Lower Bay Results (in terms of restoration site)	Reference
2004	38	60.5	Species abundance and richness > reference, but untreated *Phragmites* marsh is also functioning well as fish habitat (> reference)	Abundance > reference at one site and < reference at other site (large creeks). Abundance < reference (small creeks). Species richness = reference (large creeks). Species richness > reference (small creeks) Both restoration sites function well as habitat; differences attributed to salinity gradient	PSEG (2004), page 14 of unnumbered Executive Summary
2005	45	58	Abundance < reference (large creeks) Richness > reference at one site and < reference at other site (large and small creeks). Abundance > reference (small creeks)	Abundance > reference (large creeks) Richness > reference at one site and < reference at other site (large and small creeks). Abundance < reference (small creeks)	PSEG (2005), pages 7-i and 7-ii
2006	36	61	Abundance > reference (large and small creeks)	Abundance > reference (large creeks) Abundance < reference (small creeks) Species richness = reference (large and small creeks).	PSEG (2006a), pages 9; 10, 7-18, 7-19
2007	55	Not given	Abundance > reference (large and small creeks) Species richness = reference (large and small creeks)	Abundance > reference (large creeks) Abundance = reference (small creeks) Species richness = reference (large and small creeks).	PSEG (2007a), page 4-6; 7-9; 7-15; 7-16

\> = greater than
< = less than
= = equals
≥ = less than or equal to
≤ = greater than or equal to

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Appendix G

401 Water Quality Certification

B.J. Beck 2-2-85
(for your collection)

State of New Jersey
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF WATER RESOURCES
TRENTON, NEW JERSEY 08625

DEC 10 1974 FILE COPY

Please reply to
P. O. Box 2809

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LIC. AND ENV.
08984
FILE No.
CODES EPS NJS

979

Mr. Meyer Scolnick
Director, Enforcement and
Regional Counsel Division
U. S. Environmental Protection Agency
26 Federal Plaza
New York, New York 10007

Re: Certification
National Pollutant Discharge
Elimination System
NJ 0005622
Public Service Electric and Gas Company
Salem Generating Station
Hancocks Bridge, New Jersey

Dear Mr. Scolnick:

This is to certify in accordance with the provisions of Section 401 of Public Law 92-500 "Federal Water Pollution Control Act Amendments of 1972" that there are no applicable effluent limitations as required under Sections 301 and 302 for this activity and that there are no applicable effluent standards under Sections 306 and 307 and that the company will conform with the effluent standards for the proposed discharge as described in the application and draft permit on file in this office with the following revision(s):

1. The discharge shall not cause the Delaware River to:

   (a) Be raised above ambient by more than 4° F (2.2° C) during September through May nor more than 1.5° F (0.8° C) during June through August, nor shall maximum temperatures exceed 86° F (30.0° C). Temperatures shall be measured outside of designated heat dissipation areas.

Mr. Meyer Scolnick Page 2

(b) The limitations specified above may be exceeded in designated heat dissipation areas by special permission on a case-by-case basis, subject to the following conditions:

(i) Heat dissipation areas shall not be longer than 3,500 feet, measured from the point where the waste discharge enters the stream.

(ii) Where waste discharges would result in heat dissipation areas in such close proximity to each other as to impair protected uses, additional limitations may be prescribed to avoid such impairment.

(iii) The rate of temperature change in designated heat dissipation areas shall not cause mortality of fish or shellfish.

(iv) The determination of heat dissipation areas shall take into special consideration the extent and nature of the receiving waters so as to meet the intent and purpose of the criteria and standards including provision for the passage of free-swimming and drifting organisms so that negligible or no effects are produced on their populations.

2. The Company shall submit a proposed program for monitoring and evaluating the nature and extent of impingement and entrainment of natural aquatic organisms resulting from the Company's activities. Such a report shall be submitted to the Regional Administrator and the State Certifying Agency within 3 months of the effective date of the permit.

This is also to certify that water quality determinations cannot be made at this time because data will not be available to provide an allocation in sufficient time to comply with the statutory deadline of December 31, 1974 for issuance of permits.

Mr. Meyer [redacted]olnick

The foregoing applies only to the effect that the proposed discharge would have on water quality as presently defined in the Regulations Establishing Surface Water Quality Standards.

Very truly yours,

John Wilford, P.E.
Acting Assistant Director

E26:L:WF9&B5

cc: Public Service Electric and Gas Company