Applicant's Environmental Report – Operating License Renewal Stage Hope Creek Generating Station

Unit 1
Docket No. 50-354
License No. NPF-57

PSEG Nuclear, LLC

This Page Intentionally Left Blank

Table of Contents

Table of Contents (Continued)

Table of Contents (Continued)

Table of Contents (Continued)

Appendices

Table of Contents (Continued)

List of Tables

Table of Contents (Continued)

List of Figures

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
CST	condensate storage tank
CVCS	Chemical and Volume Control System
CWA	Clean Water Act
CWS	Circulating Water System
DAW	Dry Active Waste
DNREC	Delaware Department of Natural Resources and Environmental Control
DRBC	Delaware River Basin Commission
DSM	demand side management
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
GWh	gigawatt-hours
GWS	Gaseous Waste System
HCGS	Hope Creek Generating Station
HEPA	high efficiency particulate air
in	inch(es)
IPA	integrated plant assessment
IPE	individual plant examination
ISFSI	Independent Spent Fuel Storage Installation
ITS	Incidental Take Statement
km	kilometers
km^2	square kilometers
kV	kilovolt
kWh	kilowatt hour
lb	pound
LLC	Limited Liability Company
LLRSF	Low Level Radioactive [Waste] Storage Facility
LOS	level of service
LWMS	Liquid Waste Management System
m	meter
m^2	square meter
m^3	cubic meter
MACCS2	MECOR Accident Consequence Code System Version 2
MGD	million gallons per day
mi	mile
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

Acronyms and Abbreviations (Continued)

NJBPU	New Jersey Board of Public Utilities
NJDEP	New Jersey Department of Environmental Protection
NJPDES	New Jersey Pollutant Discharge Elimination System
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.
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
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

Acronyms and Abbreviations (Continued)

scfm	standard cubic feet per minute
SCR	selective catalytic reduction
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
SWIS	Service Water Intake Structure
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

This Page Intentionally Left Blank

Chapter 1

Introduction

This Page Intentionally Left Blank

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 Hope Creek Generating Station (HCGS) pursuant to NRC Operating License NPF-57. The license will expire on April 11, 2026.

PSEG Nuclear, LLC, is seeking license renewal of the HCGS operating license and has prepared this Environmental Report in conjunction with its application to NRC to renew the HCGS operating license, 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, Postconstruction 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 HCGS, 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 license would allow HCGS to operate until April 11, 2046, an additional 20 years of operation beyond the current licensed operating period of 40 years.

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 HCGS 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), as supplemented (NRC 1996b and 1999a);
- NRC supplemental information published 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 HCGS 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)(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
10 CFR 51.53(c)(3)(ii)(E)	4.9	Impacts of Refurbishment on Terrestrial Resources
	4.10	Threatened or Endangered Species
10 CFR 51.53(c)(3)(ii)(F)	4.11	Air Quality During Refurbishment (Non-Attainment or Maintenance Areas)

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)(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 Hope Creek Generating Station Licensee and Ownership

HCGS is owned 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.

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 the HCGS license and is applying to renew that license.

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.”

This Page Intentionally Left Blank

Chapter 2

Site and Environmental Interfaces

This Page Intentionally Left Blank

2.1 Location and Features

HCGS 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. HCGS is located at River Mile 51, 27 km (17 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 HCGS 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)

HCGS occupies about 62 hectares (153 acres) of approximately 300 hectares (740 acres)[1] owned by PSEG on Artificial Island. The Salem Nuclear Generating Station (Salem) 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 HCGS site boundary from the HCGS reactor building is 902 meters (2,960 ft). The nearest residence is approximately 5.5 km (3.4 mi) west of the HCGS site in Bay View Beach, Delaware. Other nearby residences are 5.6 km (3.5 mi) east-northeast and 5.6 km (3.5 mi) northwest of the HCGS 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).

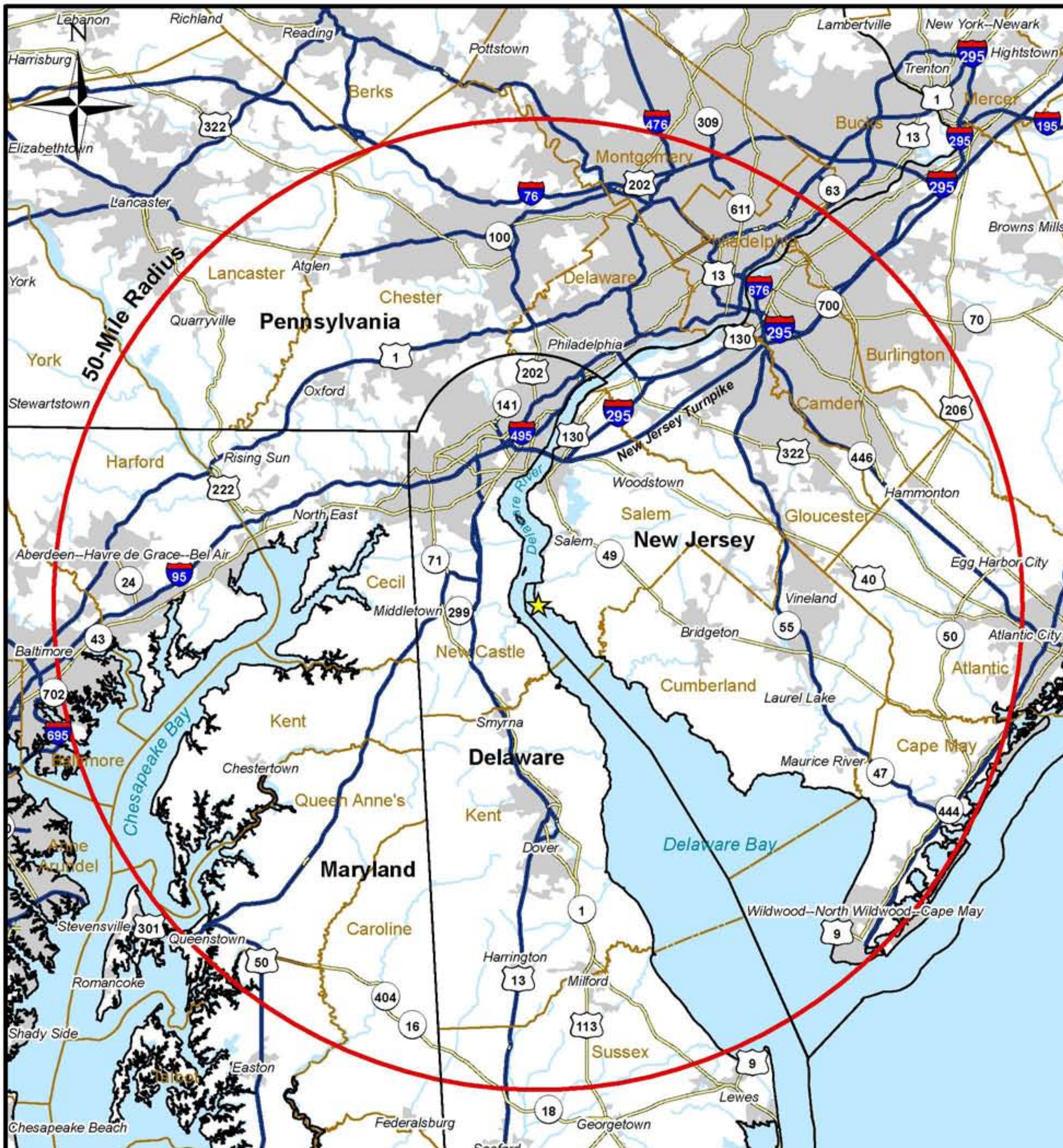
There are no major highways or railroads within about 11 km (7 mi) of the HCGS site; the only land access is a road that PSEG constructed to connect its property with an existing secondary road about 5 km (3 mi) to the east. Barge traffic has access to the site by way of the Intracoastal Waterway channel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

Section 3.1 describes key features of HCGS, 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 HCGS and includes all the information necessary for the NRC to prepare a Supplemental Environmental Impact Statement for HCGS. PSEG has prepared a second Environmental Report that is specific to Salem.

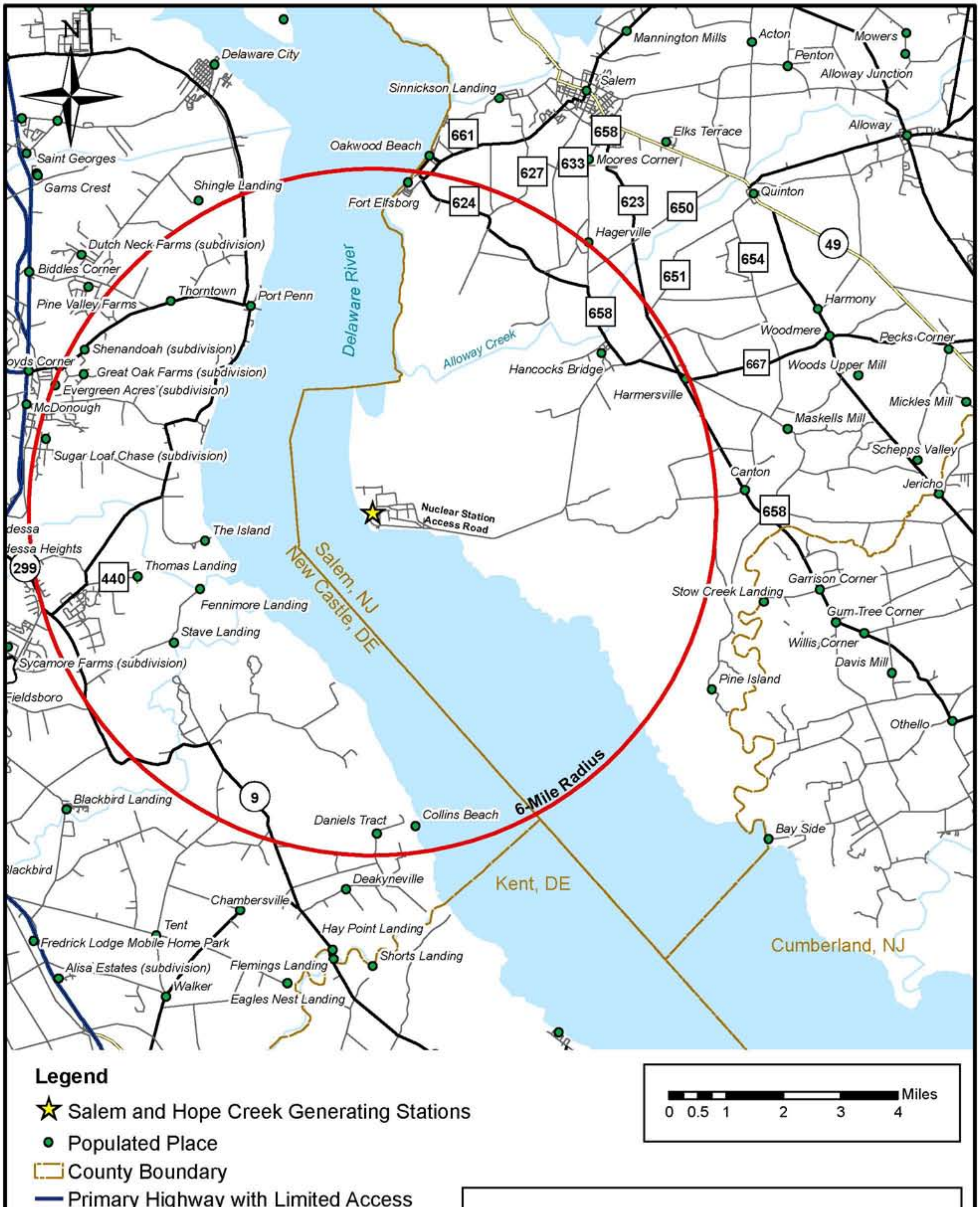


Legend

- ☆ Salem and Hope Creek Generating Stations
- State Boundary
- County Boundary
- Primary Highway with Limited Access
- Primary Highway
- Urban Area
- Water

Miles: 0 5 10 20 30

Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 2.1-1 50-Mile Region



Hope Creek 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 Schuylkill River, which joins the Delaware at Philadelphia. The Delaware River has a total volume of about 450 billion 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 to 43 km (0.2 mi to 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). HCGS is located adjacent to the Delaware Estuary. However, the documents referenced in this Environmental Report refer inconsistently to the water body adjacent to HCGS 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 fresh-water flow into the Delaware Estuary averages 645 m^3 per second (cubic meter [m^3]/sec; 22,783 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 1013 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: freshwater, 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 HCGS, 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, fresh-water 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 fresh-water inflow, which varies twice daily with 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 upon the water resources; develop hydroelectric potential; improve navigation; control the movement of salt-water; control stream pollution; and regulate stream flow (DRBC 1961).

2.2.1 PSEG BIOLOGICAL MONITORING PROGRAM

HCGS is located adjacent to Salem. The aquatic resources in the Delaware Estuary at HCGS are the same as those at Salem. PSEG has conducted biological monitoring of the Delaware Estuary since 1968. In fulfillment of requirements of the 1994 and 2001 New Jersey Pollutant Discharge Elimination System (NJPDES) permits for Salem, PSEG developed and implemented an extensive biological monitoring program for the Delaware Estuary, which is described in the Salem license renewal Environmental Report, along with a summary of some recent results

(PSEG 2009a). The information and analyses of the aquatic community in the Delaware Estuary are also relevant to HCGS.

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, and six additional freshwater zones were 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 fresh-water 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 HCGS in its Estuary Transition Zone, the New Jersey beach seine sampling program locates HCGS in Region 1, the DRBC water quality zone is 5, and the PSEG monitoring program locates HCGS in its Zone 7.

Primarily two data sources have been used to describe the fishery in the vicinity of HCGS. The NJPDES renewal application for Salem that PSEG submitted in 2006 (PSEG 2006a) includes the Comprehensive Demonstration Study (CDS; Section 4) and 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, and 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 within 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 six percent of fish in bottom trawl collections in 2002, but were relatively uncommon in 2003 and 2004 (less than one 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 ten 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 eight 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 ten 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 HCGS 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 (ten 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 HCGS) 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 HCGS), 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 2003).

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 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 2.2.1.1. Blue crab catches are also reported.

Beginning in 1995, PSEG collected samples at 32 selected locations between the mouth of the Bay and the Chesapeake & Delaware Canal (5 km [3 mi] north of HCGS) 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-centimeter (cm) (3/8-in) bar mesh netting. Beach seine samples are 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 crab 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, 1999a, 2000a, 2001, 2002, 2003, 2004a, 2005, 2006b, and 2007a), composing more than 50 percent of the annual seine catch in eight 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 five 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 freshwater and brackish portions of the river (PSEG 2005).

2.2.2 POTENTIAL IMPACT OF HCGS OPERATIONS ON AQUATIC RESOURCES

The following discussion is based on conclusions drawn from aquatic monitoring required by the Salem NJPDES permit. Because HCGS and Salem are adjacent and both use water from the Estuary, the conclusions regarding trends and long-term stability of populations of target fish species are relevant to both plants.

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, Appendix E) 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 (DNREC) 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 Station 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.

HCGS withdraws approximately one-fourth of the water that Salem withdraws from the Estuary. It follows that if the operation of Salem is not measurably affecting the fishery, the operation of HCGS also is not affecting the fishery.

2.2.3 STATUS OF AQUATIC RESOURCES

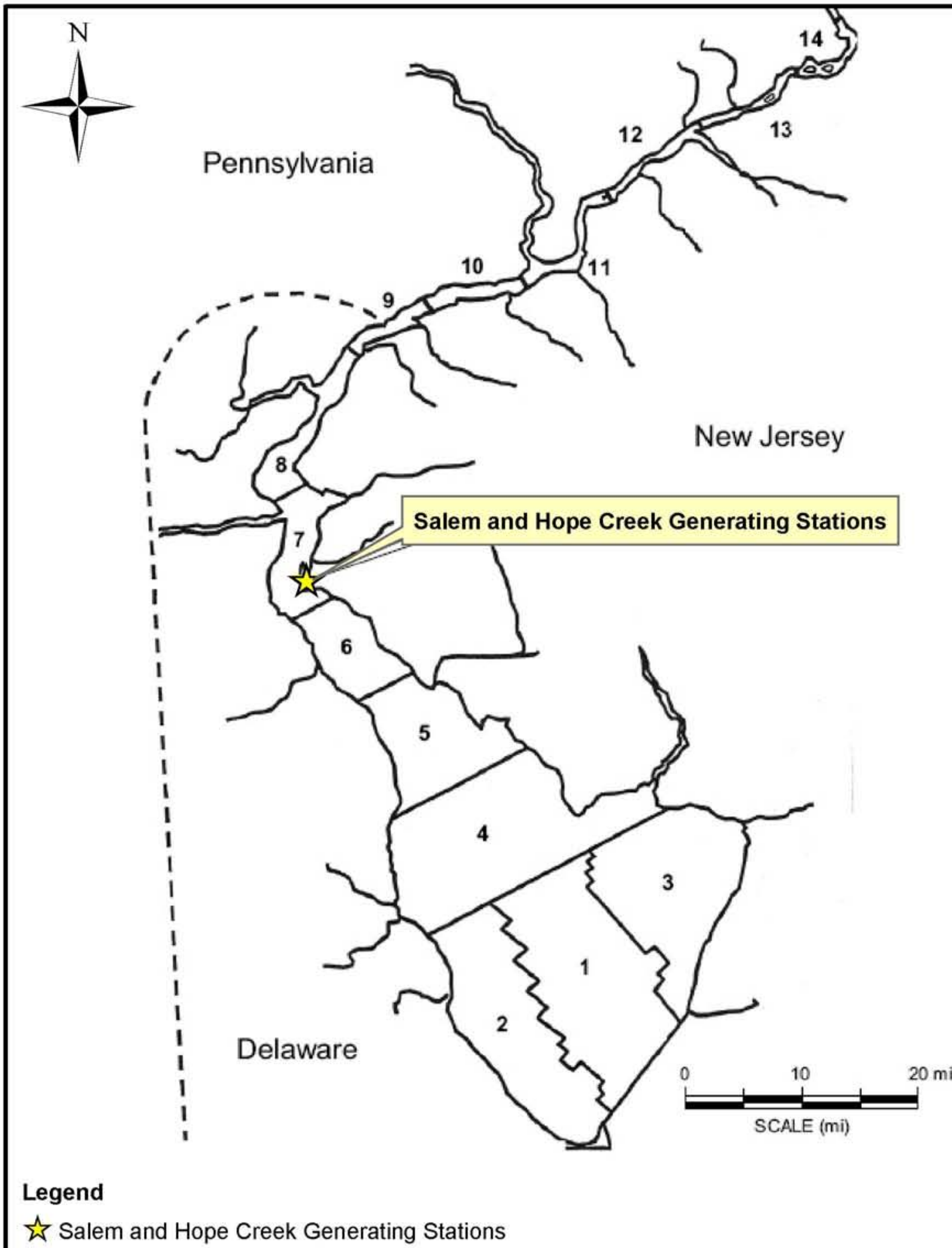
HCGS is located on the Delaware Estuary adjacent to Salem, and the aquatic resources analyzed as a requirement of Salem's NJPDES permit are the same resources that are present at HCGS. PSEG has periodically assessed population and community characteristics of the Delaware Estuary such as species composition 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 that could potentially be 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 of the stations 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 the changes expected to occur if Salem (or HCGS) was adversely affecting fish populations. Most species have increased in abundance since 1998. Rates of mortality due to station operations during this period that 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 DNREC 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 using 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 effect of the stations is 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). HCGS has operated for more than 20 years. 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. 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.



Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 2.2-1 PSEG Biological Sampling Zones

2.3 Ground-Water Resources

HCGS is adjacent to Salem in the New Jersey Coastal Plain, approximately 29 km (18 mi) south of the Fall Line (PSEG 2009c). The HCGS site is on the eastern shore of the Delaware River at approximately River Mile 51. The Delaware Estuary borders the PSEG-owned property on Artificial Island that contains the HCGS and Salem 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 two and 11 m per km (ten and 60 ft per mi) (ARCADIS 2006).

There are four primary water-bearing zones underlying the HCGS and Salem 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 three and 12 m (ten 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 meter/meter (0.007 feet/foot) (PSEG 2007b). Recharge to the unit at the site is primarily through direct infiltration at an outcrop area (PSEG 2009b).

The Kirkwood Formation is approximately 12 m (40 ft) bgs in the vicinity of HCGS/Salem. 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 meter/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 2009b).

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 2009b). Recharge to the Mount Laurel-Wenonah aquifer at the site is through leakage of overlying aquifers (PSEG 2009b).

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 three to five 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 2009b)

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 2009b)

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 HCGS and Salem 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 HCGS and Salem 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 HCGS ground-water usage, refer to Section 3.1.4.

<u>Ground-Water Tritium</u>

Tritium has not been detected in ground water beneath the HCGS in any concentrations that exceed the EPA Drinking Water Standard or that suggest an adverse trend (PSEG 2008a). In 2003, PSEG identified tritium in ground water from onsite sampling wells near the Salem Unit 1 Fuel Handling Building (FHB). The source of tritium was the Salem Unit 1 Spent Fuel Pool, the tritium release to the environment has been stopped, and tritium concentrations above the New Jersey Ground Water Quality Criterion have not migrated to the property boundary. Neither strontium nor plant-related gamma emitters were detected in any ground-water well. In September 2005, a ground-water recovery system (GRS) began operating to reverse 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. The ground-water remediation project is being performed in accordance with the Remedial Action Work Plan approved by NJDEP. (PSEG 2008a) The effectiveness of the ground-water extraction system is discussed more fully in the Salem license renewal Environmental Report, Section 2.3 (PSEG 2009a). HCGS is hydraulically upgradient of Salem, and routine monitoring of ground-water wells has not identified any impacts on ground water at HCGS as a result of tritium released at Salem.

2.4 Critical and Important Terrestrial Habitats

HCGS occupies about 62 hectares (153 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 hectares (740 acres) on Artificial Island. HCGS was constructed on a portion of this property between 1974 and 1986. HCGS is immediately adjacent to the approximately 89-hectare (220-acre) Salem 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 (nine ft) above sea level. Construction of HCGS resulted in the permanent loss of 62 hectares (153 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 six km (four 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 (ten 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 2004b). 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 (ten mi) of HCGS (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 ten km (six 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 HCGS and Salem sites to the transmission grid. The approximately 171 km (106 mi) of corridors associated with HCGS and Salem 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 [one to two 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.

The third corridor exits the site toward the north for a distance and then turns west and crosses the Delaware River into Delaware. It contains the Salem-Keeney line. This line, although now connected to HCGS, was constructed to connect Salem to the transmission grid. Therefore, no line evaluated in this Environmental Report extends into Delaware, and protected species found in Delaware are not evaluated here.

Only the HCGS-New Freedom transmission line, which is located in the more northern of the two transmission corridors extending east-northeast from the HCGS and Salem sites, was originally built to connect HCGS to the electricity transmission grid. Accordingly, it is the only transmission line for which impacts are assessed in this Environmental Report.

All three corridors cross land identified as critical bald eagle foraging habitat (NJDEP 2006). In addition, both of the corridors extending east-northeast from the HCGS and Salem sites traverse approximately two miles of marsh habitat east of the PSEG property and then traverse a combination of forested and agricultural lands, and for approximately one-quarter of their total distance nearest 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 line corridor maintenance in the New Jersey 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 HCGS and Salem 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. PSE&G performs ground inspections annually and aerial inspections once every five years, and maintains 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 HCGS and its associated transmission line 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 corridor, which as noted in Section 3.1.6 is the only transmission corridor for which impacts are assessed in this Environmental Report, crosses portions of Salem, Gloucester, and Camden counties in New Jersey (Figure 3.1-3). 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) and the New Jersey Department of Environmental Protection (NJDEP 2008a), 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, and Camden counties. Most of these species have not been observed on the HCGS site. Some endangered or threatened bird species could move through the site during seasonal migrations. Federally listed species recorded in Salem, Gloucester, and Camden counties, and state-listed species that have been observed on the HCGS site or along the transmission line, 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 HCGS site but could occur along the transmission corridor. 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 HCGS, but is known from other transmission corridors in the Pine Barrens (NJDEP 2008a, DNREC 2008).

Four federally listed plant species have been recorded in Salem, Gloucester, and Camden counties: chaffseed, sensitive joint vetch, swamp pink, and Knieskern's beaked-rush. 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).

Bald eagles (*Haliaeetus leucocephalus*) and peregrine falcons (*Falco peregrinus*) are occasionally seen in the vicinity of HCGS (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 eight km (five mi) from the HCGS 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 HCGS site and in areas along the Delaware Estuary (NJDEP 2008f). PSEG has erected nesting platforms for ospreys at off-site locations, and birds are currently using the platforms (TNC 2008).

The Cooper's hawk (*Accipiter cooperii*), bobolink (*Dolichonyx oryzivorus*), and grasshopper sparrow (*Ammodramus savannarum*) have been observed within ten km (six mi) of HCGS (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 2008b).

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 can 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.

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 freshwater 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).

Atlantic sturgeon (Acipenser oxyrinchus oxyrinchus) occurs in the Delaware River. In 2006, the National Marine Fisheries Service (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 one of 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, 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 on 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 1999a) 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 HCGS. 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 1999a).

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
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 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
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 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 or decrease within its natural cycle); U = Undetermined (a species about which there is not enough information available to determine the status) (NJDEP 2008a).
[c] Source of county occurrence: USFWS (undated); NJDEP (2008a).
[d] Sea turtles and sturgeon are not included in county lists maintained by USFWS (undated) and NJDEP (2008a), but are listed by the USFWS at 50 CFR 17.11and are known 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
1.1, 1.2, 2.1	1.3, 1.4, 2.2, 2.3, 2.4, 3.1, 3.2, 3.3, 4.1, 4.2	3.4, 4.3, 4.4

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 HCGS vicinity. Approximately 501,820 people live within 32 km (20 mi) of HCGS, 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 HCGS, 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 HCGS regional population ranks of sparseness Category 4 and proximity Category 4 result in the conclusion that HCGS 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 HCGS (Figure 2.1-1). The MSAs nearest HCGS 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 HCGS is the city of Salem (13 km [eight 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 approximately 152,000; 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 138,000 to 156,000; an increase of 13 percent. (Table 2.6-1)

Because approximately 81 percent of HCGS 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 plant are paid to municipalities in Salem County, they are the counties with the greatest potential to be socioeconomically affected by license renewal at HCGS, 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 HCGS 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 Salem and Cumberland 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 HCGS, 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 time period (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 HCGS 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 HCGS, 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 number 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-mi) 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 HCGS Employees

County and State of Residence	Number of Employees	Percent of Total
Adams, OH	1	0.1
Atlantic, NJ	3	0.3
Bergen, NJ	1	0.1
Berks, PA	2	0.2
Burlington, NJ	24	2.8
Camden, NJ	40	4.6
Cape May, NJ	3	0.3
Cecil, MD	12	1.4
Chester, PA	31	3.6
Cumberland, NJ	76	8.7
Dane, WI	1	0.1
Darlington, SC	1	0.1
Delaware, PA	25	2.9
Fairfax, VA	1	0.1
Gloucester, NJ	137	15.8
Harford, MD	1	0.1
Howard, MD	1	0.1
Hunterdon, NJ	1	0.1
Kent, DE	1	0.1
Lake, IN	1	0.1
Lancaster, PA	2	0.2
Lehigh, PA	1	0.1
Luzerne, PA	1	0.1
Montgomery, PA	7	0.8
New Castle, DE	144	16.6
New London, CT	1	0.1
Ocean, NJ	1	0.1
Onondaga, NY	1	0.1
Saint Lucie, FL	1	0.1
Salem, NJ	346	39.8
Wayne, OH	1	0.1
Total	**869**	**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

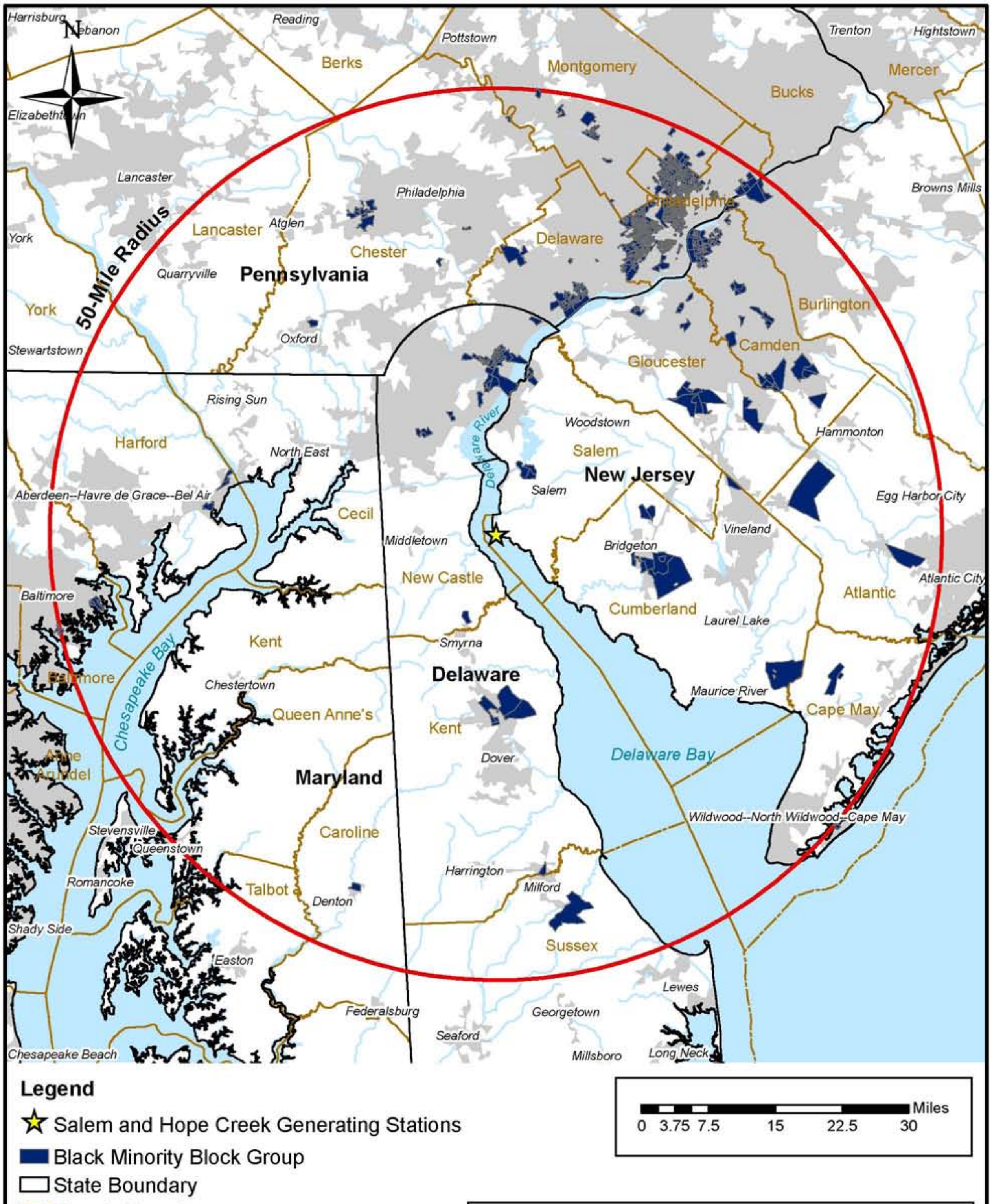
Table 2.6-5 Environmental Justice Summary (Continued)

	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

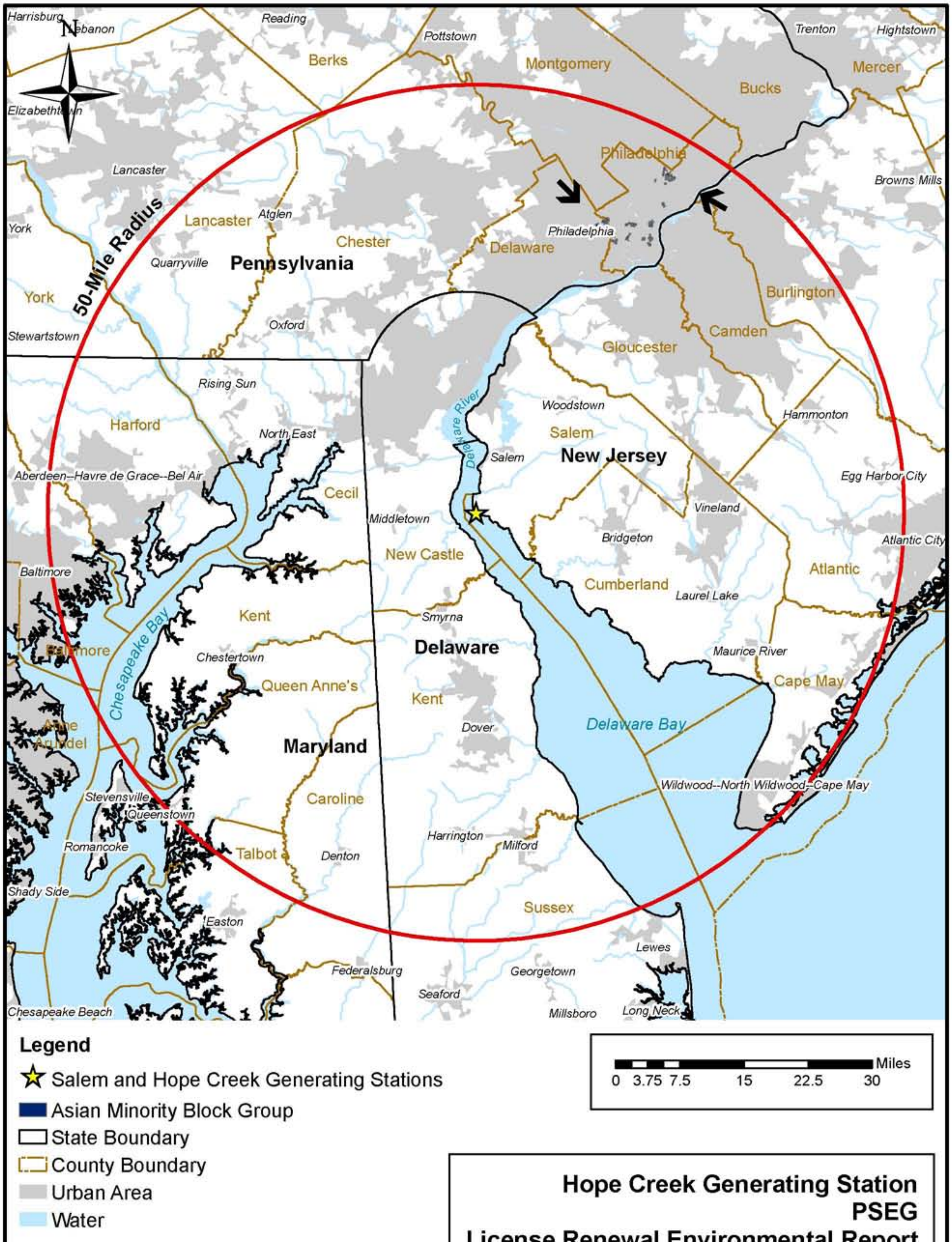
Highlighted counties are completely contained within the 50-mile radius.

[a] USCB 2000a

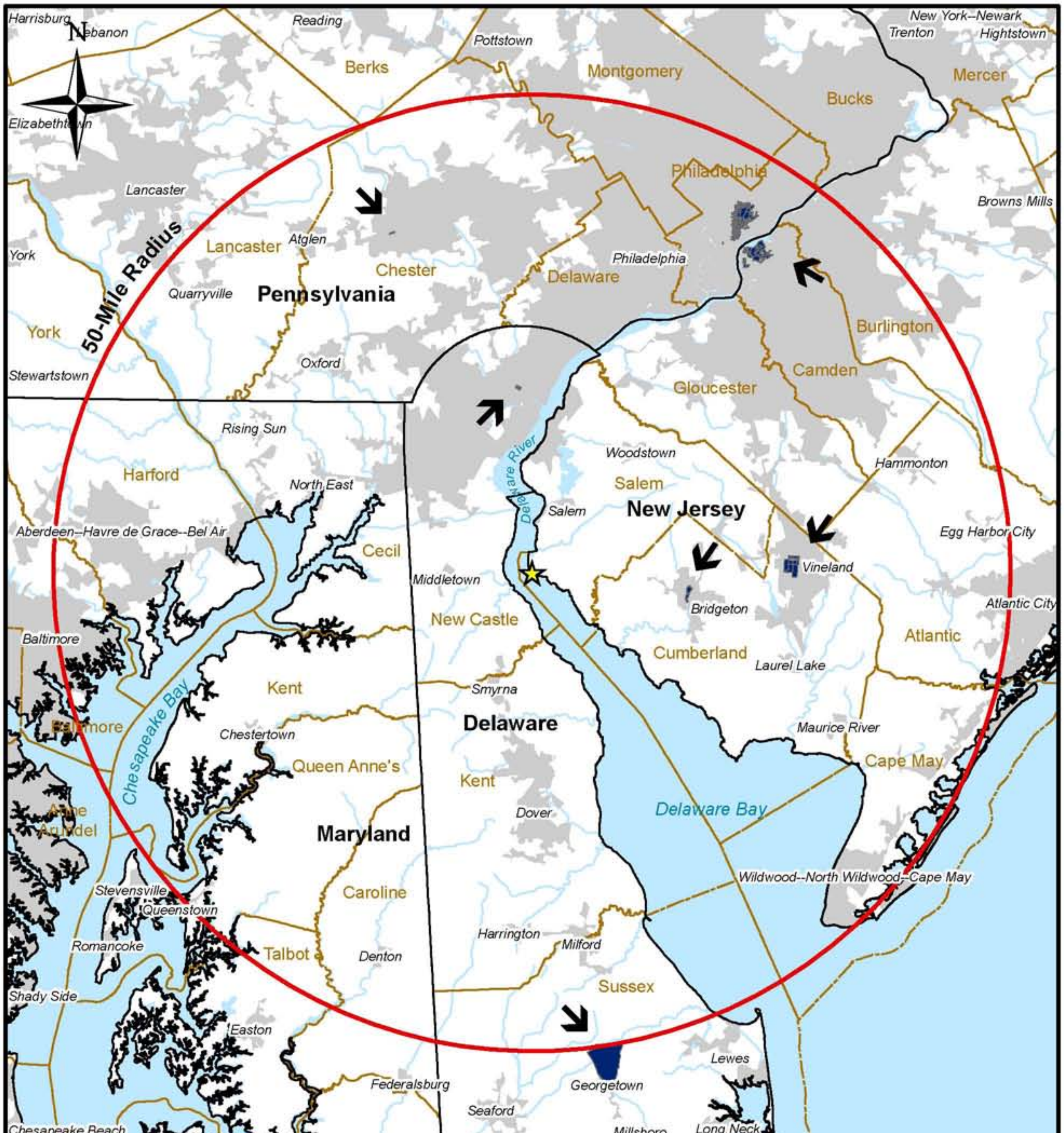
[b] Table entries denote number of census block groups, except on lines indicated as “percentages.”



Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 2.6-1 Black Minority Populations



Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 2.6-2 Asian Minority Populations

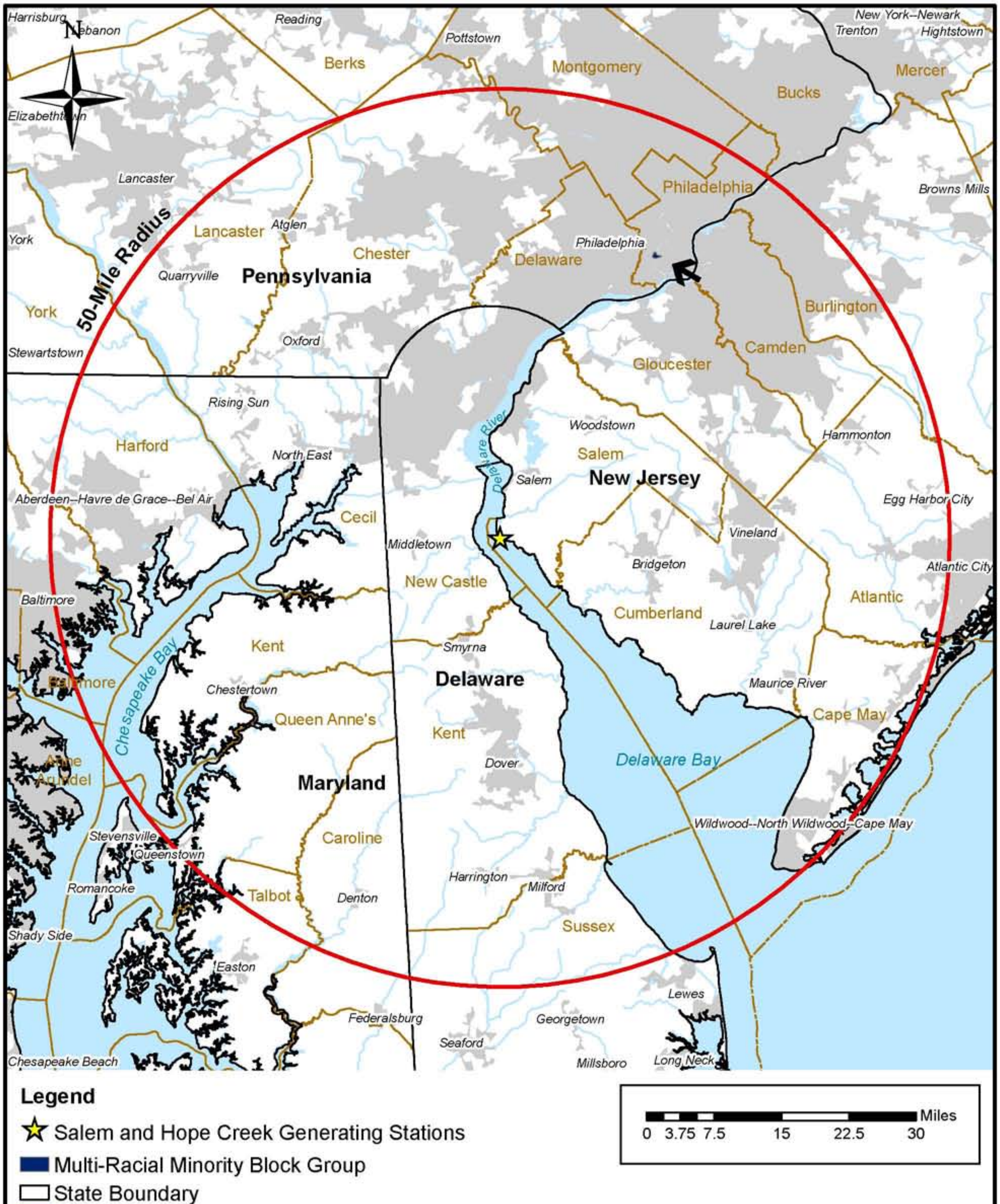


Legend

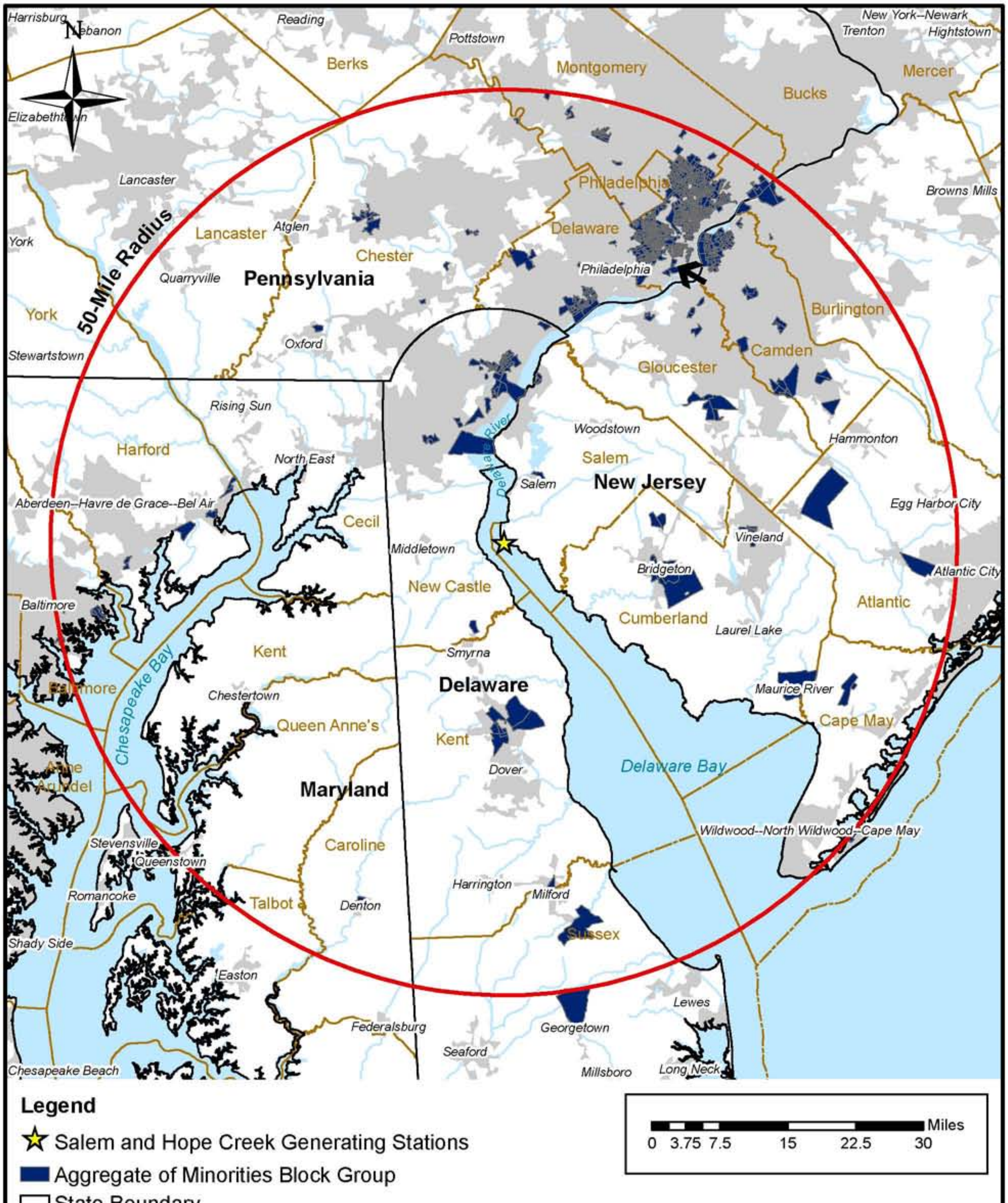
- Salem and Hope Creek Generating Stations
- Other Minority Block Group
- State Boundary
- County Boundary
- Urban Area
- Water

0 3.75 7.5 15 22.5 30 Miles

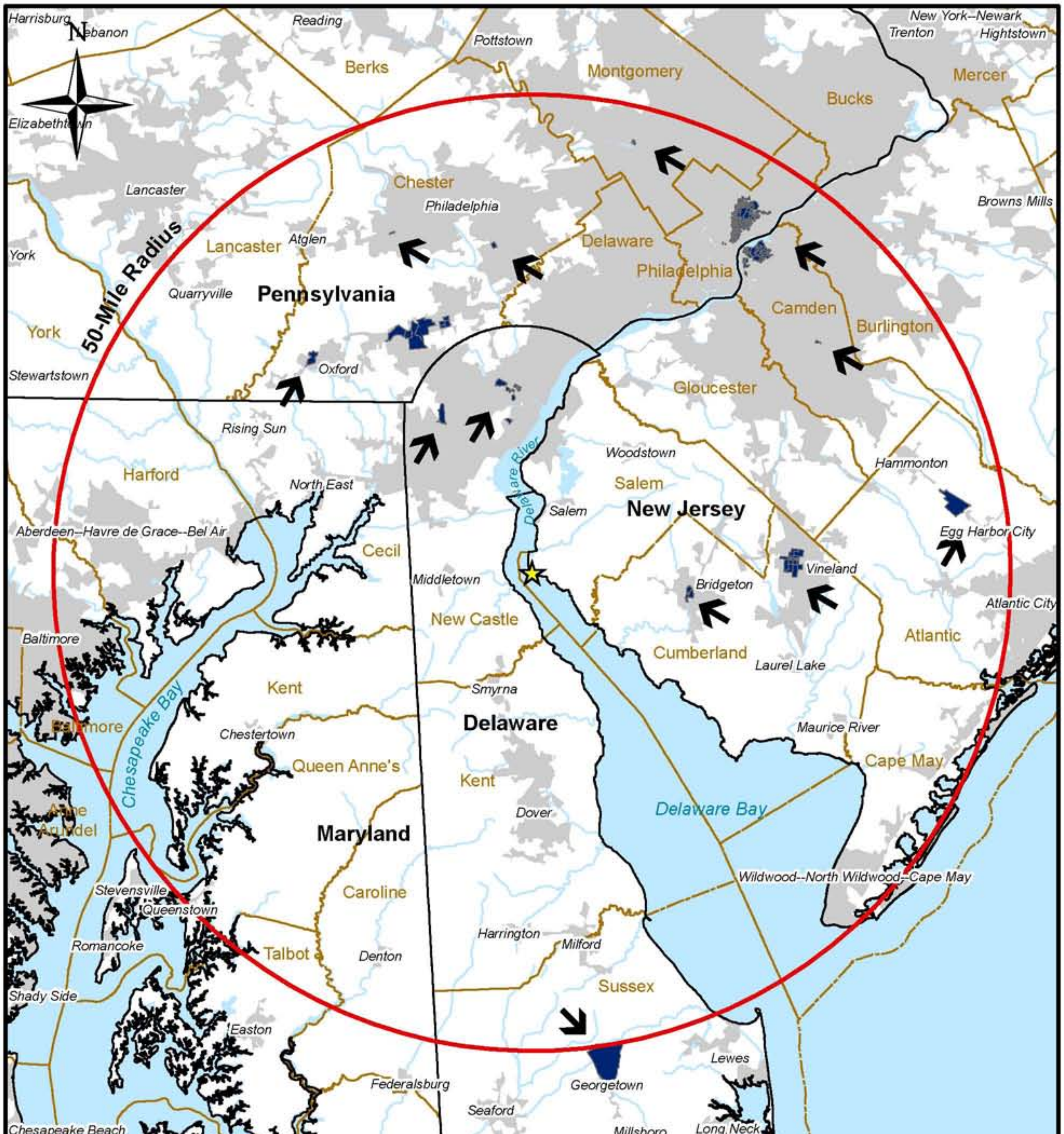
Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 2.6-3 Other Minority Populations



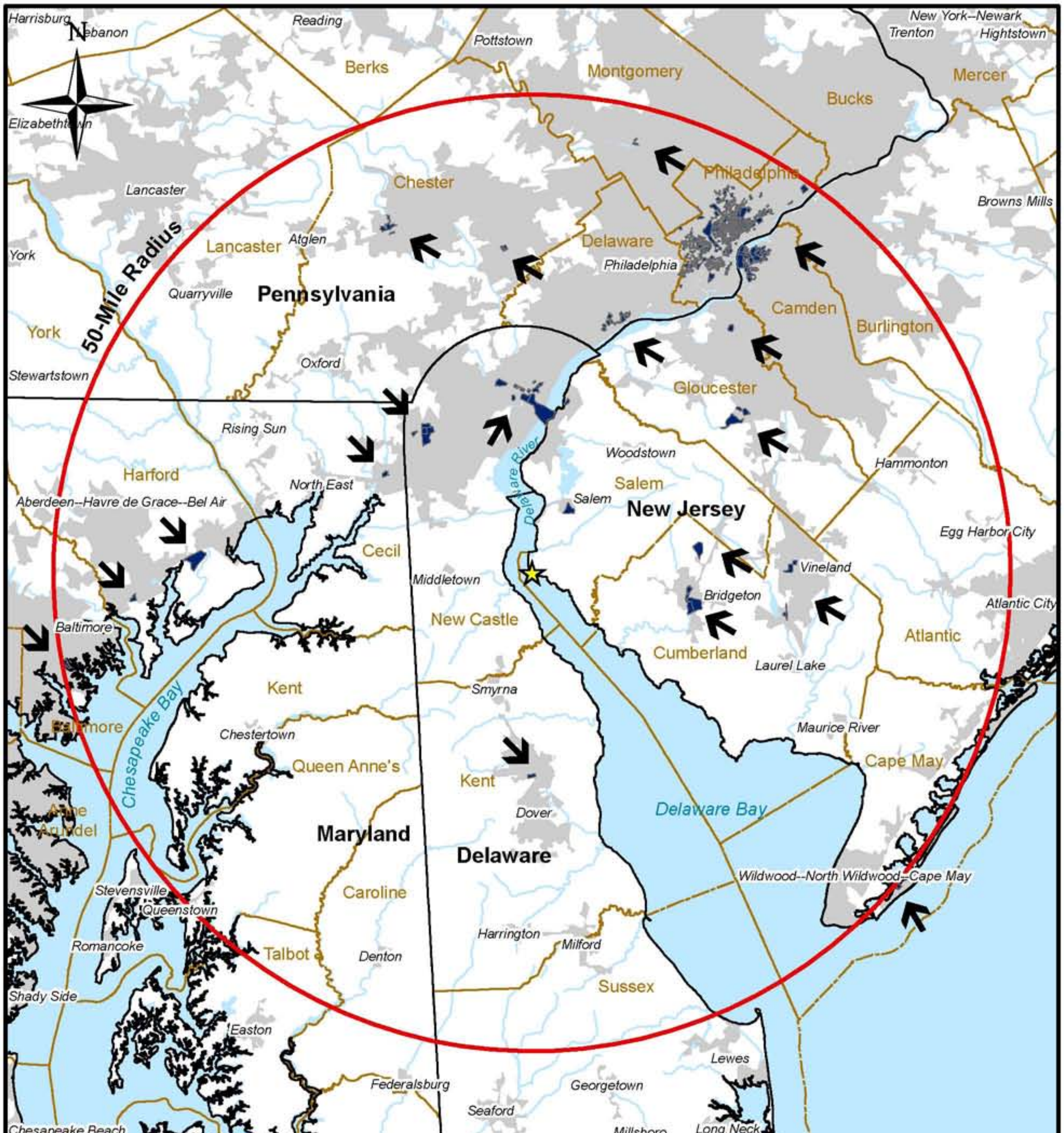
Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 2.6-4 Multi-Racial Minority Populations



Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 2.6-5 Aggregate of Minorities Populations



Hope Creek 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

0 3.75 7.5 15 22.5 30 Miles

Hope Creek Generating Station
PSEG
License Renewal Environmental Report
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 HCGS. Over the last five years, the taxes paid to Lower Alloways Creek Township for HCGS ranged from a low of $457,029 in 2006 to a high of $485,624 in 2005 (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 Salem and HCGS. Table 2.7-1 summarizes PSEG's property tax payments to Lower Alloways Creek and the City of Salem from 2003 to 2007.

From 2003 through 2007, Lower Alloways Creek Township collected between $2,099,185 (in 2003) and $2,325,378 (in 2005) annually in total commercial property tax revenues (Table 2.7-1). From 2003 to 2007, HCGS's property tax payments represented 20.8 to 22.1 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 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 1.03 to 1.34 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 HCGS and the Energy and Environmental Resource Center, 2003 - 2007

	2003	2004	2005	2006	2007
PSEG's Property Taxes for HCGS					
Amount PSEG Paid in Property Tax	$464,677	$474,512	$485,624	$457,029	$480,476
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	22.1	21.1	20.9	20.8	20.8
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	1.34	1.31	1.20	1.05	1.03
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.

2.8 Land Use Planning

This section focuses on Salem County because the property taxes paid by PSEG for HCGS 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 PSEG pays property taxes to these municipalities, which host the Energy and Environmental Resource Center and HCGS, 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 ten percent of Salem County is developed for residential, commercial, or industrial use. Over half the county's land comprises tidal and fresh water 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 1,900 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 – seven percent
- Commercial – <one percent
- Industrial – three 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 HCGS is in Salem County and most of the HCGS 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 (approximately14,400 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. 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). 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 HCGS is via Alloways Creek Neck Road, a small two-lane road, to Nuclear Station Access Road. The combined HCGS and Salem workforces use the Nuclear Station Access Road entrance. Approximately 11 km (seven mi) east of HCGS, Alloways Creek Neck Road intersects County Route 658, which has a north-south orientation (Figure 2.9-1). Employees traveling to HCGS 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 HCGS by traveling south on County Route 658 to Alloways Creek Neck Road. Employees traveling to HCGS 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 HCGS by traveling west on Alloways Creek Neck Road. Employees from farther south than Greenwich or from the southeast could reach HCGS by using a variety of state highways and secondary roads to access State Route 49. From State Route 49, these employees could reach HCGS 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 HCGS 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: EPA 2008a; NJDEP 2007b

[a] Population served may include more or less persons than previously specified within the geopolitical boundaries

MUA = Municipal Utility Authority

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

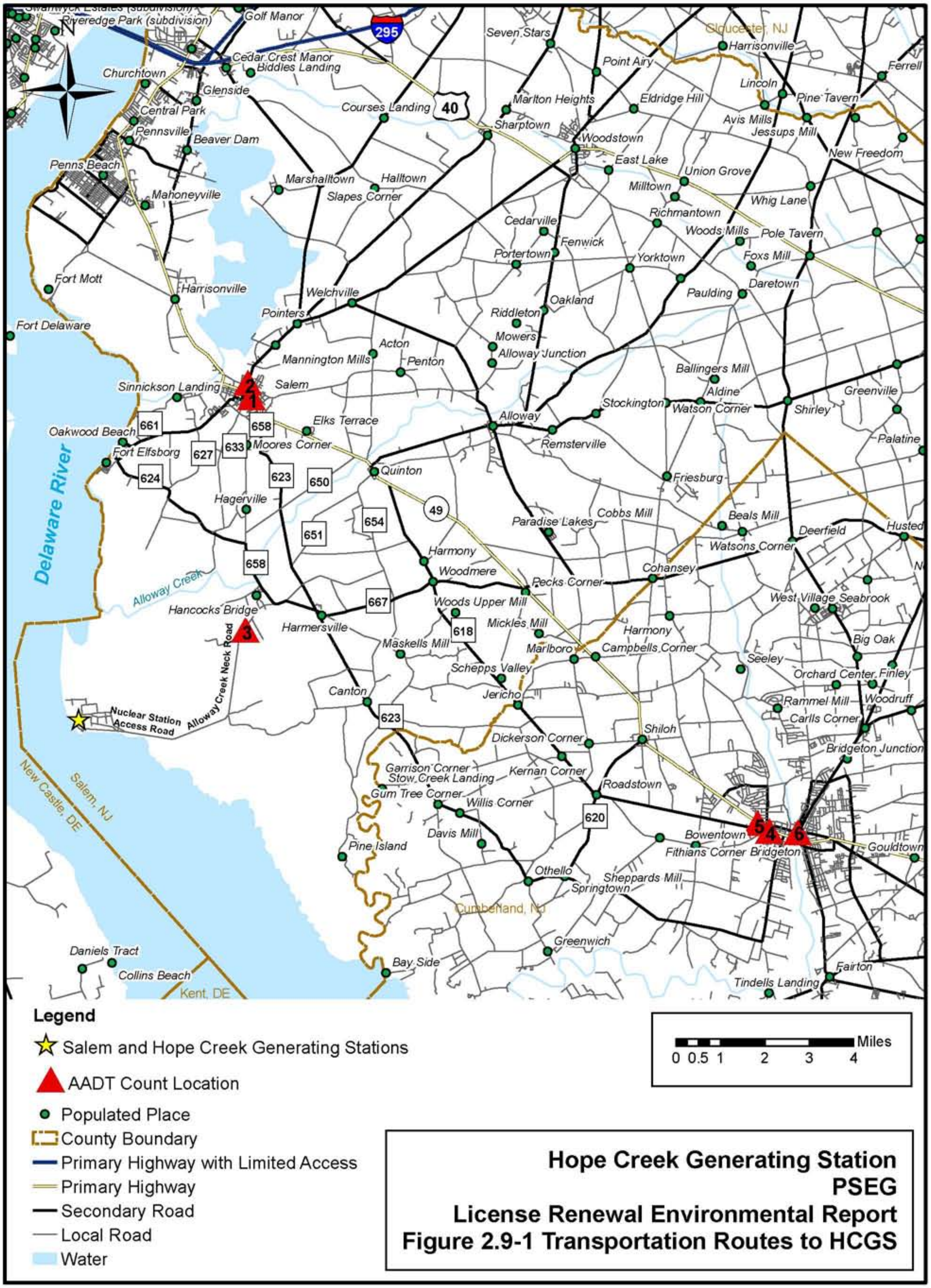
Water System Name	Population Served[a]	Primary Water Source Type	Average Daily Production (MGD)	Maximum Capacity (MGD)
Artesian Water Company, Inc.	6,483	Purchased surface water	NA	NA
City of Wilmington Water	140,000	Surface water	29	61
Tidewater Utilities, Inc.	30,000	Ground water	NA	NA
United Water 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 HCGS

	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.



Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 2.9-1 Transportation Routes to HCGS

2.10 Meteorology and Air Quality

HCGS 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 the most 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 the 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, the EPA significantly strengthened its national air quality standards for ground-level ozone. As the regulations require, NJDEP has provided recommendations to EPA regarding areas to be designated as attainment, non-attainment, or unclassifiable. (NJDEP 2009) The 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 HCGS, 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 HCGS 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 HCGS, and is the only Class I area located within 161 km (100 mi) of HCGS (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 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

HCGS 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 (1,500 acres) with an average elevation of three m (nine ft) above msl (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 (ten-mi) radius of the station (NRC 1984). 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, six locations in Salem County, New Jersey (NPS 2008a), and 17 locations in New Castle County, Delaware (NPS 2008b), fall within a ten-km (six-mi) radius of the HCGS (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 HCGS

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 HCGS 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	Two miles South of HCGS 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 HCGS, 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 HCGS

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

2.12.2 ELECTRIC CAPACITY IN THE IMMEDIATE VICINITY OF HCGS

2.12.2.1 Salem Nuclear Generating Station

The Salem Nuclear Generating Station and HCGS are co-located on Artificial Island. Salem is a two-unit plant utilizing pressurized water reactors (PWRs) designed by Westinghouse Electric. Each unit has a current licensed thermal power at 100 percent power of 3,459 MWt (PSEG 2009c). An air-cooled combustion turbine peaking unit rated at approximately 40 MWe (referred to as "Salem Unit 3") is also present.

Salem has a once-through circulating water system (CWS) for condenser cooling that withdraws water from and discharges water to the Delaware Estuary. The intake structure for the CWS is on the south shore of Artificial Island and the Salem Service Water System (SWS) has an independent intake structure located upstream of the CWS intake. Discharge for both systems is through a submerged pipe that extends 152 m (500 ft) into the estuary approximately halfway between the SWS and CWS intakes. Each unit's CWS pumps approximately 3.97 million liters (1.05 million gallons) per minute from the river.

PSEG has a current NJPDES (No. NJ0005622) permit for Salem that limits intake flow from the Delaware Estuary to a 30-day average of 11.5 billion liters (3.0 billion gallons) per day of circulating water (NJDEP 2004).

PSEG is authorized by the Delaware River Basin Commission (DRBC) to withdraw surface water from the Delaware Estuary through the Salem CWS and SWS intakes 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 2001)

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 HCGS and Salem 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 HCGS and Salem, 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 2008c). 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).

This Page Intentionally Left Blank

Chapter 3

The Proposed Action

This Page Intentionally Left Blank

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 term of the operating license for HCGS 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 HCGS 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 HCGS is available in several documents. In 1984, the NRC issued the Final Environmental Statement (FES) related to operation of HCGS (NRC 1984). The Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS; NRC 1996b) describes HCGS features. Finally, in accordance with NRC requirements, PSEG routinely revises the Updated Final Safety Analysis Report (UFSAR) for HCGS to reflect current plant design and operating features (PSEG 2009b). PSEG has referred to each of these and additional documents while preparing the 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 HCGS site are shown in Figure 3.1-2. Major buildings include the following:

- Unit 1 reactor building which houses the nuclear steam supply system including the reactor, reactor coolant pumps, and related equipment;
- The turbine/administration building;
- The cooling tower;
- The adjacent Salem Nuclear Generating Station (Salem); and
- Other structures and facilities of interest such as the service water intake structure, discharge structure, switchyard, the Independent Spent Fuel Storage Installation (ISFSI), the low-level radioactive waste interim storage building, and the nuclear department administration building.

3.1.1 REACTOR AND CONTAINMENT SYSTEMS

HCGS is a one-unit plant utilizing a boiling water reactor (BWR) designed by General Electric. Bechtel was the original plant builder and architect-engineer. The license for fuel loading and low-power testing was issued on April 11, 1986. Following fuel loading and a period of testing the NRC issued the Facility Operating License, NPF-57, authorizing full commercial operation, which began December 20, 1986. The original licensed core power for HCGS was 3,293 MWt (PSEG 2009b). HCGS underwent a 1.4 percent (46 MWt) measurement uncertainty recapture uprate in 2001 and a 15 percent (501 MWt) extended power uprate in 2008 (NRC 2008a, NRC 2008b). HCGS's current licensed thermal power is 3,840 MWt (PSEG 2009b). At 100 percent reactor power, the electrical output is estimated to be approximately 1,265 MWe (NRC 2008b).

The nuclear steam supply system includes a boiling water reactor (BWR), reactor coolant system (RCS), and associated auxiliary fluid systems. The RCS consists of the two reactor recirculation pump loops external to the reactor vessel. Each external loop contains one recirculation pump and two motor-operated gate valves for pump maintenance. Each loop also contains a flow measuring system. (PSEG 2009b)

Auxiliary systems 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 2009b)

The reactor building houses the reactor, the primary containment, and fuel handling and storage areas. The primary containment is a steel shell, shaped like a light bulb, enclosed in reinforced concrete, and interconnected to a torus-type steel suppression chamber. The reactor building is capable of containing any radioactive materials that might be released due to a loss-of-coolant accident. (PSEG 2009b)

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

HCGS is licensed for low-enriched uranium-dioxide fuel with enrichments to a nominal 5.0 percent by weight uranium-235 and an allowable fuel burn-up of 60,000 megawatt-days per metric ton uranium (NRC 2008b). The uranium-dioxide fuel is in the form of high-density ceramic pellets. Fuel rods used in the reactors consist of Zircaloy-based tubing with fuel pellets stacked inside and sealed with a welded end plug (PSEG 2009b).

The HCGS spent fuel pool facility provides storage space for the spent fuel assemblies. The pool is designed to store up to 3,976 fuel assemblies (PSEG 2009b).

The NRC issued a general license to PSEG authorizing an Independent Spent Fuel Storage Installation (ISFSI) at the HCGS 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 HCGS 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 complete offload capability is lost (NRC 2004).

3.1.3 COOLING AND AUXILIARY WATER SYSTEMS

HCGS has a closed cycle circulating water system for condenser cooling that consists of a natural draft cooling tower and associated withdrawal, circulation, and discharge facilities. HCGS withdraws brackish water with the Service Water System (SWS) from the Delaware

Estuary through an intake structure. Service Water provides cooling to Reactor Auxiliaries Cooling System, Safety Auxiliaries Cooling System, and other heat exchangers, and is discharged to the cooling tower basin to serve as condenser cooling water makeup to replace the water lost through evaporation and cooling tower blowdown. Cooling tower blowdown and other station effluents are discharged into the Delaware Estuary through an underwater conduit located 458 m (1,500 ft) upriver of the SWS intake (PSEG 1983). Onsite ground-water wells provide fresh water for domestic/potable, industrial, and fire protection needs. The following subsections describe the water systems at HCGS.

3.1.3.1 Surface Water

PSEG has a current NJPDES permit from the New Jersey Department of Environmental Protection for HCGS (No. NJ0025411; NJDEP 2003). The NJPDES permit authorizes the use of surface water and the discharge of effluents within the terms and conditions specified in the permit. The SWS withdraws an average of 253 million liters per day (66.8 million gallons per day [MGD]) from the Delaware Estuary. Approximately 25 million liters per day (6.7 MGD) are immediately returned as screen and strainer backwash, 49 million liters per day (13 MGD) are evaporated in the cooling tower process, and the remainder is returned to the Delaware Estuary in accordance with the NJPDES permit.

PSEG is authorized by the DRBC for consumptive use by HCGS of brackish water from the Delaware Estuary (DRBC 1984a, DRBC 1984b). This authorization includes provisions allowing for compensatory releases from storage or reduction in withdrawal from PSEG facilities on the Delaware River in specified low-flow conditions at Trenton. The Merrill Creek reservoir in Washington, New Jersey, stores water that can be used to make up for evaporative water loss from certain electric generating facilities on the Delaware River. PSEG is a member of the Merrill Creek Owners Group.

Service Water System

The SWS withdraws brackish water from the Delaware Estuary through an intake structure. After use in the SWS, the water is used as make-up for the cooling water system (CWS). The intake structure, which has eight intake bays, is parallel to the Delaware Estuary shoreline (Figure 3.1-1). Only four of the bays are equipped with service water pumps and associated equipment. The four empty bays were originally intended to supply service water to a second reactor, which was never constructed. The intake system has trash racks, Ristroph traveling screens, and a fish-return system. (NJDEP 2002)

The trash racks extend 4 m (13 ft) in front of the intake; river currents sweep the face of the intake structure, and the trash racks, which are set on 7.6-cm (3-in) centers, prevent heavy debris from entering the intake and damaging the traveling screens. Mechanical rakes remove collected debris, which is aggregated in trash containers for off-site disposal. The intake velocity at the trash racks is about 0.03 m/sec (0.1 ft/sec). (NJDEP 2002)

Behind the trash racks is a skimmer wall that prevents the entrance of oil slicks or surface ice. Intake water flows under the skimmer wall at a maximum velocity of approximately 0.11 m/sec (0.35 ft/sec), into four bays, each 3.4 m high by 2.9 m wide (11 ft high by 9.5 ft wide). The water then flows through a traveling screen, at a maximum velocity of approximately 0.12 m/sec (0.39 ft/sec). The traveling screens have a bucket on the lower lip designed to prevent re-impingement of fish on the screen and provide the mechanism to return the fish to the river. The buckets allow organisms to remain in the water while being lifted to fish return troughs.

Organisms are washed into the fish-return trough with a low-pressure screen spray. As the screen moves further along the sprocket, high-pressure spray washes debris into the debris trough. The fish and debris troughs return water, fish, and debris to the Delaware Estuary south of the SWS intake structure. (NJDEP 2002)

After passing through the traveling screens, the estuary water enters the service water pumps. During normal operation, two or three station service water pumps, depending on the temperature of the Delaware Estuary, are required. The four service water pumps are each rated at 62,459 liters per minute (16,500 gallons per minute [gpm]) (NJDEP 2002). Sodium hypochlorite is continuously added at the suction of the service water pumps as a biocide to prevent fouling (NJDEP 2002).

Circulating Water System

Once the water exits the service water system it is sent to the cooling tower basin for use as make-up water for the CWS. The circulating water system (CWS) consists of one natural draft cooling tower with make-up, blowdown, and basin bypass systems; the four circulating water pumps; a two-pass surface condenser; and a closed loop circulating water piping arrangement. The cooling tower basin contains approximately 34 million liters (9 million gallons) of water. The CWS provides approximately 2.317 million liters per minute (612,000 gpm) from the cooling tower basin by means of four pumps (NJDEP 2002). The CWS pumps supply cooling water to the main condenser to condense steam from the turbine, and return this condenser cooling water back to the cooling tower for removal of heat and recirculation. In normal operation, all four circulating water pumps continuously operate. At least two pumps must operate to sustain electric power production (PSEG 1983).

The main condenser is a double-pass, three-shell, horizontal, de-aerating type surface condenser. Each shell has two tube bundles, two inlet-outlet boxes, and two reversing-end water boxes. From the condenser, the water returns to the cooling tower to complete the cooling cycle (PSEG 1983).

A single counterflow, hyperbolic, natural draft cooling tower dissipates the heat from the circulating water system. Continuous blowdown controls the build-up of solids in the cooling tower basin (NJDEP 2002). 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. Monthly average evaporative losses in the cooling tower consume between 36,340 liters per minute (9,600 gpm; January) and 49,210 liters per minute (13,000 gpm; July). Sodium hydroxide is added to the circulating water system to minimize scaling. Sodium hypochlorite is used to prevent biofouling in the cooling tower, and cooling tower blowdown is dechlorinated with ammonium bisulfate prior to discharge (NJDEP 2002).

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 HCGS and Salem sites combined. The discussion of ground water in this section includes use at both the HCGS and Salem sites for the following reasons.

- NJDEP issued a single permit for both sites combined. Although each site uses separate 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 HCGS and Salem 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 withdrawal systems for HCGS and Salem are interconnected in order to transfer water between the stations, if needed.

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

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. 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 (PSEG 2009c). The Demineralized Water Makeup system uses ion-exchange resin to provide the ultrapure water required.

Ground water at Salem is primarily withdrawn 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 m (293 ft), respectively, in the Mt Laurel-Wenonah 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, 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.

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 HCGS and Salem 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 HCGS/Salem wells, as indicated in Table 3.1-3. Of the four primary HCGS/Salem 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 three 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 groundwater 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 during the period 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).

Groundwater 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 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 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 groundwater 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 on 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 plant-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 criteria contained in 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 2008a).

3.1.4 RADIOACTIVEWASTE MANAGEMENT SYSTEMS

3.1.4.1 Liquid Radioactive Waste Systems

The Liquid Waste Management System (LWMS) is designed to collect, store, process, and dispose of or recycle all radioactive or potentially radioactive liquid waste generated by plant operation or maintenance. The LWMS consists of five process subsystems, each for collecting, storing, processing, monitoring, and disposing of specific types of liquid wastes in accordance with their conductivity, chemical composition, and radioactivity (PSEG 2009b). These subsystems are:

- Equipment drain (high-purity waste)
- Floor drain (low-purity waste)
- Regenerant waste (high-conductivity waste)
- Chemical waste (decontamination solution waste and chemistry lab drains)
- Detergent drain waste (laundry waste and personnel decontamination drains)

Sufficient treatment capability is available to process certain liquid waste to meet demineralized water quality requirements. Liquid wastes that cannot be processed to meet the quality requirement for use as demineralized water are released into the cooling tower blowdown line for discharge to the Delaware Estuary at a permitted outfall. The releases are controlled and monitored to ensure that regulatory limits on the radioactivity discharged to the environment are not exceeded (PSEG 2009b).

Potentially radioactive liquid wastes are collected in tanks in the Auxiliary Building. System components are segregated in shielded enclosures with controlled access to minimize exposure to plant personnel. During liquid waste processing, radioactive contaminants are removed from the wastewater, either by demineralization or filtration. This ensures that the water returned to the condensate storage tank (CST) is restored to demineralized-water quality, and any other water is discharged to the environment via the cooling tower blowdown line through a permitted outfall. If the liquid is recycled to the plant, it meets the purity requirements for CST makeup. If the liquid is discharged to the environment, the activity concentration is consistent with the radiation exposure standards in 10 CFR 20. The radioactivity removed from the liquid wastes is concentrated in the filter media and ion exchange resins, which are managed as solid radioactive wastes.

3.1.4.2 Gaseous Radioactive Waste Systems

The Gaseous Waste Management Systems (GWMS) include all systems that process potential sources of airborne releases of radioactive materials during normal operation and anticipated operational occurrences. Included are the Off-gas System and various ventilation systems. These reduce radioactive gaseous releases from the plant by filtration or delay, which allows decay of radioisotopes prior to release (PSEG 2009b).

The function of the Off-gas System is to collect and delay the release of non-condensable radioactive gases removed from the main condenser. Off-gases consist of activation gases, fission product gases, radiolytic hydrogen and oxygen, and condenser air in-leakage. The Off-gas System uses a catalytic recombiner and a cooler condenser for control of hydrogen concentration and volume reduction, respectively. The remaining non-condensable gas (principally air with traces of krypton and xenon) is delayed in a series of eight, 61-cm-(24-in)-diameter, 17-m-(55-ft)-long holdup pipes. At a flow rate of 75 standard cubic feet per minute (scfm), these pipes provide a minimum of ten minutes of delay for off-gas prior to entering the ambient charcoal treatment section. Selective adsorption of fission-product noble gases (xenon and krypton) on charcoal is used to provide time for delay before release (PSEG 2009b). The off-gas stream then passes through a high efficiency particulate air (HEPA) filter where radioactive particulate matter and any charcoal particles are retained. The off-gas stream is directed to the north plant vent where it is combined with air from the Solid Radioactive Waste System exhaust and chemical lab exhaust before being released (PSEG 2009b).

Plant ventilation systems process airborne radioactive releases from other plant sources, such as equipment leakage, maintenance activities, the mechanical vacuum pump, and the Steam Seal System. (PSEG 2009b)

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 2009b)

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 2009b). 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 2009b)

The LLRSF is intended to serve as an interim storage facility for HCGS and Salem 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 HCGS and Salem over a five-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 2009b)

PSEG expects Barnwell and the LLRSF will provide adequate low-level radioactive waste management capacity through the HCGS license renewal term.

HCGS currently does not have processes that result in the generation of mixed waste (i.e., waste having both a hazardous waste 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 waste generated at HCGS 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 HCGS.

3.1.5 NON-RADIOACTIVE WASTE MANAGEMENT SYSTEMS

A common sewage treatment system located at HCGS and operated by HCGS staff treats domestic wastewater from both HCGS and Salem. 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 HCGS and Salem 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 2007b)

At HCGS, the low-volume and oily waste system collects and treats potentially oily wastewater from area, building, and equipment drains throughout the site. Collected waste streams are processed through an API-type oil water separator for removal of solid and floatable materials. Treated effluent is then discharged through the internal monitoring point which is combined with cooling tower blowdown before discharge to the Delaware Estuary.

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 (NRC 1984) for HCGS identifies three 500-kV transmission lines needed to deliver electricity generated by HCGS to the transmission system. One 0.8-km (0.5-mi) onsite tie line was built to connect HCGS with Salem. Two lines previously connected to Salem (Salem-New Freedom North and Salem-Keeney) were re-routed to the HCGS switchyard.

After construction of HCGS, 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 referred to as the HCGS-New Freedom transmission line. Another transmission line that preexisted HCGS, called the Salem-New Freedom South line, also connects Salem to the New Freedom substation. The Salem-New Freedom North, Salem-New Freedom South, and Salem-Keeney lines were not constructed to connect HCGS to the grid. The only new transmission lines constructed as a result of the HCGS are the HCGS-New Freedom line, the tie line, and short reconnections for Salem-New Freedom North and Salem-Keeney. The HCGS-Salem tie line and the short reconnections do not pass beyond the site boundary and, therefore, are not evaluated in this Environmental Report. Nevertheless, for completeness, all lines are described below.

- *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.

- *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 six km (four 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-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.

The HCGS-New Freedom line is the only offsite transmission line constructed at the time HCGS was constructed; therefore, it is the only line analyzed in this Environmental Report. In total, the transmission line is 69 km (43 mi) long occupying about 738.5 hectares (1,825 acres) of transmission corridor. This corridor passes through the marshes and wetlands north and east of HCGS then crosses land that is primarily agricultural or forested. Corridors that pass through pastures generally continue to be used as pastures. This line also passes through or near residential and urban areas with low population densities. It crosses several roadways including state highway 55, U.S. highway 40, and the Atlantic City Expressway.

PSE&G owns and operates the HCGS-New Freedom transmission line, which connects 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. This transmission line would remain under PSE&G ownership and would stay in service if the HCGS operating license was not renewed and the unit was decommissioned.

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

Table 3.1-1 Salem and HCGS 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	47.56	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

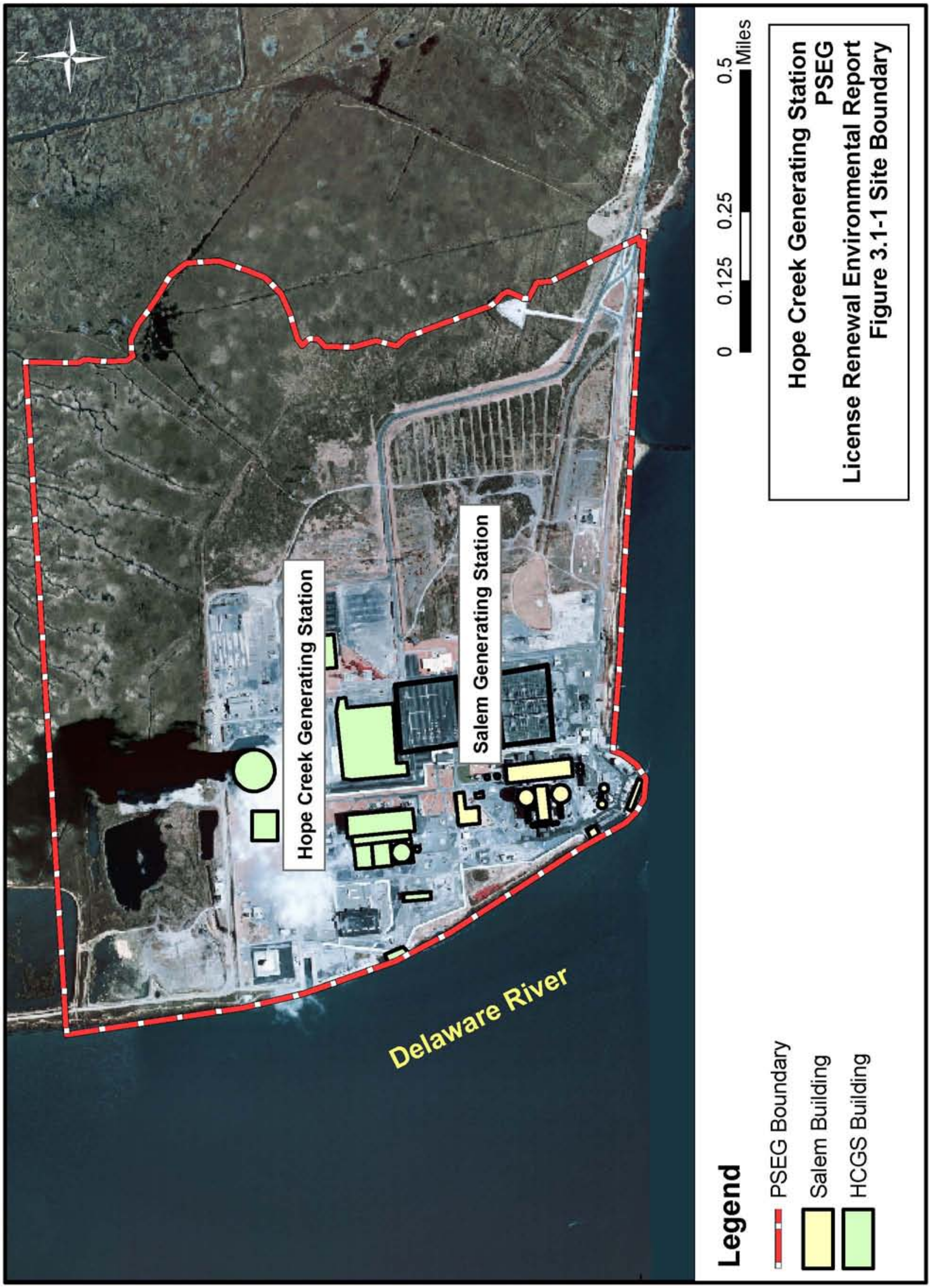
Table 3.1-3 Ground-Water Elevation Data Range (in feet) for Salem and HCGS Ground-Water Wells, 2000 – 2008. (The aquifer range includes data from all production wells monitored in that aquifer.)

	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

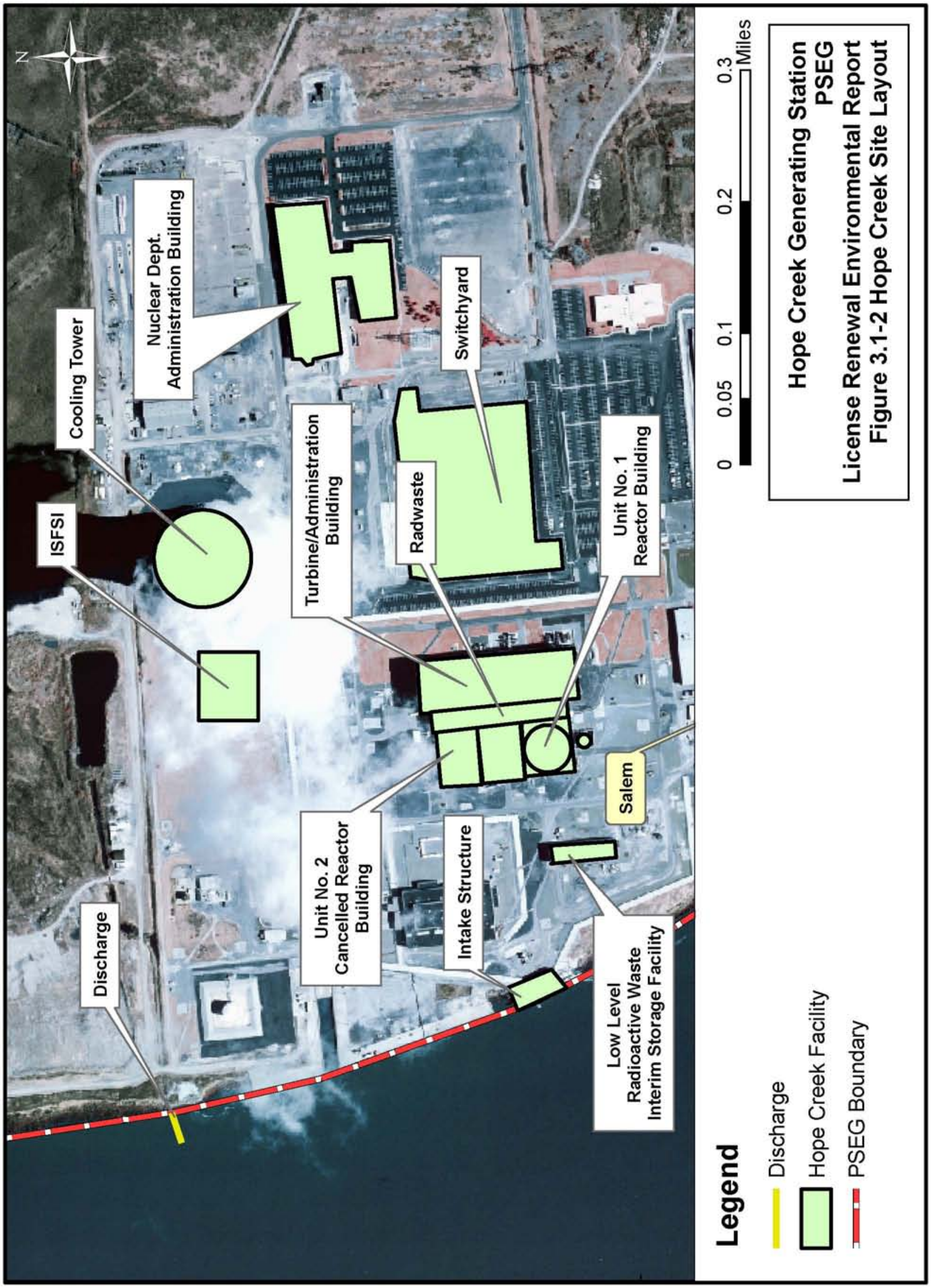
Source: TetraTech 2009

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

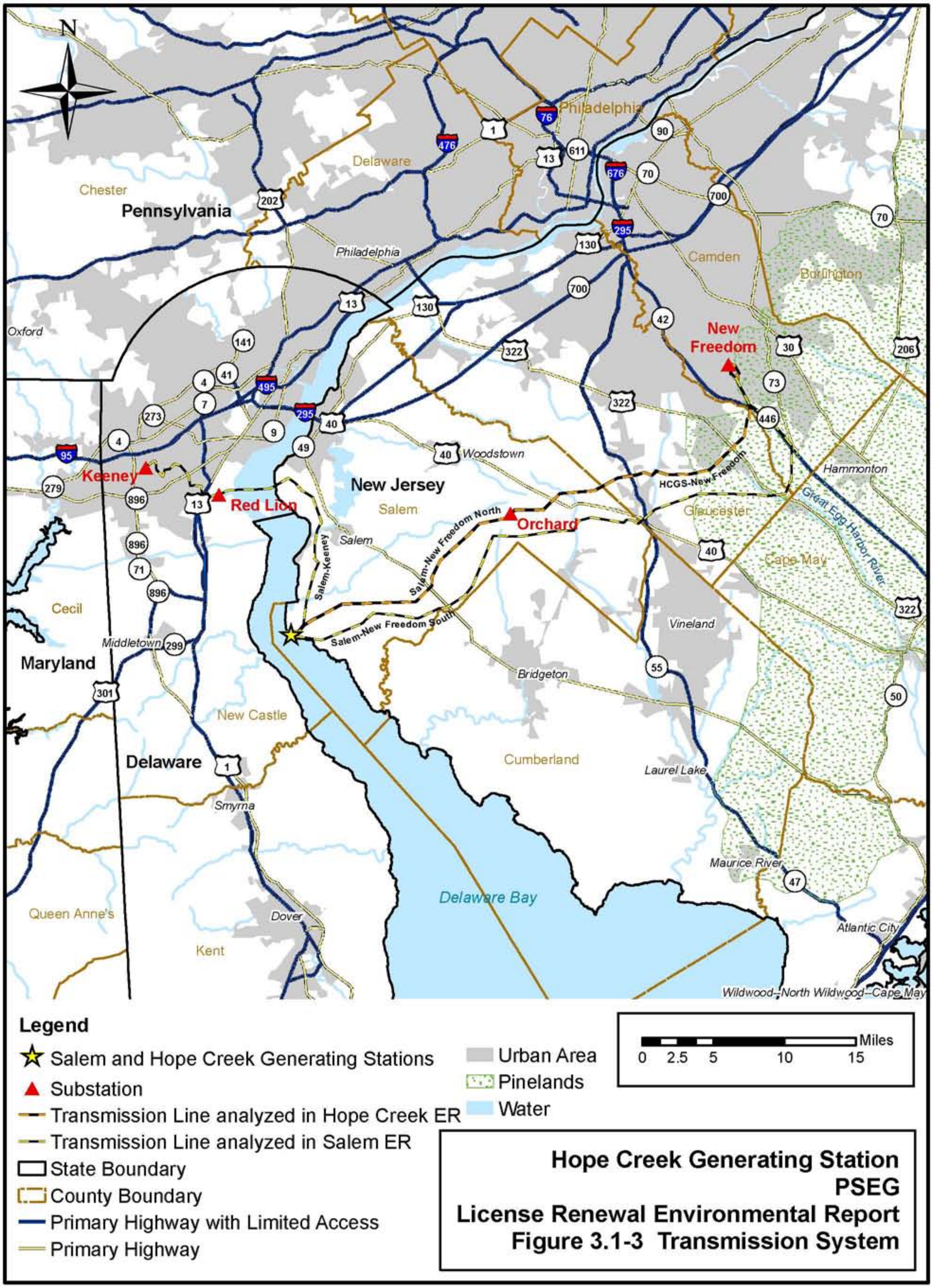
Present Name	Built during construction of	Segments	Presently Connected to	Analyzed in LR report for
Salem-New Freedom South	Salem	None	Salem	Salem
Salem-New Freedom North	Salem	None	HCGS	Salem
Salem-Keeney	Salem	HCGS to Red Lion, Red Lion to Keeney	HCGS	Salem
HCGS-New Freedom	HCGS	Salem to Orchard; Orchard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



Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 3.1-1 Site Boundary

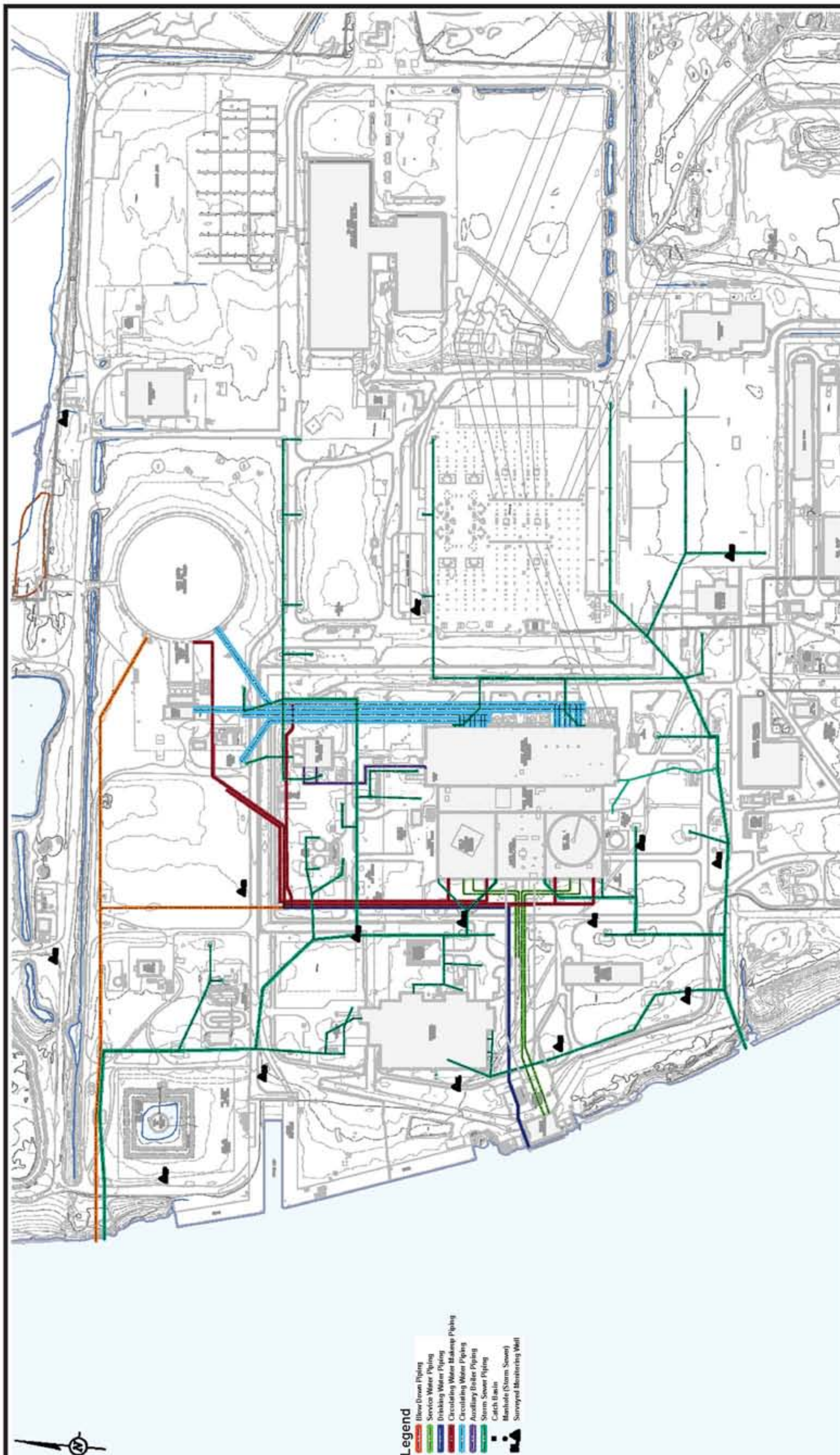


Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 3.1-2 Hope Creek Site Layout



Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 3.1-3 Transmission System

Hope Creek Generating Station
PSEG
License Renewal Environmental Report
Figure 3.1-4 Salem RGPP Wells



Hope Creek 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…" 10 CFR 51.53 (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 HCGS. 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 HCGS 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 HCGS renewed license period. PSEG has included the IPA as Section 2 of this HCGS 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 HCGS. These programs are described in the Hope Creek 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 HCGS administrative control procedures associated with license renewal.

3.4 Employment

3.4.1 CURRENT WORK FORCE

HCGS currently employs a workforce of approximately 513 regular, full-time employees and shares up to an additional 270 PSEG corporate and 86 matrixed employees with Salem. To ensure conservatism, the analyses in this Environmental Report include the total complement of corporate and matrixed employees as part of the HCGS workforce. Approximately 81 percent of the employees live in Cumberland, Gloucester, and Salem counties, New Jersey, and New Castle County, Delaware. Addresses for permanent residences of the remaining employees are distributed across 27 counties in Connecticut, Florida, Indiana, Maryland, New Jersey, New York, Ohio, Pennsylvania, South Carolina, Virginia, and Wisconsin with numbers ranging from one to 40 employees per county. Less than three percent of the workforce has permanent residences located outside of New Jersey, Pennsylvania, or Delaware (see Table 2.6-2).

HCGS 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 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 HCGS 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 ten 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 five- and ten-year in-service inspection and refueling outages. (NRC 1996b)

PSEG has determined that the GEIS scheduling assumptions are reasonably representative of HCGS incremental license-renewal, workload scheduling. Many HCGS license-renewal SMITTR activities would have to be performed during outages. Although some HCGS 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 three-month duration of a ten-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 HCGS staff. However, for purposes of analysis in this Environmental Report, PSEG conservatively assumes that HCGS 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 plant work force for the period of extended operation creates 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.

Chapter 4

Environmental Consequences of the Proposed Action and Mitigating Actions

This Page Intentionally Left Blank

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 HCGS operating license. 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); and
- 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 8 of the 69 Category 1 issues do not apply to HCGS because they are specific to design or operational features that are not found at the facility. Because HCGS 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 HCGS, 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 HCGS. 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. Twelve Category 2 issues apply to operational features that HCGS does not have or to an activity, refurbishment, which HCGS is not planning to undertake. If the issue does not apply to HCGS, the section explains the basis for inapplicability.

For the nine Category 2 issues that PSEG has determined to be applicable to HCGS, 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 HCGS 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 HCGS uses a cooling tower and withdraws from and discharges to an estuary (NRC 1996b; Table 5.13). Therefore, this issue does not apply because HCGS does not use cooling ponds or withdraw cooling tower makeup 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). 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.

NJDEP has determined that the location, design, construction, and capacity of HCGS's cooling water system is the best technology available. This technology significantly minimizes the potential mortality of aquatic life typically associated with cooling water intake structures, namely impingement and entrainment, as CWA Section 316(b) requires. This minimization of mortality is primarily due to the lesser amount of intake flow of closed-cycle cooling systems as compared to once-through cooling systems. (NJDEP 2002)

The issue of entrainment of fish and shellfish in early life stages does not apply to HCGS because the plant does not use once-through cooling or cooling pond heat dissipation systems. As described in Section 3.1.2, HCGS uses a closed-cycle cooling system with a cooling tower that withdraws make-up water from the Delaware Estuary and discharges blowdown to the Delaware Estuary. Appendix B provides the current NJPDES permit for HCGS.

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 impacts of impingement are small at many plants, but they may be moderate or large at others (NRC 1996b). 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.

NJDEP has determined that the location, design, construction, and capacity of HCGS's cooling water system is the best technology available. Ristroph screens and very low velocities at the intake significantly minimize the potential mortality of aquatic life typically associated with cooling water intake structures, namely impingement and entrainment, as CWA Section 316(b) requires. This minimization of mortality is primarily due to the lesser amount of intake flow of closed-cycle cooling systems as compared to once-through cooling systems. (NJDEP 2002)

HCGS does not use once-through cooling or cooling pond heat dissipation systems. Therefore, the issue of impingement does not apply. As described in Section 3.1.2, HCGS uses a closed-cycle cooling system with a cooling tower that withdraws make-up water from the Delaware Estuary and discharges blowdown to the Delaware Estuary. Appendix B provides the current NJPDES permit for HCGS.

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.

HCGS uses a cooling tower. Therefore, this issue does not apply because HCGS does not use once-through cooling or cooling pond heat dissipation systems. Appendix B provides the current NJPDES permit for HCGS.

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 ground water per minute, an assessment of the impact of the proposed action on ground water use must be provided." 10 CFR 51.53(c)(3)(ii)(C)**
>
> **"Plants that use more than 100 gpm may cause ground water use conflicts with nearby ground water 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. This could deplete the ground-water supply available to offsite users, an impact that could warrant mitigation. Information to be ascertained includes: (1) HCGS 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, HCGS used average rates of 518 to 749 liter per minute (137 to 198 gpm) of ground water from the two facility wells during the period from 2002 through 2008. Therefore, the issue of ground-water use conflicts does apply at HCGS 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 HCGS during 2002 through 2008. Table 3.1-3 presents water level elevation data for production wells at HCGS during 2000 through 2008.

Ground-water use in the Upper Raritan Formation has not been adversely impacted by HCGS withdrawals because, as Section 2.3 indicates, there are no off-site wells within 1.6 km (1 mi) of the HCGS 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 HCGS and Salem. 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 ground water 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 HCGS surface water withdrawals and discharges are from and to a brackish estuary (NRC 1996b; Table 5.13). Therefore, this issue does not apply because HCGS does not use cooling tower technology that withdraws makeup 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 ground water 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.

As Section 3.1 describes, HCGS withdraws its service water, which is also used for cooling tower makeup water, from surface water. Ground water is only withdrawn for potable and other uses. Therefore, this issue does not apply because HCGS 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 ground water 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.

HCGS 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 HCGS. 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 or 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 plant operations through the renewal period. In addition, compliance with the Endangered Species Act requires consultation with the appropriate federal agency (NRC 1996b, Sections 3.9 and 4.1).

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

As discussed in Section 3.2, no refurbishment activities at HCGS 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 HCGS or along its associated transmission corridor. Except for the potential impacts to aquatic species described below, current operations of HCGS are not believed to affect any listed terrestrial or aquatic species or their habitats. Similarly, PSE&G vegetation management practices along the transmission corridor 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.

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). That biological opinion, considering both Salem and HCGS, noted that no threatened or endangered sea turtle or turtles takes had been documented at HCGS, and that no additional measures were required at HCGS to protect sea turtles. It was silent on the impact of HCGS on shortnose sturgeon. The 1993 incidental take statement was reviewed and revised in 1999 (NMFS 1999b). The 1999 revised incidental take statement does not mention or modify prior NMFS findings regarding HCGS. No turtle takes have been documented at HCGS since 1999. Also, HCGS has appropriate controls in place at the service water system intake for managing the impacts of short-nosed sturgeon impingement. These controls have been reviewed by NMFS, as discussed above.

One plant species federally listed as threatened is known from one corridor not associated with HCGS. 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 line associated with HCGS (see Section 2.5). PSE&G and PHI work cooperatively with state regulatory agencies, including the New Jersey Pinelands Commission, to ensure 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, the USFWS, and NMFS requesting information on any listed species or critical habitats that might occur on the HCGS 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 HCGS license 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 HCGS. 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 HCGS discharges to an estuary (NRC 1996b; Table 5.13). As discussed in Section 3.1.2, HCGS has a cooling tower that uses brackish water from an estuary and discharges to the same estuary. Water flow rate in the estuary is discussed in Section 2.2. HCGS 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 HCGS transmission line's in 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 field. This charge results in a current that flows through the object to the ground. The current is called "induced" because there is no direct connection between the line and the object. The induced current can also flow to the ground through the body of a person who touches the object. An object that is insulated from the ground can actually store an electrical charge, becoming what is called "capacitively charged." A person standing on the ground and touching a vehicle or a fence receives an electrical shock due to the sudden discharge of the capacitive charge through the person's body to the ground. After the initial discharge, a steady-state current can develop, the magnitude of which depends on several factors, including the following:

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

In 1977, 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.

HCGS Transmission Lines

As described in Section 3.1.6, there is one 500-kilovolt line that was constructed to connect HCGS to the transmission system. This line is the following:

- HCGS-New Freedom (via Orchard substation)

In addition, two lines originally built for Salem have since been connected to HCGS. Although not part of this report's scope of analysis, results from the analysis in the Salem license renewal Environmental Report (PSEG 2009a) for these lines are provided in Table 4.13-1:

- Salem-New Freedom North

- Salem-Keeney (via Red Lion substation)

For completeness, the results from the analysis described in the Salem license renewal Environmental Report (PSEG 2009a) for the fourth transmission line associated with the Salem, Salem-New Freedom South, are also included in Table 4.13-1.

Induced Current Analysis

This analysis of the HCGS 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 a computer code called 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 the 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 induced current of 4.0 milliamperes (on HCGS-New Freedom line) (Table 4.13-1).

PSE&G, owner and operator of the transmission line, conducts 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 for 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 HCGS transmission line because the NESC standard is not exceeded at any location.

Table 4.13-1 Maximum Induced Current from HCGS and Salem 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 is the only line constructed to connect HCGS to the electric grid, and therefore the only line analyzed in this Environmental Report. The other lines are analyzed in the Salem Environmental Report (PSEG 2009a).

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 HCGS during the period of extended operation.

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 60 direct jobs would be filled by in-migrating residents and any indirect jobs created by 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, HCGS is located in a high population area and 81 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 tax revenues from HCGS, 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 HCGS 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 2000), 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 HCGS 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 plant 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 systems' available capacity.

NRC's analysis of impacts to public water supply systems 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 off-site public water system, there are no off-site 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 resources or private potable water wells. As discussed in Section 3.2, PSEG plans no refurbishment activities fort HCGS. Therefore, there also would be no refurbishment-related impacts on local public water supply 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 HCGS during the period of extended operation. As Section 3.4 indicates, PSEG analyzed a hypothetical 60-person increase in HCGS employment attributable to license renewal. Section 2.6 describes the HCGS 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 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 54,805 liters per day (14,490 gpd) (161 persons x 341 liters per day [90 gpd] per person) would be geographically distributed, in the same manner as the existing HCGS 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 per day (34 million gallons) per day for Cumberland, Gloucester, and Salem counties (Table 2.9-1) and more than 132 million liters (35 million gallons) per day for New Castle County (Table 2.9-2). Any increase in demand resulting from renewal of the HCGS operating license would not create shortages in capacity for 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 HCGS. 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 (2.6 km^2), and at least one urban area with a population of 100,000 or more within 80 km (50 miles)…." (NRC 1996b, Section 3.7.5, pg. 3-21)

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 HCGS. 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).

Population-Related Impacts

Based on the GEIS case-study analysis, NRC concluded that all new population-driven land-use changes during the license-renewal term at all nuclear plants would be SMALL. Population growth caused by license renewal would represent a much smaller percentage of the local area's total population than the percent change resulting from the initial population growth that occurred at the start of operations (NRC 1996b).

Tax-Revenue-Related Impacts

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

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 HCGS 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 or more 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 recently updated their 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 HCGS's tax basis and, consequently, no changes to land use based on renewal of the license.

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 Township'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 is only a small portion of the City of Salem's total property tax revenues. With no new construction activities 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 HCGS. Therefore, PSEG anticipates neither an increase in the assessed value of HCGS due to refurbishment-related improvements, nor any related tax-increase-driven changes to offsite land-use and development patterns. HCGS 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 HCGS has not affected land-use patterns. The HCGS 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 HCGS on both tax revenues and land-use in Salem County would be SMALL.

Property Values

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 HCGS 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 HCGS because there are no residential properties within 3.2 km (2 mi) of HCGS. The area within 3.2 km (2 mi) of the HCGS 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 HCGS. Accordingly, the multiplier effect of the HCGS 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 HCGS, on property values. PSEG suspects that such an affect, if any, is outweighed by positive benefits beyond 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 HCGS, 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 HCGS would add 60 additional employees during the period of extended operations. PSEG's HCGS workforce includes 513 employees and shares up to an additional 270 PSEG corporate and 86 matrixed employees with Salem. 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 HCGS represents a 12 percent increase above the 513 regular, full-time employees assigned to HCGS; a smaller percentage of the total employees of HCGS and Salem, 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 HCGS (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 archaeological properties will be affected by the proposed project." 10 CFR 51.53(c)(3)(ii)(K)**
>
> **"Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 71**
>
> **"…Sites are considered to have small impacts to historic and archaeological resources if (1) the State Historic Preservation Officer (SHPO) identifies no significant resources on or near the site; or (2) the SHPO identifies (or has previously identified) significant historic resources but determines they would not be affected by plant refurbishment, transmission lines, and license-renewal-term operations and there are no complaints from the affected public about altered historic character; and (3) if the conditions associated with moderate impacts do not occur." (NRC 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 that 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. HCGS 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 corridor.

Currently, PSEG is not aware of any historic or archaeological resources that have been affected by HCGS operations. Properties within 10 km (6 mi) of HCGS 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 line 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 SHPO, PSEG has requested concurrence that operation of HCGS during the term of license renewal would have no effect on historic and archaeological resources. Copies of the correspondence are presented in Appendix D. PSEG concludes that continued operation of HCGS over the license renewal term would not impact historic or archaeological resources over the period of extended operation. 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 HCGS. 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 HCGS fuel into the reactor and from the reactor into the containment structure.

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 HCGS 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.

PSEG used industry, NRC, and HCGS-specific information to create a list of 23 SAMAs for consideration. PSEG analyzed this list to screen out any SAMAs that (1) would not apply to the HCGS design, (2) had already been implemented at HCGS, or (3) would achieve results that PSEG had already achieved at HCGS by other means. Two of the SAMAs were screened out based on these criteria. Therefore, PSEG prepared cost estimates for 21 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 13 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 HCGS Plant Health Committee processes.

4.21 Cumulative Impacts

PSEG considered the potential cumulative impacts of HCGS'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 HCGS is Salem. Salem is adjacent to HCGS on Artificial Island and uses Delaware Estuary water and ground water, as does HCGS. 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

4.21.1.1 Aquatic Resources

Section 2.2 describes the aquatic environment affected by Salem and Hope Creek. Section 3.1 describes HCGS water use. The water use at Salem is described in the Salem license renewal Environmental Report, Section 3.1 (PSEG 2009a). Appendix F in that report describes restoration projects in the Delaware Estuary that are a requirement of the Salem NJPDES permit, and their results.

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 (22,778 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 generation 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 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 1970, and the number of fish has increased). (PSEG 2006a).

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 HCGS and Salem has had no adverse environmental impact on the Delaware Estuary aquatic community.

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

4.21.1.2 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 HCGS and Salem operations is the Pinelands National Reserve, which preserves 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 Salem, 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 HCGS or Salem. Any development in the Pinelands National Preserve must be approved by the Commission. Cumulative impacts of HCGS and Salem 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 the 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 HCGS and Salem 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 of 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 HCGS and Salem operations, which previously have 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 HCGS and Salem 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 HCGS and Salem 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 discharge to 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 HCGS and Salem. Hence, the potential for enhancement of thermophilic organisms due to the cumulative impacts of HCGS and Salem, which previously has been SMALL, will remain SMALL throughout the license renewal term.

The electric-field induced currents from transmission lines constructed to connect HCGS and Salem 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)

HCGS and Salem 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.

Chapter 5

Assessment of New and Significant Information

5.1 Discussion

NRC

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

The 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 HCGS, (2) an extensive review of documents related to environmental issues at HCGS, (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 HCGS 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 HCGS, 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 at Salem, PSEG evaluated information about tritium in the ground water beneath the Salem site (Section 3.1.3). The information indicates that tritium remediation is in progress at Salem, HCGS is hydraulically upgradient of Salem, and the Radiological Groundwater Protection Program at HCGS has not identified any impacts on ground water at HCGS as a result of tritium released at Salem. Furthermore, tritium has not been detected in ground water beneath HCGS in any concentrations that exceed the EPA Drinking Water Standard or that suggest an adverse trend (PSEG 2008a), and there is no human exposure pathway for tritium in the vicinity of HCGS. Hence, PSEG has concluded that changes in tritium-related ground-water quality are not significant at HCGS and would not preclude current or future uses of the ground water.

In its entirety, PSEG's assessment did not identify any new and significant information regarding the HCGS environment or operations that would (1) make any generic conclusion codified by the NRC for Category 1 issues not applicable to HCGS, (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

6.1 License Renewal Impacts

PSEG has reviewed the environmental impacts of renewing the HCGS operating license 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 NRC findings for the 54 Category 1 issues that apply to HCGS, 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 the HCGS license renewal would have on resources associated with Category 2 issues. Because HCGS and Salem 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 HCGS Unit 1

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 HCGS does not 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	**NONE.** This issue does not apply because HCGS does not use a once-through cooling system or cooling ponds for heat dissipation.
26	Impingement of fish and shellfish	**NONE.** This issue does not apply because HCGS does not use a once-through cooling system or cooling ponds for heat dissipation.
27	Heat shock	**NONE.** This issue does not apply because HCGS does not use a once-through cooling system or cooling ponds for heat dissipation.
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 HCGS does not withdraw make-up water from a small river.
35	Ground-water use conflicts (Ranney wells)	**NONE.** This issue does not apply because HCGS does not use Ranney wells.
39	Ground-water quality degradation (cooling ponds at inland sites)	**NONE.** This issue does not apply because HCGS does not use cooling ponds.
Terrestrial Resources		
40	Refurbishment impacts	**NONE.** This issue does not apply because refurbishment is not planned for HCGS.
Threatened or Endangered Species		
49	Threatened or endangered species	**SMALL.** HCGS operations have no impact on threatened or endangered species or their habitats. NMFS has issued a biological opinion that operation of HCGS is not likely to jeopardize the continued existence of loggerhead, Kemp's ridley, and green sea turtles, or shortnose sturgeon. One federally threatened plant grows on a section of one transmission corridor in Salem County and two protected terrestrial animal species are known from the vicinity of the 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.

Table 6.1-1 Environmental Impacts Related to License Renewal at HCGS Unit 1 (Continued)

No.	Category 2 Issue	Environmental Impact
Air Quality		
50	Air quality during refurbishment (non-attainment and maintenance areas)	**NONE.** This issue does not apply because refurbishment is not planned for HCGS.
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 HCGS 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 one transmission line constructed to connect HCGS to the electric grid, modeling predicts induced currents of 4.0 millamperes or less, which is 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 two 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 public water supply.
66	Public services: education (refurbishment)	**NONE.** This issue does not apply because refurbishment is not planned for HCGS.
68	Off-site land use (refurbishment)	**NONE.** This issue does not apply because refurbishment is not planned for HCGS.
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 HCGS 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. HCGS taxes comprise less than two percent of Salem County tax revenues. Taxes on the Energy and Environmental Resources Center are less than three 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.** HCGS 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 corridor associated with HCGS, and construction is not planned on-site or in the transmission corridor during the license renewal terms. Hence, no impacts to historic or archaeological resources are expected.

Table 6.1-1 Environmental Impacts Related to License Renewal at HCGS Unit 1 (Continued)

No.	Category 2 Issue	Environmental Impact
Postulated Accidents		
76	Severe accidents	**SMALL.** PSEG identified 13 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 HCGS 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.

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, and the NJPDES permit effluent monitoring. These monitoring programs ensure that the plant's permitted emissions and discharges are within regulatory limits and any unusual or off-normal emissions/discharges would be quickly detected, allowing for the mitigation of potential impacts.

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 HCGS 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 HCGS also creates a very low probability of accidental radiation exposure to inhabitants of the area.

- Operations of HCGS 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 HCGS and Salem combined) and is required to maintain discharges at or below NJPDES permit requirements.

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 HCGS 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 activities;
- 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 HCGS site was established with the decision to convert approximately 62 hectares (153 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. 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 738.5 hectares (1,825 acres) in 60 km (43 mi) of transmission corridor are associated with the HCGS project.

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

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

Experience with other experimental, developmental, and commercial nuclear plants has demonstrated the feasibility of decommissioning and dismantling such plants sufficiently to restore a site to its former use. The degree of dismantlement will take into account the intended new use of the site and a balance among health and safety considerations, salvage values, and environmental impact. However, decisions on the ultimate disposition of these lands have not yet been made. Continued operation for an additional 20 years would not increase the short-term productivity impacts described here.

Chapter 7

Alternatives to the Proposed Action

This Page Intentionally Left Blank

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 HCGS operating license. The chapter identifies actions that PSEG might take and associated environmental impacts, if the NRC does not renew the plant's operating license. 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 HCGS operating license.

HCGS is a generator of electricity in New Jersey owned by PSEG (PSEG 2008b). In 2008, upgrades to HCGS increased the power level of the reactor to approximately 1,265 MWe (NRC 2007). This power would be unavailable to customers in the event the HCGS operating license was not renewed. PSEG thinks that any alternative to renewal of the HCGS license would be unreasonable if it did not include replacing the capacity of the HCGS unit. 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 HCGS until the existing license expires, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of the equivalently sized 1,155-megawatt-electric [MWe] Washington Public Power Supply System Nuclear Project 2 (the “reference” boiling-water reactor). As the HCGS unit is nominally rated at 1,265 MWe, this description is applicable to decommissioning activities that PSEG would conduct at HCGS.

As the GEIS notes, the 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. The 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 HCGS’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 HCGS license would not expire until 2026 without renewal, decommissioning under the no-action alternative may not be complete until 2086, assuming that decommissioning takes no more than the allowed 60 years from permanent cessation of operations (10 CFR 50.82 (a)(3)). Hence, decommissioning under the no action alternative may not be complete until more than 75 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. HCGS 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 (eight percent), natural gas (26 percent), hydroelectric (five 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 (six percent), hydroelectric (two percent), renewable sources (<one 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 HCGS's nominal base-load capacity of 1,265 MWe. PSEG accounted for the fact that HCGS is a base-load generator and that any feasible alternative to HCGS 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 HCGS.

Based on these evaluations, it was determined that new plant systems capable of replacing the capacity of HCGS 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. Considering that the existing HCGS operating license expires in 2026, PSEG believes construction of new nuclear capacity may be a feasible alternative to license renewal for HCGS.

For the purposes of the HCGS license renewal environmental report, PSEG's analysis of new generating capacity alternatives includes the technologies it considers feasible: pulverized coal-fired units, gas-fired units, and new nuclear 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 ten percent rate reduction phased in over four years. The Act also required the State's electric utilities to divest their electric generation assets. Consequently, PSEG sold its generation assets, including HCGS, 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 Renewable Portfolio Standards (RPS), which require all suppliers selling retail electricity in New Jersey (retail electric suppliers) to include renewable 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 retail competition areas 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 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 2007).

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), new nuclear generating capacity (Section 7.2.1.2), and purchased power (Section 7.2.1.3) as reasonable alternatives to HCGS license renewal. Section 7.2.1.4 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 7.2.1.5 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 site 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 this analysis, HCGS 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 HCGS 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.

Gas-Fired Generation

One unit with a nominal net capacity of approximately 1,265 MWe could be assumed to replace the total 1,265 MWe HCGS 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 HCGS. The hypothetical plant would be composed of three pre-engineered natural gas-fired combined-cycle systems producing 420 MWe of net plant power for a total of 1,260 MWe (GE Power 2001). Although this provides less capacity than the existing unit, it ensures against overestimating environmental impacts from the alternatives. The shortfall in capacity could be replaced by other methods.

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 (1,260 MWe). The hypothetical plant would be composed of two pre-engineered super-critical pulverized coal-fired units producing 630 MWe of net plant power for a total of 1,260 MWe. In defining the coal-fired alternative to HCGS, 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 EPA for minimizing emissions and estimated emissions 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 Construct and Operate New Nuclear Generating Capacity

Since 1997, the NRC has certified four new standard designs for nuclear power plants under 10 CFR 52, Subpart B. Four additional designs are undergoing certification reviews, and four others are undergoing pre-application reviews. All of the plants currently certified or undergoing certification reviews are light-water reactors; several of the designs in precertification review are not, including the Pebble Bed Modular Reactor and the Advanced Candu Reactor, ACR-700. (NRC 2009)

The NRC staff considered new nuclear generating capacity as an alternative to license renewal for the Beaver Valley Power Station (NRC 2009). In its analysis, the NRC staff assumed that

1,900 MWe of new nuclear generation would be installed in the form of either one or two units having a certified design. Impact analyses did not reference a particular design, and impacts generally applicable to all certified designs were assumed. PSEG has reviewed the NRC analysis of new nuclear capacity for Beaver Valley, believes it to be sound, and notes that it addresses more capacity than the approximately 1,260 MWe discussed in this analysis. PSEG has assumed construction at the HCGS site of one new nuclear unit having a certified design, and has scaled from the NRC analysis for Beaver Valley where appropriate. See Table 8.0-2 more details.

7.2.1.3 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 HCGS's load requirements in the event the existing operating license for HCGS is 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 HCGS capacity. From a local perspective, loss of HCGS 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.

7.2.1.4 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 percent of the 2004 to 2007 Business as Usual savings potential of 1,205 GWh and almost 44 percent 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 HCGS 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 1,265 MWe by 2026 to replace the HCGS nominal base-load capacity of approximately 1,265 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 HCGS 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 HCGS 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 HCGS, 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 HCGS would result in a sizable reduction in operating personnel compared to the current workforce of 869 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 HCGS. In addition, the purpose for HCGS license renewal is to allow PSEG Nuclear to sell wholesale power generated by HCGS 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 HCGS operating license.

7.2.1.5 Other Alternatives

This section identifies alternatives that PSEG has determined are not reasonable for replacing HCGS and the bases for these determinations. PSEG accounted for the fact that HCGS is a base-load generator and that any feasible alternative to HCGS 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 one to three 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 three percent to five 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 HCGS nominal base-load generating capacity of 1,265 MWe with wind power, assuming a capacity factor of 30 percent, would require a large greenfield site about 61,400 hectares (151,800 acres) in size, of which approximately 2,460 hectares (6,070 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 Standards, it concludes that wind, due to its intermittent nature, is unsuitable to provide base-load generating capacity (NJDEP 2005, New Jersey Governor's Office 2008). Similarly, PSEG has concluded that wind power is not a reasonable alternative to HCGS 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 three to five 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 1 hectare (2.5 acres) per MWe for photovoltaic and two 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 HCGS generating capacity with solar photovoltaic power, assuming a capacity factor of 16 percent, would require dedication of about 9,500 hectares (23,400 acres). Replacement of HCGS generating capacity with solar thermal power, assuming a capacity factor of 40 percent would require dedication of about 11,400 hectares (28,100 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 HCGS 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, which is less than HCGS nominal baseload capacity. 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 HCGS nominal base-load capacity of approximately 1,265 MWe. There are no undeveloped sites in the ROI that would be environmentally suitable for a single hydroelectric facility similar in generation size to HCGS. (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 HCGS nominal base-load capacity of 1,265 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 HCGS generating capacity would require flooding approximately 508,900 hectares (1,257,600 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 HCGS 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 HCGS.

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 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 HCGS, and PSEG has concluded that, due to cost and production limitations, tidal, ocean thermal, and wave technologies are not reasonable alternatives to HCGS 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 1,265-MWe nominal base-load capacity of HCGS. 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 HCGS. 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 HCGS 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 HCGS 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 HCGS 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 HCGS.

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 HCGS license renewal.

Petroleum

The ROI has several existing 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 HCGS would require about 62 hectares (152 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 HCGS 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 HCGS and that it is not a reasonable alternative to HCGS 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 HCGS 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 HCGS 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 two 400-MWe natural gas combined-cycle units and 65 MWe of power purchased from the wholesale electricity market could replace the HCGS nominal generating capacity

(1,265 MWe net). When operating, the combined cycle plant 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 HCGS operating license. Therefore, a combination of alternatives is not considered a reasonable alternative to HCGS 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 HCGS license renewal: gas-fired generation, coal-fired generation, new nuclear generation, and purchased power. For the impacts of coal- and gas-fired generation that are not specifically discussed 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 three-unit combined-cycle plant at HCGS. 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 = 17 metric tons (19 tons) per year

NO_X = 291 metric tons (321 tons) per year

CO = 60 metric tons (66 tons) per year

CO_2 = 2,940,000 metric tons (3,240,000 tons) per year

Particulates:

Filterable Particulate Matter = 51 metric tons (56 tons) per year (all particulate matter 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 courts 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, commenced 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 four 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 over 2.72 million metric tons (3 million short 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 short tons) of CO_2 per year in 2018, as was explained above. Accordingly, the addition of 1,260 MWe of gas-fired generation would likely challenge compliance with this budget. HCGS 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 combined cycle 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 HCGS, PSEG estimates that 18 hectares (44 acres) on the previously disturbed HCGS 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, rights-of-way to minimize impacts. A new pipeline of approximately 40.6 cm (16-inch) diameter would require a 30.5 m (100-ft) wide corridor. This new construction may also necessitate an upgrade of the statewide pipeline network. Impacts to land use would be SMALL.

PSEG estimates an average construction workforce of 560 employees with a peak of 1,010 workers. Socioeconomic impacts from the construction workforce would be minimal, if worker relocation is not required, which would be the case if, like HCGS, the site is near metropolitan areas such as the cities of Salem, Wilmington, Bridgeton, and Vineland. However, PSEG estimates a reduced workforce of 48 for gas operations, resulting in adverse socioeconomic impacts due to the loss of 869 personnel responsible for HCGS 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 HCGS (see Section 2.6).

If the gas-fired units were located at HCGS, impacts to aquatic resources and water quality would be smaller than the impacts of the existing HCGS due to changes in the plant's cooling water withdrawals from and discharges to the Delaware River. These impacts would be offset by the concurrent shutdown of HCGS. 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 HCGS. A coal plant comparable to the 1,260-MWe gas plant chosen for this alternatives analysis could comprise two 630-MWe (net) units.

Air Quality

A coal-fired plant would emit SO_2, NO_X, particulate matter, CO, and carbon dioxide (CO_2), which is a greenhouse gas. A coal-fired plant also would emit mercury, which is a regulated pollutant in New Jersey. 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 2006a), the coal-fired alternative emissions are estimated to be as follows:

SO_2 = 2,946 metric tons (3,247 tons) per year

NO_X = 881 metric tons (971 tons) per year

CO = 881 metric tons (971 tons) per year

CO_2 = 9,700,000 metric tons (10,700,000 tons) per year

Mercury = 146 kilograms (322 pounds) per year

Particulates:

PM_{10} (particulates having a diameter of less than 10 microns) = 24 metric tons (27 tons) per year

$PM_{2.5}$ (particulates having a diameter of less than 2.5 microns) = 6 metric tons (7 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 can not 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. 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 10 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 short tons) of CO_2 per year in 2018, as was explained above. Accordingly, the addition of 1260 MWe of coal-fired generation would likely challenge compliance with this budget. HCGS 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, regulatory-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 3.52 million metric tons (3.88 million tons) of coal having an ash content of 6.13 percent. After combustion, 45 percent of this ash, approximately 96,750 metric tons (107,000 tons) per year, would be marketed for beneficial reuse. The remaining ash, approximately 119,000 metric tons (131,000 tons) per year, would be collected and disposed of in an authorized disposal facility. In addition, approximately 74,600 metric tons (82,300 tons) of scrubber sludge would be disposed of each year (based on annual limestone usage of about 96,900 metric tons [107,000 tons]). PSEG estimates that ash and scrubber waste disposal over a 20-year plant life (the time considered for license renewal) would require approximately 26 hectares (65 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 power plant would require 70 hectares (174 acres) and ash disposal would require an additional 52 hectares (130 acres) of land and associated terrestrial habitat over 40 years, or 26 hectares (65 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 HCGS, receive coal via barge (EIA 2008c, EIA 2008d).

PSEG estimates an average construction workforce of 1,010 employees with a peak of 1,955 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 172 workers for the coal-fired alternative. This is a sizable reduction in operating personnel compared to HCGS's 869 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 similar to impacts of HCGS, due to the new plant's use of the cooling water from and discharge to the Delaware Estuary, and would be offset by the concurrent shutdown of HCGS. 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 New Nuclear Capacity

As discussed in Section 7.2.1.2, under the new nuclear capacity alternative, PSEG would construct one or two new nuclear generating units using an NRC certified standard design.

Air Quality

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

Waste Management

High-level radioactive wastes would be similar to those associated with the continued operation of HCGS. Low-level radioactive waste impacts from a new nuclear plant would be slightly greater but similar to the continued operation of HCGS. The overall impacts are characterized as SMALL.

Other Impacts

PSEG estimates that construction of the reactor(s) and auxiliary facilities would affect 255 to 510 hectares (630 to 1260 acres) of land and associated terrestrial habitat. Because most of this construction would be on previously disturbed land, impacts at the HCGS site would be SMALL to MODERATE. For the purposes of analysis, PSEG has assumed that the existing barge facilities would be used for reactor vessel and other deliveries under this alternative. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of onsite.

PSEG estimates a peak construction work force of approximately 3650 workers. The surrounding communities would experience moderate to large demands on housing and public services. Long-term job opportunities would be comparable to continued operation of HCGS. Therefore, PSEG concludes that socioeconomic impacts during construction and operation would be SMALL TO LARGE.

Impacts to aquatic resources and water quality would be similar to impacts of HCGS, due to use by the new unit(s) of the existing cooling water intake and discharge structures. If two units were to be constructed, a second cooling tower may be required increasing impacts to aquatic resources and water quality.

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

7.2.2.4 Purchased Power

As discussed in Section 7.2.1.2, 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.

7.2.2.5 Conclusion

Based on the analyses done for reasonable alternatives that could generate the same amount of electricity as generated by HCGS, 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 HCGS license renewal.

Table 7.2-1 Gas-Fired Alternative

Characteristic	Basis
Plant size = 1,260 MWe ISO rating net combined cycle consisting of three 420 MWe systems with heat recovery steam generators	Manufacturer's standard size gas-fired combined-cycle plant (≤ HCGS net capacity of 1,265 MWe) (GE Energy 2007)
Plant size = 1,314 MWe ISO rating gross	Based on 4 percent onsite power usage
Number of units = 3	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 = 110 lb/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 = 1,260 MWe ISO rating net consisting of two 630 MWe (net) units	Size set = to gas-fired alternative (≤ HCGS nominal base-load capacity of 1,265 MWe)
Plant size = 1,340 MWe ISO rating gross	Based on 6 percent onsite power usage
Number of units = 2	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 = 5510 lb/ton	Typical for pulverized bituminous coal, tangentially fired, dry-bottom, NSPS (EPA 1998a)
Heat rate = 8,740 Btu/kWh	EIA forecast for a new supercritical coal-fired plant beginning operation in 2026 (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 technology and widely demonstrated 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 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
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

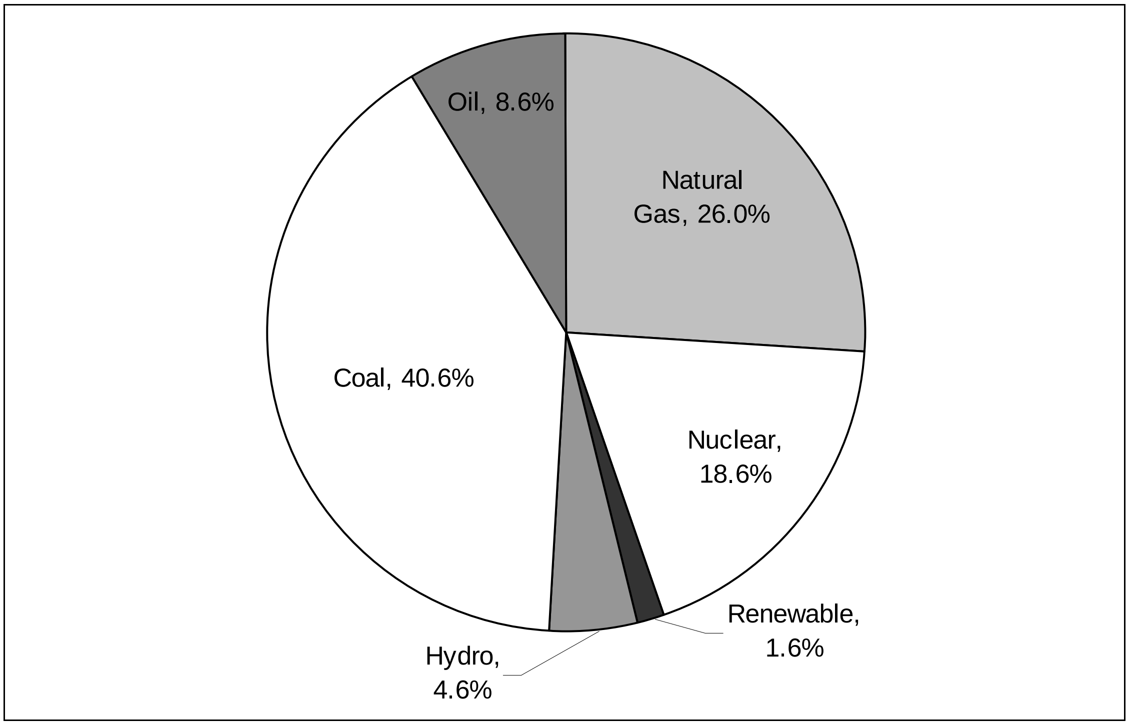


Figure 7.2-1 PJM Regional Generating Capacity (2006)

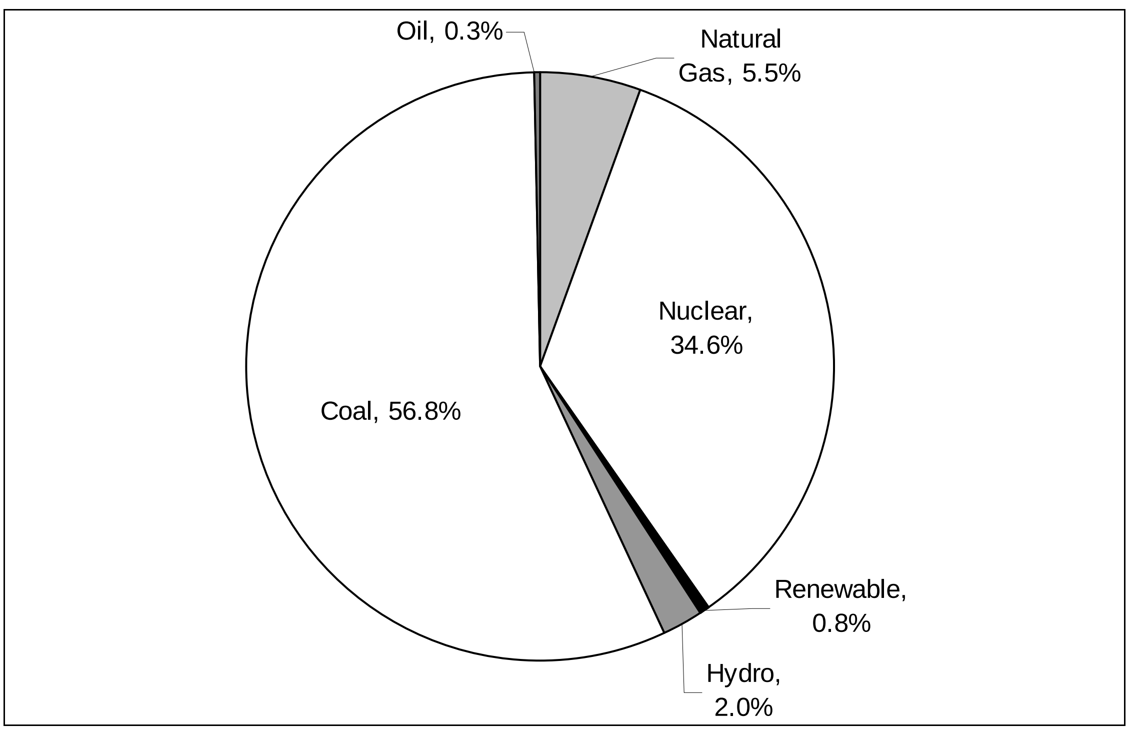


Figure 7.2-2 PJM Regional Energy Output by Fuel Type (2006)

This Page Intentionally Left Blank

Chapter 8

Comparison of Environmental Impacts of License Renewal with the Alternatives

This Page Intentionally Left Blank

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 HCGS license 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 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 (Decommissioning)	With New Nuclear Power	With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Land Use	SMALL	SMALL	SMALL to MODERATE	SMALL to MODERATE	SMALL	SMALL to MODERATE
Water Quality	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Air Quality	SMALL	SMALL	SMALL	MODERATE	SMALL to MODERATE	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	SMALL to MODERATE	SMALL to MODERATE	SMALL	SMALL to MODERATE
Threatened or Endangered Species	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Human Health	SMALL	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Socioeconomics	SMALL	SMALL	SMALL TO LARGE	MODERATE	MODERATE	MODERATE
Waste Management	SMALL	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Aesthetics	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Cultural Resources	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.
MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.
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 New Nuclear Power	With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Alternative Descriptions					
HCGS license renewal for 20 years, followed by decommissioning	Decommissioning following expiration of current HCGS license. Adopting by reference, as bounding for HCGS decommissioning, GEIS description (NRC 1996b, Section 7.1)	New construction at an existing site, assumed to be HCGS	New construction at an existing site, assumed to be HCGS	New construction at an existing site, assumed to be HCGS	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	Upgrade of barge slip or installation of a new rail spur	Construct 40.6-cm (16-inch) diameter gas pipeline in a 30.5-m (100-ft) wide corridor. May require upgrades to existing pipelines	
					Construct new transmission lines to interconnect to the PJM region
		One or two units using a certified NRC standard design producing 1,260 MWe net, capacity factor 0.90	Two 630-MWe (net) tangentially fired, dry bottom units producing 1,260 MWe net; capacity factor 0.90	Three pre-engineered 420-MWe gas-fired combined-cycle systems with heat recovery steam generators, producing combined total of 1,260 MWe. capacity factor: 0.90	

Table 8.0-2. Impacts Comparison Detail (Continued)

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives			
		With New Nuclear Power	With Coal-Fired Generation	With Gas-Fired Generation	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; 8,740 Btu/kWh; 6.13% ash; 0.88% sulfur; 10 lb/ton nitrogen oxides; 3.52 x 10^6 metric tons (3.88 x 10^6 tons) coal/yr	Natural gas, 1,034 Btu/ft^3; 5,687 Btu/kWh; 0.00066 lb sulfur/MMBtu; 0.0109 lb NO_x/MMBtu; 5.3 x 10^8 m^3 (1.9 x 10^{10} ft^3) gas/yr	
			Low NO_x burners, over-fire air and selective catalytic reduction (95% NO_x reduction efficiency)	Selective catalytic reduction with steam/water injection	
			Wet scrubber – lime/limestone desulfurization system (95% SO_x removal efficiency); 96,900 metric tons (107,000 tons) lime/yr		
			Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency)		
513 permanent, 270 corporate, and 86 matrixed employees		Comparable to present HCGS workforce (Section 7.2.2.3)	172 workers (Section 7.2.2.2)	48 workers (Section 7.2.2.1)	

Table 8.0-2. Impacts Comparison Detail (Continued)

		No-Action Alternatives			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With New Nuclear Power**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**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 – 255 to 510 hectares (630 to 1260 acres) required for the power block and associated facilities at HCGS location (Section 7.2.2.3)	SMALL to MODERATE – 70 hectares (174 acres) required for the power block and associated facilities at HCGS location; 26 hectares (65 acres) for ash/sludge disposal during 20-year license renewal term (Section 7.2.2.2)	SMALL– 18 hectares (44 acres) for facility at HCGS 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, 4, and 6-11). One Category 2 ground-water issue applies (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 similar to HCGS by using cooling tower and discharging to the Delaware Estuary. (Section 7.2.2.3)	SMALL – Construction impacts minimized by use of best management practices. Operational impacts similar to HCGS by using cooling tower and discharging 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 New Nuclear Power	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)	SMALL – Air emissions are primarily from non-facility equipment and diesel generators and are comparable to those associated with the continued operation of HCGS (Section 7.2.2.3)	MODERATE – 2,946 metric tons (3,247 tons) SO_X/yr 881 metric tons (971 tons) NO_X/yr 881 metric tons (971 tons) CO/yr 6 metric tons (7 tons) $PM_{2.5}$/yr 24 metric tons (27 tons) PM_{10}/yr 146 kilograms (322 pounds) mercury/yr 9,700,000 metric tons (10,700,000 tons) CO_2 /yr (Section 7.2.2.2)	SMALL to MODERATE – 17 metric tons (19 tons) SO_X/yr 291 metric tons (321 tons) NO_X/yr 60 metric tons (66 tons) CO/yr 51 metric tons (56 tons) $PM_{2.5}$/yr 2,940,000 metric tons (3,240,000 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, 28-30, and 45-48). Four Category 2 issues do not apply (Section 4.2, Issue 25; Section 4.3, Issue 26; and Section 4.4, Issue 27; Section 4.9, Issue 40).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 90)	SMALL – Impacts would be comparable to those associated with continued operation of HCGS (Section 7.2.2.3)	SMALL to MODERATE – 26 hectares (65 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 New Nuclear Power	**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	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)	SMALL – Impacts would be comparable to continued operation of HCGS (Section 7.2.2.3)	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 New Nuclear Power	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 tax revenues 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 HCGS 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.	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 91)	Construction: MODERATE to LARGE – Peak construction workforce of 3650 could affect housing and public services in surrounding counties. Operation: SMALL – Impacts would be comparable to those associated with the continued operation of HCGS (Section 7.2.2.3)	MODERATE – Reduction in permanent workforce at HCGS could adversely affect surrounding counties. (Section 7.2.2.2)	MODERATE – Reduction in permanent workforce at HCGS 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 New Nuclear Power	With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Capacity of public water supply and transportation infrastructure minimizes potential for related impacts (Section 4.15, Issue 65 and Section 4.18, Issue 70) Two Category 2 issues do not apply (Section 4.16, Issue 66 and Section 4.17.1, Issue 68)					
Waste Management Impacts					
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 77-85)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 87)	SMALL – radioactive wastes would be similar to those associated with the continued operation of HCGS (Section 7.2.2.3)	MODERATE – 191,000 metric tons (131,000 tons) of coal ash and 74,600 metric tons (82,300 tons) of scrubber sludge annually would require 26 hectares (65 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 NO_X 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 comparable to those from existing HCGS facilities (Section 7.2.2.3)	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 HCGS facilities (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies (NRC 1996b)

Table 8.0-2. Impacts Comparison Detail (Continued)

		No-Action Alternatives			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With New Nuclear Power**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With Purchased Power**
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 7.2.2.3)	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)

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
ft^3 = cubic foot
gal = gallon
GEIS = Generic Environmental Impact Statement (NRC 1996)
kWh = kilowatt-hour
lb = pound
m^3 = cubic meter
MM = million
MW = megawatt

NO_X = nitrogen oxide
PJM = regional electric distribution network
$PM_{2.5}$ = particulates having diameter less than 2.5 microns
PM_{10} = particulates having diameter less than 10 microns
SHPO = State Historic Preservation Officer
SO_X = sulfur dioxide
TSP = total suspended particulates
yr = year

Chapter 9

Status of Compliance

This Page Intentionally Left Blank

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 HCGS 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 operation associated with renewal of the HCGS operating license. 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 HCGS 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 HCGS environmental documentation, and communication with state and federal environmental protection agencies. Based on this assessment, PSEG concludes that HCGS is in substantive compliance with applicable environmental standards and requirements. Minor deviations from applicable standards or requirements are corrected, and notification is provided to regulatory agencies, as required. For example, HCGS identified an error in an emission factor in the Air Operating Permit, which would cause emissions to be calculated in excess of the limitation. PSEG immediately terminated operation of the equipment and worked with NJDEP to obtain an Administrative Consent Order allowing continued operation of the equipment pending a modification to the Air Operating Permit. The Air Operating Permit modification was received in May 2009, and actions are in progress to terminate the Administrative Consent Order.

Table 9.1-2 lists additional environmental authorizations and consultations related to NRC renewal of the HCGS license 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 or 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 HCGS license renewal might have. Appendix C includes copies of PSEG correspondence with USFWS, NMFS, and NJDEP and replies that have been received. In 1993, NMFS issued a biological opinion that the continued operation of HCGS would not jeopardize threatened or endangered aquatic species (NMFS 1993). NMFS reviewed that opinion in 1999 and found that HCGS 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 HCGS 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 SHPO 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). HCGS's 401 Certification is provided in Appendix F. The NRC 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 the 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 HCGS NJPDES permit (NJ0025411) (included in Appendix B). In addition, the cover letter to the NJDEP dated October 18, 2007, 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 remains pending. Because the NJPDES permit was filed in a timely manner, HCGS 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 applicants for a federal license to conduct an activity that could affect a state's coastal zone. HCGS, 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.

HCGS is not within the Delaware Coastal Management Area.

Table 9.1-1 Authorizations for Current HCGS 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	NPF-57	Issued: 4/11/1986 Expires: 4/11/2026	Operation of HCGS
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-73-193 CP (Revised)	Issued: 4/27/1984 Expires: None	Construction and operation of HCGS
Delaware River Basin Commission	Delaware River Basin Compact (DRBC) Resolutions Nos. 71-4 and 71-4	Water Use Contract	84-9-E-741	Issued: 12/12/1984 Expires: None	Water Use contract for Delaware River water withdrawal in compliance with D-73-193 CP
Delaware River Basin Commission	Delaware River Basin Compact, Section 3.8	Oxygen Demand Wasteload Allocation	D-85-60	Issued: 3/3/1986 Expires: None	Allocation for First Stage Oxygen Demand discharge to Delaware Estuary
Delaware River Basin Commission	Delaware River Basin Compact, Section 3.8	Sewage Treatment Plant	D-87-70	Issued: 11/2/1987 Expires: None	Installation of new Sewage Treatment Plant

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

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
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 Amended: 1/21/1999 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.), NJ 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.	Hope Creek New Jersey Pollutant Discharge Elimination System Permit – Surface Water	NJ0025411	Issued: 12/31/2003 Effective: 3/1/2003 Expires: 2/29/08 Administratively continued while current application is being reviewed.	Wastewater (industrial surface water, thermal surface water and stormwater runoff) discharges 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 Environmental Protection	Clean Air Act (42 USC 7401)	Air Pollution Control Operating Permit (Title V Operating Permit)	BOP080001	Issued: 2/2/2005 Modified: 3/26/09 Expires: 2/1/2010	Air emissions from all sources
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 Expires: None	Transmission Corridor

Table 9.1-1 Authorizations for Current Hope Creek Operations (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
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	107040041000	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: 9/14/1980 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 Hope Creek 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, 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
New Jersey Department of Environmental Protection	N.J.A.C. 13:19-1 et seq.	CAFRA Permit	74-014	Issued: 9/3/1975 Expires: None	Land use associated with HCGS

Table 9.1-1 Authorizations for Current Hope Creek Operations (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
New Jersey Department of Environmental Protection	N.J.A.C. 7: 1C-1.5 (C) and 7:7-4.10,	CAFRA Permit	1704-90-0014-5-CAM	Issued: 4/25/1995 Expires: None	Land use associated with Sandblast Facility Modifications
New Jersey Department of Environmental Protection	N.J.A.C. 13: 9A-4	Type “B” Wetlands Permit	W74-02	Issued: 2/28/1975 Extended: 8/19/1995 Expires: None	Construction of HCGS
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 FRP (40 CFR 9 and 112), and the USEPA Hazardous Waste Contingency Plan (40 CFR 265 Subparts C and D)	Facility Response Plan Approval	0200087	Submitted: 2/15/2008	Spill/Discharge Response Program
U.S. Environmental Protection Agency	Spill Prevention, Control, and Countermeasure (SPCC) rule (40 CFR 112), Appendix F, Sections 1.2.1 and 1.2.2	SPCC Plan		Submitted: 2/15/2008	Spill/Discharge Prevention Plan
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 Fuels
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

Table 9.1-1 Authorizations for Current Hope Creek Operations (Continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
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
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 into the State of Virginia

.

Table 9.1-2 Authorizations for Hope Creek 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 NPDES 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 HCGS 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.

This Page Intentionally Left Blank

Chapter 10

References

This Page Intentionally Left Blank

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.

AEC 1971. Salem Nuclear Generating Station, Units 1 and 2–Supplemental Environmental Report Operating License Stage. Docket Nos. 50-272 and 50-311. Washington, DC, U.S. Atomic Energy Commission.

AEC 1973. Final Environmental Statement Related to the Salem Nuclear Generating Station Units 1 and 2, Public Service Electric and Gas Company. Docket Nos. 50-272 and 50-311. Washington, DC, U. S. Atomic Energy Commission, Directorate of Licensing. Publication date: April 1973.

Alaimo Group 2005. 2005 Master Plan Reexamination Report. Approved by the Lower Alloways Creek Township Planning Board. Publication date: June 22, 2005.

ARCADIS 2006. Site Investigation Report, Salem Generating Station. Newtown, Pennsylvania. Publication date: July 15, 2006.

AWEA 2008a. Legislative Affairs: Production Tax Credit Extension. Washington, DC, American Wind Energy Association. Retrieved April 22, 2008, from http://www.awea.org/legislative/.

AWEA 2008b. Wind Energy Projects Throughout the United States of America. Washington, DC, American Wind Energy Association. Retrieved May 9, 2008, from http://www.awea.org/projects/.

BBNEP 2001. The Barnegat Bay Estuary Program Characterization Report, Chapter 4: Historic Uses. Toms River, NJ, Barnegat Bay National Estuary Program, Scientific and Technical Advisory Committee. Retrieved May 29, 2008, from http://www.bbep.org. Publication date: January 2001.

BEA 2008. Regional Economic Accounts. Washington, DC, U.S. Department of Analysis, Bureau of Economic Analysis. Retrieved June 20, 2008, from http://www.bea.gov/regional/reis/.

Bezdek, R. H., and R. M. Wendling 2006. The Impacts of Nuclear Facilities on Property Values and Other Factors in the Surrounding Communities. Int. J. Nuclear Governance, Economy and Ecology 1(1): 122–144.

Blomquist, G. 1974. The Effect of Electric Utility Power Plant Location on Area Property Value. Land Economics 50(1): 97–100. Publication date: February 1974.

CEC 2009. Ocean Energy. Sacramento, CA, California Energy Commission. Retrieved June 19, 2009, from http://www.energy.ca.gov/oceanenergy.

CEEEP 2008. Draft Review and Update of Energy Efficiency Market Assessment for the State of New Jersey, Center for Energy, Economic and Environmental Policy. Retrieved February 13, 2009, from http://policy.rutgers.edu/ceeep/EEAssessmentfinaldraft%20July%203%202008.pdf. Publication date: June 2008.

Clark, D. and L. Nieves 1994. An Interregional Hedonic Analysis of Noxious Facility Impacts on Local Wages and Property Values. Journal of Environmental Economics and Management 27: 235–253.

Clark, D., L. Michelbrink, T. Allison, and W. Metz 1997. Nuclear Power Plants and Residential Housing Prices. Growth and Change 28 (Fall): 496–519.

Creswell, R.L., C.L. Ohs, and C.L. Miller 2007. Candidate Species for Florida Aquaculture: Atlantic croaker, *Micropogonias undulatus*. Fact Sheet FA-148, Gainesville, Florida, Florida Cooperative Extension Service, Institute of Food and Agricultural Sciences, University of Florida.

Dames & Moore 1988. Final Report, Study of Groundwater Conditions and Future Water-Supply Alternatives, Salem/Hope Creek Generating Station, Artificial Island, Salem County, New Jersey. Prepared for PSE&G. Publication date: July 15, 1988.

Delaware Estuary Program 1996. The Scientific Characterization of the Delaware Estuary. Prepared by Herpetological Associates, Inc., Forked River, NJ, for the Delaware Estuary Program. Publication date: April 1996.

Diaz, R.J. and C. P. Onuf 1985. Habitat Suitability Index Models: Juvenile Atlantic Croaker (Revised). Biological Report 82(10.98). Prepared for National Coastal Ecosystems Team, Division of Biological Services, U.S. Fish and Wildlife Service, Dept. of the Interior, Washington, DC.

DNREC 2008. Letter from Edna Stetzar (Delaware Department of Natural Resources and Environmental Control) to TetraTech NUS regarding rare species information for license renewal of the Salem and Hope Creek Generating Stations. Dated August 19, 2008.

DRBC 1961. Delaware River Basin Compact. U.S. Public Law 87-328, Approved September 27, 1961, 75 Statutes at Large 688. Reprinted 2007. West Trenton, NJ, Delaware River Basin Commission. Retrieved September 22, 2008, from http://www.state.nj.us/drbc/regs/compa.pdf.

DRBC 1984a. Docket No. D-73-193 CP (Revised). Revision of the Hope Creek Generating Station Project Previously Included in the Comprehensive Plan. West Trenton, New Jersey, Delaware River Basin Commission. Publication date: May 1, 1984.

DRBC 1984b. Water Supply Contract Between DRBC and PSEG Concerning the Water Supply at Hope Creek Generating Station. Delaware River Basin Commission. Issue date: December 12, 1984.

DRBC 2000. Groundwater Withdrawal. Docket No. D-90-71 Renewal. West Trenton, New Jersey, Delaware River Basin Commission. Publication date: November 1, 2000.

DRBC 2001. Docket No. D-68-20 (Revision 2). Approval to Revise Delaware River Basin Docket D-68-20 (CP). West Trenton, New Jersey, Delaware River Basin Commission. Publication date: September 26, 2001.

DRBC 2008. Delaware River State of the Basin Report. West Trenton, New Jersey, Delaware River Basin Commission. Retrieved March 20, 2009 from http://www.statte.nj.us/drbc/SOTB/index.htm.

DSIRE 2007. State Incentives for Renewable Energy. Database of State Incentives for Renewables and Efficiency. Raleigh, North Carolina, NC Solar Center, NC State University. Retrieved September 11, 2008, from http://www.dsireusa.org/index.cfm?EE=1&RE=1.

EERE 2003. Wind Resource Maps. Golden, Colorado, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Retrieved April 23, 2008, from http://www.eere.energy.gov/windandhydro/windpoweringamerica/wind_maps.asp.

EERE 2004. PV FAQs—How Much Land Will PV Need to Supply our Electricity? DOE/GO-102004-1835. Golden, CO, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Retrieved May 6, 2008, from http://www.nrel.gov/docs/fy04osti/35097.pdf.

EERE 2005a. Ocean Tidal Power. Golden, Colorado, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Retrieved September 12, 2008, from http://apps1.eere.energy.gov/consumer/renewable_energy/ocean/index.cfm/mytopic=50008.

EERE 2005b. New Wave Energy Prototypes Deployed in Hawaii and New Jersey. Golden, Colorado, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Retrieved May 9, 2008, from http://www.eere.energy.gov/states/state_news_detail.cfm/news_id=9551/state=NJ. Publication date: November 23, 2005.

EERE 2006a. Solar America Initiative, Technology Improvement Opportunities. Solar Energy Technologies Program, Technology Pathway Partnership Technical Exchange Meeting, Chicago, IL, April 18-19. Golden, Colorado, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Retrieved May 5, 2008, from http://www1.eere.energy.gov/solar/solar_america/pdfs/breakout_atios_041706.pdf.

EERE 2006b. Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants. DOE-ID-11263. Golden, Colorado, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Retrieved May 6, 2008, from http://hydro2.inel.gov/resourceassessment/.

EERE 2008. Alternative Energy Sources by State. Golden, Colorado, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Retrieved May 6, 2008, from http://www.eere.energy.gov/states/alternatives/resources_by_state.cfm.

EIA 1996. Inventory of Power Plants in the United States. Table 20. Existing Generating Units at U.S. Electric Utilities by State, Company, and Plant, as of January 1, 1996. Washington, DC, U.S. Department of Energy, Energy Information Administration. Publication date: December 1996.

EIA 2007a. Status of Electricity Restructuring by State. Washington, DC, U.S. Department of Energy, Energy Information Administration. Retrieved September 9, 2008, from www.eia.doe.gov/cheaf/electricity/page/restructing/restructure-elect.html.

EIA 2007b. State Electricity Profiles 2006. DOE/EIA-0348(01)/2. Washington, DC, U.S. Department of Energy, Energy Information Administration. Retrieved March 26, 2008, from http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html. Publication date: November 21, 2007.

EIA 2007c. Cost and Quality of Fuels for Electric Plants 2005 and 2006, Tables 14.A, 14.B, 15.A, 15.B. Document No. DOE/EIA-0191(2006). Washington, DC, U.S. Department of Energy, Energy Information Administration. Retrieved May 9, 2008, from http://www.eia.doe.gov/cneaf/electricity/cq/cq_sum.htm. Publication date: October 2007.

EIA 2008a. State Energy Consumption, Price, and Expenditure Estimates (SEDS): Table 7. Washington, DC, U.S. Department of Energy, Energy Information Administration. Retrieved May 9, 2008, from http://www.eia.doe.gov/emeu/states/_seds.html. Publication date: February 29, 2008.

EIA 2008b. Renewable Energy Annual, 2006 Edition. Washington, DC, U.S. Department of Energy, Energy Information Administration. Retrieved May 7, 2008, from http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/rea_sum.html. Publication date: April 2008.

EIA 2008c. Domestic Distribution of U.S. Coal by Destination State, Consumer, Origin and Method of Transportation, 2006. Washington, DC, U.S. Department of Energy, Energy Information Administration. Retrieved May 19, 2008, from http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/coal_distributions.html. Publication date: April 2008.

EIA 2008d. State Energy Profiles 2006. New Jersey. Washington, DC, U.S. Department of Energy, Energy Information Administration. Retrieved May 19, 2008, from http://tonto.eia.doe.gov/state/.

EIA 2008e. Cost and Quality of Fuels for Electric Plants 2006 and 2007, Tables 14.A and 15.A. Document No. DOE/EIA-0191(2007). Washington, DC, U.S. Department of Energy, Energy Information Administration. Retrieved February 19, 2009, from http://www.eia.doe.gov/cneaf/electricity/cq/cqa2007.pdf. Publication date: December 2008.

EIA 2008f. Assumptions to the Annual Energy Outlook 2008 with Projections to 2030, NEMS Electricity Market Module. Document No. DOE/EIA 0554(2008). Washington, DC, U.S. Department of Energy, Energy Information Administration. Retrieved February 19, 2009 from http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf#page=3. Publication date: June 2008.

EPA 1998a. AP-42 Compilation of Air Pollutant Emission Factors, 5th Edition. Vol. 1, Stationary Point Sources and Area Sources. Section 1.1, Bitumous and Subbittumous Coal Combustion. Washington, DC, Environmental Protection Agency. Retrieved May 9, 2008, from http://www.epa.gov/ttn/chief/ap42/. Publication date: September 1998.

EPA 1998b. Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone. Washington, DC, Environmental Protection Agency. Federal Register 63 (207): 57356–57404. Publication date: October 27, 1998.

EPA 2000a. AP-42 Compilation of Air Pollutant Emission Factors, 5th Edition. Vol. 1, Stationary Point Sources and Area Sources. Section 3.1, Stationary Gas Turbines. Washington, DC, Environmental Protection Agency. Retrieved April 7, 2008, from http://www.epa.gov/ttn/chief/ap42/.

EPA 2000b. AP-42 Compilation of Air Pollutant Emission Factors, 5th Edition. Vol. 1, Stationary Point Sources and Area Sources. Section 3.1, Emission Factor Query Database. Washington, DC, Environmental Protection Agency. Retrieved April 7, 2008, from http://www.epa.gov/ttn/chief/ap42/ch03/related/c03s01.html.

EPA 2003. Water on Tap: What You Need To Know. Report No. EPA 816- K-03-007. Washington, DC, U. S. Environmental Protection Agency, Office of Water. Publication date: October 2003.

EPA 2006a. National Ambient Air Quality Standards for Particulate Matter; Final Rule. Washington DC, Environmental Protection Agency. Federal Register 71 (200): 61144–61233. Publication date: October 17, 2006.

EPA 2006b. Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies. Final Report EPA-430/R-06/006. Washington, DC, Environmental Protection Agency. Retrieved April 7, 2008, from http://www.epa.gov/air/caaac/coaltech/2007_01_epaigcc.pdf. Publication date: July 2006.

EPA 2008a. Safe Drinking Water Information System. Washington, DC, U.S. Environmental Protection Agency. Retrieved March 26, 2008, from http://www.epa.gov/enviro/html/sdwis/sdwis_ov.html.

EPA 2008b. Strengthened National Standards for Ground-Level Ozone. Washington, DC, U.S. Environmental Protection Agency. Retrieved March 21, 2008, from http://www.epa.gov/air/ozonepollution/actions.html.

EPA 2008c. Particulate Matter. Air and Radiation. PM Standards Revision-2006. Washington, DC, Environmental Protection Agency. Retrieved March 15, 2008, from http://www.epa.gov/oar/ particlepollution/naaqsrev2006.html.

EPRI 2006. Generation Technologies in a Carbon-constrained World. Presentation by S. Specker to the Resources for the Future Policy Leadership Forum, March 30, 2006, in Washington, DC. Palo Alto, CA, Electrical Power Research Institute. Retrieved April 8, 2008, from http://www.eande.tv/showAssets/related/040406/document_eetv_01.pdf.

Farrell, C. and W. W. Hall, Jr. 2004. Economic Impact Study of the Progress Energy, Inc., Brunswick Nuclear Power Facility on North Carolina State Planning Region O. Washington, DC, Nuclear Energy Institute (NEI). Publication date: October 2004.

FC2000 2008. Worldwide Stationary Fuel Cell Installation Database. Washington, DC, Fuel Cells 2000. Retrieved May 8, 2008, from http://www.fuelcells.org/info/databasefront.html.

FCT 2007. Fuel Cells Market Survey: Large Stationary Applications 2006. Royston, Hertfordshire, United Kingdom, Fuel Cell Today. Retrieved May 8, 2008, from http://www.fuelcelltoday.com/media/pdf/surveys/2007-Large-Stationary.pdf.

Feller, G. 2003. Wind, Waves & Tides—Economically Viable Energy from the Worlds Oceans. EcoWorld Magazine. Retrieved May 9, 2008, from http://www.ecoworld.com/home/articles2.cfm?tid=334. Publication date: August 9, 2003.

FERC 2006. Issued Preliminary Permits as of October 5, 2006. Washington, DC, Federal Energy Regulatory Commission. Retrieved May 6, 2008, from http://www.ferc.gov/industries/hydropower/gen-info/licensing/pre-permits.asp#skipnavsub.

Folland, S. and R. Hough 2000. Externalities of Nuclear Plants: Further Evidence. Journal of Regional Science 40(4): 735–753. Publication date: April 2000.

Gamble, H. B. and R. H. Downing 1982. Effects of Nuclear Power Plants on Residential Property Values. Journal of Regional Science 22(4): 457–478.

GE Energy 2007. Gas Turbine and Combined Cycle Products. Atlanta, Georgia, GE Energy. Document No. GEA 12985E. Publication date: June 2005.

GE Power 2001. Advanced Technology Combined Cycles. Document No. GER-3936A. Retrieved February 20, 2009, from http://www.gepower.com/prod_serv/products/gas_turbines_cc/en/stag/index.htm. Publication date: May 2001.

GHC 2008. U.S. Geothermal Projects and Resource Areas. Klamath Falls, OR, Oregon Institute of Technology, Geo-Heat Center. Retrieved May 7, 2008, from http://geoheat.oit.edu/dusys.htm. Publication date: January 1, 2008.

Gloucester County 2007. 2007 Gloucester County, New Jersey, Comprehensive Economic Development Strategy. (CEDS).

IEEE 2006. National Electrical Safety Code. New York, New York, Institute of Electrical and Electronics Engineers. Report C2-2007. Publication date: August 1, 2006.

INEEL 1998. U.S. Hydropower Resource Assessment Final Report. Document No. DOE/ID-10430.2. Idaho Falls, ID, Idaho National Engineering and Environmental Laboratory. Retrieved May 16, 2008, from http://hydropower.inel.gov/resourceassessment/pdfs/doeid-10430.pdf.

INGAA 2000. Implications of Reduced Gas Use on Emissions From Power Generation. Washington, DC, Interstate Natural Gas Association of America. Retrieved April 7, 2008, from http://www.ingaa.org/File.aspx?id=282.

KEMA, Inc. 2004. New Jersey Energy Efficiency and Distributed Generation Market Assessment. Retrieved February 12, 2009, from http://www.njcleanenergy.com/files/file/Kema_Report.pdf. Publication date: August 2004.

Ling, H. 2003. Invasive Plant Species. New Brunswick, New Jersey, Native Plant Society of New Jersey. Retrieved March 26, 2008, from http://www.npsnj.org/invasive _species_0103.htm.

Lower Alloways Creek Township 1992. Master Plan. Adopted by Salem County, New Jersey, Lower Alloways Creek Township Planning Board on September 17, 1992.

McGowan, J. G., and S. R. Connors 2000. Windpower: A Turn of the Century Review. Annual Review of Energy and Environment 25: 147–197.

Metz, W. C., T. Allison, and D. E. Clark 1997. Does Utility Spent Nuclear Fuel Storage Affect Local Property Values? Radwaste Magazine 4: 27–33. Publication date: May 1997.

NatureServe 2008. Nature Serve Explorer, an Online Encyclopedia of Life. Retrieved March 27, 2008, from http://www.natureserve.org/explorer/index.htm.

NCDC 2008a. Climatography of the United States, No. 60, Climate of the States. Climate of New Jersey. Asheville, NC, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Climatic Data Center. Retrieved March 17, 2008, from http://cdo.ncdc.noaa.gov/climatenormals/clim60/states/Clim_NJ_01.pdf.

NCDC 2008b. Climatography of the United States, No. 20, 1971–2000. Weather Station Data Summaries, Woodstown Pittsgrove Station, Salem, New Jersey. U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Climatic Data Center. Retrieved March 17, 2008, from http://cdo.ncdc.noaa.gov/climatenormals/clim20/nj/289910.pdf.

NEI 2003. Economic Benefits of Millstone Power Station. Washington, DC, Nuclear Energy Institute. Retrieved February 9, 2009, from http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/economicbenefitsstudies/millstone. Publication date: July 2003.

NEI 2004a. Economic Benefits of Diablo Canyon Power Station. Washington, DC, Nuclear Energy Institute. Retrieved February 9, 2009, from http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/economicbenefitsstudies/diablo canyon. Publication date: February 2004.

NEI 2004b. Economic Benefits of Indian Point Energy Center. Washington, DC, Nuclear Energy Institute. Retrieved February 9, 2009, from http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/economicbenefitsstudies/indianpoint. Publication date: April 2004.

NEI 2004c. Economic Benefits of Palo Verde Nuclear Generation Station. Washington, DC, Nuclear Energy Institute. Retrieved February 9, 2009, from http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/economicbenefitsstudies/palo verde. Publication date: November 2004.

NEI 2004d. Economic Benefits of the Duke Power-Operated Nuclear Power Plants. Washington, DC, Nuclear Energy Institute. Retrieved February 9, 2009, from http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/economicbenefitsstudies/dukepower. Publication date: December 2004.

NEI 2005a. Economic Benefits of Wolf Creek Generating Station. Washington, DC, Nuclear Energy Institute. Retrieved February 9, 2009, from http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/economicbenefitsstudies/wolfcreek. Publication date: July 2005.

NEI 2005b. Economic Benefits of Three Mile Island Unit 1. Washington, DC, Nuclear Energy Institute. Retrieved February 9, 2009, from http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/economicbenefitsstudies/threemileisland1. Publication date: November 2005.

NEI 2006a. Economic Benefits of Salem and Hope Creek Nuclear Generating Stations. Nuclear Energy Institute. Retrieved February 9, 2009, from http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/economicbenefitsstudies/salemhopecreek/. Publication date: September 2006.

NEI 2006b. Economic Benefits of The Exelon Pennsylvania Nuclear Fleet. Washington, DC, Nuclear Energy Institute. Retrieved February 9, 2009, from http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/economicbenefitsstudies/exelonpennsylvania. Publication date: August 2006.

NEI 2007. NEI Groundwater Protection Initiative 07-07—Final Guidance. Washington, DC, Nuclear Energy Institute. Publication date: August 2007.

Nelson, J. P. 1981. Three Mile Island and Residential Property Values: Empirical Analysis and Policy Implications. Land Economics 57(3): 364–372. Publication date: August 1981.

New Castle County 2007. New Castle County Code, Sub. No. 2 to Ordinance No. 06-140, To Revise Chapter 28 of the New Castle County Code (Planning) and Chapter 40 of the New Castle County Code (also Known as the Unified Development Code—UDC) Regarding Article 33 (Definitions) Regarding Comprehensive Planning). Introduced December 12, 2006.

New Jersey Governor's Office 2008. New Jersey Master Plan. Trenton, NJ. Publication date: October 2008.

New Jersey Pinelands Commission 2009. New Jersey Pinelands Electric-Transmission Right-of-Way Vegetation Management Plan, Final Draft. R.G. Lathrop and J.F. Bunnell, Rutgers University, New Brunswick, New Jersey. Publication date: February 2009.

NJBPU 2008. New Jersey's Clean Energy Program: 2007 Annual Report. Trenton, New Jersey, New Jersey Board of Public Utilities. Retrieved February 12, 2009, from http://www.njcleanenergy.com/files/file/Library/2007%20FINAL%20annual%20report.pdf.

NJDEP 2001. New Jersey Rare Species and Natural Community Lists by County. Trenton, New Jersey, New Jersey Department of Environmental Protection, Division of Parks and Forestry, Natural Heritage Program. Retrieved March 20, 2008, from http://www.nj.gov/dep/parksandforests/ natural/heritage/countylist.html.

NJDEP 2002. Hope Creek Generating Station Permit NJ0025411, Surface Renewal Water Permit Action, Draft Permit and Fact Sheet and Statement of Bases. Trenton, New Jersey, New Jersey Department of Environmental Protection. Issue date: November 7, 2002.

NJDEP 2003. Final Consolidated Permit Renewal Action, Hope Creek Generating Station NJPDES Permit NJ0025411. Trenton, New Jersey, New Jersey Department of Environmental Protection. Issue date: January 15, 2003.

NJDEP 2004. Water Allocation Permit WAP040001. Trenton, New Jersey, New Jersey Department of Environmental Protection. Issue date: December 30, 2004.

NJDEP 2005. What Wind Turbine Development Can, and Cannot Do, for the State of New Jersey. Trenton, New Jersey, New Jersey Department of Environmental Protection. Retrieved April 23, 2008, from http://www.state.nj.us/njwindpanel/docs/windturbine_faq.pdf.

NJDEP 2006. New Jersey Landscape Project Map Book. Department of Endangered and Non-game Species. Trenton, New Jersey, New Jersey Department of Environmental Protection. Retrieved May 14, 2008, from http://www.state.nj.us/dep/fgw/ensp/mapbook.htm.

NJDEP 2007a. New Jersey Bald Eagle Project, 2007. Division of Fish and Wildlife, Trenton, New Jersey, New Jersey Department of Environmental Protection. Publication date: December 2007.

NJDEP 2007b. Public Water System Deficit/Surplus for Cumberland, Gloucester, and Salem Counties. Trenton, New Jersey, New Jersey Department of Environmental Protection. Retrieved March 26, 2008, from http://www.nj.gov.

NJDEP 2007c. Map of New Jersey Coastal Zone. Trenton, New Jersey, New Jersey Department of Environmental Protection, Coastal Management Program. Retrieved November 23, 2008, from http://www.nj.gov/dep/cmp/czm_map.html.

NJDEP 2008a. Letter from Herbert A. Lord (New Jersey Department of Environmental Protection) to TetraTech NUS regarding Rare Species Information for License Renewal of the Salem and Hope Creek Generating Stations. Dated: June 25, 2008.

NJDEP 2008b. New Jersey's Endangered and Threatened Wildlife. New Jersey Department of Environmental Protection, Division of Fish and Wildlife. Trenton, New Jersey, New Jersey Department of Environmental Protection. Retrieved March 27, 2008, from http://www.nj.gov/dep/fgw/tandespp.htm.

NJDEP 2008c. New Jersey Rare Plant Species and Ecological Community Lists by County. Trenton, New Jersey, New Jersey Department of Environmental Protection, Division of Parks and Forestry, Natural Heritage Program. Retrieved February 9, 2009 from http://www.nj.gov/dep/parksandforests/natural/heritage/countylist.html.

NJDEP 2008d. New Jersey Bald Eagle Project, 2008. Trenton, New Jersey, New Jersey Department of Environmental Protection, Division of Fish and Wildlife. Publication date: December 2008.

NJDEP 2008e. Peregrine Falcon Research and Management Program in New Jersey, 2008. Trenton, New Jersey, New Jersey Department of Environmental Protection, Division of Fish and Wildlife.

NJDEP 2008f. The 2008 Osprey Project in New Jersey. Trenton, New Jersey, New Jersey Department of Environmental Protection, Division of Fish and Wildlife. Retrieved February 12, 2009, from http://www.state.nj.us/dep/fgw/ensp/pdf/osprey08.pdf.

NJDEP 2008g. Bureau of Air Quality Planning. Attainment Areas Status. Trenton, New Jersey, New Jersey Department of Environmental Protection. Retrieved March 27, 2008, from http://www.state.nj.us/dep/baqp/aas.html.

NJDEP 2009. Letter from Mark Mauriello (Acting Commissioner-NJDEP) to Honorable George Pavlou (Acting Regional Administrator - USEPA Region 2) regarding recommendations for ozone non-attainment boundaries. Dated: April 1, 2009.

NJDOT 2007. NJ Traffic Count. Trenton, New Jersey, New Jersey Department of Transportation. Retrieved March 13, 2008, from http://www.nj.gov/transportation/refdata/roadway/traffic.shtm.

NJGS 1965. Widmer, K. Geology of the Groundwater Resources of Mercer County. Trenton, New Jersey, New Jersey Geological Survey. Geological Report Series No. 7.

NJGS 1995. Navoy, A.S., and G. B. Carleton, Ground-Water Flow Conditions in the Potomac-Raritan-Magothy Aquifer System, Camden Area, New Jersey. Trenton, New Jersey, New Jersey Geological Survey, Geologic Survey Report GSR 38.

NMFS 1993. Biological Opinion and Incidental Take Statement Regarding Continued Operation of Salem and Hope Creek Nuclear Generating Stations. Silver Spring, Maryland, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service. Publication date: January 21, 1993.

NMFS 1998a. Final Recovery Plan for the Shortnose Sturgeon, *Acipenser brevirostrum*. Silver Spring, Maryland, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Shortnose Sturgeon Recovery Team. Publication date: December 1998.

NMFS 1998b. Essential Fish Habitat Description. Winter Flounder, *Pleuronecetes americanus*. Gloucester, Massachusetts, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Northeast Regional Office, New England Fisheries Management Council. Retrieved November 18, 2008, from www.nero.noaa.gov/hcd/winter.pdf. Publication date: October 7, 1998.

NMFS 1998c. Essential Fish Habitat Description. Windowpane Flounder, *Scopthalmus aquosus*. Gloucester, Massachusetts, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Northeast Regional Office, New England Fisheries Management Council. Retrieved November 18, 2008, from www.nero.noaa.gov/hcd/windowpane.pdf. Publication date: October 7, 1998.

NMFS 1999a. Essential Fish Habitat Source Document: Butterfish, *Peprilus triacanthus*, Life History and Habitat Characteristics. Technical Memorandum NMFS-NE-145. Woods Hole, Massachusetts, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Northeast Region. Retrieved November 18, 2008 from http://www.nefsc.noaa.gov/nefsc/publications/tm/tm145/. Publication date: September 1999.

NMFS 1999b. Incidental Take Statement for Salem Nuclear Generating Station. Silver Spring, Maryland, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Office of Protected Resources. Publication date: January 21, 1999.

NMFS 2007. "Endangered and Threatened Wildlife and Plants; Notice of Availability of the Status Review Report for Atlantic Sturgeon in the United States," Federal Register, Vol. 72, No. 63, pages 15865-15866. Washington, D.C. April 3.

NPS 2008a. National Register of Historic Places Information System, Salem County, New Jersey. U.S. Department of the Interior, National Park Service, National Register of Historic Places. Retrieved April 18, 2008, from http://www.nr.nps.gov.

NPS 2008b. National Register of Historic Places Information System, New Castle County, Delaware. U.S. Department of the Interior, National Park Service, National Register of Historic Places. Retrieved April 26, 2008, from http://www.nr.nps.gov.

NRC 1981. Storage of Low-level Radioactive Wastes at Power Reactor Sites. Generic Letter 81-38, Washington DC, U.S. Nuclear Regulatory Commission. Publication date: November 10, 1981.

NRC 1984. Final Environmental Statement related to the operation of Hope Creek Nuclear Generating Station, Docket No. 50-354, Public Service Electric and Gas Company, Atlantic City Electric Company. NUREG-1074. Washington DC, U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation. Publication date: December 1984.

NRC 1996a. Environmental Review for Renewal of Nuclear Power Plant Operating Licenses. Washington, DC, U.S. Nuclear Regulatory Commission, Federal Register 61 (109): 28467–28497. Publication date: June 5, 1996.

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

NRC 1996c. Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Correction. Washington, DC, U.S. Nuclear Regulatory Commission, Federal Register 61 (147): 39555–39556. Publication date: July 30, 1996.

NRC 1996d. Environmental Review for Renewal of Nuclear Power Plant Operating Licenses. Washington, DC, U.S. Nuclear Regulatory Commission, Federal Register 61 (244): 66537–66554. Publication date: December 18, 1996.

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

NRC 1996f. 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. Washington, DC, U.S. Nuclear Regulatory Commission. Volumes 1 and 2. NUREG-1529. Publication date: May 1996.

NRC 1999a. Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS). Volume 1, Addendum 1. NUREG-1437. Washington, DC, U.S. Nuclear Regulatory Commission. Publication date: May 1996.

NRC 1999b. Changes to Requirements for Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Final Rule. Washington, DC, U.S. Nuclear Regulatory Commission. Federal Register 64 (171): 48496–48507. Publication date: September 3, 1999.

NRC 2000. Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses; Supplement 1 to Regulatory Guide 4.2. Washington, DC, U.S. Nuclear Regulatory Commission.

NRC 2001. Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues. Office Instruction No. LIC-203. Effective June 21, 2001.

NRC 2002. Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities. Supplement 1; Regarding the Decommissioning of Nuclear Power Reactors. NUREG-0586, Supplement 1. Washington, DC, U.S. Nuclear Regulatory Commission. Publication date: November 2002.

NRC 2004. Briefing Package for March 15, 2004, Drop-in Visit by Public Service Enterprise Group (PSEG) Nuclear, LLC. Hope Creek Generating Station and Salem Nuclear Generating Station, Unit Nos. 1 and 2. Attachment to e-mail from G. Meyer to R Blough. ML060610205. Retrieved August 14, 2008, from http://www.nrc.gov/reading-rm/adams/web-based.html. Dated March 11, 2004.

NRC 2005. Memorandum and Order in the Matter of Exelon Generation Company, LLC (Early Site Permit for Clinton ESP Site). Docket No. 52-007-ESP, ASLB No. 04-821-01-ESP. Washington, DC, U.S. Nuclear Regulatory Commission, Atomic Safety and Licensing Board. Ruling Date: July 28, 2005.

NRC 2007. Hope Creek Generating Station Draft Environmental Assessment and Finding of No Significant Impact Related to the Proposed License Amendment to Increase the Maximum Reactor Power Level. Washington, DC, U.S. Nuclear Regulatory Commission. Federal Register 72(203): 59563–59573. Publication date: October 22, 2007.

NRC 2008a. Approved Applications for Power Uprates. Washington, DC, U.S. Nuclear Regulatory Commission. Retrieved March 21, 2008, from http://www.nrc.gov/reactors/operating/licensing/power-uprates/approved-applications.html.

NRC 2008b. PSEG Nuclear, LLC; Hope Creek Generating Station Final Environmental Assessment and Finding of No Significant Impact, Related to the Proposed License Amendment to Increase the Maximum Reactor Power Level. Docket No. 50-354. Washington, DC, U.S. Nuclear Regulatory Commission. Federal Register 73(48): 13032–13044. Publication date: March 11, 2008.

NRC 2009. Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Supplement 36 Regarding Beaver Valley Power Station, Units 1 and 2, Final Report. NUREG-1437, Supplement 36. Office of Nuclear Reactor Regulation. Washington, D.C. Publication date: May 2009.

NREL 2005. A Geographic Perspective on the Current Biomass Resource Availability in the United States. Report No. NREL/TP-560-39181. National Renewable Energy Laboratory. Retrieved May 7, 2008, from http://www.nrel.gov/docs/fy06osti/39181.pdf. Publication date: December 2005.

NREL 2008. What is Ocean Thermal Energy Conversion? Golden, Colorado, National Renewable Energy Laboratory. Retrieved May 9, 2008, from http://www.nrel.gov/otec/what.html.

NRRI 2007. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Silver Spring, Maryland, National Regulatory Research Institute. Retrieved May 5, 2008, from http://nrri.org/pubs/electricity/07-03.pdf. Publication date: February 14, 2007.

Offshore Wind 2008. North American Offshore Wind Project Information. Retrieved April 23, 2008, from http://www.offshorewind.net/index.html.

O'Herron, J. C., K. W. Able, and R. W. Hastings 1993. Movements of Shortnose Sturgeon, *Acipenser brevirostrum*, in the Delaware River. Estuaries 16(2): 235–240. Publication date: June 1993.

OMB 2008. Detailed Information on the Low Income Home Energy Assistance Program Assessment. U.S. Office of Management and Budget. Pages 474–492 in Annual Energy Outlook 2008, Document No. DOE/EIA-0383 (2008), ADAMS Accession No. ML082880730. Publication date: June 2008.

Orth-Rodgers 2002. Planning for the Future: A Summary of Cumberland County Planning Initiatives. Prepared for the Cumberland County Department of Planning and Development. Somerset, New Jersey. Publication date: October 2002.

PJM 2005. Vegetation Management Plan for Facilities Within MAAC. Report No. 44085. Norristown, Pennsylvania, PJM Interconnection, LLC. Publication date: March 2005.

PJM 2007a. PJM 2006 Regional Transmission Expansion Plan, Section 2: Developing an Expansion Plan. Norristown, PA. PJM Interconnection, LLC. Retrieved March 24, 2008 from http://www.pjm.com/planning/2006-reg-trans-ex-plan.html.

PJM 2007b. PJM 2006 Regional Transmission Expansion Plan, Section 2: Developing an Expansion Plan. Norristown, Pennsylvania, PJM Interconnection, LLC. Retrieved March 24, 2008, from http://www.pjm.com/planning/2006-reg-trans-exp-plan.html.

PJM 2007c. 2006 State of the Market Report. Volume II: Detailed Analysis. Market Monitoring Unit. Norristown, Pennsylvania, PJM Interconnections, LLC. Retrieved September 11, 2008 from http://www.pjm.com/market-monitor/som-reports.html. Publication date: March 8, 2007.

PJM 2007d. 2007 PJM Load, Capacity, and Transmission Report. Norristown, Pennsylvania, PJM Interconnection, LLC. Retrieved May 7, 2008, from http://www.pjm.com/documents/downloads/reports/2007-pjm-411.pdf. Publication date: July 25. 2007.

PJM 2009. 2008 PJM Annual Report. Norristown, Pennsylvania, PJM Interconnection, LLC. Retrieved June 24, 2009 from http://www.pjm.com/about-pjm/who-we-are/annual-report.aspx.

PSEG 1983. Hope Creek Generating Station, Applicant's Environmental Report, Operating License Stage. Public Service Enterprise Group. Publication date: March 1983.

PSEG 1984. Salem Generating Station 316(b) Demonstration Project. Newark, New Jersey, Public Service Enterprise Group. Publication date: February 1984.

PSEG 1995. 1995 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program. Publication date: June 1995.

PSEG 1996. 1996 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 1997. 1997 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 1998. 1998 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 1999a. Application for Renewal of the Salem Generating Station NJPDES Permit. Newark, New Jersey, Public Service Enterprise Group Publication date: March 4, 1999.

PSEG 1999b. 1999 Annual Report. Newark New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 2000. 2000 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 2001. 2001 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 2002. 2002 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 2003. 2003 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 2004a. 2004 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 2004b. Alloway Creek Watershed Phragmites-Dominated Wetland Restoration Management Plan. Newark, New Jersey, Public Service Enterprise Group. Publication date: February 17, 2004.

PSEG 2005. 2005 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 2006a. Salem NJPDES Permit Renewal Application. NJPDES Permit No. NJ0005622. Newark, New Jersey, Public Service Enterprise Group. Issue date: February 1, 2006.

PSEG 2006b. 2006 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 2007a. 2007 Annual Report. Newark, New Jersey, Public Service Enterprise Group, Biological Monitoring Program.

PSEG 2007b. Radiological Environmental Monitoring Program for Salem Generating Station, Unit1: Docket No. 50-272; Salem Generating Station, Unit 2, Docket No. 50-311; Hope Creek Generating Station: Docket No. 50-354. 2006 Annual Radiological Environmental Operating Report, January 1 to December 31, 2006. Report Number LR-N07-0089. Newark, New Jersey, Public Service Enterprise Group. Publication date: April 2007.

PSEG 2008a. Radiological Environmental Monitoring Program for Salem Generating Station, Unit1: Docket No. 50-272; Salem Generating Station, Unit 2, Docket No. 50-311; Hope Creek Generating Station: Docket No. 50-354. 2007 Annual Radiological Environmental Operating Report, January 1 to December 31, 2007. LR-N08-0097. Newark, New Jersey, PSEG Nuclear, LLC. Publication date: May 2008.

PSEG 2008b. The Hope Creek Generating Station. Newark, New Jersey, Public Service Enterprise Group. Retrieved June 5, 2008, from http://www.pseg.com/companies/nuclear/hopecreek.jsp.

PSEG 2008c. PSEG Power LLC, Letter to U.S. Nuclear Regulatory Commission (D. Matthews) regarding Update to Letter of Intent Dated January 31, 2008. ADAMS Accession Number ML083430036. Dated December 2, 2008.

PSEG 2009a. Applicant's Environmental Report—Operating License Renewal Stage, Salem Generating Station. Newark, New Jersey, Public Service Enterprise Group. Publication date: August 2009.

PSEG 2009b. Hope Creek Generating Station Updated Final Safety Analysis Report, Rev. 17. Newark, New Jersey, Public Service Enterprise Group. Publication date: June 2009.

PSEG 2009c. Salem Generating Station—Updated Final Safety Analysis Report. Document No. PSEG-0008, Revision 24. Newark, New Jersey, Public Service Enterprise Group. Publication date: May 11, 2009.

Rephann, T. J. undated (circa 1997). The Economic Impacts of LULUs. Revised version published in Environment and Planning C: Government and Policy 2000 18(4): 393 - 407. Retrieved February 9, 2009, from http://www.equotient.net/papers/lulu.pdf.

RNP 2007. Wave and Tidal Energy. Portland, Oregon, Renewable Northwest Project. Retrieved May 9, 2008, from http://www.rnp.org/renewtech/Wave%20Tidal%20FactSheet%2007April4.pdf. Publication date: March 2007.

Rukenstein and Associates 2004. Smart Growth Plan. Delaware River and I-295/NJ Turnpike. Planned Growth Corridor. Salem County, New Jersey. Retrieved September 30, 2008, from www.salemcountynj.gov/cmssite/downloads/departments/Planning_Board/regionalplan2004.pdf. Submittal date: January 21, 2004.

Salem Main Street 2003. Main Street Revitalization Master Plan. City of Salem, New Jersey. Publication date: September 2003.

Schainker, R. B. 2006. Shaping & Firming Wind Energy with Electric Energy Storage. Retrieved September 12, 2008, from http://cwec.ucdavis.edu/forum2006/proceedings/Schainker_CWEC2006.pdf. Publication date: December 13, 2006.

Sheppard, S. C. 2007. Declaration of Stephen C. Sheppard. New York State Notice of Intention to Participate and Petition to Intervene and Supporting Declarations and Exhibits, Volume II of II, filed on November 30, 2007, pp 23–38 of 274. United States Nuclear Regulatory Commission; In re: License Renewal Application Submitted by Entergy Nuclear Indian Point 2, LLC, et al., Docket No. 50-247-LR and 50-286-LR, ASLBP No. 07-858-03-LR-BD01. Retrieved February 9,2009, from at http://ehd.nrc.gov/EHD_Proceeding/doccontent.dll?library=EHD2_ADAMS^HQ2KAD108&id=080950018:1.

State of New Jersey 2008. Property Tax Information. Retrieved March 4, 2008, from http://www.state.nj.us/dca/lgs/taxes/taxmenu.shtml.

TetraTech 2008. Salem/Hope Creek Calculation Package for Socioeconomics. Aiken, SC, TetraTech NUS. Publication date: November 2008.

TetraTech 2009. Salem/Hope Creek Generating Station Calculation Package for Ground Water Pumpage, Salem & Hope Creek Generating Station. Aiken, SC, Tetra Tech NUS. Publication date: February 23, 2009.

TNC 2008. The Nature Conservancy Ecological Assessment. Report, 2008.

UNESCO 2009. United Nations Educational, Scientific and Cultural Organization, FAQ—Biosphere Reserves? Retrieved March 9, 2009, from http://portal.unesco.org/science/en/ev.php-URL_ID=6797&URL_DO=DO_TOPIC&URL_SECTION=201.html.

USCB 1982. Characteristics of the Population. General Social and Economic Characteristics. New Jersey. Report Number PC80-1-C32. Washington, DC, U.S. Census Bureau. Publication date: February 1982.

USCB 1995. Population of Counties by Decennial Census 1900 to 1990. Washington, DC, U.S. Census Bureau. Retrieved March 11, 2008, from http://www.census.gov. Publication date: March 27, 1995.

USCB 2000a. P1. Total Population [1] – Universe: Total Population. Data Set: Census 2000 Summary File 1 (SF1) 100-Percent Data. Washington, DC, U.S. Census Bureau. Retrieved March 11, 2008, from http://factfinder.census.gov.

USCB 2000b. Census 2000 Demographic Profile Highlights. Washington DC, U.S. Census Bureau. Retrieved May 12, 2008, from http://factfinder.census.gov.

USCB 2003. Table 3b. Population in Metropolitan and Micropolitan Statistical Areas Ranked Separately by 2000 Population for the United States and Puerto Rico: 1990 and 2000. Washington, DC, U.S. Census Bureau. Retrieved May 12, 2008, from http://www.census.gov/.

USCB 2006. 2006 American Community Survey Data Profile Highlights. Washington, DC, U.S. Census Bureau. Retrieved March 11, 2008, from http://factfinder.census.gov/.

USCB 2008a. Metropolitan and Micropolitan Statistical Area Estimates. Table 1. Annual Estimates of the Population of Metropolitan and Micropolitan Statistical Areas: April 1, 2000 to July 1, 2007. Washington, DC, U.S. Census Bureau. Retrieved May 15, 2008, from http://www.census.gov/population/www/estimates/CBSA-est2007-annual.html.

USCB 2008b. State and County Quick Facts, People Quick Facts, Salem and Cumberland Counties. Washington, DC, U.S. Census Bureau. Retrieved April 20, 2008, from www.census.gov.

U.S. Court of Appeals for the Seventh Circuit 2006. Environmental Law and Policy Center et. al. v. U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC. No. 06-1442 (7th Cir. 2006). Decision date: December 5, 2006.

USDA 2004. 2002 Census of Agriculture - Volume 1, Geographic Area Series, Part 8 (Delaware), Part 20 (Maryland), Part 30 (New Jersey), and Part 38 (Pennsylvania). U.S. Department of Agriculture. Publication date: June 2004.

USFWS undated. Northeast Region Ecological Services, Endangered Species, Listings, State and County Listings: New Jersey. Washington, DC, U.S. Fish and Wildlife Service. Retrieved February 28, 2008, from http://www.fws.gov/northeast/endangered.

USFWS 1999. Endangered and Threatened Wildlife and Plants; Final Rule To Remove the American Peregrine Falcon From the Federal List of Endangered and Threatened Wildlife, and To Remove the Similarity of Appearance Provision for Free-Flying Peregrines in the Conterminous United States. Washington, DC, U.S. Fish and Wildlife Service. Federal Register 64(164): 46542–46558. Publication date: August 25, 1999.

USFWS 2007. Endangered and Threatened Wildlife and Plants; Removing the Bald Eagle in the Lower 48 States From the List of Endangered and Threatened Wildlife. Washington, DC, U.S. Fish and Wildlife Service. Federal Register 72(130): 37346–37372. Publication date: July 9, 2007.

USGS 1980. Luyzier, L. J., Digital-Simulation and projection of Head Changes in the Potomac-Raritan-Magothy Aquifer System, Coastal Plain, New Jersey 78p. West Trenton New Jersey, U. S. Department of the Interior, U.S. Geological Survey, Water-Resources Investigations 80-11.

USGS 1983. Walker, R. L., Evaluation of Water Levels in Major Aquifers of the New Jersey Coastal Plain, 1978. U. S. Department of the Interior, U.S. Geological Survey, Water-Resources Investigations Report 82-4077.

USGS 1999. Cauller, S.J., G. B. Carleton, and M. J. Storck, Hydrogeology of, Water Withdrawal from, and Water Levels and Chloride Concentrations in the Major Coastal Plain Aquifers of Gloucester and Salem Counties, New Jersey. West Trenton New Jersey, U. S. Department of the Interior, U.S. Geological Survey, Water-Resources Investigations Report 98-4136.

USGS 2001a. Lacombe, P.J., and R. Rosman, Water levels in, Extent of Freshwater in, And Water Withdrawals from Ten confined Aquifers, New Jersey and Delaware Coastal Plain, 1998. Reston, Virginia, U. S. Department of the Interior, U.S. Geological Survey, Water-Resources Investigations 00-4143,

USGS 2001b. Simulation of Ground-Water Flow in the Potomac-Raritan-Magothy Aquifer System Near the Defense Supply Center Philadelphia, and the point Breeze Refinery, Southern Philadelphia County, Pennsylvania. 48 p. New Cumberland, Pennsylvania, U. S. Department of the Interior, U.S. Geological Survey, Water-Resources Investigations 01-4218.

USGS 2003. Sloto, R. A., Historical Ground-Water-Flow Patterns and Trends in Iron Concentrations in the Potomac-Raritan-Magothy Aquifer System in Parts of Philadelphia, Pennsylvania, and Camden and Gloucester Counties, New Jersey, 43 p, 9 pl. New Cumberland, Pennsylvania, U. S. Department of the Interior, U.S. Geological Survey, Scientific Investigations Report 03-4255.

USGS 2007. Summary of the Ground-Water-Level Hydrologic Conditions in New Jersey 2006, Fact Sheet 2007-3049. West Trenton, NJ, U. S. Department of the Interior, U.S. Geological Survey, New Jersey Water Science Center. Publication date: June 2007.

USGS 2009. V. T. DePaul, R. Rosman, and P. J. Lacombe, Water-Level Conditions in Selected Confined Aquifers of the New Jersey and Delaware Coastal Plain, 2003. 135p. Reston, Virginia, U. S. Department of the Interior, U.S. Geological Survey, Scientific Investigations Report 2008-5145.

Appendix A

NRC NEPA Issues for License Renewal of Nuclear Power Plants

This Page Intentionally Left Blank

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. HCGS 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 HCGS has no plans to undertake.
2. Impacts of refurbishment on surface water use	1	NA	Issue applies to an activity, refurbishment, that HCGS 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 HCGS 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	NA	Issue applies to a plant feature, once-through cooling that HCGS does not have.
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	NA, and discussed in Section 4.1	Issue applies to a plant feature, cooling towers using make-up water from a small river, that HCGS does not have.
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	NA	Issue applies to an activity, refurbishment, that HCGS 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

Table A-1. HCGS Environmental Report Discussion of License Renewal NEPA Issues[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
19. Distribution of aquatic organisms	1	4 Introduction	4.2.2.1.6/4-19
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	NA, and discussed in Section 4.2	Issue applies to a plant feature, once-through cooling or a cooling pond, that HCGS does not have.
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	NA, and discussed in Section 4.3	Issue applies to a plant feature, once-through cooling or a cooling pond, that HCGS does not have.
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	NA, and discussed in Section 4.4	Issue applies to a plant feature, once-through cooling or a cooling pond, that HCGS does not have.
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)			
28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	4 Introduction	4.3.3/4-33
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	4 Introduction	4.3.3/4-33
30. Heat shock for plants with cooling-tower-based heat dissipation systems	1	4 Introduction	4.3.3/4-33
Groundwater Use and Quality			
31. Impacts of refurbishment on groundwater use and quality	1	NA	Issue applies to an activity, refurbishment, that HCGS has no plans to undertake.

Table A-1. HCGS 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 HCGS 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 withdrawing make-up water from a small river, that HCGS 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 HCGS does not have.
36. Groundwater quality degradation (Ranney wells)	1	NA	Issue applies to a feature, Ranney wells, that HCGS 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 HCGS 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 HCGS 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 HCGS has no plans to undertake.
41. Cooling tower impacts on crops and ornamental vegetation	1	NA	Issue applies to a feature, mechanical draft cooling towers, which HCGS does not have.
42. Cooling tower impacts on native plants	1	NA	Issue applies to a feature, mechanical draft cooling towers, which HCGS does not have.
43. Bird collisions with cooling towers	1	4 Introduction	4.3.5.2/4-45
44. Cooling pond impacts on terrestrial resources	1	NA	Issue applies to a feature, cooling ponds, that HCGS does not have.

Table A-1. HCGS Environmental Report Discussion of License Renewal NEPA Issues[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
45. Power line right-of-way management (cutting and herbicide application)	1	4 Introduction	4.5.6.1/4-71
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 HCGS 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 HCGS has no plans to undertake.
55. Occupational radiation exposures during refurbishment	1	NA	Issue applies to an activity, refurbishment, that HCGS 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 ponds or , canals that discharge to a small river, that HCGS 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

Table A-1. HCGS Environmental Report Discussion of License Renewal NEPA Issues[a] (Continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
62. Occupational radiation exposures (license renewal term)	1	4 Introduction	4.6.3/4-95
Socioeconomics			
63. Housing impacts	2	4.14	3.7.2/3-10 (refurbishment - not applicable to HCGS) 4.7.1/4-101 (renewal term)
64. Public services: public safety, social services, and tourism and recreation	1	4 Introduction	<u>Refurbishment</u> (not applicable to HCGS) <u>Renewal Term</u> 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 HCGS) 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 HCGS 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 HCGS 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 HCGS) 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 HCGS) 4.7.7/4-114 (renewal term)
72. Aesthetic impacts (refurbishment)	1	NA	Issue applies to an activity, refurbishment, that HCGS 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. HCGS 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. HCGS 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 Hope Creek Generating Station's New Jersey Pollutant Discharge Elimination System permit NJ 0025411, which authorizes the discharge of wastewater to the Delaware River and stipulates the conditions of the permit.

This Page Intentionally Left Blank

Table of Contents

This Page Intentionally Left Blank

DISCLAIMER

The full text of certain NPDES permits and the associated fact sheets has been made available to provide online access to this public information. EPA is making permits and fact sheets available electronically to provide convenient access for interested public parties and as a reference for permit writers. The ownership of these documents lies with the permitting authority, typically a State with an authorized NPDES program.

While EPA makes every effort to ensure that this web site remains current and contains the final version of the active permit, we cannot guarantee it is so. For example, there may be some delay in posting modifications made after a permit is issued. Also note that not all active permits are currently available electronically. Only permits and fact sheets for which the full text has been provided to Headquarters by the permitting authority may be made available. Headquarters has requested the full text only for permits as they are issued or reissued, beginning November 1, 2002.

Please contact the appropriate permitting authority (either a State or EPA Regional office) prior to acting on this information to ensure you have the most up-to-date permit and/or fact sheet. EPA recognizes the official version of a permit or fact sheet to be the version designated as such and appropriately stored by the respective permitting authority.

The documents are gathered from all permitting authorities, and all documents thus obtained are made available electronically, with no screening for completeness or quality. Thus, availability on the website does not constitute endorsement by EPA.

Gresney

RECEIVED
JUL 10 2003
By

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

James E. McGreevey
Governor

Bradley M. Campbell
Commissioner

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

JAN 15 2003

Gabor Salamon, Manager – Nuclear Safety and Licensing
PSEG Nuclear LLC
P.O. Box 236
Hancocks Bridge, NJ 08038

U.S. EPA, REGION II

Re: Final Consolidated Renewal Permit Action
Category(s): B -Industrial Wastewater
RF -Stormwater
NJPDES Permit No. NJ0025411
HOPE CREEK GENERATING STATION
Lower Alloways Creek, Salem County

Dear Permitte:

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. This permit action authorizes discharge activity(ies) applicable to the discharge category(ies) identified above. This permit action authorizes the permittee to discharge cooling tower blowdown with internal monitoring points, and stormwater with tidal influx .

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 Consolidated 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).

As per N.J.A.C. 7:14A-4.2(e)3, any person planning to continue discharging after the expiration date of an existing NJPDES permit shall file an application for renewal at least 180 calendar days prior to the expiration of the existing permit.

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.

New Jersey is an Equal Opportunity Employer
Recycled Paper

per_Fncv.rtf

As a result of this permit action, your monitoring report forms have been changed. Enclosed with this permit are the new monitoring report forms (MRFs). Beginning the effective date of the permit, please use the new MRFs. Questions regarding the new forms shall be directed to this Bureau for further clarification.

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

Sincerely,

Pilar Patterson, Chief
Bureau of Point Source Permitting Region 2

Enclosures

cc: Permit Distribution List

Masterfile #: 15647; PI #: 46815

per_Fncv.rtf

Swezey,
? Steve ? web?

U.S. EPA, R

2003 APR -4

WATER PROGRAMS BRANCH

State of New Jersey

James E. McGreevey
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

Bradley M. Campbell
Commissioner

RECEIVED
JUL 10 2003
By

APR 01 2003

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Gabor Salaman, Manager – Nuclear Safety
PSEG Nuclear LLC
PO Box 236/N21
Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Re: Final Surface Water Administrative Mod Permit Action – Clarification
of Stormwater Requirements
Category: B-Industrial Wastewater, NJPDES Permit No. NJ0025411
Hope Creek Generating Station, Lower Alloways Creek Twp., Salem County

Dear Permittee:

The Department issued your **final** New Jersey Pollutant Discharge Elimination System (NJPDES) permit renewal on December 31, 2002. As you know, a clarification was issued on February 24, 2003 to change the expiration date from February 31, 2008 to February 29, 2008. It has come to our attention that certain other permit conditions need clarification. Therefore, this administrative modification serves to change the following permit conditions:

- Delete the stormwater monitoring requirements indicated on page 1 of 16 of Part III. Although these requirements were included in the draft permit issued on November 7, 2002, it was clearly the Department's intent to delete these requirements in any final permit action and the inclusion of these requirements was clearly an error. This is discussed on page 8 of the Response to Comments document included in the December 31, 2002 final permit action.

- Delete Attachment 1. Specific stormwater requirements are included in Part IV where the language in Part IV is either identical to Attachment 1 or, in instances where the language is slightly reworded, the intent is the same. It is redundant to include both the stormwater conditions of Part IV and Attachment 1 and serves to complicate the permit. As a result, Attachment 1 has been deleted.

Please replace Part III, page 1 of 16 and Attachment 1 with the enclosed "placeholder" sheets. Questions or comments regarding the final action should be addressed to Susan Rosenwinkel at (609) 292-4860.

Sincerely,

Pilar Patterson, Chief
Bureau of Point Source Permitting Region 2

Enclosures
cc: Permit Distribution List
Masterfile #: 15647; PI #: 46815

Fncv_dsw.rtf

New Jersey is an Equal Opportunity Employer
Recycled Paper

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: NJ0025411

Final: Consolidated Minor Modification

Permittee:
PSEG NUCLEAR LLC
PO BOX 236/N21
ALLOWAY CREEK NECK RD
HANCOCKS BRIDGE, NJ 08038

Co-Permittee:

Property Owner:
PUBLIC SERVICE ELECTRIC AND GAS CO.
80 PARK PLAZA
PO BOX 570
NEWARK, NJ 07102

Location Of Activity:
HOPE CREEK GENERATING STATION
ARTIFICIAL ISLAND
FOOT OF BUTTONWOOD RD
LOWER ALLOWAYS CREEK, NJ 08038

Authorization(s) Covered Under This Approval	Issuance Date	Effective Date	Expiration Date
B – Industrial Wastewater RF - Stormwater	12/31/03	3/1/03	2/29/08

Authorization(s) Covered Under This Approval	Issuance Date	Effective Date	Expiration Date
Clarification of Permit Conditions	3/12/03	3/1/03	2/29/08

By Authority of:
Commissioner's Office

DEP AUTHORIZATION
Pilar Patterson
Bureau of Point Source Permitting – Region 2
Division of Water Quality

(Terms, conditions and provisions attached hereto)

Division of Water Quality

PART III
LIMITS AND MONITORING REQUIREMENTS

A. STORMWATER DISCHARGE

Monitored Location Group Members

463A Stormwater, 464A Stormwater, 465A Stormwater

**ATTACHMENT 1:
CONTENTS OF THE
STORMWATER
POLLUTION PREVENTION PLAN**

Pages i and 1 – 8 have been deleted via this minor permit modification effective March 1, 2003. All requirements as contained in Attachment 1 of the final permit renewal issued on December 31, 2002 are either identical in wording or in intent to those conditions contained in item H of Part IV-Stormwater thereby making Attachment 1 redundant. As a result Attachment 1 is being deleted.

HOPE CREEK GENERATING STATION
Surface Water Renewal Permit Action

NJPDES Permit Number: NJ0025411
Program Interest Number: 46815

Table of Contents

This permit package contains the items listed below:

toc_dsw.rtf

STAY REQUEST AND TRACKING FORM

I. Permit Containing Condition(s) to Be Stayed:

HOPE CREEK GENERATING STATION

Issuance Date of Final Permit Decision	Permit Number
12/31/02	NJ0025411

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.

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

I. Permit Being Appealed:

HOPE CREEK GENERATING STATION

Issuance Date of Final Permit Decision	Permit Number
12/31/02	NJ0025411

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).

B. If you are a person seeking consideration as a party to the action:

1. A statement setting forth each legal or factual question alleged to be at issue;

*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.

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 [add if necessary: *and in accordance with repealed N.J.A.C. 7:14A-8.4, if the public comment period began or ended before May 5, 1997*)];
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
      Bureau of Point Source Permitting
      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: __________

Working Cost Center 4___; Susan Rosenwinkel, Bureau of Point Source Permitting – Region 2

Response to Comments
Page 1 of 8
Permit No. NJ0025411

New Jersey Department of Environmental Protection
Division of Water Quality
Bureau of Point Source Permitting – Region 2

RESPONSE TO COMMENTS

Comments were received on the draft NJPDES Permit Renewal No. NJ0025411 issued on November 7, 2002. The thirty (30) day public comment period began on November 19, 2002, when the Public Notice was published in the *Today's Sunbeam*. It was also published in the DEP Bulletin on November 13, 2002. It ended on December 19, 2002. The following person[s] commented during the public comment period:

1. Gabor Salamon, Manager-Nuclear Safety and Licensing, PSE Nuclear LLC in a letter dated December 24, 2002.

A summary of the timely and significant comments received, the New Jersey Department of Environmental Protection's (Department) responses to these comments, and an explanation of any changes from the draft action have been included below:

Comments on Chemical-Specific Conditions forOutfalls DSNs 461A, 461C, and 462B

Fact Sheet, Section 5, page 5 of 28 - Station Outfalls and Discharge Components

Comment 1: The draft permit states that "[While] the permittee's stormwater discharges are currently regulated under Stormwater Pollution Prevention Plan requirements, the Department has determined it appropriate to regulate the stormwater discharges under the General Stormwater Permit NJ0088315 which will be issued upon finalization of this draft renewal permit.". PSEG Nuclear LLC ("hereafter PSEG") believes it is not appropriate to regulate the stormwater discharges under the General Stormwater Permit concurrent with the stormwater requirements contained in this individual NJPDES permit. The permit application requested continued regulation under the Stormwater Pollution Prevention Plan requirements and those requirements appear to be continued, though modified, in the Draft permit. PSEG requests the sentence quoted above be deleted.

Response 1: The Department agrees that the inclusion of this sentence was made in error. The permittee is correct in that this subject permit contains individual stormwater requirements as noted throughout the rest of the permit.. This clarification is hereby noted for the Administrative Record.

Fact Sheet, Section 5, page 7 of 28 - Yard Drains (DSN's 463A, 464A, 465A)

Comment 2: The Department has renamed outfall DSN 462A as outfall DSN 465 because the NJEMS database will not accept both DSN 462A and DSN 462B. DSN 462B has been retained because it has a regulatory history where limits and monitoring conditions have been set and data have been collected. PSEG reminds the Department that DSN 462A also has a regulatory history where limits and monitoring conditions were set and data have been collected for the period October 1985 through March 1997.

Response 2: The Department agrees that DSN 462A has a regulatory history although the Department maintains that it is appropriate to rename DSN 462A as outfall DSN 465 in this subject permit action due to the reason noted above. Therefore, no changes to the final permit have been made as a result of this comment, although the Department notes this information for the Administrative Record.

Fact Sheet, Section 8.B, page 10 of 28 - DSN 461A

Comment 3: The Department has changed the frequency for monitoring Chlorine Produced Oxidants (CPO) from three times per week to continuous monitoring. The data collected during the three times per week monitoring conducted by PSEG during the term of the existing permit demonstrates that CPO is not normally present in the discharge as indicated in the Permit Summary Table at page 18 of 28. PSEG believes continuous monitoring is not warranted and periodic grab sampling is more appropriate.

PSEG has responsibly performed an evaluation to determine the CPO concentration when there was a reason to believe unmonitored CPO may have been discharged. In June 2000, a discharge occurred that contained sodium hypochlorite at a time that no effluent monitoring was in progress. PSGEG notified the Department, conducted an internal investigation, and performed calculations to determine the concentration of CPO in the effluent. CPO was determined to be within the limitations of the NJPDES Permit. Although a continuous monitoring device would have precluded the need for PSEG to calculate the effluent CPO concentrations, a continuous monitoring device would not have changed the effluent concentration.

Continuous chlorine analyzers were installed to monitor the cooling tower blowdown (DSN 461A) until 1997, when the Department modified the requirement for CPO monitoring to three times per week. The inherent difficulty of maintaining analyzer operations in this region of the Estuary was demonstrated during this period of continuous monitoring. The two primary methods for continuous chlorine analysis are amerometric and specific-ion electrode. The high suspended solids and silt concentrations present in the Estuary tend to clog instrument flow pats and specific ion electrode membranes. The abrasiveness of the silt also causes excessive wear on moving components such as pumps and valves. These factors limit the effectiveness of continuous chlorine analyzers because of the extensive routine and corrective maintenance.

PSEG requests the continuous monitoring requirement be deleted. If the three times per week current sampling program is inadequate, PSEG recommends modifying the sample frequency to daily (seven days per week).

Response 3: The Department maintains that a continuous sampling frequency is appropriate for DSN 461A. This discharge is continuously chlorinated and is of a significant volume. In addition, the Department notes that there was a unanticipated discharge of chlorine produced oxidants in June 2000. Although the Department agrees that the installation of continuous chlorine monitors may not have prevented this discharge, the presence of continuous chlorine monitors could have better evaluated the amount of chlorine produced oxidants in the discharge in comparison to an evaluation by calculations.

No changes to the permit have been made as a result of this comment.

Fact Sheet, Section 8.B, page 11 of 28 - DSN 461A

Comment 4: The last paragraph indicates that effluent limitations for oil and grease have been included at DSN 461A. For clarification, the parameter limited at DSN 461C equivalent to oil and grease is total petroleum hydrocarbons.

Response 4: The permittee is correct in noting that total petroleum hydrocarbons is limited at DSN 461C; therefore, this sentence on page 11 erroneously identifies oil and grease as opposed to total petroleum hydrocarbons. The Department has correctly noted that total petroleum hydrocarbons is limited at DSN 461C as indicated on page 5 of Part III as well as on pages 12 and 19 of the Fact Sheet. The Department hereby notes this clarification pertaining to page 11 for the Administrative Record. Because the correct parameter is included on page 5 of Part III, no changes to the final permit are necessary as a result of this comment.

Fact Sheet, Section 8.b., page 13 of 28 - DSN 462B

Comment 5: The Department has incorporated a monthly average concentration limit for BOD_5 of 30 mg/L and a weekly limit of 45 mg/L as DSN 462B. PSEG believes these new limitations are not appropriate for this discharge. The reference to N.J.A.C. 7:14A-12.2(b) is not appropriate since DSN 462B discharges to DSN 461A and, therefore, DSN 462B is not a "direct discharge". N.J.A.C. 7:14A-12.2 is only applicable to a direct discharge. Upon completion of the rerouting of the DSN 462B discharge to DSN 461A, this is an internal monitoring point and not a direct discharge (1997 Permit Fact Sheet, page 60 of 86).

The Department indicates these limitations are particularly appropriate where the flow volumes fluctuate over time. The effluent flow from DSN 462B for January 2001 through February 2002 was an average of 0.01 MGD and a maximum of 0.03 MGD, and for the period of April 1997 through March 2001 the effluent flow was an average of 0.02 MGD and a maximum of 0.07 MGD (Permit Summary Table, page 20 of 28). The maximum effluent flow during that five year period was only 25% of the design flow of the sewage treatment plant (0.28MGD) and the range of values does not indicate a highly variable flow that would warrant imposition of additional limitations. The monthly minimum Percent Removal of BOD_5 limitation of 87.5% (more stringent than N.J.A.C. 7:14A-12.2(b) and the monthly average loading limitation for BOD_5 of 8 kg/day (based on the DRBC allocation) have been adequate since the 1985 NJPDES Permit and new limitations are not warranted at this time.

Response 5: The Department has determined that the intent of N.J.A.C. 7:14A-12.2(b) is that the limitations contained in this regulation pertain to direct discharges to surface water as opposed to discharges to a municipal utilities authority which then discharge to surface waters. Therefore, the Department does not agree that N.J.A.C. 7:14A-12.2(b) should be interpreted to mean that these limitations are not appropriate for this internal monitoring point. These secondary treatment limitations set the standard for the level of treatment appropriate for sanitary discharges and the Department maintains that they are appropriate for DSN 461C since it is a sanitary discharge.

The Department also maintains that concentration limits are particularly appropriate for this discharge given the variable flow rates of influent sanitary wastewater. It is the Department's understanding that the amount of personnel present at the plant can widely fluctuate during refueling outages given the fact that the facility makes use of this time to maintain Station operations which result in the presence of additional Station personnel. Therefore, the Department has determined that both concentration and mass limitations are appropriate for this discharge.

The Department recognizes that the permittee typically discharges well below the design flow rate; however, N.J.A.C. 7:14A-12.2 does not make exception for this circumstance. The Department also recognizes that the mass limit of 8 kg/day for BOD_5 may be more stringent than the concentration limits at N.J.A.C. 7:14A-12.2 given certain flow circumstances; however, the Department has determined that it is required to apply these concentration limits.

No changes to the permit have been made as a result of this comment.

Fact Sheet, Section 8.b, page 13 of 28 - DSN 462B

Comment 6: The Fact Sheet states that there is a weekly average TSS limitations of 45 mg/L at DSN 462B in the current permit and thus this limitation was retained. The weekly average TSS limitation was deleted from DSN 462B upon rerouting DSN 462B to discharge to DSN 461A (see 1997 NJPDES Permit, Part III-B/C, Section 1.C.2). The Fact sheet for the 1997 NJPDES Permit states that "the seven-day average limitation of 45 mg/L will be deleted since this will be an internal monitoring point and there will not be a direct discharge". Since the limitation is not retained from the current Permit and DSN 462B is not a direct discharge, PSEG requests the weekly average limitation for TSS be deleted.

Response 6: The Department recognizes that it has incorrectly stated that the weekly average limitation for TSS has been retained from the existing permit. Nonetheless, based on the rationale indicated in **Response 5** above, the Department maintains that inclusion of this limit is appropriate based on the secondary treatment standards.

No changes to the permit have been made as a result of this comment.

Fact Sheet, Section 8.K, page 16 of 28 - DSN 461A

Comment 7: Consistent with the comments above regarding continuous CPO monitoring , if the Department determines that continuous CPO monitoring is not required, the schedule of compliance would not be required.

Response 7: Please refer to **Response 3.**

Fact Sheet, Section 13, page 20 of 28

Comment 8: The permit summary table for DSN 462B indicates that there is a 45 mg/L TSS weekly average limitation. As discussed above, the current permit does not contain a weekly average limitation of reporting requirement for TSS.

Response 8: The Department agrees that the 45 mg/L TSS weekly average limitation was deleted in the February 14, 1997 NJPDES Permit as noted in Section 1.C.2, Part III-B/C. Nonetheless, the Department has determined it appropriate to include this limitation at this time for the reasons discussed in **Response 6.**

Permit, Part III, Section A, Table III-B-1, page 2 of 16

Comment 9: As discussed above, PSEG believes continuous monitoring is not warranted and periodic grab sampling is more appropriate. The continuous monitoring requirement identified as "final" should be deleted and the three times per week grab sample identified as "initial" should be retained for the term of the Permit.

Response 9: Please refer to **Response 3.**

Permit, Part III, Section A, Table III-C-2, page 6 of 16

Comment 10: The Quantification Limit of 20 micrograms per liter for Ammonia Nitrogen (as N) is not achievable using approved analytical methodologies by the New Jersey Certified Laboratories contacted. The Department has recognized the challenge of meeting the Recommended Quantitation Levels (hereafter "RQLs") at the Fact Sheet, Section 8.E., page 14 of 28 in stating that "the quantitation levels listed therein can be reliably and consistently achieved by most state certified laboratories for most of the pollutants" (emphasis added). Ammonia Nitrogen appears to be one of the exceptions. The Delaware Estuary in the vicinity of the Station has a background ammonia nitrogen concentration of approximately five to ten times the proposed RQL. PSEG recommends the RQL for Ammonia Nitrogen be changed to 100 micrograms per liter. Additionally, PSEG requests clarification that the term Recommended Quantitation Level as used in this section has the same meaning as the term Quantification Limit as used in Part III of the Permit, or the Department provide a description of the difference and how these would be applied.

Response 10: The Department agrees that inclusion of the RQL of 20 ug/L was made in error in this section which pertains to the Wastewater Characterization Requirements for DSN 461C. The Department has deleted the RQL for DSN 461C in this final permit action and has not specified an RQL for ammonia.

For purposes of clarification, the term "quantification limit", as used on page 14 of 28 of the Fact Sheet, is used interchangeably with the term "recommended quantitation level" as used on page 6 of 16 of Part III as well as in other areas of the permit.

Permit, Part III, Section A, Table III-D-1, page 7 of 16

Comment 11: As discussed above (see comments regarding Fact Sheet, Section 8.B., page 13 of 29), PSEG believes imposition of these new BOD_5 limitations are not appropriate for this discharge.

Response 11: Please refer to **Response 5.**

Permit, Part III, Section A, Table III-D-1, page 8 of 16

Comment 12: As discussed above (see comments regarding Fact Sheet, Section 8.b., page 13 of 28), PSEG believes imposition of this new TSS limitation is not appropriate for this discharge.

Response 12: Please refer to **Response 6.**

Permit, Part IV, Section E.1.e, page 3 of 12

Comment 13: PSEG believes the parenthetical limitation following the authorization to utilize sodium hypochlorite is inappropriate. The parenthetical limits sodium hypochlorite usage by stating "although not in excess of two hours per day". Sodium hypochlorite is normally continuously added to the systems. PSEG is limited to discharging chlorine produced oxidants to two hours per day from the addition of sodium hypochlorite and meets this requirement by dechlorinating the effluent of the cooling tower blowdown using ammonium bisulfite before discharge. This limitation is contained in Part IV, Section G.1. PSEG request deletion of the parenthetical following the words "sodium hypochlorite".

Response 13: The Department has reviewed the condition in Section E.1.e. and agrees that the parenthetical reference to "although not in excess of two hours per day" is unnecessary given the referenced in this same condition to item G.1. This parenthetical phrase has been deleted in the final permit action. This change affects item E.i.e, page 3 of 12 in Part IV.

Clarification to Final Permit Initiated by the Department

Item 9.b., Part IV

Please note that as per a request from the Delaware River Basin Commission, the Department has slightly modified the language in item 9.b. of Part IV in this final permit action where this language pertains to the applicable DRBC document.

Conditions Related to Part IV, Section Stormwater

Permit effluent limitations, non-numeric effluent limitations, monitoring requirements, Best Management Practices (BMPs) and other conditions are authorized by the Federal Water Pollution Control Act (33 U.S.C. 1251 et seq.), and the New Jersey State Water Pollution Control Act (N.J.S.A. 58:10A-1 et seq.). These statutes are implemented by the National Pollutant Discharge Elimination System (NJPDES) (40 CFR 122) and the New Jersey Pollutant Discharge Elimination System (NJPDES) (N.J.A.C. 7:14A) permit program.

Concerning the permit renewal, the NJDEP is authorized under the federal regulations (40 CFR 122.4) and under NJPDES rules (N.J.A.C. 7:14A-6.2(b)) to impose BMPs to control and abate the discharge of pollutants. The NJDEP may impose BMPs when BMPs are reasonably necessary to achieve effluent limitations and standards to carry out the purposes and intent of the State and Federal Acts. Additionally, the NJDEP believes that it is not feasible at this time to establish water quality based effluent limits (WQBEL) for this stormwater discharge. The proposed limitations incorporated in the SPPP are consistent with the NJDEP's and USEPA's Stormwater permitting philosophy of reducing the amount of pollution created and to prevent pollution from occurring in the first place (see 24 N.J.R 2352).

The primary method used in NJPDES Stormwater Permits, since the formation of the Stormwater Permit Program, has been the Stormwater Pollution Prevention Plan (SPPP). Since the inception of NJDEP's Stormwater Permit Program the approach to the abatement of pollutants in stormwater has focused on pollution prevention rather than end of pipe treatment. The SPPP requirements and monitoring requirements operate as limitations and control on stormwater effluent discharges to prevent stormwater contamination and are intended to achieve Best Available Technology Economically Achievable (BAT) and Best Conventional Pollutant Control Technology (BCT). The SPPP focuses on several areas of control, such as inventory, mapping, inspections, schedules and very importantly Best Management Practices (BMPs).

The BMPs incorporated in any facility's SPPP are the primary mechanism used in stormwater management to eliminate the discharge of pollutants into the State's receiving waters. It has been the position of the NJDEP that in the circumstance when the elimination of contact with source material is not an economically viable option for a facility the NJDEP may require the reduction of the pollutant load using BMPs. This is done through an individual facility permit and would also include a determination that the receiving water quality is not being adversely impacted. This difference between the elimination of pollutants and the reduction of pollutants entering a facility's stormwater runoff is how the NJDEP approaches permitting a facility.

The State's Basic Industrial Stormwater Discharge General Permit ("the General Permit" NJ0088315) regulates a facility towards achieving the goal of eliminating contact of source material with stormwater runoff, which has been informally referred to as the "no exposure" requirement. The belief being that the greatest environmental benefit would be derived from the complete elimination of exposure of source material. Therefore, the NJDEP Stormwater Permitting Program has structured permits, which are available to the regulated community, with an incentive to apply for the General Permit by having reduced fees and administrative costs, and by eliminating requirements for monitoring/sampling. The reason behind eliminating monitoring in the general permit goes to the premise that if you eliminate the source you eliminate the need to monitor.

Those facilities for various economic reasons who can not comply with the "no exposure" performance standard in the general permit must apply for an individual permit. Individual permits require sampling and monitoring. The main purpose for including sampling and monitoring requirements in an individual stormwater permit is to verify that BMPs are effective in controlling and abating pollutants in the facility's stormwater runoff, and to evaluate whether the discharge is negatively impacting the receiving water.

After review of the facility's SPPP and prior to drafting today's final permit NJDEP contacted the Permittee, PSEG Nuclear LLC ("PSEG"), regarding the option of applying for an authorization under the General Permit. PSEG declined to apply for the General Permit Authorization and requested that stormwater continue to be permitted under its individual permit. Based on PSEG's request NJDEP concluded that the Hope Creek facility still has exposed source material that contacts its stormwater runoff and therefore must be regulated based on the policies outlined above. This would include sampling and monitoring of its stormwater discharge, which is why this was included in the proposed permit.

PSEG, has commented that,

"The Department reviewed the stormwater study in the October 31, 1996 Draft NJPDES Permit Fact Sheet ("1996 Fact Sheet") and stated that the "stormwater study demonstrated that representative monitoring of stormwater could not be achieved with the existing conveyance system elevations due to tidal intrusion in the system by Delaware River water" (1996 Fact Sheet, Page 65 of 86). The Department further determined that modifications to the existing conveyance system elevations were not practical (1996 Fact Sheet, page 65 of 86)."

This statement made in the 1996 Fact Sheet was a summary of the conclusions made by PSEG in its stormwater study dated July 13, 1990 and did not represent the opinion of the NJDEP. The opinions expressed by NJDEP regarding the stormwater study and the implementation of capital projects by PSEG actually began with the final paragraph of page 66 of 86 Pages and stated,

"As a result of the implementation of the capital projects and the BMP required under the ACO, the average TSS values reported on Hope Creek Generating Station's DMRs since 1992 have consistently been lower than the values reported prior to the installation of the capital projects and the BMP. The NJDEP's Bureau of Stormwater Permitting and the Bureau of Standard Permitting have inspected the site and have determined that the continued use of BMPs instead of numeric limits is the most appropriate means of regulating the discharge of pollutants from this site in stormwater runoff" (Page 67 of 86 Pages)."

.s the NJDEP's position that the DMR data was representative since the decision to remove the numeric limitations was in part based on the evaluation of the performance of the BMPs using the DMR data as stated in the aforementioned paragraph. As indicated by PSEG, the NJDEP did replace the numeric effluent limitations and monitoring conditions in the existing permit for the stormwater outfalls with BMPs and Page 67 of 86 of the fact sheet stated this;

"The Department finds that the continuance of the numeric effluent limitations and monitoring conditions is unwarranted and infeasible based on the following: 1) the tidal intrusion of the Delaware River into the stormwater conveyance system reported in the stormwater study submitted by the permittee in 1990; and 2) the material and substantial changes at the facility implemented between 1989 and 1992 through its capital improvement projects and implementation of the BMPs such as minimization and elimination of contact of source materials with stormwater runoff.."

As PSEG noted in its comments, this paragraph does state and confirm PSEG's conclusion that the numeric limitations are unwarranted and infeasible based in part on the tidal intrusion of the Delaware River in the stormwater conveyance system. However, it does not specifically identify representative sampling as the basis for it being unwarranted and infeasible. The statement does not go into detail as to how the writer arrived at this decision. Notwithstanding, the NJDEP's position is that the samples collected must have been representative if the numeric limitations were in part removed and replaced with BMPs using DMR data. In retrospect the NJDEP believes that the statement should have been documented further. In addition, due to the capital project instituted at the facility, which resulted in changes in the management of stormwater runoff, new representative sample locations and continuous monitoring could have been included in the 1997 final permit, as per the January 11, 1990 Administrative Consent Order (ACO) that states in paragraph 23:

" PSE&G shall develop and implement a Best Management Practices Plan ('BMPP") to control the discharge of suspended solids in stormwater runoff from the site and a plan of study ("the Study") to determine the most feasible method by which representative monitoring of stormwater outfalls 462A, 463A and 464 may be performed to account for all applicable sources of stormwater originating from the site in accordance with the enforcement compliance schedule in paragraph twenty –five (25)."

Additionally, the Draft Fact Sheet noticed on November 19, 2002, did state that the stormwater drainage systems may contain Delaware River water. In consideration of the above mentioned facts, and based on the comments received by PSEG, NJDEP is renewing today's permit with the stormwater requirements contained in the 1997 final permit. The NJDEP will re-evaluate the information submitted by PSEG regarding the intrusion of water from the Delaware River and representative sampling of the conveyance system; and will inspect the site with PSEG to specifically identify new representative sample locations for the stormwater discharge from the areas of industrial activity. The permit will then be modified to include the appropriate sampling and monitoring requirements used for individual permits to verify the performance of the BMPs based on the current NJDEP policies outlined in the statements above.

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: NJ0025411

Final: Consolidated Renewal Permit Action

Permittee:
PSEG NUCLEAR LLC
PO BOX 23
ALLOWAY CREEK NECK ROAD
HANCOCKS BRIDGE, NJ 08038

Co-Permittee:

Property Owner:
PUBLIC SERVICE ELECTRIC & GAS COMPANY
80 PARK PLAZA
PO BOX 570
NEWARK, NJ 07101

Location Of Activity:
HOPE CREEK GENERATING STATION
ARTIFICIAL ISLAND
FOOT OF BUTTONWOOD RD
LOWER ALLOWAYS CREEK, SALEM COUNTY, NJ 08038-0000

Authorization(s) Covered Under This Approval	Issuance Date	Effective Date	Expiration Date
B -Industrial Wastewater RF -Stormwater	12/31/2002	3/1/2003	2/31/2008

By Authority of:
Commissioner's Office

DEP AUTHORIZATION
Pilar Patterson
Bureau of Point Source Permitting --Region 2
Division of Water Quality

(Terms, conditions and provisions attached hereto)

Division of Water Quality

HOPE CREEK GENERATING STATION
Lower Alloways Creek

Permit No. NJ0025411
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

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-1.10(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.

8. **Residuals Management**

a. The permittee shall comply with land-based sludge management criteria and shall conform with the requirements for the management of residuals and grit and screenings under N.J.A.C. 7:14A-6.15(a), which includes:

i. Standards for the Use or Disposal of Residual, N.J.A.C. 7:14A-20;

ii. Section 405 of the Federal Act governing the disposal of sludge from treatment works treating domestic sewage;

iii. The Solid Waste Management Act, N.J.S.A. 13:1E-1 et seq., and the Solid Waste Management Rules, N.J.A.C. 7:26;

iv. The Sludge Quality Assurance Regulations, N.J.A.C. 7:14C;

v. The Statewide Sludge Management Plan promulgated pursuant to the Water Quality Planning Act, N.J.S.A. 58:11A-1 et seq., and the Solid Waste Management Act, N.J.S.A. 13:1E-1 et seq.; and

vi. The provisions concerning disposal of sewage sludge and septage in sanitary landfills set forth at N.J.S.A. 13:1E-42 and the Statewide Sludge Management Plan.

vii. Residual that is disposed in a municipal solid waste landfill unit shall meet the requirements in 40 CFR Part 258 and/or N.J.A.C. 7:26 concerning the quality of residual disposed in a municipal solid waste landfill unit. (That is, passes the Toxicity Characteristic Leaching Procedure and does not contain "free liquids" as defined at N.J.A.C. 7:14A-1.2.)

b. If any applicable standard for residual use or disposal is promulgated under section 405(d)of the Federal Act and Sections 4 and 6 of the State Act and that standard is more stringent than any limitation on the pollutant or practice in the permit, the Department may modify or revoke and reissue the permit to conform to the standard for residual use or disposal.

c. The permittee shall make provisions for storage, or some other approved alternative management strategy, for anticipated downtimes at a primary residual management alternative. The permittee shall not be permitted to store residual beyond the capacity of the structural treatment and storage components of the treatment works. N.J.A.C. 7:14A-20.8(a) and N.J.A.C. 7:26 provide for the temporary storage of residuals for periods not exceeding six months, provided such storage does not cause pollutants to enter surface or ground waters of the State. The storage of residual for more than six months is not authorized under this permit. However, this prohibition does not apply to residual that remains on the land for longer than six months when the person who prepares the residual demonstrates that the land on which the residual remains is not a surface disposal site or landfill. The demonstration shall explain why residual must remain on the land for longer than six months prior to final use or disposal, discuss the approximate time period during which the residual shall be used or disposed and provide documentation of ultimate residual management arrangements. Said demonstration shall be in writing, be kept on file by the person who prepares residual, and submitted to the Department upon request.

d. The permittee shall comply with the appropriate adopted District Solid Waste or Sludge Management Plan (which by definition in N.J.A.C. 7:14A-1.2 includes Generator Sludge Management Plans), unless otherwise specifically exempted by the Department.

e. The preparer must notify and provide information necessary to comply with the N.J.A.C. 7:14A-20 land application requirements to the person who applies bulk residual to the land. This shall include, but not be limited to, the applicable recordkeeping requirements and certification statements of 40 CFR 503.17 as referenced at N.J.A.C 7:14A-20.7(j).

f. The preparer who provides biosolids to another person who further prepares the biosolids for application to the land must provide this person with notification and information necessary to comply with the N.J.A.C. 7:14A-20 land application requirements.

g. Any person who prepares bulk residual in New Jersey that is applied to land in a State other than New Jersey shall comply with the requirement at N.J.A.C. 7:14A-20.7(b)1.ix and/or 20.7(b)1.x, as applicable, to provide written notice to the Department and to the permitting authority for the State in which the bulk residual is proposed to be applied.

PART III
LIMITS AND MONITORING REQUIREMENTS

A. STORMWATER DISCHARGE

Monitored Location Group Members

463A Stormwater, 464A Stormwater, 465A Stormwater

Consolidated DMR Reporting Requirements:

Submit a Semi-Annual DMR: within twenty-five days after the end of every 6 month monitoring period beginning from the effective date of the permit (EDP).

Table III - A - 1: Consolidated DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
pH	Effluent Gross Value	REPORT SU	Daily Maximum	1 / 6 Months	Grab	January thru December	Final	
Petrol Hydrocarbons, Total Recoverable	Effluent Gross Value	REPORT MG/L	Daily Maximum	1 / 6 Months	Grab	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Gross Value	REPORT MG/L	Daily Maximum	1 / 6 Months	Grab	January thru December	Final	

B. 461A DSN 461A - DSW

Location Description

Samples shall be collected at a point after combination with all wastewater components and after dechlorination but prior to discharge to the Delaware River. DSN 461A is located at latitude 39 degrees, 28', 14" and long. 75 degrees 32' 34". DSN 461A discharges to Zone 5 of the Delaware River. The initial period is effective from the effective date of the permit (EDP) to EDP + 1 year whereas the final period becomes effective on EDP + 1 year. The permittee shall install a continuous sampler for CPO by EDP + 1 year.

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	Continuous	Metered	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	Continuous	Metered	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Intake From Stream	REPORT MGD	Monthly Average	Continuous	Metered	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Intake From Stream	REPORT MGD	Daily Maximum	Continuous	Metered	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	
Chlorine Produced Oxidants	Effluent Gross Value	0.2 MG/L	Monthly Average	Continuous	Grab	January thru December	Final	0.1 Rec Quant Level
Chlorine Produced Oxidants	Effluent Gross Value	0.5 MG/L	Daily Maximum	Continuous	Grab	January thru December	Final	0.1 Rec Quant Level
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Monthly Average	Continuous	Metered	January thru December	Final	
Temperature, oC	Effluent Gross Value	36.2 DEG.C	Daily Maximum	Continuous	Metered	January thru December	Final	
Temperature, oC	Intake From Stream	REPORT DEG.C	Monthly Average	Continuous	Metered	January thru December	Final	
Temperature, oC	Intake From Stream	REPORT DEG.C	Daily Maximum	Continuous	Metered	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Gross Value	REPORT MG/L	Monthly Average	1 / Month	Grab	January thru December	Final	

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
Carbon, Tot Organic (TOC)	Effluent Gross Value	REPORT MG/L	Daily Maximum	1 / Month	Grab	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Net Value	REPORT MG/L	Monthly Average	1 / Month	Calculated	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Net Value	REPORT MG/L	Daily Maximum	1 / Month	Calculated	January thru December	Final	
Carbon, Tot Organic (TOC)	Intake From Stream	REPORT MG/L	Monthly Average	1 / Month	Grab	January thru December	Final	
Carbon, Tot Organic (TOC)	Intake From Stream	REPORT MG/L	Daily Maximum	1 / Month	Grab	January thru December	Final	
Heat (summer) (per Hr.)	Effluent Gross Value	REPORT MBTU/HR	Monthly Average	1 / Day	Calculated	June thru August	Final	
Heat (summer) (per Hr.)	Effluent Gross Value	534 MBTU/HR	Daily Maximum	1 / Day	Calculated	June thru August	Final	
Heat (winter) (per Hr.)	Effluent Gross Value	REPORT MBTU/HR	Monthly Average	1 / Day	Calculated	September thru May	Final	
Heat (winter) (per Hr.)	Effluent Gross Value	662 MBTU/HR	Daily Maximum	1 / Day	Calculated	September thru May	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Monthly Average	Continuous	Metered	January thru December	Initial	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	Continuous	Metered	January thru December	Initial	
pH	Effluent Gross Value	6.0 SU	Daily Minimum	1 / Week	Grab	January thru December	Initial	
pH	Effluent Gross Value	9.0 SU	Daily Maximum	1 / Week	Grab	January thru December	Initial	
Chlorine Produced Oxidants	Effluent Gross Value	0.2 MG/L	Monthly Average	3 / Week	Grab	January thru December	Initial	0.1 Rec Quant Level
Chlorine Produced Oxidants	Effluent Gross Value	0.5 MG/L	Daily Maximum	3 / Week	Grab	January thru December	Initial	0.1 Rec Quant Level
Temperature, oC	Effluent Gross Value	REPORT DEG.C	Monthly Average	Continuous	Metered	January thru December	Initial	
Temperature, oC	Effluent Gross Value	36.2 DEG.C	Daily Maximum	Continuous	Metered	January thru December	Initial	
Temperature, oC	Intake From Stream	REPORT DEG.C	Monthly Average	Continuous	Metered	January thru December	Initial	
Temperature, oC	Intake From Stream	REPORT DEG.C	Daily Maximum	Continuous	Metered	January thru December	Initial	

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
Carbon, Tot Organic (TOC)	Effluent Gross Value	REPORT MG/L	Monthly Average	1 / Month	Grab	January thru December	Initial	
Carbon, Tot Organic (TOC)	Effluent Gross Value	REPORT MG/L	Daily Maximum	1 / Month	Grab	January thru December	Initial	
Carbon, Tot Organic (TOC)	Effluent Net Value	REPORT MG/L	Monthly Average	1 / Month	Calculated	January thru December	Initial	
Carbon, Tot Organic (TOC)	Effluent Net Value	REPORT MG/L	Daily Maximum	1 / Month	Calculated	January thru December	Initial	
Carbon, Tot Organic (TOC)	Intake From Stream	REPORT MG/L	Monthly Average	1 / Month	Grab	January thru December	Initial	
Carbon, Tot Organic (TOC)	Intake From Stream	REPORT MG/L	Daily Maximum	1 / Month	Grab	January thru December	Initial	
Heat (summer) (per Hr.)	Effluent Gross Value	REPORT MBTU/HR	Monthly Average	1 / Day	Calculated	June thru August	Initial	
Heat (summer) (per Hr.)	Effluent Gross Value	534 MBTU/HR	Daily Maximum	1 / Day	Calculated	June thru August	Initial	
Heat (winter) (per Hr.)	Effluent Gross Value	REPORT MBTU/HR	Monthly Average	1 / Day	Calculated	September thru May	Initial	
Heat (winter) (per Hr.)	Effluent Gross Value	662 MBTU/HR	Daily Maximum	1 / Day	Calculated	September thru May	Initial	

C. 461C DSN 461C - DSW INTERNAL

Location Description

Samples for this internal monitoring point shall be collected after all treatment has been performed and prior to mixing with cooling tower blowdown. This internal discharge point discharges through DSN 461A where DSN 461A discharges at latitude 39 degrees, 28', 14" and long. 75 degrees 32' 34".

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	Continuous	Metered	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	Continuous	Metered	January thru December	Final	
Solids, Total Suspended	Effluent Gross Value	30 MG/L	Monthly Average	1 / Month	Composite	January thru December	Final	
Solids, Total Suspended	Effluent Gross Value	100 MG/L	Daily Maximum	1 / Month	Composite	January thru December	Final	
Petrol Hydrocarbons, Total Recoverable	Effluent Gross Value	10 MG/L	Monthly Average	2 / Month	Grab	January thru December	Final	
Petrol Hydrocarbons, Total Recoverable	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	1 / Month	Composite	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Gross Value	50 MG/L	Daily Maximum	1 / Month	Composite	January thru December	Final	

C. 461C DSN 461C - DSW INTERNAL

Location Description

Samples for this internal monitoring point shall be collected after all treatment has been performed and prior to mixing with cooling tower blowdown. This internal discharge point discharges through DSN 461A where DSN 461A discharges at latitude 39 degrees, 28', 14" and long. 75 degrees 32' 34".

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	Continuous	Metered	January thru December	Final	
Flow, In Conduit or Thru Treatment Plant	Effluent Gross Value	REPORT MGD	Daily Maximum	Continuous	Metered	January thru December	Final	
Solids, Total Suspended	Effluent Gross Value	30 MG/L	Monthly Average	1 / Month	Composite	January thru December	Final	
Solids, Total Suspended	Effluent Gross Value	100 MG/L	Daily Maximum	1 / Month	Composite	January thru December	Final	
Petrol Hydrocarbons, Total Recoverable	Effluent Gross Value	10 MG/L	Monthly Average	2 / Month	Grab	January thru December	Final	
Petrol Hydrocarbons, Total Recoverable	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	1 / Month	Composite	January thru December	Final	
Carbon, Tot Organic (TOC)	Effluent Gross Value	50 MG/L	Daily Maximum	1 / Month	Composite	January thru December	Final	

E. SI6A OIL/WATER SEPARATOR

Location Description

A representative sample of residuals generated by the Oil/Water Separator shall be analyzed pursuant to the Sludge Quality Assurance Regulations (SQAR, N.J.A.C. 7:14C).

Discharge Categories

Industrial Wastewater

Residuals DMR Reporting Requirements:

Submit an Annual DMR: due 60 calendar days after the end of each calendar year.

Table III - E - 1: Residuals DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Nitrate Nitrogen, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Nitrogen, Kjeldahl Total, Dry Wt	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Styrene	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Nitrogen, Ammonia Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Sulfide, Total (as S)	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Magnesium Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Barium, Total (as Ba)	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Boron, Total (as B)	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Manganese, Total (as Mn)	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Titanium, Total (as Ti)	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Molybdenum Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Phosphorus Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Arsenic, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	

Table III - E - 1: Residuals DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Cobalt, Total (as Co)	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Silver, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Antimony, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Aluminum, Total (as Al)	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Selenium, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Copper, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Cadmium, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Zinc, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Lead, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Nickel, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Mercury, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Chromium, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Iron, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Benzene, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Bis(2-chloroethyl) ether, Dry Wt	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Butyl benzyl-phthalate, Dry Wt	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Dimethyl phthalate, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Naphthalene Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
2-Chloronaphthalene, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	

Table III - E - 1: Residuals DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Di-n-butyl phthalate Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Hexachlorobenzene, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Carbon Tetrachloride Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Chlorobenzene, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Chloroform Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Ethylbenzene Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Methylene Chloride, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Tetrachloroethylene, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Toluene, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Trichloroethylene, Dry Weight	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
1,1,1-Trichloro-ethane, Dry Wt	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Carbon disulfide	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Vinyl acetate	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Xylene	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Acetone	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Phenol, Single Compound, Dry Wt	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
2,4-D	Industrial Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	

Residuals WCR - Monthly Reporting Requirements:

Submit a Monthly WCR: due 60 calendar days after the end of each calendar month.

Table III - E - 2: Residuals WCR - Monthly Limits and Monitoring Requirements

Parameter	Compliance Quantity	Units	Sample Type	Monitoring Period	Phase	Quantification Limit
Sludge Landfilled	REPORT	DMT/MO	Calculated	January thru December	Final	
Sludge Land Applied	REPORT	DMT/MO	Calculated	January thru December	Final	
Sludge Disposed Out-of-State	REPORT	DMT/MO	Calculated	January thru December	Final	
Amt Sludge Rmvd, Wet Cubic Yards	REPORT	WCY/MO	Calculated	January thru December	Final	
Amt Sludge Rmvd, Wet Metric Tons	REPORT	WMT/MO	Calculated	January thru December	Final	
Amt Sludge Rmvd, Gallons	REPORT	GAL/MON	Calculated	January thru December	Final	
Sludge Bene Use Out-of-State	REPORT	DMT/MO	Calculated	January thru December	Final	
Sludge Surface Disposed	REPORT	DMT/MO	Calculated	January thru December	Final	
Total Amount of Sludge Removed	REPORT	DMT/MO	Calculated	January thru December	Final	
Sludge Incinerated	REPORT	DMT/MO	Calculated	January thru December	Final	
Sludge Disposed-Other Methods	REPORT	DMT/MO	Calculated	January thru December	Final	
Sludge/Septage Rcvd Offsite Srces Wet MT	REPORT	WMT/MO	Calculated	January thru December	Final	
Sludge/Septage Rcvd Offsite Srces Gals	REPORT	GAL/MON	Calculated	January thru December	Final	
Sludge/Septage Rcvd Offsite Srces Wt Yd3	REPORT	WCY/MO	Calculated	January thru December	Final	
Solids, Total	REPORT	%TS	Composite	January thru December	Final	

Residuals Transfer Reporting Requirements:

Submit a Monthly RTR: due 60 calendar days after the end of each calendar month.

F. SL1A STP SYSTEM

Location Description

A representative sample of residuals generated by the STP System shall be analyzed pursuant to the Sludge Quality Assurance Regulations (SQAR, N.J.A.C. 7:14C).

Discharge Categories

Industrial Wastewater

Residuals DMR Reporting Requirements:

Submit an Annual DMR: due 60 calendar days after the end of each calendar year.

Table III - F - 1: Residuals DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Solids, Total	Residuals	REPORT %TS	Monthly Average	1 / Year	Composite	January thru December	Final	
Nitrate Nitrogen, Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Nitrogen, Kjeldahl Total, Dry Wt	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Potassium Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Nitrogen, Ammonia Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Calcium Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Molybdenum Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Phosphorus Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Arsenic, Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Selenium, Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Copper, Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Beryllium Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Cadmium, Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	

Table III - F - 1: Residuals DMR Limits and Monitoring Requirements

Parameter	Sample Point	Limit	Statistical Base	Sampling Frequency	Sample Type	Monitoring Period	Phase	Quantification Limit
Zinc, Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Lead, Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Nickel, Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Mercury, Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	
Chromium, Dry Weight	Residuals	REPORT MG/KG	Monthly Average	1 / Year	Composite	January thru December	Final	

Residuals WCR - Annual Reporting Requirements:

Submit an Annual WCR: due 60 calendar days after the end of each calendar year.

Table III - F - 2: Residuals WCR - Annual Limits and Monitoring Requirements

Parameter	Compliance Quantity	Units	Sample Type	Monitoring Period	Phase	Quantification Limit
Sludge Landfilled	REPORT	DMT/YR	Calculated	January thru December	Final	
Sludge Land Applied	REPORT	DMT/YR	Calculated	January thru December	Final	
Sludge Disposed Out-of-State	REPORT	DMT/YR	Calculated	January thru December	Final	
Amt Sludge Rmvd, Wet Cubic Yards	REPORT	WCY/YR	Calculated	January thru December	Final	
Amt Sludge Rmvd, Wet Metric Tons	REPORT	WMT/YR	Calculated	January thru December	Final	
Amt Sludge Rmvd, Gallons	REPORT	GAL/YEAR	Calculated	January thru December	Final	
Sludge Bene Use Out-of-State	REPORT	DMT/YR	Calculated	January thru December	Final	
Sludge Surface Disposed	REPORT	DMT/YR	Calculated	January thru December	Final	
Total Amount of Sludge Removed	REPORT	DMT/YR	Calculated	January thru December	Final	
Sludge Incinerated	REPORT	DMT/YR	Calculated	January thru December	Final	
Sludge Disposed-Other Methods	REPORT	DMT/YR	Calculated	January thru December	Final	
Solids, Total	REPORT	%TS	Composite	January thru December	Final	

Residuals Transfer Reporting Requirements:

Submit an Annual RTR: due 60 calendar days after the end of each calendar year.

PART IV

SPECIFIC REQUIREMENTS: NARRATIVE

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. The permittee shall utilize analytical methods that will ensure compliance with the Quantification Levels (QLs) listed in PART III. If the permittee and/or contract laboratory determines that the QLs achieved for any pollutant(s) generally will not be as sensitive as the QLs specified in PART III, the permittee must submit a justification of such to the Bureau of Point Source Permitting Region 2. Failure to submit a justification is a permit violation.

d. 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.

e. All monitoring shall be conducted as specified in Part III.

f. All sample frequencies expressed in Part III are minimum requirements. However, if additional samples are taken, analytical results shall be reported as appropriate.

g. The permittee shall perform all residual analyses in accordance with the analytical test procedures specified in 40 CFR 503.8 and the Sludge Quality Assurance Regulations (N.J.A.C. 7:14C) unless other test procedures have been approved by the Department in writing or as otherwise specified in the permit.

h. Flow shall be measured using a flow meter at DSN's 461A, 461C and 462B.

i. The net amount of heat per unit time shall be calculated by multiplying heat capacity, discharge flow, and discharge-intake temperature difference.

j. Net limitation shall be calculated by multiplying [(gross effluent concentration)*(gross effluent flow) - (intake concentration)*(intake flow)}/(gross effluent flow).

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. When quantification levels (QL) and effluent limits are both specified for a given parameter in Part III, and the QL is less stringent than the effluent limit, effluent compliance will be determined by comparing the reported value against the QL.

f. 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.

g. For intermittent discharges, the permittee shall obtain a sample during at least one of the discharge events occurring during a monitoring period. Place a check mark in the "No Discharge this Monitoring Period" box on the monitoring report submittal form 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:

   DSN 461A: sodium hypochlorite, ammonium bisulfite and sodium hydroxide. Refer to item G.1. for more information concerning chlorine produced oxidants. There shall be no detectable amount of the 126 priority pollutants contained in chemicals added for cooling tower maintenance in the discharge from DSN 461A.

   DSN 461C: Carbohydrazide, Ammonium Hydroxide, Hydrazine.

   All outfalls: If the permitee decides to begin using additional agents or replace the above agents in the future, the permitee 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. This permit includes a schedule for compliance for the following parameters:
   An alternate sample type for chlorine produced oxidants at DSN 461A. The initial phase limits are effective from EDP until EDP + 1 year. The final phase will become effective on EDP +1 year

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).

F. CONDITIONS FOR MODIFICATION

1. **Causes for modification**

   a. Pursuant to N.J.A.C. 7:14A-6.2(a)(10)(iii), the Department may modify or revoke and reissue any permit to incorporate limitations or requirements to control the discharge of toxic pollutants, including whole effluent, chronic and acute toxicity requirements, chemical specific limitations or toxicity reduction requirements, as applicable.

   b. The Department may incorporate requirements to file monitoring data required by this permit electronically through a minor modification in accordance with N.J.A.C. 7:14A-16.5(a)1.

   c. The permittee may request a minor modification to eliminate the monitoring requirements associated with a discharge authorized by this permit when the discharge ceases due to changes at the facility.

G. Custom Requirement

1. **Chlorine Produced Oxidants at DSN 461A:**

a. Chlorine produced oxidants may not be discharged from any unit for more then two hours in any one day and not more than one unit in any plant may discharge chlorine produced oxidants at any one time. Both these conditions remain in effect unless the permittee can demonstrate to the Department that the units in a particular location cannot operate at or below this level of chlorination. Any alternate condition would be subject to a permit modification.

2. **Effluent Temperature at DSN 461A**

   a. Effluent temperature shall be measured at DSN 461A on a continuous basis. 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.

3. **Discharge of PCB's at all Outfalls**

   a. There shall be no discharge of polychlorinated biphenyl compounds (PCB's) such as those which are commonly used for transformer fluid.

4. **Continuous Monitoring**

   a. As indicated in Part III, continuous monitoring is required for certain parameters at DSN's 461A, 461C, and 462B. In the event the continuous monitors are temporarily unavailable due to maintenance, calibration, or inoperability of the continuous monitor, the permitee may use one of the following methods for reporting during such interim periods:.

      i. DSN 461A Effluent Temperature- temperature detector located at the dechlorination system, a temporary continuous temperature monitor, or manual sampling once per twelve hour shift.

      ii. DSN 461A Intake Temperature - a temporary continuous temperature monitor, intake temperature at the adjacent Salem Generating Station, or manual sampling once per twelve hour shift.

      iii. DSN 461A Effluent Flow- an installed float meter, manual measurement of the height over the effluent weir once per shift, or a calculation based on the difference between intake flow and estimated evaporative losses.

      iv. DSN 461A Intake Flow - calculations based on pump run hours.

      v. DSN 461A Effluent CPO - manual sampling once per twelve hour shift.

      vi. DSN 461C Effluent Flow- calculations based on lift station pump operating hours or pumping events.

      vii. DSN 462B Effluent Flow - manual measurement of the height of the effluent over a V-notched weir.

   b. Any results from the alternative monitoring methodologies shall not be reported for periods when the primary monitoring device is correctly operating. This authorization to use alternative monitoring methodologies does not alleviate permittee's obligation to maintain the primary monitoring instrumentation and devices and to ensure their proper operability and availability to the maximum extent practicable consistent with the applicable requirements of N.J.A.C. 7:14A-1 et. seq.

5. **Service Water Bypass**

   a. To facilitate necessary Station maintenance, the permitee is authorized to temporarily redirect service water to discharge through DSN 463A, bypassing DSN 461A. The addition of sodium hypochlorite (or any other chemical biocide authorized by the Department) shall be terminated during the bypass discharge. The following conditions shall be met by the permittee when service water is discharged through DSN 463A:.

i. Provide written notification to the Chief, Bureau of Point Source Permitting-Region 2 and the Southern Bureau of Compliance Water Enforcement prior to the bypass discharge. This notification shall include the expected dates of the bypass, confirmation that sodium hypochlorite addition to the service water will be terminated during the bypass, and a brief description of the reason the bypass is necessary.

ii. Provide oral notification to the Southern Bureau of Compliance and Water Enforcement at least 24 hours prior to commencing the bypass discharge.

6. **Flow Measurements using Rhodamine WT Dye**

a. The permitee is authorized to perform periodic flow measurement testing of the cooling tower related systems using Rhodamine WT Dye as a tracer. This dye will discharge to the Delaware River through outfall DSN 461A. The following conditions must be met by the permittee:.

i. Provide written notification to the Chief, Bureau of Point Source Permitting- Region 2 and the Southern Bureau of Compliance Water Enforcement prior to the use of Rhodamine WT dye. This notification shall include the expected dates of the discharge, the expected concentration of Rhodamine WT dye in the effluent, and the anticipated concentration of Rhodamine WT due to be added.

ii. Provide oral notification to the Southern Bureau of Compliance and Water Enforcement at least 24 hours prior to commencing the discharge of Rhodamine WT dye.

iii. Within thirty (30) days of completion of the flow measurement testing, provide written notification of completion to the Chief, Bureau of Point Source Permitting-Region 2 and the Southern Bureau of Compliance and Water Enforcement. This notification shall include the actual dates of the discharge, the actual concentration of Rhodamine WT dye in the effluent at DSN 461A, and the total quantity of Rhodamine WT dye added.

7. **Other Regulatory Requirements**

a. 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.

b. 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.

8. **Section 316 Determination Upon Permit Issuance**

a. With respect to Section 316 (b), the Department will make a determination at the time of permit renewal which will include, but will not be limited to, an evaluation of whether technologies, their costs and benefits, and potential for application at the Station have changed.

9. **Compliance with DRBC 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.

b. The permittee shall ensure that any thermal discharge complies with the temperature and heat dissipation requirements imposed in any current DRBC docket D-73-193 CP and any revisions thereto.

10. **Alternate Temperature Condition**

a. Given a coincident occurrence of a wet bulb temperature that exceeds 76 degrees Fahrenheit and a relative humidity below 60 percent during a given day for a period equal to or greater than 60 minutes, the daily maximum temperature limit does not apply and monitoring only is required. If these two conditions for wet bulb temperature and relative humidity occur, as well as an exceedance of the temperature limit of 97.1 degrees Fahrenheit at DSN 461A, the permittee is required to submit a chart with columns for the following data for each hour of that day: (1) Cooling Tower Blowdown Flow (gpm); (2) Intake Temperature (degrees Fahrenheit); (3) Blowdown Temperature (degrees Fahrenheit); (4) Change in Temperature (degrees Fahrenheit); (5) MBTU/Hour; (6) Dry Bulb Temperature (degrees Fahrenheit); (7) Dew Point Temperature (degrees Fahrenheit); (8) Wet Bulb Temperature (degrees Fahrenheit); and (9) Relative Humidity (percent).

b. Dry bulb temperature, dew point, barometric pressure and wind speed and direction are measured at 15-minute intervals at Hope Creek's meteorological Station. Wet bulb temperature and relative humidity are computed using measurements of dry bulb temperature and dew point with a numerical algorithm that relates the dependence of wet bulb temperature and relative humidity on dew point, dry bulb temperature, and atmospheric pressure. In the event that data are not available from the Hope Creek meteorological Tower, then PSEG may utilize data collected at the Wilmington meteorological Station (Wilmington). The use of another alternative source (other than Hope Creek meteorological Tower data or Wilmington metorological Station) must be approved in advance by the Department and duly noted on the monitoring report form. The permittee must retain records of the Wilmington data or any other data in its monitoring report form back up file for the term specified by the applicable provisions of the NJPDES regulations.

11. Proper Operation and Maintenance of Cooling Tower

a. The Department reserves the right to revoke the alternate temperature condition at DSN 461A, which is conditional on the occurence of extreme meteorological conditions, if it is determined that the cooling tower is not being properly operated and maintained.

Stormwater

A. Monitoring

1. **(Reserved)**

B. Reporting

1. **(Reserved)**

C. Record Keeping

1. **(Reserved)**

D. Submittals

1. **(Reserved)**

E. Operations and Maintenance

1. **(Reserved)**

F. Stormwater Pollution Prevention Plan

1. **(Reserved)**

G. Site Specific Best Management Practices

1. **(Reserved)**

H. Custom Requirement

1. **Stormwater Pollution Prevention Plan**

The following outline provides the key elements of an acceptable Stormwater Pollution Prevention Plan (SPPP). The purpose of the SPPP is to meet the following objectives:

a. to identify potential sources of pollutants and source materials onsite which may reasonably be expected to affect the quality of stormwater discharges associated with industrial activity.

b. to describe and ensure that practices are implemented to eliminate and/or reduce pollutants from source materials in stormwater discharges associated with industrial activity.

c. to ensure compliance with the terms and conditions of this permit.

Note: Source materials are defined as any material or machinery, located at the facility and directly or indirectly related to process or other industrial activities, which could be a source of pollutants in a stormwater discharge associated with industrial activity that is subject to the Clean Water Act and/or 40 CFR 122.26. Source materials include, but are not limited to, raw materials;intermediate products; final products; waste materials; by-products; industrial machinery and fuels; and lubricants, solvents, and detergents that are related to process or other industrial activities. Material or machinery that are not exposed to stormwater or that are not located at the facility are not source materials.

2. **Stormwater Pollution Prevention Team**

   The permittee shall continue to identify a Stormwater Pollution Prevention Team in the SPPP. The SPPP shall be updated to name specific individuals or positions within the facility organization if members of the team change. The team is responsible for implementing the SPPP in accordance with good engineering practices, and for the plan's implementation and maintenance. The plan shall clearly identify the responsibilities of each team member. The activities and responsibilities of the team shall address all aspects of the facility's SPPP which are provided below.

3. **Description of Existing Environmental Management Plans**

   The team shall evaluate the facility's exisiting environmental management plans and programs for consistency with this permit and determine which provisions, if any, from these other plans can be incorporated by reference into the SPPP. Examples of plans which may be referred to when applicable to the site include: the current BMP Plan, Discharge Prevention Containment and Countermeasures (DPPC), Discharge Cleanup and Removal (DCR), Preparedness Prevention and Contingency Plan (PPCP, 40 CFR Parts 264 and 265), the Spill Prevention Control and Countermeasures (SPPC) requirements (40 CFR Part 112), the National Pollutant Discharge Elimination System Toxic Organic Management Plan (NPDESTOMP, 40 CFR Parts 413, 433, and 469), and the Occupational Safety and Health Administration (OSHA) Emergency Action Plan (29 CFR Part 1910). A copy of any plans referred to in the SPPP should be kept on-site with the SPPP.

4. **Site Assessment**

   The Site Assessment shall describe the physical facility and the potential pollutant sources (materials, activities and areas) which may be reasonably expected to affect the quality of stormwater discharges. The key elements of the site assesssment shall include, at a minimum, the following requirements:

   a. Inventory Requirements

      The facility must update annually (more frequently if considered appropriate) an inventory, which includes, at a minimum, the following:.

      i. list of the general categories of source materials that have been used, loaded/unloaded, stored, treated, spilled, leaked and/or disposed onsite in a manner to allow exposure to stormwater.

      ii. list of any domestic watewater, non-contact cooling water, treated groundwater or process wastewater that is generated at the facility and discharged through seperate storm sewers to surface waters. List any current NJPDES permits or permit applications that the facility may have for such discharges.

   b. Mapping Requirements

      A site map drawn to an appropriate scale that clearly shows the following:.

      i. buildings and other permanent structures.

      ii. paved areas and roadways.

      iii. Surface water bodies (e.g., rivers, lakes, streams, bays, estuaries) that are located on or about the property which receive or may receive stormwater from the site.

      iv. location of all stormwater discharge points and outfalls.

      v. location of each point or sewer segment, where domestic wastewater, treated groundwater, process wastewater or non-contact cooling water generated by the facility enters storm sewers that discharge to surface waters.

vi. outline of the drainage area within the facility boundaries for each stormwater outfall and a depiction of the flow direction (e.g., arrowhead of stormwater in each drainage area).

vii. locations where source materials are likely to be exposed to stormwater, and the following activities and/or areas, at a minimum; storage areas, palleted materials, outdoor handling, treatment or disposal areas, loading and/or unloading areas, manufacturing and/or processing areas, waste storage areas, vehicles/equipment maintenance areas, vehicle/equipment fueling areas, hazardous waste storage or disposal areas, areas of spills and/or leaks of source materials, and access routes.

viii. locations of existing stormwater structural control measures (e.g., containment, berms, dentention/retention basins, grassed swales).

ix. areas of exisiting and potentential soil erosion.

c. Narrative Description of Exisiting Conditions

The SPPP shall continue to include a narrative description concerning the existing management of all source materials at the facility which are handled, treated, stored, disposed, or which otherwise exist in a manner allowing contact with stormwater. The narrative description shall be updated to reflect current practices and address the following where appropriate:.

i. any discharges of domestic wastewater, non-contact cooling water, treated groundwater or process waste that are listed in accordance with Item H.4.a.ii above (unless such discharges have been authorized by this or other NJPDES permits or identified in applications or requests for authorization submitted for other NJPDES permits).

ii. description of types of industrial activities and/or areas (e.g. fueling material handling, manufacturing or processing areas) at the site.

iii. the actual or potential pollutant categories associated with each industrial area and/or activity where source materials are likely to be exposed to stormwater including, but not limited to: fueling stations, loading/unloading areas, maintenance shops, areas where spills and/or leaks of source materials frequently occur, equipment or vehicle cleaning areas, outdoor storage areas,outdoor manufacturing or processing areas , onsite waste disposal areas, aboveground liquid storage tanks, outside storage of raw materials, by-products, or finished products, (e.g., fueling area - diesel fuels, gasoline, petroleum hydrocarbons).

iv. a description of existing management practices employed to: eliminate contact of source materials with stormwater; minimize or reduce pollutants from source materials through structural or non-structural measures; divert stormwater to specific areas on or off-site, including diversions to containment areas, holding tanks, treatment facilities, or sanitary or combined sewers; treat stormwater discharging from the site; and prevent or permit any discharges of domestic wastewater, non-contact cooling water, treated groundwater or process wastewater to surface water.

5. Best Management Practices (BMP) Selection and Plan Design

The permittee shall continue to evaluate the information from the site assessment phase of this plan to identify potential and existing sources of stormwater containment by source material. All discharges to surface water of domestic wastewater, non-contact cooling water, treated groundwater and process waste water must be eliminated or permitteed by this or another NJPDES permit. Based upon the site assessment performed, the permittee shall develop BMPs that will effectively eliminate or reduce pollutant loadings in stormwater discharges from the facility in accordance with the following sections. BMPs are measures used to prevent or mitigate pollution from any type of activity. The evaluation and selection of the BMPs addressing each area, and/or activity where source materials are exposed to stormwater discharging to surface water, shall be documented in the SPPP and shall include at a minimum the following BMPs:

a. Non-Stormwater Discharges into Storm Sewers

The facility shall ensure that it does not generate and discharge, through storm sewers to surface waters, any domestic wastewater, non-contact cooling water, treated groundwater or process wastewaters unless that discharge is authorized by this or another NJPDES permit or identified in an application or request for authorization submitted for another NJPDES permit.

b. Removal, Cover or Control of Industrial Activities

Except as specified and required herein for certain, specific exposures of source materials, all other source materials shall be moved indoors, covered, used, handled, and/or stored in a manner so as to minimize contact with stormwater that is discharged to surface water. Each BMP that prevents such contact shall be identified and discussed in the SPPP.

c. Diverting Stormwater

Approved diversion of contaiminated stormwater to either a domestic or industrial wastewater treatment plant may also be considered when choosing an appropriate BMP where feasible. (Diversion to groundwater may require a seperate NJPDES permit. Consult the Department's Groundwater Permitting Unit at (609) 292-0407).

d. Spill Prevention and Response

Identify in the SPPP areas where actual or potential spills of source materials are exposed to stormwater and may be discharged with stormwater. Include their accompanying drainage points. Where appropriate, specific material handling procedures, storage requirements and use of equipment such as diversion valves shall be developed and practiced to prevent and/or eliminate spills and/or leaks of source materials from being exposed to stormwater. Procedures for cleaning up spills shall be specifically included in the plan and made available to the appropriate personnel through scheduled employee training. In addition, the facility shall provide and otherwise make available to its personnel the appropriate and neccessary small cleanup equipment to effect an immediate and thorough spill cleanup.

e. Good Housekeeping

The SPPP must continue to include a good housekeeping program to help maintain a clean and orderly work place. For certain activities or areas, the discharge of stormwater exposed to source materials may be prevented merely by using good housekeeping methods. The following are some simple procedures that a facility can consider incorporating into an effective good housekeeping program:.

i. conduct cleanup immediately after discovery of leaks and spills,.

ii. implement careful material storage practices,.

iii. improve operation and maintenance of industrial machinery and processes,.

iv. maintain an up-to-date material inventory,.

v. maintain well organized work areas,.

vi. provide regular pickup and disposal of waste materials,.

vii. maintain clean and dry floors and ground surfaces by using brooms, shovels, vacum cleaners, or cleaning machines, and.

viii. train employees about good housekeeping practices.

f. Preventative Maintenace

The SPPP shall continue to include a Preventative Maintenance Program to include timely and regular inspections and maintenance of stormwater management devices (e.g., cleaning oil/water separators, catch basins, drip pans, detention basins, covers, treatment units) and routine inspections of facility equipment and operations to detect faulty equipment. Equipment (such as tanks, piping, containers, and drums) should be checked regularly for signs of deterioration.

g. Inspections and Evaluation Process.

i. Regular Inspections

The SPPP shall require regular inspections of the facility's equipment, exposed source materials and industrial areas to provide that all elements of the SPPP are in place and working properly. Inspections shall be conducted by qualified, trained plant personnel. Records of these inspections shall be kept onsite and shall contain, at a minimum: date, locations of any identified problems, steps taken to correct problem and prevent reoccurence, and the inspectors' names and titles. These reports shall also record any incidents such as leaks, accidental discharges, and failures or breakdowns of structual BMPs.

ii. Annual Inspections

The SPPP shall require an annual inspection of the entire facility in accordance with Item H.9.b. below.

iii. Evaluation Process

The SPPP shall include a system to routinely and continually evaluate the SPPP for effectiveness, flaws that have developed, and required maintenance. The routine evaluation must include, but not be limited to, regular annual inspections, inspection logs and records, internal reporting, plan revisions to correct flaws detected in the SPPP or to reflect changes, additions at the facility, and logs of preventive maintenance performed at the facility. In addition, the Annual Reports and Certifications required under Item H.9.b below,. are integral to the evaluation process.

6. Implementation Schedule

The SPPP shall continue to include an implementation schedule for all new or retrofitted structural and non-structural BMPs. This shall include a schedule(s) for the removal, coverage, and minimization of exposure of source materials to stormwater and/or stormwater diversion ot treatment.

7. General Plan Requirements

This section provides additional requirements to the administrative requirements related to the finalized SPPP. It covers required signatures and requirements for plan location and access.

a. Required Signatures for the SPPP and Stormwater Certifications

The SPPP and Stormwater Certifications shall be signed as follows.

i. for a corporation, by a principal executive officer of a least the level of vice president.

ii. for a partnership or sale proprietorship, by a general partner of the proprietor respectively.

iii. for a municipality, State, Federal or other agency, by either a principal executive officer or a ranking officer.

iv. for i., ii., or iii. above, by a duly authorized representative, provided that: the representative is authorized by a person described in i., ii., or iii. above; this authorization specifies either an individual or a position responsible for the overall operation of the regulated facility or activity (e.g., plant manager, superintendent); and the written authorization was submitted to the Department.

b. Plan Location and Public Access.

i. The SPPP and inspection and preventative maintenance records or logs shall be maintained onsite at all times. These documents must be made available, upon request, to a representative of the Department and to the owner and operator of any municipal separate storm sewer receiving the stormwater discharge.

ii. Updates of the facility's SPPP shall be submitted annually to the Regional Water Compliance and Enforcement Offices, the Bureau of Point Source Permitting-Region 2, Bureau of Nonpoint Pollution Control and to the Department's Central File Room.

8. **Special Requirements**

a. Facilities Subject to Emergency Planning and Community Right-to-Know Statute

For facilities subject to the Emergency Planning and Community Right-to Know Act (EPCRA) Section 313, the SPPP shall include, or cite the location of any spill reports prepared under that Act.

b. Facilities with SPCC Plans, DPCC Plans, or DCR Plans

The SPPP shall include, or cite the location(s) of, any Spill Prevention Control and Countermeasures Plan (SPCC Plan) prepared under 40 CFR 112 and Section 3.1 of the Clean Water Act, 33 U.S.C. S1321; and any Discharge Prevention, Containment and Countermeasures Plan (DPCC plan) and Discharge Cleanup and Removal Plan (DCR plan) prepared under N.J.A.C 7.1 E.

c. Facilities Undergoing Construction Activities

Whenever construction activities are undertaken at the facility, the SPPP shall be amended, if neccessary, so that the SPPP continues to be accurate and to meet the requirements of this permit.

9. **Compliance - Inspections and Reports**

a. Submit an SPPP Implementation and Inspection Recertification: annually from the effective date of the permit (EDP) which is consistent with the schedule that was established in the former permit, (e.g., if the recertification was due to be submitted by July 1 of each subsequent year then under the renewed permit the recertification shall continue to be submitted on July 1 of any given year).

b. The permittee shall submit the following recertification to the Bureau of Permit Management on the Monitoring Report - Transmittal Sheet annually:

"I certify that the facility has been inspected to identify areas contributing to the stormwater discharge(s) authorized under NJPDES/DSW permit No. NJ0025411 and to evaluate whether the stormwater pollution prevention plan (SPPP) prepared under the permit complies with the permit and is properly implemented.".

c. The permittee shall continue to conduct annual inspections of the facility to assess all areas contributing to the stormwater discharge authorized by this permit and to evaluate whether the SPPP complies with, and is implemented in accordance with this permit, and whether additional measures are needed to meet the conditions of this permit. A summary of each inspection shall be included in the SPPP.

d. The permittee shall prepare a report annually summarizing the inspection. This report shall include the date of inspection and name(s) and titles(s) of the inspector(s) and shall accompany the certification above that the facility is in compliance with its SPPP and this permit, except that if there are any incidents of non-compliance, those incidents shall be identified in the certification. If there are incidents of non-compliance, the report shall identify the steps being taken to remedy the noncompliance and to prevent such inicidents from reocurring. The report and certification shall be signed in accordance with Item H.7.a. of this permit, and a copy shall be maintained onsite for a period of five years. This period may be extended by written request by the Department at any time.

**ATTACHMENT 1:
CONTENTS OF THE
STORMWATER
POLLUTION PREVENTION PLAN**

Table of Contents

I. Stormwater Pollution Prevention Plan

The following outline provides the key elements of an acceptable Stormwater Pollution Prevention Plan (SPPP). The purpose of the SPPP is to meet the following objectives:

A. to identify potential sources of pollution and source materials onsite which may reasonably be expected to affect the quality of stormwater discharges associated with industrial activity;

B. to describe and ensure that practices are implemented to eliminate and/or reduce pollutants from source materials in stormwater discharges associated with industrial activity; and

C. to ensure compliance with the terms and conditions of this permit.

II. Stormwater Pollution Prevention Team

The permittee shall form and identify a Stormwater Pollution Prevention Team in the SPPP. The SPPP shall name a specific individual or individuals within the facility organization who are members of the team. The team is responsible for developing the SPPP in accordance with good engineering practices, and in the plan's implementation, and maintenance. The plan shall clearly identify the responsibilities of each team member. The activities and responsibilities of the team shall address all aspects of the facility's SPPP which are provided below.

III. Description of Existing Environmental Management Plans

The SPPP team shall evaluate the facility's existing environmental management plans and programs for consistency with this permit and determine which provisions, if any, from these other plans can be incorporated by reference into the SPPP.

Examples of plans which may be referred to when applicable to the site include: Discharge Prevention Containment and Countermeasure (DPCC), Discharge Cleanup and Removal (DCR), Preparedness Prevention and Contingency Plan (PPCP, 40 CFR Parts 264 and 265), the Spill Prevention Control and Countermeasures (SPCC) requirements (40 CFR Part 112), the National Pollutant Discharge Elimination System Toxic Organic Management Plan (NPDESTOMP, 40 CFR Parts 413, 433, and 469), and the Occupational Safety and Health Administration (OSHA) Emergency Action Plan (29 CFR Part 1910). A copy of any plans referred to in the SPPP should be kept on-site with the SPPP.

IV. Site Assessment

The Site Assessment shall describe the physical facility and the potential pollutant sources (materials, activities and areas) which may be reasonably expected to affect the quality of stormwater discharges. The key elements of the site assessment shall include, at a minimum, the following requirements:

A. Inventory Requirements

Each facility must develop and update annually, as appropriate, an inventory which includes, at a minimum, the following:

1. list of the general categories of source materials that have been used, loaded/unloaded, stored, treated, spilled, leaked and/or disposed onsite in a manner to allow exposure to stormwater; and

2. list of any domestic wastewater, non-contact cooling water, or process waste water (see definitions in Part IV of permit), that is generated at the facility and discharged through separate storm sewers (see definition in Part IV of permit) to surface waters. List any current NJPDES (New Jersey Pollutant Discharge Elimination System) permits or permit application that the facility may have for such discharges.

B. Mapping Requirements

A site map drawn to an appropriate scale that clearly shows the following:

1. buildings and other permanent structures;

2. paved areas and roadways;

3. surface water bodies (e.g., rivers, lakes, streams, bays, estuaries) that are located on or abut the property which receive or may receive stormwater from the site;

4. all stormwater discharge locations;

5. location of each point or sewer segment, where domestic sewage, process waste water, or non-contact cooling water generated by the facility enters storm sewers that discharge to surface waters;

6. outline of each drainage area within the facility boundaries and a depiction of flow direction (e.g., arrow head) of stormwater in each drainage area;

7. locations where source materials are likely to be exposed to stormwater, and the following activities and/or areas, at a minimum; storage areas, palleted materials, outdoor handling, treatment or disposal areas, loading and/or unloading areas, manufacturing and/or processing areas, waste storage areas, vehicle/equipment maintenance areas, vehicle/equipment fueling areas, hazardous waste storage or disposal areas, areas of spills and/or leaks of source materials, and access routes;

8. location of existing stormwater structural control measures (e.g., containment, berms, detention/retention basins, grassed swales, oil/water separators); and

9. areas of existing and potential soil erosion.

C. Narrative Description of Existing Conditions

The SPPP shall include a narrative description concerning the existing management of all source materials at the facility which are handled, treated, stored, disposed, or which otherwise exist in a manner allowing contact with stormwater. The narrative description shall address the following where appropriate:

1. any discharges of domestic sewage, non-contact cooling water, or process water that are listed in accordance with A.2 above (unless such discharges have been authorized by other NJPDES permits or identified in applications or requests for authorization submitted for other NJPDES permits);

2. description of type of industrial activities and/or areas (e.g., fueling, material handling, manufacturing or processing areas) at the site;

3. the actual or potential pollutant categories associated with each industrial area and/or activity where source materials are likely to be exposed to stormwater including, but not limited to: fueling stations, loading/unloading areas, maintenance shops, areas where spills and/or leaks of source materials frequently occur, equipment or vehicle cleaning areas, outdoor storage areas, outdoor manufacturing or processing areas, onsite waste disposal areas, above ground liquid storage tanks, outside storage of raw materials, by-products, or finished products, (e.g., fueling area - diesel fuels, gasoline, petroleum hydrocarbons); and

4. a description of existing management practices employed to : a) eliminate contact of source materials with stormwater; b) minimize or reduce pollutants from source materials through structural or non-structural measures; c) divert stormwater to specific areas on or off-site, including diversion to containment areas, holding tanks, treatment facilities, or sanitary or combined sewers; d) treat stormwater discharging from the site; and e) prevent or permit any discharges of domestic wastewater, non-contact cooling water, or process wastewater to surface water.

V. Best Management Practices (BMP) Selection and Plan Design

The permittee shall evaluate the information from the site assessment phase of this plan to identify potential and existing sources of stormwater contaminated by source material. **All discharges to surface water of domestic sewage, non-contact cooling water, and process waste water must be eliminated or permitted.** Based upon the site assessment performed, the permittee shall develop BMP's that will effectively eliminate or reduce pollutant loadings in stormwater discharges from the facility in accordance with the following sections. BMPs are

3

measures used to prevent or mitigate pollution from any type of activity. The evaluation and selection of the BMP's addressing each area, and/or activity where source materials are exposed to stormwater discharging to surface water, shall be documented in the SPPP and shall include at a minimum the following BMPs:

A. Non-Stormwater Discharges into Storm Sewers

The facility shall ensure that it does not generate and discharge, through storm sewers to surface waters, any domestic sewage, non-contact cooling water, or process wastewaters, unless that discharge is authorized by another NJPDES permit or identified in an application or request for authorization submitted for another NJPDES permit.

B. Removal, Cover or Control of Industrial Activities

Except as specified and required in Part IV of the permit for certain, specific exposures of source materials, all other source materials shall be moved indoors, covered, used, handled, and/or stored in a manner so as to prevent contact with stormwater that is discharged to surface water. Each BMP that prevents such contact shall be identified and discussed in the SPPP.

C. Diverting Stormwater

Approved diversion of contaminated stormwater to either a domestic or industrial wastewater treatment plant may also be considered when choosing an appropriate BMP where feasible. (Diversion to groundwater may require a separate NJPDES permit. Consult the Bureau of Nonpoint Pollution Control.)

D. Spill Prevention and Response

Areas where actual or potential spills of source materials are exposed to stormwater discharges can occur, and their accompanying drainage points shall be identified clearly in the SPPP. Where appropriate, specific material handling procedures, storage requirements and use of equipment such as diversion valves shall be developed and practiced to prevent and/or eliminate spills and/or leaks of source materials from being exposed to stormwater. Procedures for cleaning up spills shall be specifically included in the plan and made available to the appropriate personnel through scheduled employee training. In addition, the facility shall provide or otherwise make available to its personnel the appropriate and necessary spill cleanup equipment to effect an immediate and thorough spill cleanup.

E. Good Housekeeping

The SPPP must include a good housekeeping program to help maintain a clean and orderly work place. For certain activities or areas, the discharge of stormwater exposed to source materials may be prevented merely by using good housekeeping methods. The following are some simple procedures that a facility can consider incorporating into an effective good housekeeping program:

1. conduct cleanup immediately after discovery of leaks and spills;

2. implement careful material storage practices;

3. improve operation and maintenance of industrial machinery and processes;

4. maintain up-to-date material inventory;

5. maintain well organized work areas;

6. provide regular pickup and disposal of waste materials;

7. maintain dry and clean floors and ground surfaces by using brooms, shovels, vacuum cleaners, or cleaning machines; and

8. train employees about good housekeeping practices.

F. Preventative Maintenance

The SPPP shall include a Preventative Maintenance Program to include timely and regular inspections and maintenance of stormwater management devices (e.g., cleaning oil/water separators, catch basins, drip pans, catch basins, detention basins, covers, treatment units) and routine inspections of facility equipment and operations to detect faulty equipment. Equipment (such as tanks, piping, containers, and drums) should be checked regularly for signs of deterioration.

G. Inspections and Evaluation Process

1. Regular Inspections

The SPPP shall require regular inspections of the facility's equipment, exposed source materials and industrial areas to provide that all elements of the SPPP are in place and working properly. Inspections shall be conducted by qualified, trained plant personnel. Records of these inspections shall be kept onsite with the SPPP. These inspection records shall consist of the following, at a minimum: date of inspection; location of and problem(s) identified; steps taken to correct problem(s) and prevent recurrence; and inspector's names and title. In addition these inspection records shall record any incidents such as leaks or accidental discharges, and any failures or breakdowns of structural BMPs.

2. Annual Inspections

The SPPP shall also require an annual inspection and shall include an annual report of the entire facility in accordance with Part IV of this permit.

3. Evaluation Process

The SPPP shall include a system to routinely and continually evaluate the SPPP for effectiveness, any flaws that may have developed, and maintenance that may be required. The routine evaluation must include, but not be limited to, regular and annual inspections, inspection logs and records, internal reporting, plan revisions to correct any flaws detected in the SPPP or to reflect changes/additions at the facility, and logs of preventative maintenance performed at the facility. In addition, the Annual Reports and Certifications required under Part IV are integral to the evaluation process.

VI. Implementation Schedule

The SPPP shall include an implementation schedule for all structural and non-structural BMP's including a schedule(s) for removal, coverage, minimization of exposure of source material to stormwater, and/or stormwater diversion or treatment. The schedule shall meet the deadlines established in the permit in accordance with Part IV.

Upon completion of the initial SPPP, those BMP's (e.g., spill response, good housekeeping) that may readily be implemented shall be done so within 30 days, if not already practiced.

VII. General Plan Requirements

This section provides additional requirements on the administrative requirements related to finalizing your SPPP. It covers (1) required signatures, (2) requirements for plan location and access, and (3) required certifications.

A. Required Signatures for SPPP and Attachments 2 and 3

The SPPP and Attachments 2 and 3 shall be signed as follows:

FOR A CORPORATION: a "responsible corporate officer" or duly authorized representative. A "responsible corporate officer" is (i) a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation; or (ii) the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second-quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

FOR A PARTNERSHIP OR SOLE PROPRIETORSHIP: a general partner or the proprietor, respectively, or duly authorized representative.

FOR A MUNICIPALITY, STATE, FEDERAL OR OTHER PUBLIC AGENCY: either a principal executive officer or ranking elected official, or duly authorized representative.

A "responsible corporate officer", general partner, proprietor, principal executive officer of a public agency, or ranking elected official may assign his or her signatory authority for this Certification to a duly authorized representative, which is a named person or generic position (e.g., plant manager, superintendent, plant engineer, operations manager, etc.) having overall responsibility for facility operation or the permittee's environmental matters, by submitting a letter to the Bureau of Nonpoint Pollution Control stating said authority and naming the person or position.

Whenever there are two or more permittees for the facility, all of those permittees shall jointly submit this Certification, unless permittees received authorization on different dates and this Certification is therefore due from them at different dates.

B. Plan Location and Public Access

1. The SPPP and inspection and preventative maintenance records or logs shall be maintained on site at all times. These documents must be made available, upon request, to a representative of the Department and to the owner and operator of any municipal separate storm sewer receiving the stormwater discharge.

2. The SPPP shall be made available to the public upon request. The facility may claim any portion of the SPPP as confidential in accordance with the provisions set forth in N.J.A.C. 7:14A-18.2.

3. A copy of the SPPP shall be submitted to the appropriate Regional Bureau of Water Compliance and Enforcement and to the Bureau of Nonpoint Pollution Control. Revisions made to the facility's SPPP shall be submitted also.

C. Certification of Stormwater Pollution Prevention Plan

1. Attachment 2 shall be signed and submitted by the permittee to the Department's Bureau of Nonpoint Pollution Control as required by Part IV of the permit.

2. Attachment 3 shall be signed and submitted by the permittee to the Department's Bureau of Nonpoint Pollution Control as required by Part IV of the permit, and annually thereafter in accordance with the permit.

VIII. Special Requirements

A. Facilities Subject to Emergency Planning and Community Right-to-Know Statute

For facilities subject to the Emergency Planning and Community Right-to-Know Act (EPCRA) Section 313, the SPPP shall include, or cite the location of, any spill reports prepared under that Act.

B. Facilities with SPCC Plans, DPCC Plans, or DCR Plans

The SPPP shall include, or cite the location(s) of, any Spill Prevention Control and Countermeasure Plan (SPCC Plan) prepared under 40 CFR 112 and section 311 of the Clean Water Act, 33 U.S.C.§1321; and any discharge prevention, containment and countermeasure plan (DPCC plan) and discharge cleanup and removal plan (DCR plan) prepared under N.J.A.C. 7:1E.

C. Facilities Undergoing Construction Activities

Whenever construction activities are undertaken at the facility, the SPPP shall be amended, if necessary, so that the SPPP continues to be accurate and to meet the requirements of Part I of this permit.

New Jersey Department of Environmental Protection
Bureau of Nonpoint Pollution Control

ATTACHMENT TWO

Stormwater Pollution Prevention Plan (SPPP)
Preparation Certification
Individual Industrial Stormwater Permit

SUBMIT A COPY OF THE PLAN ALONG WITH THIS CERTIFICATION TO THE BUREAU OF NONPOINT POLLUTION CONTROL AND THE APPROPRIATE REGIONAL BUREAU OF WATER COMPLIANCE AND ENFORCEMENT. THE ORIGINAL PLAN AND A COPY OF THIS CERTIFICATION ARE TO REMAIN ON SITE AVAILABLE FOR INSPECTION. ALL REVISIONS MADE TO THE PLAN ALSO SHALL BE SUBMITTED.

Facility Name:____

NJPDES No. ____________________

" I certify under penalty of law that the Stormwater Pollution Prevention Plan (SPPP), this Preparation Certification, and all attached documents were prepared by qualified personnel under my direction or supervision in accordance with a system designed to assure that this information was properly gathered and evaluated. Based on my inquiry of those individuals immediately responsible for obtaining this information, I believe and certify that the information in the SPPP and all attached documents is true, accurate, and complete.

" I further certify that a copy of the SPPP and all applicable attachments for this permitted facility have been submitted to NJDEP's Regional Water Enforcement and Compliance Office and to NJDEP's Bureau of Nonpoint Pollution Control in accordance with Attachment 1 and the deadlines of the permit. I am aware that pursuant to the Water Pollution Control Act, N.J.S.A. 58:10A-1 et seq., there are significant civil and criminal penalties for making a false statement, representation, or certification any application, record, or other document filed or required to be maintained under that Act, including fines and/or imprisonment.

"I certify that the SPPP referred to in this SPPP Preparation Certification has been signed and the original is retained at the facility in accordance with the permit, and that it will be fully implemented at the facility in accordance with the terms and conditions or the permit. I further certify that if any part of this stormwater pollution prevention plan requires the consent of the owner(s) of or another operating entity for the facility, that consent has been obtained."

WHO MUST SIGN?

FOR A CORPORATION: a "responsible corporate officer" or duly authorized representative. A "responsible corporate officer" is (i) a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation; or (ii) the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second-quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

FOR A PARTNERSHIP OR SOLE PROPRIETORSHIP: a general partner or the proprietor, respectively, or duly authorized representative.

FOR A MUNICIPALITY, STATE, FEDERAL OR OTHER PUBLIC AGENCY: either a principal executive officer or ranking elected official, or duly authorized representative.

____
(if applicable, print name of corporation, partnership, or public agency submitting this Certification)

______________________________ ______________
(signature) (date)

____
(print name)

Att2-10/17/00

New Jersey Department of Environmental Protection
Bureau of Nonpoint Pollution Control

ATTACHMENT THREE

Stormwater Pollution Prevention Plan (SPPP)
Initial Implementation and Inspection Certification
Individual Industrial Stormwater Permit

SUBMIT THIS FORM ONCE, AFTER SPPP IS IMPLEMENTED. FOR EXISTING FACILITIES, THE SPPP MUST BE IMPLEMENTED WITHIN 18 MONTHS FROM THE EFFECTIVE DATE OF THE PERMIT UNLESS THE DEPARTMENT GRANTS AN EXTENSION.

Facility Name:____

NJPDES No. ____________________

"I certify under penalty of law that this Stormwater Pollution Prevention Plan (SPPP) Implementation and Inspection Certification and all attached documents were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate this information. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering this information, the information in this Stormwater Pollution Prevention Plan (SPPP) Implementation and Inspection Certification and all attached documents is to the best of my knowledge and belief true, accurate, and complete.

"I certify that the facility has been inspected to identify areas contributing to the stormwater discharge(s) authorized under the permit and to evaluate whether the SPPP prepared complies with the permit requirements for stormwater discharge of the permit and is being properly implemented.

"I certify that the SPPP referred to in this Stormwater Pollution Prevention Plan Implementation and Inspection Certification has been and will continue to be fully implemented at this facility in accordance with the terms and conditions of the permit. I also specifically certify that this facility does not generate and discharge, through storm sewers to surface waters, any domestic wastewater, non-contact cooling water, or process waste water (including leachate and contact cooling water) other than stormwater, unless that discharge is authorized by another NJPDES permit, identified in an application (or request for authorization) submitted for another NJPDES permit or, proof that a determination has been made by the NJDEP that no permit is necessary.

"I also certify that this facility is not in violation of any condition of the permit for preparation and implementation of a SPPP, except for any incidents of noncompliance (which are noted in the attached report). For any incidents of noncompliance identified in the annual inspection (or made known to me during the course of the past year), I have attached a report identifying these incidents, and identifying steps taken or during the past year), I have attached a report identifying these incidents, and identifying steps taken or being taken to remedy the noncompliance and to prevent such incidents from recurring. If the attached report identifies any incidents of noncompliance, I certify that any remedial or preventative steps identified therein were or will be taken in compliance with the schedule set forth in the attachment to this certification. I am aware that pursuant to the Water Pollution Control Act, N.J.S.A. 58:10A-1 et seq., there are significant civil and criminal penalties for making a false statement, representation, or certification any application, record, or other document filed or required to be maintained under that Act, including fines and/or imprisonment."

WHO MUST SIGN?

FOR A CORPORATION: a "responsible corporate officer" or duly authorized representative. A "responsible corporate officer" is (i) a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation; or (ii) the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second-quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

FOR A PARTNERSHIP OR SOLE PROPRIETORSHIP: a general partner or the proprietor, respectively, or duly authorized representative.

FOR A MUNICIPALITY, STATE, FEDERAL OR OTHER PUBLIC AGENCY: either a principal executive officer or ranking elected official, or duly authorized representative.

A "responsible corporate officer", general partner, proprietor, principal executive officer of a public agency, or ranking elected official may assign his or her signatory authority for this Certification to a duly authorized representative, which is a named person or generic position (e.g., plant manager, superintendent, plant engineer, operations manager, etc.) having overall responsibility for facility operation or the permittee's environmental matters, by submitting a letter to the Bureau of Nonpoint Pollution Control stating said authority and naming the person or position.

Whenever there are two or more permittees for the facility, all of those permittees shall jointly submit this Certification, unless permittees received authorization on different dates and this Certification is therefore due from them at different dates.

____

(if applicable, print name of corporation, partnership, or public agency submitting this Certification)

______________________________ ____________

(signature) **(date)**

____

(print name)

Please attach all reports and plan revisions to this certification and submit it to the Bureau of Nonpoint Source Control and submit a copy to the appropriate Regional Bureau of Water Compliance and Enforcement. The original SPPP and a copy of this certification are to remain ON SITE available for inspection.

Att3-10/18/00

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

State of New Jersey
DEPARTMENT OF ENVIRONMENTAL PROTECTION

JON S. CORZINE
Governor

Division of Water Quality
PO Box 029 Trenton, NJ 08625-0029
FAX: (609) 777-0432

LISA P. JACKSON
Commissioner

NJPDES Permit Application
Request For Additional Administrative Information

Date: 09/20/2007

George P. Barnes, VP
PSE&G Nuclear LLC
PO Box 236-N21 - Alloway Creek Neck Rd
Hancocks Bridge, NJ 08038

Re: Consolidated Renewal Permit Action
NJPDES NJ0025411
Hope Creek Generating Station
Lower Alloways Creek Twp, Salem County

Dear Mr. Barnes:

Your application dated 8/30/07 and received on 08/31/2007 is administratively incomplete. The following information is needed to complete the administrative review:

1. Form RF is required for this permit. I've enclosed the form.

The above noted information should be submitted to my attention within 30 days of receipt of this letter to maintain an active review status. Your application will not continue to be processed until the above noted information is received by the Department. If no response is received within 30 days, the application may be administratively closed.

Should you have any questions regarding the requested information, you may contact me at (609) 984-4428. Please refer to the NJPDES number and subject matter when making inquiries.

Sincerely,

Annette DeBlois

Annette DeBlois, Program Technician
Bureau of Permit Management

cc: Bureau of Point Source Permitting Region 2
Bureau of Nonpoint Pollution Control
Southern Bureau of Water Compliance and Enforcement
BPM File – PI: 46815 / MF: 15647
Central File-Administrative Record

admincom.rtf

PSEG Nuclear LLC
P.O. Box 236, Hancocks Bridge, New Jersey 08038-0236

OCT 18 2007

HCH-2007-107

PSEG
Nuclear LLC

CERTIFIED MAIL
RETURN RECEIPT REQUESTED
ARTICLE NUMBER: 7003 0500 0003 4469 3860

Ms. Annette DeBlois, Program Technician
Bureau of Permit Management
Division of Water Quality
New Jersey Department of Environmental Protection
PO Box 029, 401 East State Street
Trenton, New jersey 08625-0029

HOPE CREEK GENERATING STATION
NJPDES PERMIT NJ0025411
APPLICATION FOR RENEWAL
COMPLETED FORM RF

Dear Ms. DeBlois:

I am in receipt of your letter dated September 20, 2007, in which you request that PSEG Nuclear LLC (PSEG Nuclear) submit a Form RF in supplement to the Hope Creek Generating Station (Hope Creek), NJPDES Renewal Application dated August 30, 2007 (Application).

PSEG Nuclear believes that it was appropriate not to include the Form RF as part of the Application because stormwater discharges at Hope Creek are mixed with industrial nonstormwater discharges that require a NJPDES-DSW permit. The Hope Creek NJPDES Permit has always allowed certain combined stormwater and industrial nonstormwater discharges. Based upon the Instructions for Form RF, that form is not required to be submitted with the Application, instead submit Form C. The stormwater outfalls are identified in the initial renewal application as Tab "Yard Drains". The information provided demonstrates that there is a potential for industrial nonstormwater to mix with the discharge and that the primary contributor to the discharge is river water which enters the drainage system through tidal action. Based on the predominance of the tidal influence on the discharge as discussed in the preapplication for this renewal application, analytical requirements on the discharge were not required.

Without limiting the foregoing, in order to continue processing the Application in a timely manner, PSEG Nuclear has submitted the enclosed Form RF, which continues to identify combined discharges of both stormwater and industrial nonstormater. The submission of this Form RF should not in any way be read to limit or amend PSEG Nuclear's request, as stated in the Application, to renew the Hope Creek NJPDES

95-2168 REV. 7/99

Permit to continue all discharges including, but not limited to, combined discharges of stormwater and industrial nonstormwater.

If you have any further questions or require additional information, please contact Ed Keating at 856-339-7902 or Erin West at 856-339-5411. Thank you for your assistance.

Very Truly Yours,

George P. Barnes

George P. Barnes
Site Vice President – Hope Creek

Enclosure

C Ms. S Rosenwinkle, NJDEP
US Nuclear Regulatory Commission, Document Control Desk,
Washington, DC 20555 (Docket 50-354)

BC Vice President - EH&S (T17A)
Plant Manager - Hope Creek
Director – Regulatory Affairs (N21)
J. G. Valeri, Esq. (T5C)
Chemistry/Environmental Manager (H15)
Environmental/Radwaste Supervisor (H15)
C. E. White (H15)
E. J. Keating (N21)

Appendix C

Special Status Species Correspondence

This Page Intentionally Left Blank

Table of Contents

This Page Intentionally Left Blank

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.

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, 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.

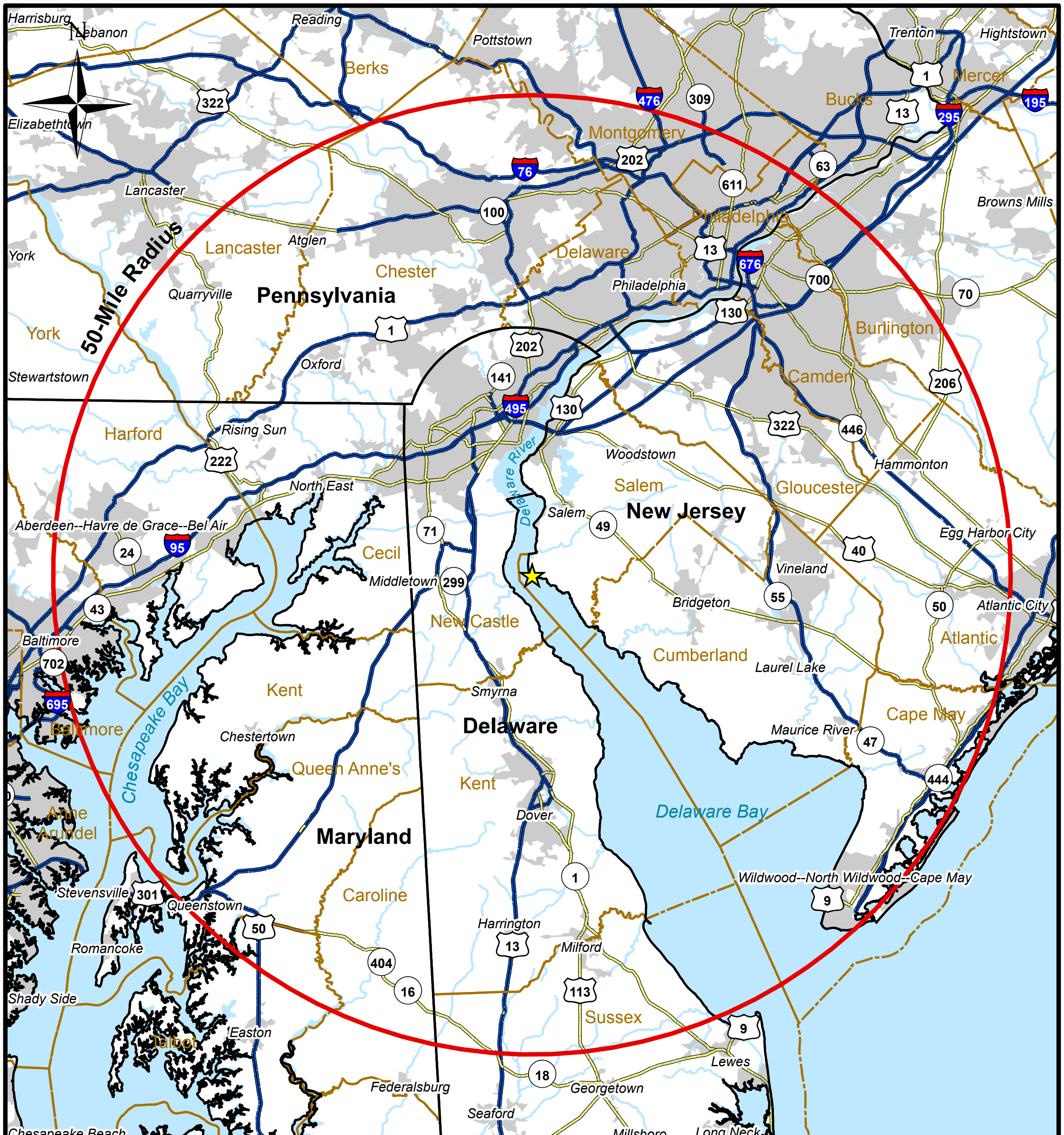
After your review of the information provided in this letter,I would appreciate your sending a letter detailing any concerns you have about potential impacts to threatened or endangered species or critical habitat in the area of the Salem and HCGS or along associated transmission corridors. PSEG Nuclear 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



Legend

★ Salem and Hope Creek Generating Stations

State Boundary

County Boundary

Primary Highway with Limited Access

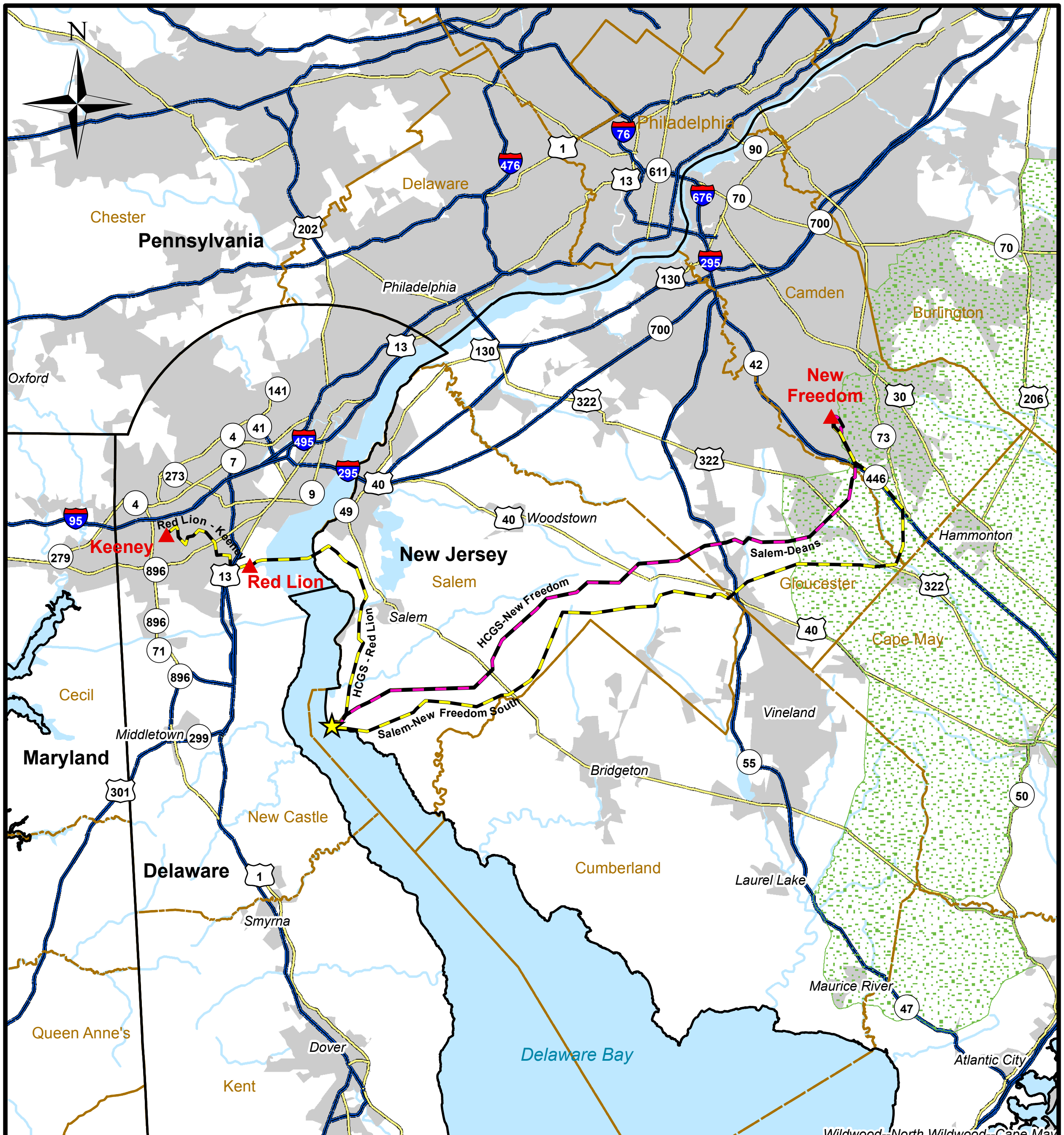
Primary Highway

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		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		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		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
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).

This page intentionally left blank.

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.

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 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.

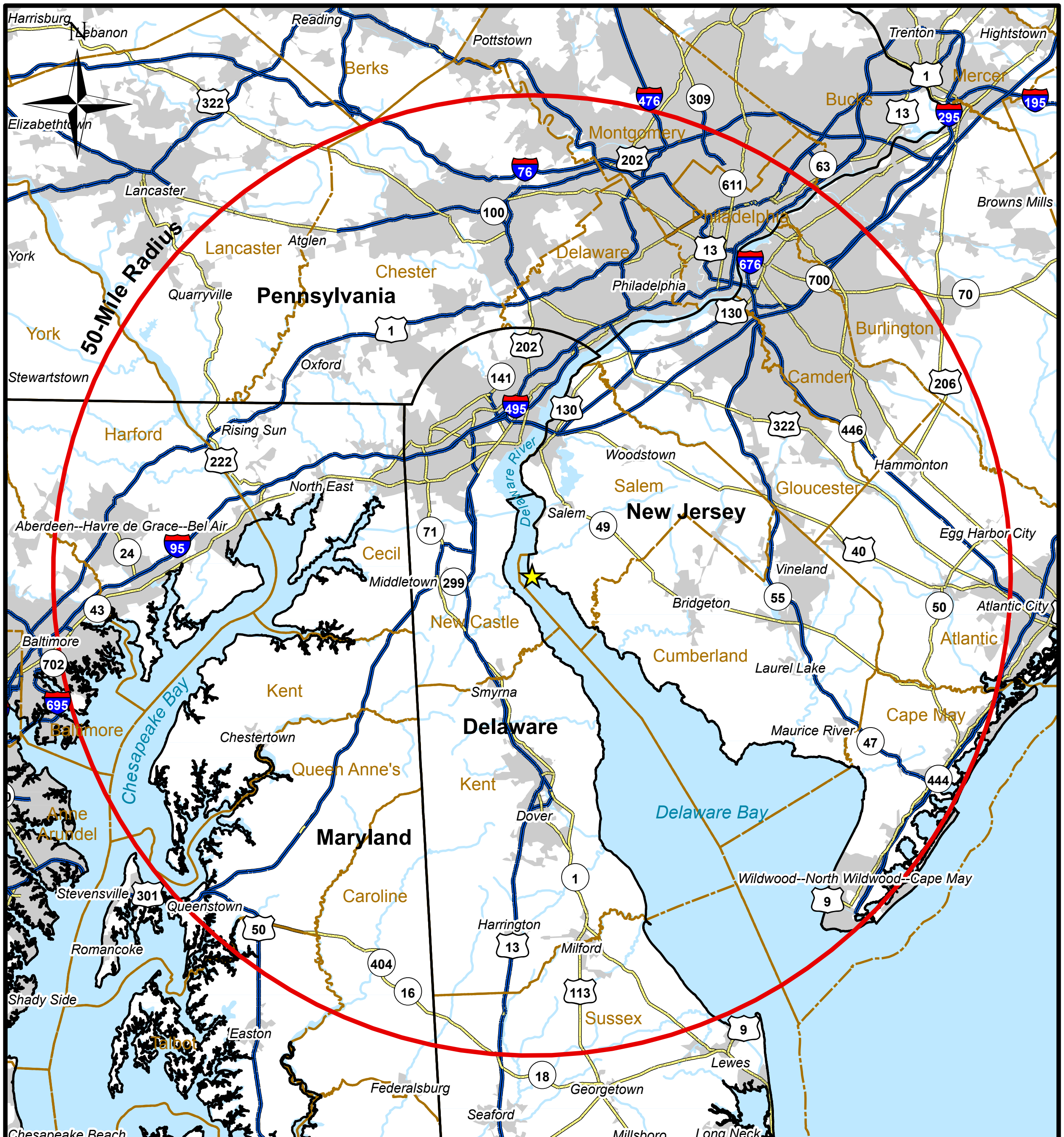
Please do not hesitate to call me at 856-339-7902, if there are questions or you need additional information to complete a review of the proposed action. Thank you in advance for your assistance.

Sincerely,

Edward J. Keating

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

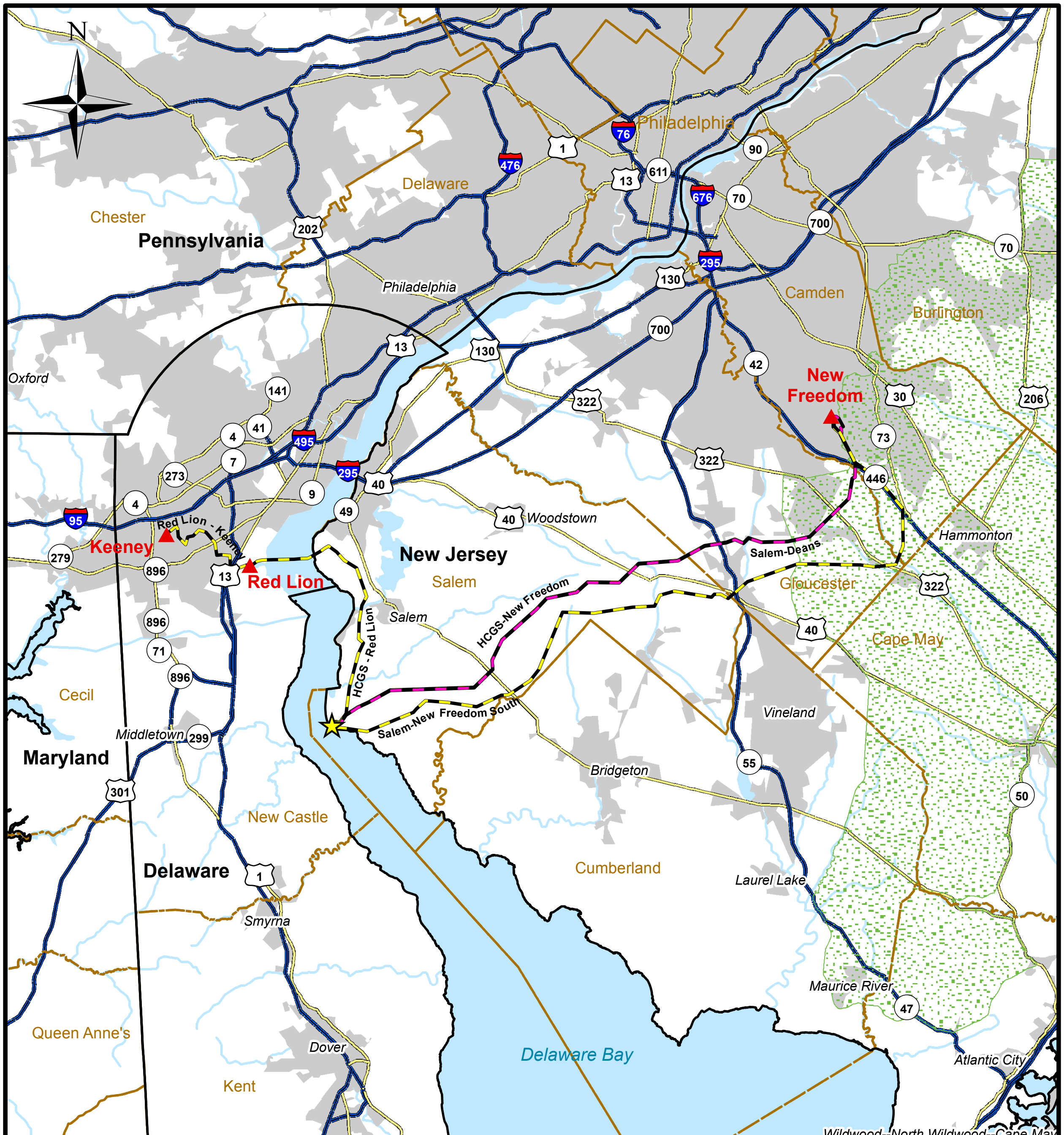


Legend

★ 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



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

0 2.5 5 10 15 Miles

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		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 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 A. Colligan

Mary A. Colligan
Assistant Regional Administrator for
Protected Resources

EC: Crocker, F/NER3

File Code: Sec 7 NRC Salem and Hope Creek Nuclear

This page intentionally left blank.

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.

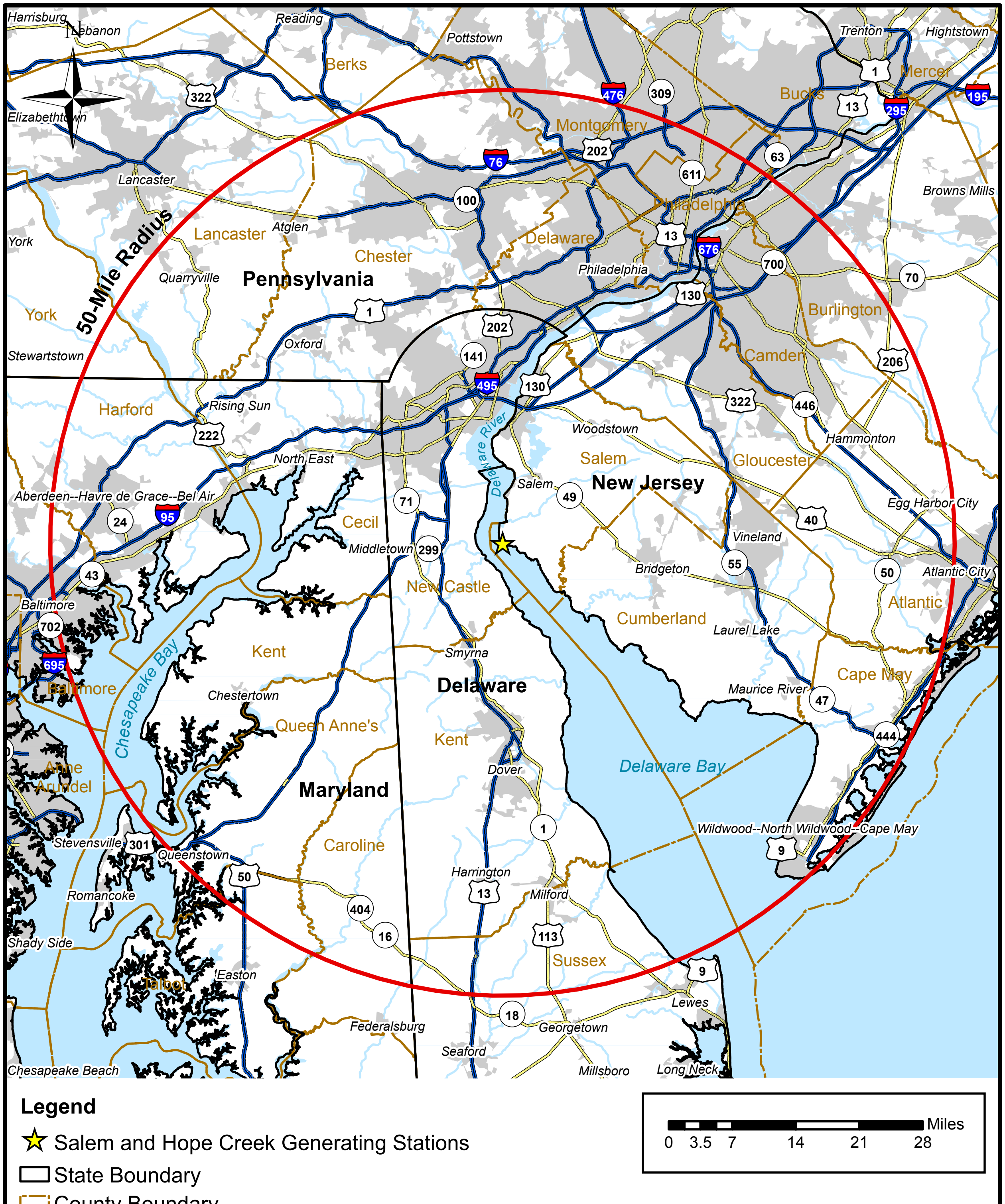
After your review of the information provided in this letter, I would appreciate your sending a letter detailing any concerns you may have about any listed species or critical habitat in the area of the Salem and HCGS sites and the associated transmission corridors. PSEG Nuclear will include copies of 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.

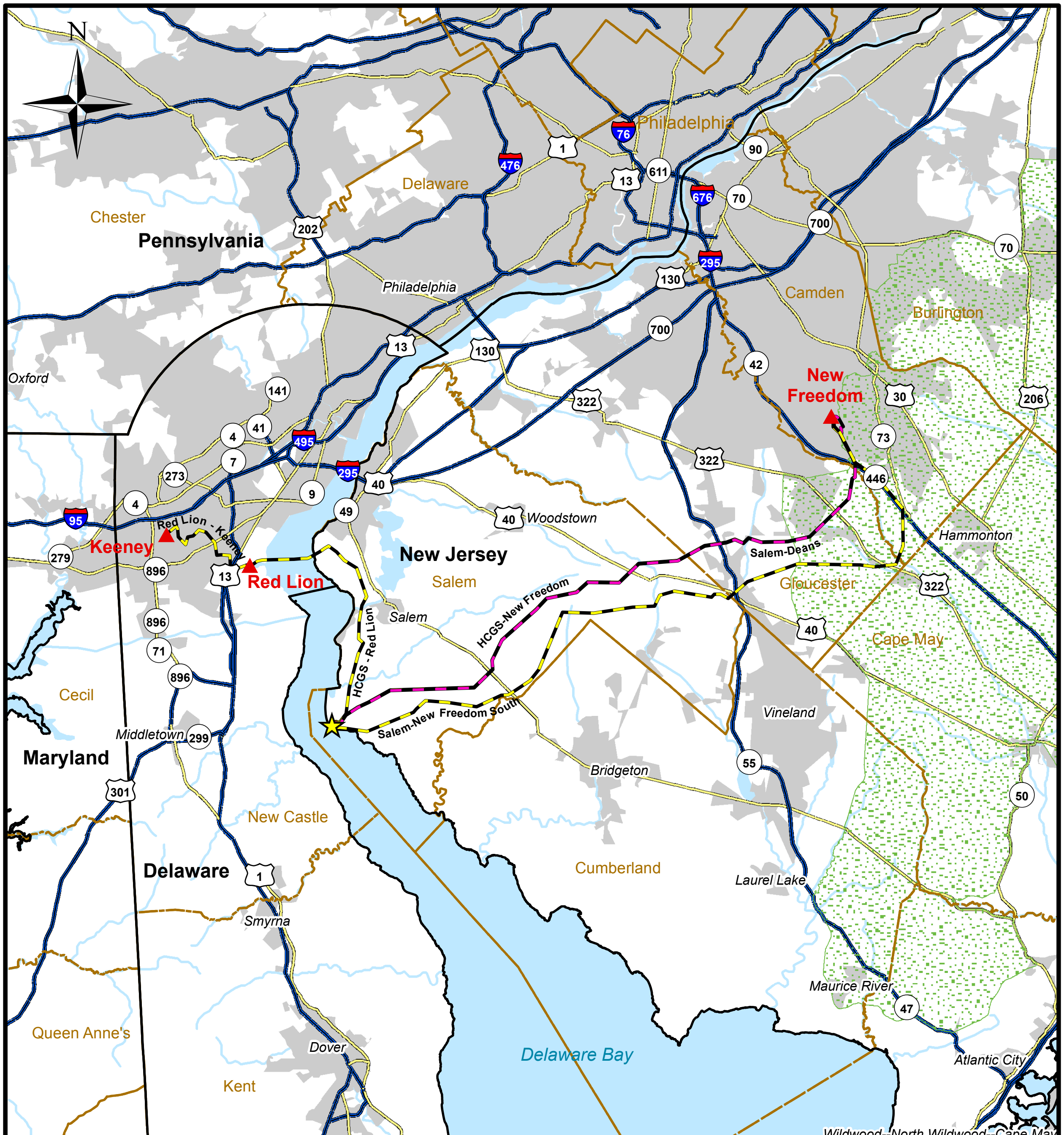
Sincerely,

Edward J. Keating
Sr. Environmental Advisor

Enclosure: Figure 1 – 50-Mile Region
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		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
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).

This page intentionally left blank.

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

New Jersey is an Equal Opportunity Employer . Printed on Recycled Paper and Recyclable

04/27/2009 10:20 8566295044 NJFW PAGE 02
RECEIVED 04/26/2009 22:05

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., Chief
Endangered and Nongame Species Program

c. Bob Cartica, Administrator – Office of Natural Lands Management

2

04/27/2009 10:20 8566295944 NJFW PAGE 03
RECEIVED 04/26/2009 22:05

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.

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; 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.

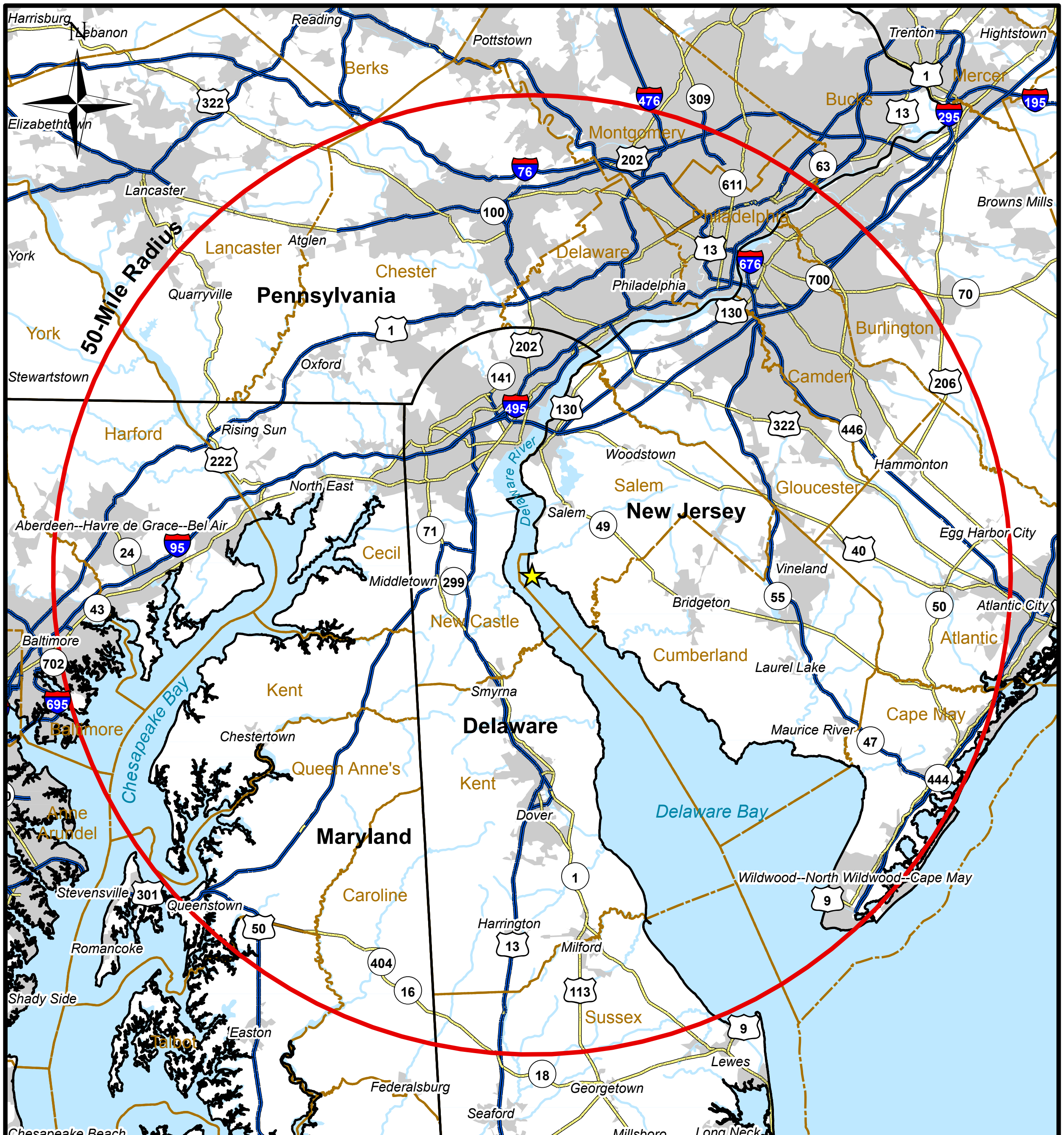
After your review of the information provided in this letter, I would appreciate your sending a letter detailing any concerns you may have about any listed species or critical habitat in the area of the Salem and HCGS sites and the associated transmission corridor in Delaware. PSEG Nuclear will include 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

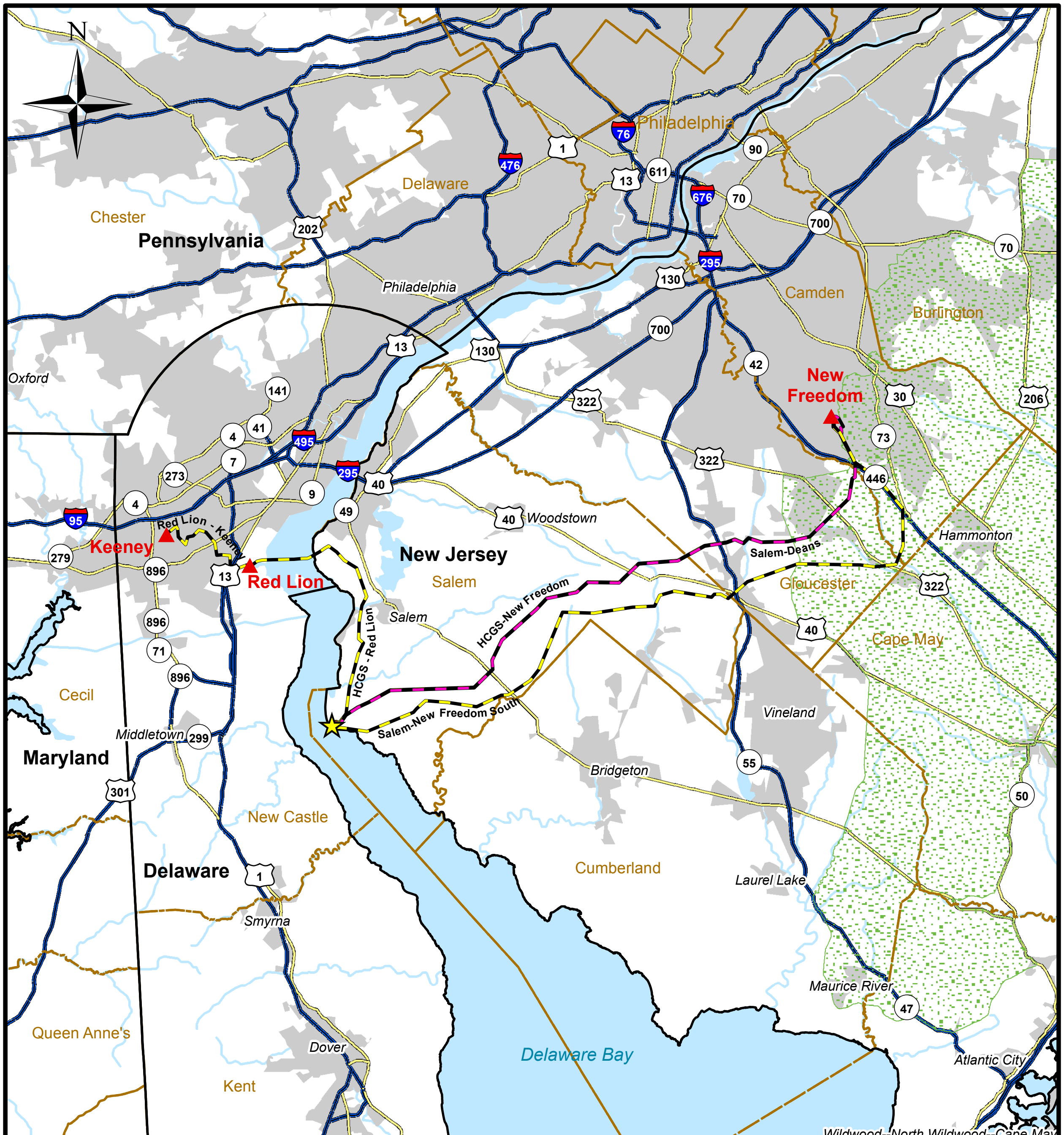


Legend

★ 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



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 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		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		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
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).

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

This Page Intentionally Left Blank

Table of Contents

This Page Intentionally Left Blank

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.

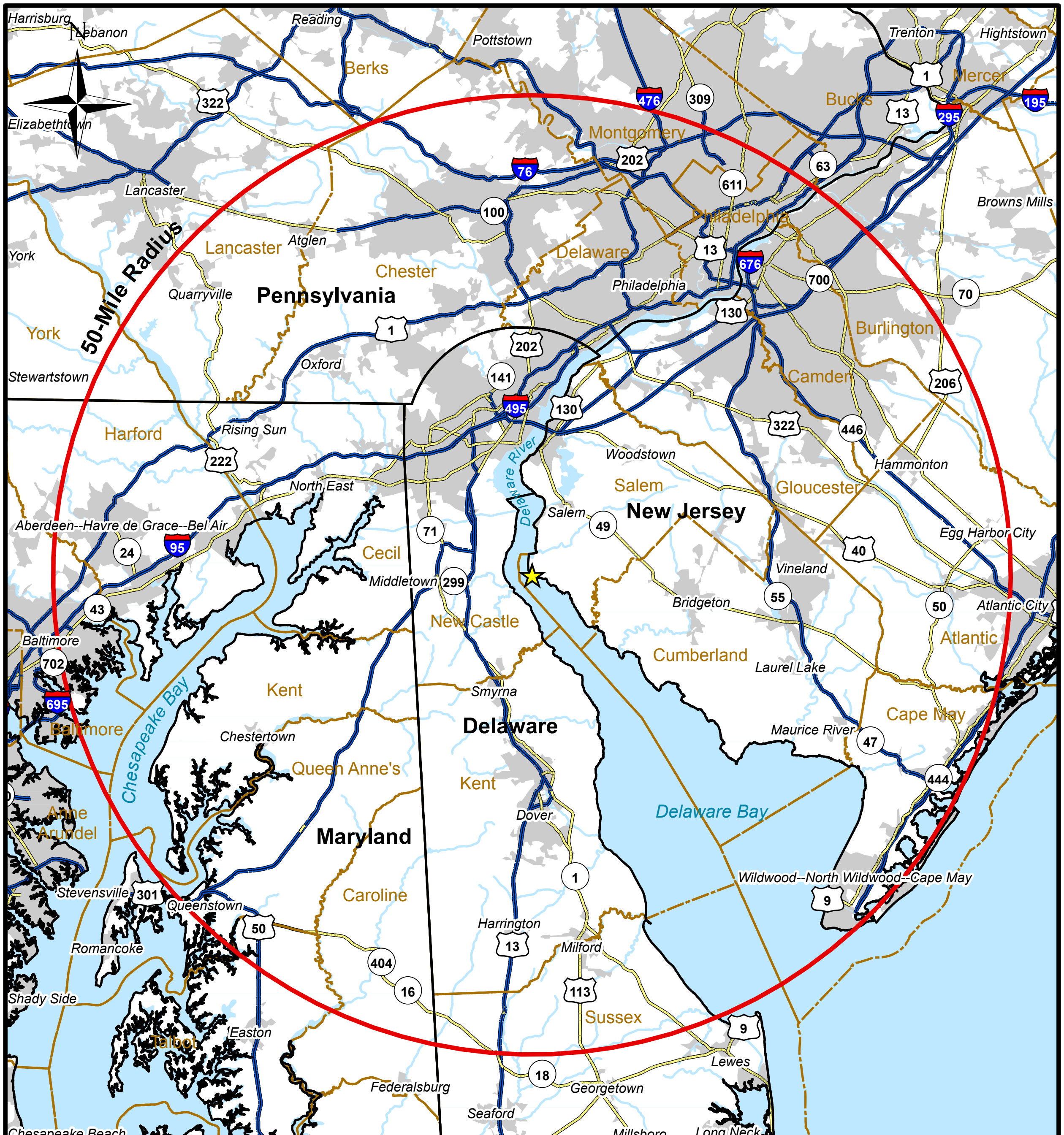
After your review of the information provided in this letter, I would appreciate your sending a letter detailing any concerns you may have about historic/archaeological properties in the area of the Salem and HCGS sites and the associated transmission corridors, or alternatively, confirming my conclusion 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

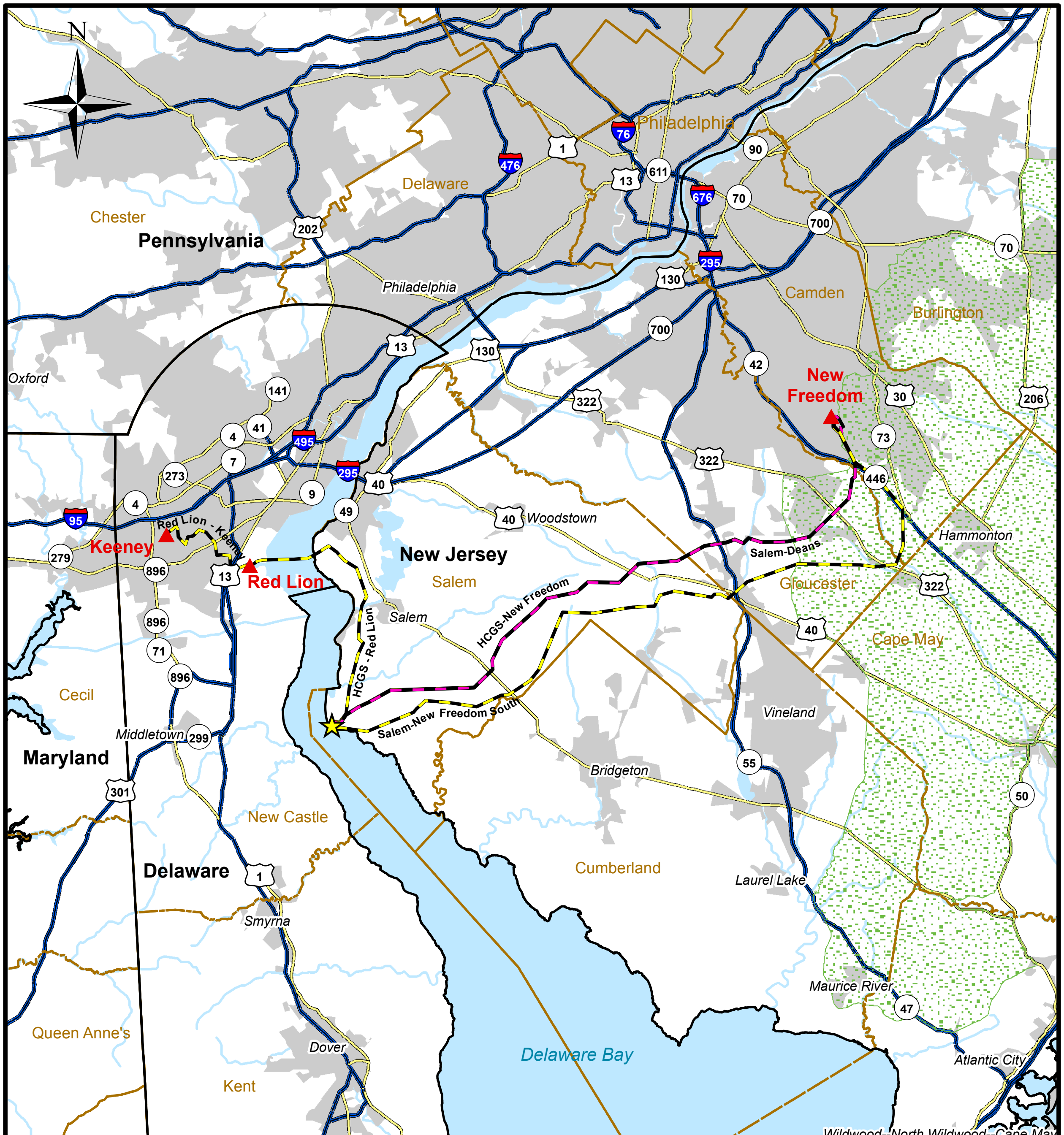


Legend

- ★ 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



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. 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)
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)

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.

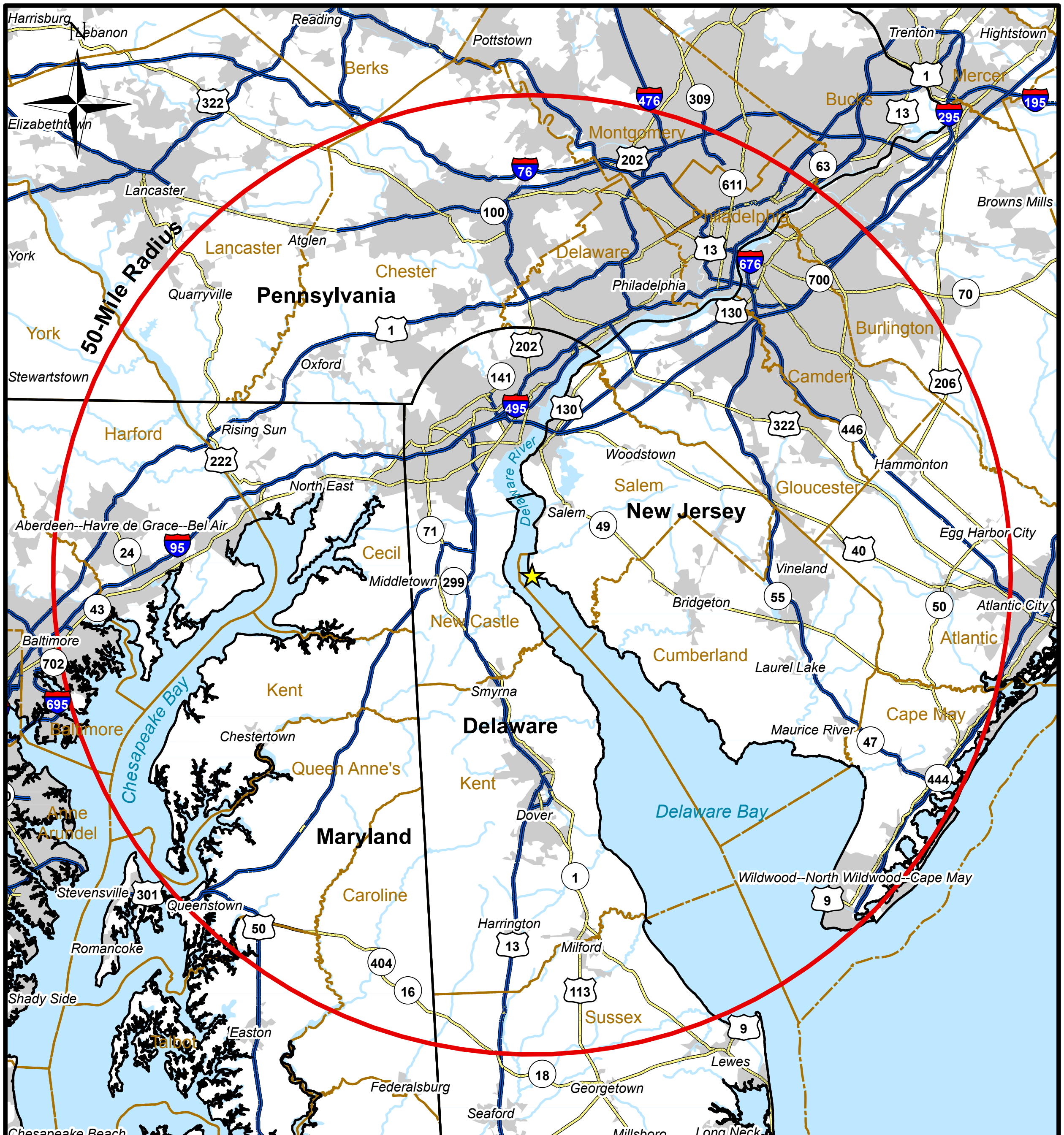
After your review of the information provided in this letter, I would appreciate your sending a letter detailing any concerns you may have about historic/archaeological properties in the area of the Salem and HCGS sites and the HCGS-Red Lion and Red Lion-Keeney transmission corridors, or alternatively, 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.

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

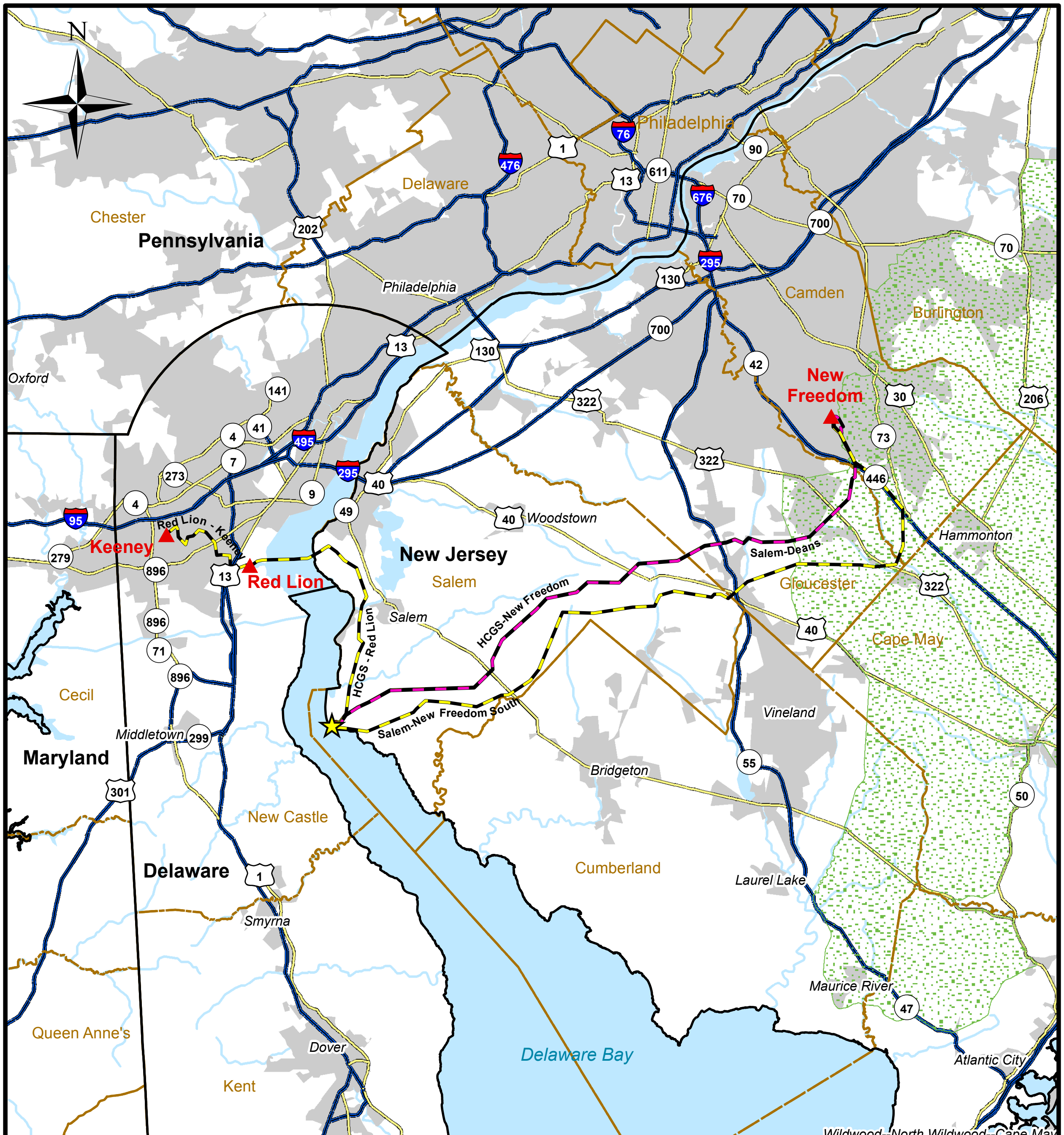


Legend

★ 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



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. 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)
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)

State of Delaware
Historical and Cultural Affairs

21 The Green
Dover, DE 19901-3611

Phone: (302) 736.7400 Fax: (302) 739.5660

FINDING OF NO ADVERSE EFFECT

Review Code: 2009.03.05.02

Agency: U.S. Nuclear Regulatory Commission

Project: License Renewal, Salem and Hope Creek Generating Station
Lower Alloways Creek Township, Salem County, NJ

The staff of the State Historic Preservation Office has reviewed the materials submitted regarding the above-cited project. Based on this review, it is our determination that the project will not adversely affect any properties listed on or eligible for listing on the National Register of Historic Places.

Timothy A. Slavin
State Historic Preservation Officer

Reviewed By: Joan N. Larrivee
Joan N. Larrivee, Architectural Historian
joan.larrivee@state.de.us

Date: 3/24/09

SAVING DELAWARE HISTORY

Appendix E

SAMA ANALYSIS

This Page Intentionally Left Blank

TABLE OF CONTENTS

Section **Page**

TABLE OF TABLES

Table **Page**

TABLE OF FIGURES

Acronyms Used in Appendix E

ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
BE	basic event
BWR	boiling water reactor
CC	component cooling
CDB	core damage bin
CDF	core damage frequency
CET	containment event tree
CRD	control rod drive
CS	core spray
CST	condensate storage tank
DG	diesel generator
ECCS	emergency core cooling system
EDG	emergency diesel generator
EE	external events
EG	emergency generator
EPRI	Electric Power Research Institute
EPZ	emergency planning zone
ET	event tree
F&O	fact and observation
FP	fire protection
FT	fault tree
FRVS	filtration, recirculation and ventilation system
HCGS	Hope Creek Generating Station
HEP	human error probability
HRA	human reliability analysis
HVAC	heating ventilation and air-conditioning
IA	instrument air
IE	initiating event
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
LOOP	loss of off-site power
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

Acronyms Used in Appendix E

MSPI	mitigating systems performance indicator
NEI	Nuclear Energy Institute
NPSH	net positive suction head
NRC	U.S. Nuclear Regulatory Commission
OECR	off-site economic cost risk
PACR	potential averted cost-risk
PRA	probabilistic risk analysis
PSA	probabilistic safety assessment
PSEG	Public Service Enterprise Group
PWR	pressurized water reactor
RB	reactor building
RCS	reactor coolant system
RDR	real discount rate
RHR	residual heat removal
RPV	reactor pressure vessel
RRW	risk reduction worth
RACS	reactor auxiliaries cooling system
SAMA	severe accident mitigation alternative
SACS	safety auxiliaries cooling system
SAG	severe accident guidelines
SBO	station blackout
SDS	seismic damage states
SRV	safety relief valve
SSW	station service water
SW	service water
SWGR	switchgear

This Page Intentionally Left Blank

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 involves identifying SAMA candidates that have potential for reducing plant risk and determining whether or not the implementation of those candidates is beneficial on a cost-risk reduction basis. The metrics chosen to represent plant risk include the core damage frequency (CDF), the dose-risk, and the offsite economic cost-risk. These values provide a measure of both the likelihood and consequences of a core damage event.

The SAMA process consists of the following steps:

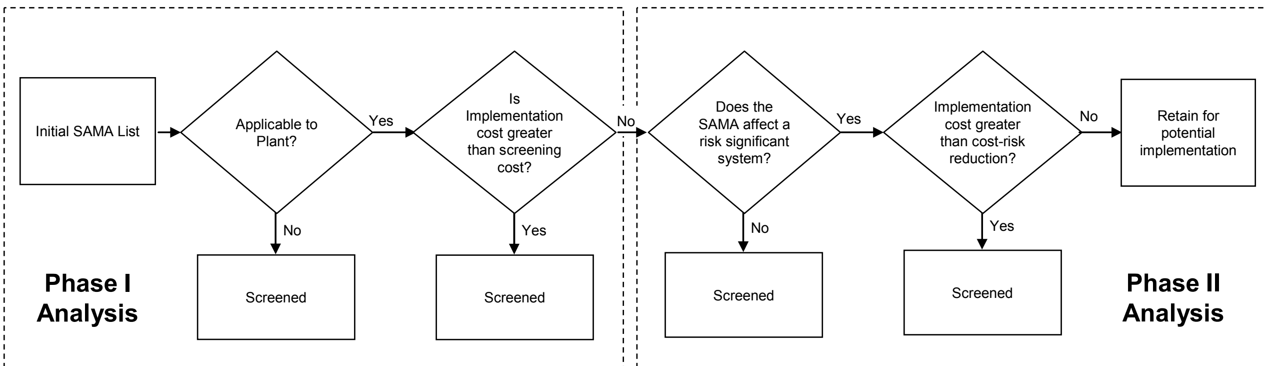
- Hope Creek Generating Station (HCGS) Probabilistic Risk Assessment (PRA) Model – Use the HCGS Internal Events PRA model as the basis for the analysis (Section E.2). Incorporate External Events contributions as described in Section E.4.6.2.
- Level 3 PRA Analysis – Use HCGS Level 1 and 2 Internal Events PRA output and site-specific meteorology, demographic, land use, and emergency response data as input in performing a Level 3 PRA using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section E.3). Incorporate External Events contributions as described in Section E.4.6.2.
- Baseline Risk Monetization – Use U.S. Nuclear Regulatory Commission (NRC) regulatory analysis techniques to calculate the monetary value of the unmitigated HCGS severe accident risk. This becomes the maximum averted cost-risk that is possible (Section E.4).
- Phase 1 SAMA Analysis – Identify potential SAMA candidates based on the HCGS Probabilistic Risk Assessment (PRA), Individual Plant Examination – External Events (IPEEE), and documentation from the industry and the NRC. Screen out SAMA candidates that are not applicable to the HCGS design or are of low benefit in boiling water reactors (BWRs) such as HCGS, candidates that have already been implemented at HCGS or whose benefits have been achieved at HCGS using other means, and candidates whose estimated cost exceeds the maximum possible averted cost-risk (Section E.5).
- Phase 2 SAMA Analysis – Calculate the risk reduction attributable to each of the remaining SAMA candidates and compare to the estimated cost of implementation

to identify the net cost-benefit. PRA insights are also used to screen SAMA candidates in this phase (Section 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 appendix. The graphic below summarizes the high level steps of the SAMA process.

SAMA SCREENING PROCESS



E.2 HOPE CREEK PRA MODEL

The SAMA analysis is based upon the 2008 update of the HCGS PSA model for internal events (i.e., HC108B model). The original IPE model was submitted in 1994 has been subsequently updated in 1994, 1999, 2000, 2003, 2004, 2005, 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 Hope Creek 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.4.6.2 and E.5.1.7 provides a description of the process used to integrate external events contribution into the Hope Creek SAMA process.

Table E.2-1 provides a summary of the models created since the IPE.

E.2.1 PRA MODEL SINCE IPE SUBMITTAL (PSEG 1994a)

The IPE submittal (PSEG 1994a) presented a summary of the Level 1 and Level 2 PSA analyses per GL 88-20 (NRC 1991a) and the IPE submittal guidance in NUREG 1335 (NRC 1989). The study was performed and documented in accordance with the guidance provided in NUREG/CR-2300 (NRC 1983). Also presented were a description of the review process, insights learned through the IPE process, PSEG management plans for the future use of the HCGS PSA, and the insights gained through the IPE process.

E.2.1.1 PRA MODEL 0 UPDATE (PSEG 1994b)

The Hope Creek PRA Model was updated in September of 1994 and identified as Rev 0. As documented in this revision to the PSA, this model represents “the second tier documentation of the Individual Plant Examination (IPE) for the HCGS.”

E.2.1.2 PRA MODEL 1.0 UPDATE (PSEG 1999)

During 1999, PSEG participated in a PRA Peer Review Certification of the Hope Creek PRA administered under the auspices of the BWROG Peer Certification Committee. The purpose of the PRA peer review process is to establish a method of assessing the technical quality of the PRA for the spectrum of its potential applications. In responding to the team comments and to incorporate plant modifications, the HCGS PRA updating was initiated in 1998. During the update, recent NRC and industry studies and findings were incorporated.

The major changes finished in this update were directed towards the Level II approach. This update integrated Level I and II. The Level I core damage sequences are categorized with the plant damage class (PDC). Sequences within one category are merged and directly used in the Level II for further analysis. The integrated approach facilitates future applications and information transfers between the Level I and II analysis.

Other important tasks accomplished in this update were:

- The database is largely updated with a consistent approach for all basic events used in the PSA model. The generic data is carefully selected and plant specific experience is used for updating.
- The sequence is further developed and the end states are either cold shutdown or core damage.
- Fault trees are developed for all special initiators.
- Cutsets containing two or more operator actions are reviewed and documented.

The following analyses were retained form the past analysis.

- Interfacing System Loss of Coolant Accidents (ISLOCA).
- The containment capacity analysis.
- Internal flooding analysis.

E.2.1.3 PRA MODEL 1.1 UPDATE (PSEG 2000a)

In 2000, a minor revision of the PSA was completed. The CDF was recalculated although the LERF was not updated in Revision 1.1 of the PRA model.

The following text documents the specific changes made in the PSA Model 1.1 update.

E.2.1.3.1 Basic Event Changes

- NR-ATWS-ADS-INH - The diagnosis error for failing to inhibit ADS is negligible (Appendix H) and on the basis that it is a virtual automatic response based on training and it is explicitly called out in LP-2 in 207 or RC/Q-19 in 101 EOP. Failure to perform is also considered negligible based on the simplicity of the actions, simulator results, and feedback from the alarm when the actions have been successfully performed. Also based on HEP of Grand Gulf and Fitzpatrick that each assigned a value less than 1.0E-05, it is concluded that the value of 7.5E-2 that was originally assigned is too conservative. Therefore the value of 1.0E-04 is assigned for this action.
- NR-SACS-SHED-01 - Human error recovery event NR-SACS-SHED-01 is re-quantified. The restoration of SACS is described in procedure No. HC.OP-AB.ZZ-0124 (Q). The Hope Creek PSA assumed that the earliest this action is required is at least 2 hours after the initiation of transient (TM= 2 hours Appendix H HCGS PSA Rev.O.) and because local nature of the action, a performance time of 1 hour is assumed. Based on NUREG/CR-4772 (NRC 1987) Table 8-1, a diagnosis BHEP of 1.0E-03 is assumed since the actual performance would only be required when the ultimate heat sink temperature (River Temperature) is high and time is not curtail. It is assumed that this action can be considered a critical action as part of a step-by-step task done under moderately high stress. Therefore an action BHEP of 0.02 is assigned, taken from Table 8-5 of NUREG/CR-4772. A recovery factor of 0.001 is applied to the action BHEP, taken from item 10 of the same table. This results in a total HEP of HEP = 1.0E-03 + 0.02 * 0.001= 0.00102 ≈ 0.001 = 1.0E-03
- NR-RHR-INIT - The quantification of post-accident operator error, NR-RHR-INIT is described in detail in the Hope Creek PSA, Appendix H. In the calculation summary for the event, it is noted that NUREG/CR-1278 (NRC 1985), the most appropriate methodology can be used to calculate a human error probability as low as 2.0E-06. However later more conservative number 2.0E-04 is used based on Table 9-1 of NUREG/CR-4772 that provides the results of the HEP calculation for failure to initiate SPC given RHR was already placed in service for injection by using NUREG/CR-1278 methodology. The post-accident human error NR-RHR-INIT included not only SPC, but also SDC and CSC. For each of these independent actions (SDC and CSC) the value of 0.1 from the NUREG/CR-1278 Chapter 20 is assigned for each action. This results in a total HEP of 2.0E-04 *0.1 *0.1 = 2.0E-06
- CHC-LOOPB-ACTUAT - The basic event CHC-XHE-FO-LOOPB with failure probability of 1.0E-01 is replaced by basic event CHC-LOOPB-ACTUAT with failure probability of 3.0E-03.
- NR-XTIE-EDG - It is noted in NUREG/CR-1278, that the most appropriate methodology can be used to calculate a Human Error Probability using written procedures under abnormal operating condition. The more conservative value predicted is using NUREG/CR-4772 Table 8-5 which performing a critical action as

part of a dynamic task done under extremely high stress. Table 8-5 provides the results of the HEP calculation for this action. The value of the quantified HEP is 0.25. The more conservative value of 0.3 is recommended for this action.

Fault Tree Changes

- The fault trees IE-HVAC.LGC, CHCA.LGC, CHCB.LGC, ZCHCA.LGC, ZCHCB.LGC, SWA.LGC, and SWB.LGC are changed to make the fault trees symmetrical.
- The basic event NR-DG-DF-6 is removed from fault tree SDGA.LGC. The basic event RHS-XHE-FO-SDC is replaced by NR-RHR-INIT in fault tree SDC.LGC. The basic event NR-VENT-5 is replaced by basic event NR-RHR-INIT in fault tree CONTVENT.LGC. The basic event NR-SW is removed from fault tree SWSA--HVC.LGC. The basic event NR-DG-DF-6 is added to fault tree EDG-TOP.LGC.

Safety Auxiliaries Cooling System (SACS)

- System Function
  - The Safety Auxiliaries Cooling System (SACS) is a closed loop cooling system designed to supply cooling water to various safety-related equipment during all plant operating modes. The system is a part of the overall system called the Safety and Turbine Auxiliaries Cooling System (STACS), which also supplies cooling water to various auxiliary equipment during normal operation and various shutdown conditions The STACS consists of two redundant loops. A simplified diagram of STACS is presented in Figure 3.2-15. Each STACS loop contains two pumps, two heat exchangers, one expansion tank, one demineralizer, and one chemical addition tank, in addition to pipes and valves. The pumps circulate the demineralized cooling water through components and equipment. The circulating water is cooled by the station service water system in the SACS heat exchangers. Each SACS loop is completely independent of the other, eliminating the possibility of a single failure causing the loss of the entire system.
- SACS Success Criteria:
  - SACS loops is considered successful in providing cooling flow if either of the following conditions are met
- Loop Operation: Two pumps and two heat exchangers in one loop are in operation. The other loop can be INOP completely. The SACS loop cross-ties are only meaningful in this configuration. Operator must re-align heat load arrangement in order to be successful. Or One pump and two heat exchangers in one loop and One pump and one heat exchanger in the other loop must be in operation. This configuration is successful with some load shedding. This configuration is denoted as Configuration I-I.
- Related Fault tree Changes
  - The following fault trees are changed to include changes in SACS system success criteria. CHCA, CHCB, CHSA, CHSB, CSA-RMLC, CSB-RMLC, CSC-RMLC, CSD-RMLD, CSC, HPI-RMLC, IAS, IGASA, IGASB, LPI, RCI-RMLC, RHA-RMLC, RHB-RMLC, RHC-RMLC, RHD-RMLC, SDGA, SDGB, SDGC, SDGD, U-TOP-N, ZCHCA AND ZCHCB.

TSC Chiller Room Cooler

- The dependency of SAC A, B, C, and D on room cooler are deleted. The Chillers supply cooling to the 1E panel room. The room has panel IAJ 482, IBJ482, 1CJ482, and IDJ482 which supply power to control logic of SACS Pumps A, B, C, and D (See Table T-11 of CBD DE-CB.EG-0054). In case of TSC Chiller failure, the room will heat up and the control panels will fail in 20 minutes (see Calculation GM-3). Therefore the TSC chiller model is needed for SACS pumps to function. The two fault trees ZCHSA, ZCHSB were built similar to ZCHA and ZCHB to reflect the TSC Chiller. In the Chiller model we take the credit of operator action to bring portable fans in case of loss of both TSC Chillers (See Loss of HVAC HC.OP-AB.ZZ-0154(Q) 1/15/99).

CONDENSATE

- When the relief valves stuck open the condensate System can not be credited. This dependency was removed in cases that relief valves stuck open. The fault tree UV-TRAS was changed to reflect these changes.
- In fault trees IE-HAVC, CHCA, CHCB, IAS, ZCHCA, ZCHCB, and CHSB, the basic event CHC-XHE-MC-FTAI, or 3 are deleted. The basic event CHC-LOOPA or B-ACTUAT includes operator fail to start and failure of auto start. The basic event CHCXHE-MC-FTA1, or 3 is included in basic event CHC-LOOPA or B-ACTUAT.
- The Basic event VAS-FAN-FS-CV2l4 in fault tree SACA-RCL was used for both fan A and C. The correct basic event for fan A is VAS-FAN-FS-AV2l4. Therefore the basic event for fan A is changed to VAS-FAN-FS-AV214.
- The Disallow maintenance fault tree was revised to include mutually exclusive events such as two train SACS, two trains SW Pumps.

<u>Event Tree Changes</u>

The event trees T(T), T(M), T(C), T(RA) were changed in order not to credit from the Condensate System when the relief valves stuck open.

<u>Specific Documentation Changes</u>

Section 1 -Project Integration

This section was not revised. However, it should be noted that during Rev. 1.1 the PSA Level II was not updated. Hence, the results mentioned in this document for Level II are not accurate.

Section 2.0 -Methodology

The methodology remains the same.

Section 3.0 System Analysis

Section 3.1

1. With the exception of the ATWS, large LOCA, loss of HVAC, loss of offsite power, and the IAS tree, all the remaining event trees are changed structurally. Also, all the values of sequences for all the event trees have changed. The main reason for structural changes is that no credit is taken for the condensate pumps in sequences that lead to high containment pressure. All the event trees are replaced with new trees in this section.
2. The write-up in this section is revised to reflect the new sequences, new Bed
3. files, and new results.
4. Table 3.1.2-3 is revised to reflect the new bed files used in various trees. New VU events are introduced, as discussed in the "Alternative Low pressure Makeup-VU" section

Section 3.2

1. Section 3.2.1.7.9.2 is modified to indicate that success of Condensate system requires that the containment pressure not exceed 1.68 psig, so the TACS cooling to the secondary condensate pump become available.
2. Section 3.2.1.15.3 is revised to reflect that SACS pumps can operate for 24 hours without room cooling.
3. Section 3.2.1.15.9.2 is revised to reflect the new success criteria for the SACS system, and the affected fault tree models.
4. A new reference is used in Section 3.2.1.15.10 of PRA Model Revision 1.1.
5. Section 3.2.1.21.1 is revised to reflect the new findings about the fault tree naming convention which had affected the PSA model for some time; this finding had affected the Equipment Area Cooling System (EACS) to the extent that the code would not show dependency of the model to this system, at all.
6. Table 3.2-6 was revised to reflect the addition of new house events in the model.

Section 3.3

1. Table 3.3.3-8 is revised to reflect addition of human recovery actions modeled.

2. Table 3.3.7-1 is revised to show new equations used in the model, as well as their new cut off frequencies.

Section 3.4

Section 3.4 is revised entirely, and the write-up reflects the new results.

Section 4.0

The backend analysis is not repeated for Revision 1.1. Hence, the results shown in this section are not applicable anymore. However, the Level II discussion continues to hold true for the most part. Table 4.3.3 is deleted with revision marks. This is also true with Section 4.7.2.

Section 5.0

This section is almost the same as Section 3.4; hence, it was revised to reflect the new finalized results.

Appendix A

No Change.

Appendix B

Revision 1 was finalized on June 6, 1999. All the fault trees that have a different date are related to revision 1.1. These can be easily identified in Appendix B, since they show up with the new Revision 1.1 markup, and have new dates on them. RA Model 1.2 Update

E.2.1.4 PRA MODEL 1.2 UPDATE (PSEG 2000b)

In June of 2000, another minor revision of the PSA was completed. The CDF was recalculated in this revision. Although the LERF was not updated in Revision 1.1 of the PSA model, Revision 1.2 provides an estimate.

The following text documents the specific changes made in the PSA Model 1.2 update.

Section 3.0 FRONT-END ANALYSIS

Section 3.1 Accident Sequence Delineation

1. Defined and developed the frequency for the following two new initiating events:
   a) Steam/Water Line Break Outside of Containment (BOC),
   b) Manual Shutdown (SD).

2. Bayesian Updated the frequency, using Hope Creek plant specific data, for the following two initiating events:
   a) Turbine Trip,
   b) Loss of Offsite Power.

3. ATWS Model has been modified significantly.

4. Two new event tree models have been added. These models are Steam/Water Line Break Outside of Containment and Manual Shutdown.

5. Sections 3.1.1.4.2 and 3.1.1.4.4 were revised to include information on the PCS and reopening the MSIVs.

6. Section 3.1.1.4.12 was revised so it does not indicate that the PCS can be recovered.

7. Section 3.1.2.1.3 was revised to state that the PCS will be available if the drywell does not exceed 1.68 psig (it is not expected to exceed this pressure).

8. Section 3.1.2.1.5 was revised not to state that feedwater can be recovered and that the PCS is not expected to be recovered and is not modeled.

Section 3.2 System Analysis

1. The SACS cooling requirement for the core spray room coolers are removed.

2. SACS fault tree descriptions are removed from the main text and are referred to the Hope Creek notebook.

3. SLC success criteria are clearly re-stated to use two SLC pumps.

Section 3.3 Quantification Process

Table 3.3.3-8 is revised to reflect all human recovery actions modeled in Level I and II of the PSA

Section 3.4 Front-End Results

Section 3.4 has been re-written.

Definition of LERF is clarified, and supporting analysis for classification of each plant damage class is provided in Table 3.4-2.

Section 4.0 BACK-END ANALYSIS

Section 4.7 has been re-written.

Section 5.0 SUMMARY OF RESULTS AND FINDINGS

This section is the same as Section 3.4; hence, it was revised to reflect the new finalized results.

Appendix B

Some changes have been made to the HCGS fault trees. See Section 3.2 of the HCGS PSA for more detailed information.

Appendix D

1. Table D-I, "HCGS Plant Specific Data Analysis For Component Failure", was revised. The primary changes in plant specific data involved the HPI, RCI, RHS, and CSS Suppression Pool Strainers.
2. Table D-4a, “Special Events Used In The Level I Analysis”, was revised. Below provides the primary changes to this table:
    a. Added basic event CAC-BOC-SY-FREQ, "BOC BREAK ISO FAILURE".
    b. Added basic event HPI-BOC-SY-FREQ, "BOC DUE TO HPCIJRCIC OR RWCU".
    c. Added basic event MSI-BOC-SY-FREQ, "BOC DUE TO MSIV". Changed probability for basic event PCS-SPE-EHC-FAIL, "EHC
    d. FOR BYPASS VALVES FAILS".
3. Table D-4b, "Special Events Used In The Level II Analysis" was revised. The Level II special event probabilities are developed separate from the Data Analysis task. The Level II special events are discussed in the Back-End Analysis presented in Section

4 of the HCGS PSA report. For convenience, Table D-4b summarizes the special event probabilities used in the Level II analysis.

Appendix E

1. The scope of identifying Common Cause Failure (CCF) events expanded to include redundant, similar components within inter-systems (i.e., HPI, RCI, RHS, and CSS Suppression Pool Strainers).

2. Table E-2, "Common Cause Failure Analysis For The HCGS PSA", was revised. The following describes the primary changes to this table:

   a. Added CCF basic event SAC-MDP-FR-DF08, "SACS A -B -C PUMPS FAIL TO RUN".
   b. Added CCF basic event SAC-MDP-FR-DF09, "SACS A -B -D PUMPS FAIL TO RUN".
   c. Added CCF basic event SAC-MDP-FR-DF10, "SACS A -C -D PUMPS FAIL TO RUN".
   d. Added CCF basic event SAC-MDP-FR-DFll, "SACS B -C -D PUMPS FAIL TO RUN".
   e. Added CCF basic event SAC-MDP-FS-DF08, "SACS A -B -C PUMPS FAIL TO START'.
   f. Added CCF basic event SAC-MDP-FS-DF09, "SACS A -B -D PUMPS FAIL TO START".
   g. Added CCF basic event SAC-MDP-FS-DF10, "SACS A -C -D PUMPS FAIL TO START".
   h. Added CCF basic event SAC-MDP-FS-DF11, "SACS B -C -D PUMPS FAIL TO START".
   i. Added CCF basic event HPI-STR-PL-DF01, "CCF FAILURE OF HPCI AND RCIC SUCTION STRAINERS".
   j. Added CCF basic event RHS-STR-PL-DF02, "CCF FAILURE OF CSS AND RHR SUCTION STRAINERS".
   k. The probabilities of various other CCF basic events ·were changed due to changes in their associated independent failure probabilities and due to changes in their associated CCF grouping sizes.

Appendix F

The table presented in this appendix of PRA Model Revision 1.2 is a print out of the HCGS Basic Event Bed File that is used by WinNupra. The changes made to the HCGS Basic Event Bed File reflect the numerous changes made in the HCGS Data Analysis.

Appendix H

This appendix is revised to reflect the new HR events, latest EOP, and Level II HRA.

Appendix I

Some Level II Basic Event probabilities in the fault trees changed. These values are listed in Appendix D, Table D-4b and in Appendix H of PRA Model Revision 1.2.

E.2.1.5 PRA MODEL 1.3 UPDATE (PSEG 2000c)

In October of 2000, another minor revision of the PSA was completed. The CDF was recalculated in this revision. The LERF was also recalculated in this update but was the same answer from Model 1.2.

The following text documents the specific changes made in the PSA Model 1.3 update.

A. SACS Success Criteria:

The detailed description of the SACS/SSWS success criteria is summarized in working file HCOO-OI and in revision summary of version1.2.The brief summary of the modified SACS criteria is described below, item 6 and 7 are the modified criteria used in version 1.3.

The success criteria of the SACS are:

1. 1 full loop with successful alignment of valves to shed load.
2. 1 pump and 2 Hx's in one loop connected to the RHR and 1 pump and 1 HX in the other loop supply to the rest of the heat load.

Thus, the failures are:

1. Failure of 1 loop with unsuccessful load shedding.
2. Failure 3 pumps.
3. Failure 3 Hx's.
4. Failure of 2 pumps in one loop and 1 Hx in another loop.
5. Failure of 2 Hx's in one loop and 1 pump in another loop.

6. Failure of one SACS pump, one heat exchanger in one loop with another SACS pump failure in another loop with operator failure to re-align the valves.
7. Failure of one SACS pump, one heat exchanger in one loop with one heat exchanger failure in another loop.

B. Fault Tree / Event tree Changed

1. sacs-a.lgc Based on the above discussion, the fault tree has been modified.
2. T(sa) event tree –The Loss of SACS/SSWS event tree has been modified. The recovery action (NR-SW) has been moved to the fault tree ie-sws.
3. ie-sacs.lgc fault tree has been modified to correct the failure mode, the failure mode is three out of four SACS trains.
4. Due to the train/system models of EOOS requirements, all trains are now modeled in IAS, SLC, and CRH systems.

C. Top Logic Model Modification due to Full Model Changes

1. Sacs-a.lgc fault tree: Model changes due to success criteria modification. Delete the IE event below the top gate, this change will not affect the result but will speed-up the calculation.
2. page 24 of main fault tree , HCTOPR12.lgc : Fault tree structure is changed due to T(sa) event tree change. Page 25 and 26 are deleted.
3. ie-sacs.lgc fault tree: fault tree has been modified to correct the failure mode, the failure mode is three out of four SACS trains. Corrections are also made to reflect those modeling made in the full model.
4. ias, slc, and crh fault trees are modified to consider symmetry of all trains in these systems.
5. iesws-a.lgc and iesws-b.lgc fault trees -Since these trees are only called by the initiating SSWS/SACS event top gate, all the LOP related events will be deleted in the final calculation (dhos-lop * dhos-nolop). To speed-up the processes, all LOP related gates are manually deleted.
6. ssws-a, ssws-b fault trees – Delete the ie-sws event below the top gate, this change will eliminate the loop error during the fault tree solution.
7. pcs and hpci fault trees -Gates calling the SSWS/SACS initiating event top gate have been modified to call a pseudo gate to speed-up the solution process.
8. ie-top fault tree – a pseudo gate is added to facilitate item 7.

9. Zchsa and zchsb – fault trees are modified to reflect the changes made in full model version 1.2.

D. PSA Application Review:

The previous AOT submittals of SSWS, SACS and EDG systems using the PSA methodology were validated and verified using version 1.3. The risk matrix and 12-week schedule risk matrix are also re-generated (see revised Calcs files). Since the results from this version is less stringent than those generated from previous version, all applications using this version will yield less severe risk than that of the previous version.

E.2.1.6 PRA MODEL 2003A UPDATE (PSEG 2003)

For the 2003A model update, the CAFTA software suite was selected. The conversion of the HCGS NUPRA PRA model to CAFTA was completed in November 2002. This straight conversion involved no model or data changes.

This converted CAFTA model was then used as the starting point for the 2003A model update which was the result of a regularly scheduled update. Major changes included: Completely revised component failure data (including extensive use of plant-specific component failure data) and initiating events data utilizing the latest operating experience. Significant changes to the following elements have been performed to meet the changes needed to respond to the PRA Peer Review and the ASME PRA Standard. These include:

- Complete new HRA using the EPRI HRA Calculator and dependency analysis
- Revised accident sequence definitions (Event Tree)
- New MAAP calculations to support the success criteria and accident sequence timing at the Extended Power Uprate (EPU) configuration
- Updated data (initiating events, component failure data and vulnerability)
- Modified System models
- Updated common cause failures incorporating the latest NRC data
- The addition of internal flood accident sequences

- EPU power level and associated MAAP 4.0.4 calculations to support timing and success criteria changes

E.2.1.7 PRA MODEL 2.0 UPDATE (PSEG 2004)

The PRA Model 2.0 Update was completed in October 2005. The important changes in this model revision are PSEG modifications on 480 VAC dependencies, SACS, success criteria, and SACS-SW HEPs.

E.2.1.8 PRA MODEL 2005 UPDATE (PSEG 2006a)

The updated 2005 PRA Model was revised 3 times (A, B, and C) during 2005 to update the PRA modeling and to address the EPU related risk assessment. The 2005A model, the 2005B, and 2005C PRA models address the following items:

- Remove conservatism in SACS-SW success criteria
- Include more detailed logic for AC power supplies
- Remove conservatism in operator action HEPs to support the EPU submittal

E.2.1.8.1 PRA Model 2005A Update

The 2005A model update was completed in October of 2005. The 2005A update was an interim PRA model to address conservatism in the Rev. 2.0 model and was never officially used for quantification purposes.

E.2.1.8.2 PRA Model 2005B Update

This minor update was completed in November of 2005, only 1 month later than the 2005A model. The PRA 2005B model was used as input for the EPU submittal. This model, like the 2005A update, removes conservatism introduced in the Rev. 2.0 model (e.g., SACS heat load manipulation HEPs).

E.2.1.8.3 PRA Model 2005C Update

The last of the minor 2005 updates is Model 2005C. This model was created due to an unscheduled update to the 2003A PRA model. This revision modifies the 2005B EPU model to support online maintenance evaluations and MSPI calculations. The only PRA model change from the 2005B EPU PRA model to the 2005C Base PRA model is to reduce the turbine trip initiating event frequency from 1.25/yr to 1.03/yr to reflect plant specific operating history.

E.2.1.9 PRA MODEL HC108A UPDATE (PSEG 2008a)

The 2008 PRA Update was performed to satisfy the PSEG internal requirement for a periodic PRA Update and to address open issues such as the ASME PRA standard self-assessment “gaps”, additional UREs, and updated data.

The 2008 periodic update includes:

- A complete update of the initiating events
- A complete revision to the HRA including simulator observations and crew interviews
- Significant modeling changes for the following:
  - Incorporation of plant changes
  - Incorporation of procedure changes
  - Resolution of discrepancies noted in the PRA self-assessment
- A complete update of the data analysis involving common cause

The HCGS 2008 PRA model (HC108A) is the result of upgrading the Hope Creek PRA model. A summary of the changes to the Hope Creek PRA model is included here.

<u>Model Framework</u>

- The CAFTA model framework developed for the 2003A model upgrade is retained for the HC108A model.
- The LERF model has been expanded to a full Level 2 with a full spectrum of radionuclide releases.
- The PRA computer model has been developed within the CAFTA environment. The model exists in two logic formats:
  - sequence model -- PRAQUANT
  - single top fault tree model -- ONE4ALL

<u>Initiating Events</u>

- Bayesian updated initiating event frequencies utilizing the most recent Hope Creek operating experience and latest generic BWR operating experience.
- Allocation of LOCA frequencies on a location and size specific basis (i.e., the LOCA locations have been subdivided for more accurate assessments of their consequences).

- Revised LOOP analysis is performed for initiating event frequencies and non-recovery probabilities including the impact of the 2003 Northeast Blackout using the latest INEEL analysis in NUREG/CR-6890 (NRC 2005) and accounting for local Hope Creek grid operating experience.
- The conditional probability of a LOOP given a transient or LOCA signal event is incorporated into the PRA modeling.

Component Data

- Individual component random failure probabilities Bayesian are updated (as applicable) based upon the most recent plant specific data and the generic sources. This included revised component failure data including extensive use of plant-specific component failure data gathered from the Hope Creek Maintenance Rule program. Generic information from NUREG/CR-6928 (NRC 2007) and NUREG/CR-1715 (NRC 2000) are used when available as the prior distribution to support Bayesian updating.
- Common cause failure (CCF) calculations are revised to incorporate the upgraded individual random basic event probabilities and the most up to date Multiple Greek Letter (MGL) parameters from NUREG/CR-5497 (NRC 1998c) and NUREG/CR-5485 (NRC 1998b) available in 2007.
- Maintenance unavailability data is based on the most recent Hope Creek operating experience up to the freeze date.

HRA

- Extensive HRA re-assessment is performed utilizing the EPRI HRA Calculator 4.0 based on operating crew interviews using the latest EOPs and support procedures. Significant input from simulator observations is also included to supplement the crew talk-through of procedures.
- Significant effort to examine dependencies among HEPs is included.
- Expansion of HRA pre-initiating events is included in the model.

Thermal Hydraulic Modeling

- MAAP 4.0.6 deterministic calculations are used to support the success criteria and HRA calculations (i.e., operator cues and time available for actions).
- Recirculation pump seal leakage failure modes are added to applicable scenarios.

System Models

- The analysis of FPS to support RPV makeup success has been added to the model.
- CST support of condensate injection is adequate when the makeup volume and flow rate requirements are small.

- Service water cross connect as an alternate water injection source to the RPV is included in the model.
- Extended DC battery life for cases with use of Portable Power supply has been assessed by PSEG and determined appropriate as a realistic approach to coping with an SBO.
- Shorter DC battery life for cases without successful DC charging from the Portable Power supply has been included in SBO accident sequence evaluations.

Accident Sequence Changes

- The accident sequence event trees were modified using the results of the latest MAAP calculations to assess success criteria.
- Addition of sequence specific success criteria for certain systems (e.g., CRD, HPCI, RCIC).

Internal Flood

- Internal Flood accident sequence evaluation has been developed and quantified consistent with the ASME PRA Standard and has been integrated into the full-power internal events model. Pipe failure data from EPRI evaluation of operating experience is the bases for the pipe failure probabilities.

Level 2

- The full spectrum of radionuclide release categories is included in the PRA model for Level 2. This will support SAMA evaluations as part of life extension initiatives.

Tracking of Model Changes for 2008 Update

- As part of the PRA update, URE changes and other significant changes were input separately and the model was recalculated to assess the resulting change impact on the CDF risk metric.

Changes that resulted in decreasing the CDF include the following:

- Seasonal success criteria for the SSW and SACS heat removal system
- Incorporation of HC.OP-AM.TSC-004 procedure to use the portable power supply for power to the DC chargers.
- Reassessment of HEPs using the latest interviews and HRA Calculation
- Changes in Basic Event Probabilities based on use of NUREG/CR-6928 latest generic date (Principally affecting EDG logic circuit failures)
- Incorporation of minor changes to flood impact logic in the system models
- Changes to SSW and DFP makeup logic within the long term response actions

- Changes to the initiating event frequencies to reflect recent industry and Hope Creek experience
- The evaluation of random and common cause data using plant specific and NRC updated data resulted in lower common cause failure probabilities. Specifically, the updated common cause failure probabilities using the latest INEEL updates to NUREG/CR-5497 are lower than those used in the 2003 model.
- The incorporation of a finer structure in the modeling of LOCAs by including location dependent LOCA contributors results in revised success criteria (less conservative) for some LOCAs.
- Improved success criteria using MAAP 4.0.6.
- Reductions in the transient initiating event frequencies based on incorporation of recent generic and Hope Creek operating experience.
- Added credit for use of CS from CST
- Added control of vent due to procedure change
- Reassessment of pre-initiator HEPs
- Reassessment of post-initiator HEPs

The HCGS PRA Update process includes an evaluation of the 2008 PRA model, data, and documentation using the ASME PRA Standard as endorsed by RG 1.200 (Rev. 1).

E.2.1.10 PRA MODEL HC108B UPDATE (PSEG 2008b)

As a result of the 2008 PRA Peer Review of HC108A PRA model and the PRA roll-out process, several refinements were identified, including a procedural change. These refinements are discussed below.

Changes in Risk Profile

The following is the integrated change in the CDF risk matrix from the 2005C model to this latest PRA model which is used for the SAMA evaluation (HC108B). The decrease in the CDF risk metric from 9.76E-6/yr (HC2005C) at 5E-11/yr truncation to 5.11E-06 (HC108B) at 1E-12/yr truncation is primarily due to:

- Seasonal success criteria for the SSW and SACS heat removal system
- Incorporation of HC.OP-AM.TSC-004 procedure to use the portable power supply for power to the DC chargers.
- Reassessment of HEPs using the latest interviews and HRA calculation results led to a reduction in the CDF of approximately 2E-6/yr
- Changes in Basic Event probabilities based on use of NUREG/CR-6928 latest generic data (Principally affecting EDG logic circuit failures)
- Incorporation of minor changes to flood impact logic in the system models
- Changes to SSW and DFP rev water makeup logic within the long term response actions
- The evaluation of random and common cause data using plant specific and NRC updated data resulted in lower common cause failure probabilities. Specifically, the updated common cause failure probabilities using the latest INEEL updates to NUREG/CR-5497 are lower than those used in the 2003 model.
- The incorporation of a finer structure in the modeling of LOCAs by including location dependent LOCA contributors results in revised success criteria (less conservative) for some LOCAs.
- Improved success criteria using MAAP 4.0.6.
- Changes to the generic initiating event frequencies
- Reductions in the transient initiating event frequencies based on incorporation of recent generic and Hope Creek operating experience.
- Added credit for use of CS from CST
- Added control of vent due to procedure change
- Reassessment of pre-initiator HEPs
- Reassessment of post-initiator HEPs
- Added procedure change to SSW/SACS to allow local manipulation of SSW to SACS heat exchangers under LOOP conditions
- Improved Inverter Room Cooling logic

Increases in CDF resulted from the following:

- The reassessment of internal floods including the inputs from design engineering, operations, and system managers, as well as the latest EPRI pipe failure rates and internal flooding analysis methodology.
- Removed SW injection to RPV for Level 1 because it is not proceduralized.
- Removed credit for Condensate Transfer as RPV injection source
- In addition, the HC108B model used the FTREX quantification engine which allowed efficient quantification at a lower truncation limit (i.e., 1E-12/yr).

E.2.2 CURRENT PRA MODEL OF RECORD

The Hope Creek PRA model of record (HC108B) was completed in December 2008. This revision is a result of the 2008 PRA Peer Review of HC108A and the roll-out process where several refinements were identified, including a procedural change. The SAMA analysis is based upon this PRA model. The changes incorporated into this model are discussed above. The risk insights from this model are discussed below.

E.2.2.1 HC108B RESULTS

The Hope Creek PRA is a systematic evaluation of plant risk utilizing the latest technology available for Probabilistic Risk Assessment (PRA). The Hope Creek PRA is classified as a full-power internal events PRA, meaning that severe accident sequences have been developed from internally initiated events, including internal floods.

A figure of merit commonly quoted in PRAs is core damage frequency (CDF). While this figure of merit does not entirely represent the value of the PRA, it is a widely used indicator. The core damage frequency (CDF) calculated in the Hope Creek 2008 PRA (HC108B) is 5.11E-6 per year (truncation at 1E-12 per year), a decrease from both the HC108A calculated value of 7.60E-6 per year (truncation at 5E-11 per year) and the 2005C calculated value of 9.76E-6 per year (truncation at 5E-11 per year).

The resulting CDF figure of merit is below the NRC’s surrogate safety goal which indicates that Hope Creek poses no undue risk and is within the range of CDFs for other nuclear plants.

In addition to the evaluation of accident sequences that could lead to core damage, the Hope Creek PRA also includes the second risk metric specified in RG 1.174, an evaluation of the containment performance by examining the Large Early Release Frequency (LERF) associated with possible radionuclide releases. The large early release frequency (LERF) calculated in the Hope Creek HC108B PRA is 4.76E-07 per year, a decrease from the HC108A calculated value of 8.63E-7 per year. Both the HC108A and HC108B increases in LERF over the 2005C value of 2.59E-7 per year were due to the reassignment of specific Level 2 sequence end states from "No LERF" to "LERF" based on the latest MAAP 4.0.6 deterministic calculations of radionuclide release timing and release magnitude. In addition, the internal flood updated evaluation resulted in additional sequences that lead directly to LERF.

E.2.2.2 HOPE CREEK LEVEL 2 PRA MODEL (PSEG 2008c)

The SAMA analysis is based upon the Hope Creek Model of record (HC108B) developed in 2008. This revision includes a complete Level 2 analysis.

E.2.2.2.1 Containment Evaluation Process

Since the publication of WASH-1400 (NRC 1975) and the Individual Plant Examinations (IPE)[1], it has been recognized that there can be significant conservatisms in risk estimates if it is assumed that containment failure and subsequent radioactive release to the environment always occur given a core damage event. By considering the active and passive mitigating system functions that can be utilized even after a significant amount of core degradation occurs, end states can be identified in which the primary containment maintains its integrity and, thereby, prevents substantial environmental release of radionuclides.

In the Hope Creek Level 1 PRA, the plant systems (and challenges to those systems) are evaluated using event tree methodology to determine the frequency of end states that may induce a condition in which the core is degraded or the primary system

---

(1) Developed in response to GL88-20.

integrity is challenged. These system event trees have evolved since the event tree development provided in WASH-1400.

In the Level 2 analysis, containment event trees (CETs) are developed to provide the link between the core damage end states of Level 1 associated with inadequate core cooling and the end states reflecting the mitigation of core damage and containment challenge, or the contribution to radionuclide release of varying magnitudes. The spectrum of radionuclide releases that could result from the core damage condition is then calculated for the postulated discrete end states of the CET. For example, the model considers the performance of the drywell sprays as an effective mitigating system in the assessment of radionuclide mitigation. The CETs describe the various potential radionuclide release paths to the environment and provide an estimate of their relative likelihoods. This process is, of course, an iterative one, requiring technical feedback between the systemic event trees, the CETs, and the plant response evaluation.

The purpose of containment event trees (CETs) is to provide estimates of the following: (1) the frequency of radionuclide releases; (2) the release magnitude; and (3) the release timing resulting from the Hope Creek Level 1 PSA. With this goal in mind, the following parameters are considered with regard to characterizing a release sequence:

- Radionuclide release and transport mechanisms
- Time of containment failure
- Containment failure mode
- Size of containment failure
- Location of containment failure
- Effect of harsh environment on the operation of key systems
- Effectiveness of suppression pool scrubbing
- Effectiveness of secondary containment filtering

The approach used to achieve these goals is similar to that used in the IDCOR program (IDCOR 1984) and the NUREG-1150 program (NRC 1990a). The CETs are developed as models of the approximate chronological progression of events describing plant behavior following the core damage end state defined in the output of the Level 1 system event trees.

The mechanics of the containment evaluation process are implemented in four major steps:

1. Identification of Severe Accident Types or Classes

   a. The first step is the identification of the spectrum of accidents that could challenge containment integrity or lead to a direct release of radionuclides.

      This also involves the identification of the timing of containment isolation/failure and core melt. For example, Class I accidents are those in which core melt has begun but the containment is intact; whereas, Class II accidents are characterized by containment failure or containment at extreme pressures but core melt has not necessarily begun. The analysis considers the full range of severe accidents that have been identified in past BWR PRAs and NUREG/CR-4920 (NRC 1988).

2. Identification of Severe Accident Progression Phenomena

   a. The next step is the identification of the important accident phenomena (i.e., radionuclide release mechanisms and degraded core or containment interactions) that affect release pathways to the environment, and examination of the plant specific containment integrity analyses available to support the envelope of successful containment states. A chronological representation of these phenomena in the containment event tree framework is developed focusing on the progression paths that could lead to a release or an arrested state. As input to the containment response evaluation, the Hope Creek PRA uses estimates of the ultimate pressure and temperature capability of the containment from a Hope Creek specific analysis.

3. CET Quantification

   a. A quantification of the various progression paths leading to a radionuclide release from containment or a successfully mitigated end state is performed. To support the event tree quantification, functional fault trees are developed. These fault trees provide a focused description of the major containment failure mechanisms as well as an aid in understanding the containment failure modes described in the CET. The models also realistically integrate the human and system responses. Operator recovery actions under severe accident conditions, as documented in the Hope Creek EOP/SAMGs, are included in the baseline quantification.

The quantification process considers the CET entry state (i.e., core damage end state), as defined by the Level 1 plant systems analysis because these affect the structure of the CET. Similar sequences are merged into an accident class and the sequences are transferred as inputs to the specific Level 2 CET which is structured specifically to treat the accident class sequences. The containment response to degraded core conditions (MAAP or equivalent calculations) and "separate effects" analysis (including the containment structural analyses) are combined and used as the technical bases for the quantification of phenomenological events, environmental conditions, or sequence boundary conditions.

4. Characterization of Radionuclide Release Bins

   a. A spectrum of radionuclide release end states is used to characterize the releases. This includes an end state referred to as “OK.” The “OK” end states are those in which the containment remains intact except for leakage. The consequences can be expressed in terms of magnitude of source terms and other release characteristics that affect ex-plant consequences such as timing. The releases are estimated using plant specific MAAP calculations. The Hope Creek PSA takes into account the best estimate progression of a given severe accident. Representative sequences are chosen for deterministic calculations. Multiple sequences of different types are calculated to lead to similar release bins.

E.2.2.2.1.1 Specific Technical Items Performed to Support the Containment Evaluation Process

<u>Sequence Grouping (Interface with the Level 1 PSA)</u>

A vital task to the accurate quantitative assessment of containment capability is ensuring that the interface and dependencies between the Level 1 PSA evaluation and the containment evaluation are precisely defined. This is assured by requiring two approaches: (1) a unique containment evaluation for each type of core damage accident end state, and (2) the transfer of cutsets from Level 1 into Level 2 to ensure the dependencies are appropriately accounted for. Such a coupled evaluation allows the following types of information to be accurately transferred from the Level 1 study to the containment evaluation and accounted for explicitly in the Level 2 assessment:

- Front line and support system unavailability
- Reactor coolant system parameters
- System recovery actions

- Time available for additional recovery and mitigative actions
- Reactor power level
- Containment status

Containment Capability Evaluation

The primary containment capability to withstand severe accident pressures and temperatures is a required part of the Level 2 evaluation. Available plant specific technical data and methods allow the estimation of the as-built ultimate load carrying capabilities.

In addition to the failure probability and failure location, the size and timing of the failure are important considerations in the source term evaluation. In order to ascertain the size of potential pressure or temperature induced failures, the details of the containment design and construction are vital.

The plant specific information necessary to evaluate the containment capability to maintain its integrity during severe accident conditions included an assessment of the following:

- The structural capability of the containment at elevated pressures and temperatures
- The containment penetrations' ability to withstand high pressure and temperatures
- The ability of hatches and seals to withstand excessive pressure and temperature conditions including:
  - Drywell head seal
  - Personnel hatch
  - Equipment hatch
- The drywell head flange connection
- The air lock design
- The equipment hatch design
- The drywell to torus vent line penetrations and bellows assemblies
- The torus to reactor building vacuum breakers
- Containment response capabilities (i.e., structural, thermo-dynamic, and hydrodynamic) under a wide spectrum and variety of severe accidents scenarios
- The design of the torus as influenced by pool hydrodynamic loadings

- Various categories of drywell and torus penetration assembly design details and materials of construction
- Containment capabilities (both drywell and suppression pool) under partial or floodup conditions

These were investigated during the Hope Creek plant specific containment capability assessment.

Scenario and Containment Event Tree Development

Accident scenarios that progress to unacceptable end-states from the Level 1 PSA (i.e., degraded core conditions) have a number of operator action recovery steps and potential physical phenomena that need to be assessed to determine the eventual end state, i.e., safe stable state or a radionuclide release. The scenarios or pathways that lead to these states are defined through the use of a containment event tree.

The Containment Event Tree (CET) provides the framework that allows the evaluation of severe accident phenomena and accident management issues. The inputs to the CET are the accident sequences from the Level 1 PSA. The output from the CET is a set of radionuclide release categories.

The criteria for successful construction of the CET include the following:

- The CET structure is compatible with the type of Level 1 PSA accident challenge identified.
- The core melt progression time phases (i.e., in-vessel and ex-vessel accident progression) are explicitly treated in the CET.
- The functional CET nodes are selected to allow the user to describe phenomenological and system functional failure modes, evaluate accident management actions, and discriminate accident sequences according to radiological release magnitude and timing.
- The radionuclide release magnitude and timing for each accident sequence end state are unambiguously determinable from the identified sequences.
- The phenomenological process which dominates the release category assigned to an accident sequence can be traced.
- Success paths for recovery of degraded core conditions during in-vessel core melt progression accidents are explicitly modeled to facilitate the development of appropriate accident management strategies.

The containment event tree includes sufficient detail to quantify the effects of plant modifications and changes in emergency procedures and Severe Accident Mitigation Guidelines (SAMGs), yet is concise enough to allow effective communication of the assessment results.

The development and evaluation of the containment event tree requires establishing success criteria for the following:

- Containment integrity
- In-vessel core cooling
- Ex-vessel core cooling
- Radionuclide release magnitude/timing

These success criteria are derived from previous PSA work and plant specific MAAP deterministic code calculations in certain cases.

The containment event tree development includes an evaluation of the detailed interaction between systems, accident progression phenomena, and operating staff actions during the initial phases of a plant challenge associated with inventory control failures leading to the evaluation of core damage in-vessel and subsequent challenge to containment. The containment event tree includes an assessment of the ability to arrest core damage in-vessel. The starting point for the Level 2 analysis is a severe accident challenge coming from the Hope Creek Level 1 assessment. Therefore, the evaluation of containment response begins with significant plant failures and problems associated with such a sequence. The starting point for Level 2 sequences is the condition of core damage.

Therefore, the initial effort by the operating staff involves evaluating the ability to arrest the challenge before vessel breach. Subsequent efforts in the CET address operating staff actions to terminate core melt progression with the containment intact. This supports the accident management evaluation and the ability to credit systems normally not successful in avoiding core damage which may in the long term support termination of a severe accident. One of the most important aspects of the Hope Creek CET methodology for future accident management is the incorporation of the Severe

Accident Management Guidelines (SAMGs) into the structure of the CET, and the quantification of the CET. Therefore, extra effort has been included in the Hope Creek PSA to carefully factor in the latest SAMGs and an HRA evaluation of the directed actions.

For the Hope Creek Mark I BWR containment type, a CET structure was developed for each of the unique types of accident challenges. From previous BWR PRAs there have been approximately 12 different types of challenges identified. These challenges have resulted in three basic structural types of CETs. Therefore, the Hope Creek CETs consist of three structurally different CET types. These CET types are then used following the appropriate plant damage states and are quantified differently depending upon the plant damage state, i.e., the Level 1 output information using the system and cutsets and dependencies applicable to each sequence of events from Level 1 all the way through the Level 2.

Phenomenological Analysis and Containment Challenge Evaluation Response

The assessment of plant response under postulated severe accident scenarios is a complex integrated evaluation. The primary and secondary containment building responses are sensitive to pressures, temperatures, flows, and event timings. These parameters also affect the operator action timings, the radionuclide release timings, and the mitigating system performance assessments. Therefore, the proper plant-specific characterization of the severe accident progression is important to the realistic representation of the plant and highly desirable for the Level 2 assessment. Deterministic calculations are used to provide the following information:

- The pressures and temperatures in the RPV, the drywell, and the wetwell for various accident scenarios
- The times to reach these pressures and temperatures which is key to the assessment of recovery (The time windows available for recovery actions must be estimated.)
- The source term magnitude and timing

The MAAP code is used to provide baseline estimates for plant responses, accident sequence timing, and radionuclide releases. All of these MAAP calculations are performed at the highest theoretical Extended Power Uprate (EPU) power level.

A critical insight for the Hope Creek containment is that RPV breach and subsequent core-coolant interactions do not by themselves result in containment overpressure/overtemperature failure within the "early" time phase if cooling is available to the debris.

Source Term Magnitude

CET outcomes that are expected to produce similar source terms (e.g., LERF) are binned into the same release category. Source term estimates are based on the Hope Creek MAAP calculations.

As part of the deterministic calculations, the radionuclide releases to the environment are determined. These releases are calculated by MAAP.

Quantification of Containment Event Trees (CET)

The CET quantification process extends the Level 1 models into the severe accident regime. Accident sequences from Level 1 with similar functional impacts are merged together into the appropriate accident classes and are transferred directly into the appropriate Level 2 CET. Each node in the CET is then evaluated using the fault tree models from the Level 1 analysis for the system or function as modified for any Level 2 limitations in timing, procedures, access, or dependencies. Therefore, when the CET is evaluated any equipment or operator failures that have already failed in the Level 1 sequence are automatically treated in the analysis, i.e., the dependencies are explicitly handled.

E.2.2.2.1.2 CET Overview

Hope Creek Containment Event Trees (CETs) are developed to provide the link between: (1) the Level 1 event tree core damage end states; and, (2) safe shutdown or radionuclide release end states that describe release magnitude and timing. The CET is used to map out the possible containment conditions affecting the radionuclide releases associated with a given core damage sequence. The portion of the spectrum of radionuclide releases which could result from the LERF end states is part of this calculation. These CETs describe the various potential radionuclide release paths to the environment and provide an estimate of their relative likelihoods. This process is, of course, iterative, and requires feedback and interactions among the analysts involved in the systemic event trees, the CET, and the plant response evaluation. The explicit link using the Level 1 sequence logic allows explicitly accounting for the dependencies between initiating events, system failures, and containment mitigation systems.

It has been recognized, since the publication of WASH-1400, that there can be a significant conservatism in the reactor plant risk estimates if the containment functionality is assumed to be ineffective following postulated core degradation or melt sequences. By considering the active and passive mitigating functions which can occur after a significant amount of core degradation, end states are likely in which the primary containment maintains its integrity or functionality. The containment event tree (CET) is a tool for identifying and analyzing the spectrum of accident scenarios which may evolve following postulated core damage accidents. CETs are developed and quantified in order to provide a realistic and systematic assessment of:

- The relative possibility of successfully mitigating postulated accidents
- The allocation of the severity and timing of associated radionuclide releases from a degraded core accident into LERF and non-LERF categories.

The containment event tree structure has been formulated to include the following objectives for the calculation of radionuclide release:

- To properly represent the time sequence of events and to divide the CET into major time periods
- To incorporate all important system, human and phenomenological occurrences including possible recovery
- To maintain a simplified representation
- To preserve the nature of the challenge throughout the analysis
- To explicitly recognize the effect of postulated containment failure modes

- To allow the identification of recovery and repair actions that can terminate or mitigate the progression of a severe accident (note that prevention measures have been addressed in the system evaluation of core damage frequency)
- To categorize the end states of the resulting sequences into groups that can be assessed for their effect on public safety

The first objective was achieved by representing the containment event tree as a series of occurrences based upon MAAP runs and NRC code results. Some compromise to time phasing occurs where two events are mutually dependent upon each other. However, the occurrence of mutually dependent events is minimized, and the event tree generally represents the chronological sequence of events from initiator to Level 2 end state.

A balance must be struck between the second and third objective to provide a comprehensive, but manageable analysis. Strict application of the second objective would cause the containment event tree to be very large, with numerous systems and actions represented. The third objective argues for simplified representation to achieve improved scrutibility and usefulness of the results. As pointed out in NUREG-1150 (NRC 1990a), it is more appropriate to use a streamlined CET, for the purposes of defining major phenomena of interest and illustrating potential mitigation measures. The streamlined CET, augmented by functional fault trees, is then believed most useful in clearly displaying important information.

In order to achieve a balance between these two principal objectives, the current analysis implements the containment event tree assessment in a time phased approach reflecting the approximate chronology of the severe accident scenarios:

- The first time phase involves occurrences up to vessel breach.
- The second time phase covers the period from vessel failure or arrest in-vessel until the intermediate term phenomena have occurred. This can be visualized as being approximately 3 to 15 hours after vessel challenge.
- The third time phase includes longer term phenomena such as containment heat removal response.

Naturally, these time phases may overlap given certain accident scenarios.

The remaining objectives were satisfied by using a sufficient number of top events and companion functional fault trees to describe qualitatively and quantitatively the systems, operator actions, phenomena, failure modes, and end states.

A set of deterministic and probabilistic analyses, and other plant information are needed as input to these models, including:

- Containment Structural Analyses
- SAMGs (Including Containment Control)
- Level 1 Analysis and Results
- Containment Walkdown Results
- P&IDs of Containment Control Systems
- Schematics of Containment Structure and Penetrations
- Technical Specifications
- Containment Leak Data
- Operating Experience
- Deterministic Model (e.g., MAAP).[1]

The CET allows a detailed characterization of the state of containment from the time of the initial core damage to either mitigation of the accident within the RPV or penetration of the RPV. The core melt progression sequences are also followed through their potential interaction with the containment to states involving either: (a) successful mitigation within the containment; or (b) a radionuclide release.

In the development of the CET, the important factors which affect the consequences for an accident are considered. Consequences in this context are measured in terms of the magnitude and timing of the radionuclide release. The primary focus of the back-end analyses is on containment failure mode and release timing rather than on source term analysis. The identification of the containment failure mode and timing is generally used

(1) The PSA utilizes the MAAP code for plant specific analyses of containment challenges and other reference plant calculations for additional support. However, industry experience and staff positions on phenomenological uncertainties are also taken into account.

as an indicator of the type of response that can either mitigate or reduce containment failure probability.

The CET structure includes event tree nodes that address the following aspects of severe accidents that are considered important for characterizing a radionuclide release:

- Core damage accident class (i.e., the entry state to the CET);
- Mitigating system response including operator actions (post core melt);
- Containment response, including pressures, temperatures and possibly failure location, path, and size, if appropriate.

Types of CETs

Several types of containment event trees are necessary to characterize various containment challenges. Three different containment event trees are used:

- CET1: Class I and III CET: Containment initially intact. These sequences are characterized by an initial loss of coolant makeup to the reactor vessel that leads to core damage. The attempts to arrest the melt progression in-vessel and ex-vessel are assessed along with containment integrity during the challenge. In all cases, the entry point to the containment event tree is at the time that the core is initially damaged.
- CET2: Class II and IV: Containment is initially failed or subject to incipient failure before core damage. For these classes of accidents, the primary containment boundary would generally fail before or at the time the molten core penetrates the reactor vessel. In Class II accident sequences, the inability to remove heat from the containment results in a gradual heat-up of the suppression pool. For Class IV accidents, the amount of energy transferred to the suppression pool exceeds its heat removal capacity.
- CET 3: Class V: CET3 is used to evaluate several distinct core melt scenarios: (1) LOCAs outside containment for which coolant makeup to the reactor vessel has failed leads to a core melt event with a direct release pathway from the vessel to the reactor building; and (2) an interfacing LOCA or drywell bypass.

Class I, II, III, IV and V CET Functional Nodes

The functional event nodes of the CET which can be considered in a detailed calculation are as follows:

- Containment Isolated (IS)

- RPV Depressurization (OP)
- Core Melt Arrested In-Vessel (RX)
- Combustible Gas Venting Initiated (GV)
- Containment Remains Intact (CZ)
- Injection Established to RPV or Drywell (SI)
- Containment Flooding Occurs with DW Vent (FC)
- Containment Heat Removal (HR)
- Containment Vent (VC)
- Suppression Pool Bypass (SP)
- No Large Containment Failure (NC)
- Inventory Make up Available (MU)
- Drywell Intact (DI)
- Wetwell Airspace Breach (WW)
- Reactor Building Effectiveness (RB)

The top level functional events analyzed in the Level 2 analysis are described in more detail below.

Containment Isolation (IS)

Containment isolation is the first nodal decision point of the CET. The "IS" node is used to assess whether the Hope Creek containment has been successfully isolated given the core damage challenge identified in the Level 1 PSA. As part of this assessment, it is noted that the containment is required to be inerted. In addition, the primary containment (drywell) pressure is maintained at a slightly higher pressure than the wetwell (~0.1psid). This operational aspect is used to limit the initial downcomer vent clearing loads on the torus. It has the side benefit of providing additional indication of the initial vacuum breaker positions prior to an event occurring. Specifically, an open vacuum breaker would not allow the differential pressure to be maintained. This increases the success probability that the vacuum breakers are initially closed, i.e., one of the potential failure modes is minimized.

The PSA examines in detail the status of the containment isolation systems prior to core melt. This node considers:

- The pathways that could significantly contribute to containment isolation failure
- The signals required to automatically isolate the penetration
- The potential for generating the signals for all initiating events
- Consideration of testing and maintenance
- The quantification of each containment isolation mode (including common-mode failure)

Initiating events and Level 1 sequences that include containment failure (i.e., Class II, IV) are transferred to CETs that bypass the IS node.

The IS node is failed by definition for containment bypass accidents (Class V). Containment bypass sequences involve those events that are initiated by a break in a pipe outside of the containment with the potential to release radionuclides directly from the RPV to secondary containment structures or to the environment. Analyses performed for other BWRs have shown that these types of scenarios result in large magnitude releases. The analyses have not taken credit for fission product retention within the system piping and retention in secondary containment buildings. Given this, Class V core damage events are modeled as leading directly to LERF.

Operator Depressurizes the Reactor Vessel (OP)

This heading represents the manual or automatic action of depressurizing the RPV. The operator recovery action to depressurize the reactor allows low pressure system injection to the RPV if the low pressure systems are operable. The upward path at this node represents successful depressurization and the down path models failure.

The status of RPV pressure can have a profound impact on the ability to successfully mitigate a severe accident and the subsequent containment response. Therefore, the determination of the RPV pressure is key to understanding subsequent active and passive mitigation capability.

Core Melt Progression Arrested In-vessel (RX)

This containment event tree node (RX) addresses the ability to arrest core melt progression within the reactor vessel. Specifically, success requires recovery of coolant makeup to the reactor vessel so that cooling may be reestablished to prevent further degradation of the fuel integrity. The time window for successful recovery of coolant inventory occurs between core melt initiation and the time when the core melt progression cannot be halted within the RPV. This can be one hour to several hours depending upon the sequence of events and the analytic model used. (The HCGS CET analysis allows 40 min. following core damage for actions to terminate core melt progression before RPV breach is inevitable).

The assessment addresses:

- The operator action to inject to the RPV
- The equipment availability
- Phenomena which may preclude successful arrest of the core melt progression in-vessel.

The makeup sources to ensure debris cooling in-vessel consist of the same sources examined in the Level 1 system evaluation. Note that "RX" success is also strongly dependent on the successful RPV depressurization at the previous node, (OP). In turn, RX also has strong influences on subsequent CET nodes such as "SI", availability of water injection to the containment after RPV breach. The "SI" node examines water recovery over a longer time frame.

Combustible Gas Venting (GV)

This node addresses the possibility that the containment may have a combustible gas mixture and no operator actions would be taken to mitigate the condition. The upward branch defines the path where the primary containment vent has been opened to control combustible gas mixtures resulting from severe accident progression, given the unlikely situation that the containment is deinerted. The downward path represents cases in which the containment remains inerted or the vent is not otherwise opened.

Early Containment Failure (CZ)

Energetic containment failure modes resulting from the core melt accident sequence initiator and the subsequent phenomenological events at the time of initial RPV breach due to debris attack are estimated to have potentially high radionuclide releases. These can also be considered early releases for Class I and III. (Exceptions may include delayed release for extended SBO event sequences.)

Event heading (CZ) describes the condition of the containment after a failure of the primary system. In the upward path, the containment has remained intact during the initial stages of core melt progression up through RPV breach and blowdown, while the downward path depicts an overpressure failure of the drywell induced near the time of the loss of primary system integrity.

The containment is the primary defense in retaining core melt fission products. The failure modes considered in the early containment failure mode include the following:

- Containment pressurization due to RPV blowdown causes rapid containment pressure rise above capability
- Steam explosion
- Recriticality
- Direct containment heating
- Hydrogen deflagration in a deinerted containment
- Combustible gas venting
- Drywell failure due to debris interaction with the concrete (see discussion under SI)

The structure of the CZ node is divided into in-vessel and ex-vessel phenomena, depending upon the success or failure of the RX node.

These items can potentially result in over-pressurizing the pedestal and drywell at the time of vessel breach. The radionuclide concentrations in the RPV and containment are high at the time of vessel breach and the flows out of the containment could be high. This means radionuclide releases have the potential to be high at this time. All of this results in minimal retention of radionuclides and the potential for large magnitude releases.

Wherever possible, the MAAP code is used for plant specific analyses of containment challenges. However, deterministic analyses regarding the capability of the Hope Creek containment to withstand the various energetic accident phenomena were not performed. Rather, industry studies and staff positions on phenomenological uncertainties were taken into account to assign failure probabilities that are deemed representative of a "generic" Mark I containment. An assessment of the Hope Creek containment capability in response to slower developing overtemperature and overpressure scenarios (e.g., loss of debris cooling, loss of containment heat removal) was performed and is documented in the Hope Creek MAAP Deterministic Calculations Notebook.

Ex-vessel steam explosions evaluated in CZ can be exacerbated by water availability into the drywell prior to RPV breach.

<u>Injection Established to RPV or Drywell (SI)</u>

The drywell floor is the location where a substantial fraction of the core debris may be deposited if core damage cannot be arrested in-vessel and the RPV is subsequently breached.

This node addresses whether adequate water is available to the drywell for debris coolability. This is contingent on equipment availability, an assessment of the phenomena of debris coolability and drywell integrity, and operator actions to initiate drywell sprays.

Subsequent to debris attack of the RPV, containment challenge may occur from direct debris interaction with the steel containment shell, high temperatures in the drywell, or a combination of high temperatures coupled with high pressures due to noncondensible gas generation. Injection of water into the containment and/or the RPV can mitigate the consequences of a core melt and prevent all of these failure modes. Each of these is discussed below:

Drywell Sprays

Drywell sprays can mitigate the consequences of a potential core melt accident. The sprays can perform at least three beneficial functions, the two most important of which are:

1. Scrubbing fission products that are not otherwise scrubbed (i.e., in the case where the suppression pool is bypassed); and
2. Providing water to cool the core debris on the drywell floor.[1]

A third function related to pressure control is useful and proceduralized but it is not explicitly quantified in the Level 2 except as implemented as part of RHR operation for suppression pool cooling.

Vessel Water Injection

RPV water injection can perform some of the same functions as spray operation mentioned above (i.e., scrub fission products from the debris), prevent containment overtemperature failure, and reduce the core concrete reaction by quenching the debris. The systems that might perform the function of coolant injection post core melt at Hope Creek include:

- Condensate
- Low pressure coolant injection
- Core spray
- Fire protection system
- SW cross tie

(1) The pedestal may contain debris. This debris is cooled by spray injected water that enters the pedestal through the pedestal doorway. In this mode of operation, containment failure could be prevented by termination of drywell wall heating and the associated temperature induced containment failure, and noncondensible gas generation due to core concrete reaction.

Operation of the vessel water injection systems after vessel failure will act to cool the core debris that remains on the drywell floor, cool the drywell atmosphere as a result of steam generation and cool the RPV internal structure (i.e., this cooling may prevent fission product revaporization from the RPV). The post-core melt water injection will prevent the drywell steel shell from failing due to debris contact and the drywell atmosphere from reaching very high temperatures and failing the drywell head seal. An added benefit for vessel water injection after vessel breach is the potential to scrub ex-vessel fission products via the water overburden.

Containment failure size and location is dependent on the status of this CET function.

Containment Flood (FC)

This node addresses the question of whether the procedures and operator actions will be taken to flood the containment with external water during the core melt progression, or whether the actions will be to maintain suppression pool level at approximately the LCO limits. The availability of an external injection water source, the instrumentation to monitor injection, and vent capability are all included.

Note that the Hope Creek SAGs restrict containment flooding if RPV is not breached and no LOCA has occurred, i.e., RPV pressure is greater than 50 psig above torus pressure.

Containment Heat Removal (HR)

This node would address the availability of the RHR system and the operator action to initiate the system for containment heat removal.

The Hope Creek Mark I containment system is provided with significant heat removal capacity and heat management capabilities. The management of heat in the containment prior to, during, and following a severe core damage event directly affects containment response. The Hope Creek containment heat capacity can be classified as both active and passive. The passive capacities include the suppression pool and the containment structure. The active heat management capabilities include the RHR system, the RWCU system, venting, and containment drywell coolers. This event tree node addresses all heat management capabilities, but the dominant influence on successful containment heat removal post core melt is the RHR system. (Note that containment venting is discussed separately below in the VC node.) Severe accident effects on the performance of the RHR system (e.g., steam binding) are considered in the model.

RWCU and drywell coolers have minimal heat removal capability and are not modeled in the PRA.

The RHR system, operating in the suppression pool cooling mode, can maintain long term containment integrity through adequate containment heat removal if other failure modes can also be mitigated. With the RHR system operating during the course of a core melt accident, containment pressure and temperature can be maintained within the structural failure criteria of the containment. As a result, the consequences of a radioactive release to the environment can be prevented.

The upward branch at this event tree node represents successful containment heat removal via the RHR system operating in the suppression pool cooling mode. The downward branch models failure of containment heat removal.

<u>Containment Vent (VC)</u>

This event heading characterizes use of the wetwell vent to relieve containment pressure. Venting provides the operator a means of removing decay heat and non-condensable gases, and maintaining the integrity of the containment. At this node, the upward path represents successful use of the vent, while the downward path represents venting failure due to mechanical faults, inadequate procedures, or operator error. Severe accident effects on the performance of the wetwell vent (e.g., high differential pressure prevents valve operation) are considered in the model.

Suppression Pool Bypass (SP)

This node is an assessment of hardware availability to preserve the suppression function of the torus and is addressed in the RB node.

If the operator is unsuccessful in maintaining the heat management functions as described in the preceding section, wetwell venting would be required to maintain containment integrity. The issue is applicable to both containment venting and containment failure scenarios. This event heading examines the potential for suppression pool bypass that would allow the release of radionuclides from the reactor vessel to pass directly out of containment without the benefit of suppression pool scrubbing during venting. The upward branch at this event tree node represents no bypass, while the downward branch models suppression pool bypass.

No Large Containment Failure (NC)

This CET node probabilistically distinguishes between containment failure modes that may result in small or large containment failure modes.

In some cases the size of the failure is determined by the accident progression, e.g., unmitigated ATWS and the NC model is a "pass-through."

Continued Inventory Makeup (MU)

This node considers the effect of harsh environment (e.g., humidity, temperature) following containment failure or venting on the availability and survivability of injection systems and components.

Containment Response Integrity (DI, WW)

The containment failure location and its size will impact the calculated radionuclide releases. Failure location and size also depend on the core melt accident sequence and the operability of mitigating systems. Section 3 of PSEG 2008 provides additional detail on the derivation of these failure mode locations, and discusses the basis for estimating the size of containment breach. The containment analysis presented in

Section 3 (PSEG 2008c) meets the ASME PRA Standard requirement that plant-specific containment analyses be performed. The analysis considers the effects of high temperatures and pressures on seals, valves, hatches, and other key areas of the containment structure (e.g., drywell head area). When studies of reference plants were used, their applicability to Hope Creek was taken into consideration and explicitly discussed.

Reactor Building Effectiveness (RB)

This node is an assessment of the active and passive features of the secondary containment, along with phenomena that may cause bypass of the secondary containment, that contribute to scrubbing radionuclide releases in the building.

Contributors to the determination of reactor building effectiveness include the following:

- Reactor Building integrity after containment failure,
- Filtration, Recirculation and Ventilation System (FRVS) operation,
- Fire sprinkler operation (water curtains),
- Hydrogen combustion in the reactor building, and
- Reactor building integrity after hydrogen combustion.

The down branch of the Reactor Building node implies minimal effectiveness of the Reactor Building to retain fission products due to primarily two failure mechanisms:

1. Combustion of gases in the reactor building causing high temperature and minimum or zero retention.
2. Direct pathway from the containment failure location to the blowout panels with minimal interaction within the reactor building.

The potential issues that influence the determination of Reactor Building effectiveness are the strong dependence of the radionuclide residence time in the Reactor Building on the following events or features of the secondary containment:

- The mode of containment failure,
- The location of containment failure relative to the reactor building point of failure,
- The location of any water flooding in or into the reactor building,

- The rate of gas production in the primary containment,
- The status of FRVS,
- The status of the railroad doors or other reactor building paths, and
- The potential for delayed[(1)] hydrogen burning in the reactor building that leads to a deflagration.

During LOCA outside containment scenarios resulting in core damage, the fission products released from a breach of the RCS and the containment may bypass the containment and be carried by gas flows from the primary system into adjacent buildings and possible to the environment. In such an event, one of the main concerns would be the plant's ability to retain fission products during transport of the fission products through the secondary structure.

It must be noted that Reactor Building responses to fission product releases from the primary system are not solely dependent on one particular plant feature or characteristic; instead, the fission product retention characteristics of the Reactor Building depends on the combination of various plant specific features and characteristics.

E.2.2.2.1.3 Release Categories

The spectrum of possible radionuclide release scenarios is represented by a discrete set of categories or bins based in part on the discussion in Section 5.1 of the 2008 Level II analysis (PSEG 2008c). The end states of the containment event sequences may be characterized according to certain key quantitative attributes that affect offsite consequences. These attributes include two important factors:

1. Timing (e.g., early or late releases); and,
2. Total quantity of fission products released.

---

(1) It is noted that MAAP burns the hydrogen discharged to the Reactor Building at the lowest combustion point on the combustion curve, thus precluding deflagration event calculations in the MAAP analysis.

Therefore, the containment event tree end states represent the source term magnitude and relative timing of the radionuclide release using a discrete set of end states. As described in Section 5.1 of the 2008 Level II analysis, the number of end state categories to be used in the source term characterization offers a level of discrimination similar to that included in numerous published PRAs.

One of the bins or radionuclide release categories is allocated to address the risk metric of Large Early Release Frequency (LERF).

Large Early Release is defined in the ASME PRA Standard (ASME 2002 and ASME 2005) as follows:

> *The rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of off-site emergency response and protective actions such that there is a potential for early health effects.*

Regulatory Guide 1.174 (NRC 2002) states the following:

> *LERF is being used as a surrogate for the early fatality QHO. It is defined as the frequency of those accidents leading to significant, unmitigated releases from containment in a time frame prior to effective evacuation of the close-in population such that there is a potential for early health effects.*

There are a number of issues regarding the definition of CET end states that are summarized below:

- NUREG-1150 (NRC 1990a) analyses and other BWR PRAs have shown that the public risk can be correlated with radionuclide release bins characterized by:
  - Magnitude of radionuclide release
  - Time of radionuclide release
  - Location and energy of the release
- For LERF end states, the magnitude of the release must be sufficient to cause early fatalities. A summary of the relationship of the Cesium and Iodine release fractions versus their potential for impacting early fatalities is presented in Section 5.4.2 of the 2008 Level 2 NB (PSEG 2008c).

The description of the source term, the release timing, and the implications of each are determined using the results of MAAP calculations. Past PRA evaluations are used for comparison purposes to ensure that the MAAP calculations demonstrate the correct trends. In addition, the information developed in previous studies has been used in making subjective assessments for these source term characterizations. The event sequences contributing to a radionuclide release are ranked on the basis of the product of the relative consequences (based on estimated radionuclide release fractions of noble gases, CsI, and Te) and their respective conditional probabilities, so that potentially risk-dominant scenarios are identified and adequately represented. Those that are similar in timing and release fractions are sorted into groups of release categories to reduce the number of release categories required to calculate the risk profile.

The next section identifies the criteria used to define the release bins used in the Hope Creek Level 2 PSA Analysis.

CRITERIA USED IN TIMING AND RELEASE MAGNITUDE ASSIGNMENTS

The release categories are defined based on two parameters: timing and severity (i.e., release magnitude). Timing of the release for each sequence is based on MAAP calculations of the sequence chronology. The classification of release magnitude is based on review of industry studies.

Timing Bins

Appendix E of the 2008 Level 2 NB (PSEG 2008c) provides a discussion of MAAP results and their implications regarding the timing of a declaration of a General Emergency – indicating the potential for population protective actions including evacuation. In Section 5.4.1.1 of the Level 2 NB (PSEG 2008c), the Hope Creek specific evacuation studies are presented that indicate that the worst case evacuation time for the EPZ is 4 hours.

Three timing categories are used, as follows:

1. Early (E) - Less than 4 hours from declaration of a General Emergency[(1)], [(2)]

2. Intermediate (I) - Greater than or equal to 4 hours, but less than 24 hours from declaration of a General Emergency

3. Late (L) - Greater than or equal to 24 hours from declaration of a General Emergency

The definition of the categories is based upon past experience concerning offsite accident response:

- 0-4 hours is conservatively assumed to include cases in which minimal offsite protective measures have been observed to be performed in non-nuclear accidents.
- 4-24 hours is a time frame in which much of the offsite nuclear plant protective measures can be assured to be accomplished.
- >24 hours are times at which the offsite measures can be assumed to be fully effective.

The General Emergency Action Level is used as the trigger for interaction.

The declaration of a General Emergency is used in this analysis to set the initial time of the clock to initiate the public protective actions. Therefore, the times cited here for the determination of radionuclide release bins are relative to the declaration of a General Emergency. This declaration is sequence dependent. See Appendix E of the Level 2 NB (PSEG 2008c) for a further discussion of this determination for Hope Creek.

<u>Evacuation Timing</u>

The evacuation time for Hope Creek Generating Station has been evaluated by KLD Associates (KLD 2004). The results of the study indicate that under the most adverse conditions evaluated, the required evacuation time is 4 hours. The evacuation time for the most restrictive segment under the worst postulated conditions is 4 hours. This means that if 4 hours warning can be given prior to the release, evacuation can be considered successfully implemented (this may be conservative).

---

(1) The cue for General Emergency is set by the Emergency Action Levels (EALs).

(2) The time for evacuation sets the time allowed for determination of an "Early" release. This definition is based on the worst case evacuation time. See HCGS E-Plan and KLD evacuation study which are discussed in Appendix E of this report.

Release Magnitude Bins

The five severity classifications associated with volatile or particulate releases[1] are defined as follows:

1. High (H) - A radionuclide release of sufficient magnitude to have the potential to cause prompt fatalities.
2. Medium or Moderate (M) - A radionuclide release of sufficient magnitude to cause near-term health effects.
3. Low (L) - A radionuclide release with the potential for latent health effects.
4. Low-Low (LL) - A radionuclide release with undetectable or minor health effects.
5. Negligible (OK) - A radionuclide release that is less than or equal to the containment design base leakage.

RELEASE SEVERITY	FRACTION OF RELEASE CSI FISSION PRODUCTS
High	greater than 10%
Medium/Moderate	1 to 10%
Low	.1 to 1.0%
Low-Low(1)	less than 0.1%
Negligible	much less than 0.1%

This relationship allows the use of results of many consequence analyses in providing source terms from the breadth of release paths analyzed in this study. Understanding the plant specific influences on each sequence source term as affected by the various release paths allows the assignment of release severity to each of the sequences. Plant specific deterministic calculations are also available for accident sequences that

(1) The effects of noble gases may be quite dramatic, causing substantial early health effects if released early in an accident and if the associated plume is directed at an occupied location. The noble gases themselves may result in early injuries or fatalities. However, in most sequences the release of noble gases may occur over a relatively extended period of time unless an energetic failure of containment or secondary containment occurs. Therefore, the noble gases are implicitly included in the definition of release categories. There may however be situations in which noble gases alone result in early health effects, those cases are considered of low probability. The focus of the release categories is on the dominant term in cost benefit evaluations from past assessments, i.e., the latent health effects for which the above formulation adequately encompasses the effects of noble gases on the release.

provide the other species of radionuclide releases that can cause different health effects.

Because timing can be an important parameter in assessing accident management and emergency response actions, the timing of the release is carried along with the end state definition.

See Table E.2-3 for a summary of the release severity and timing classification scheme.

E.2.2.2.1.4 Summary of Results

The containment event tree end states are characterized using a two-term matrix (i.e., severity and timing) as shown in Table E.2-3.

E.2.2.3 PRA MODEL OF RECORD SUMMARY (PSEG 2008c)

The Hope Creek PRA is a systematic evaluation of plant risk utilizing the latest technology available for Probabilistic Risk Assessment (PRA). The Hope Creek PRA is classified as a full-power internal events PRA meaning that severe accident sequences have been developed from internally initiated events, including internal floods.

A figure of merit commonly quoted in PRAs is core damage frequency (CDF). While this figure of merit does not entirely represent the value of the PRA, it is a widely used indicator. The core damage frequency (CDF) calculated in the Hope Creek 2008 PRA (HC108B) is 5.11E-6 per year (at a truncation of 1E-12 per year), a decrease from both the HC108A calculated value of 7.6E-6 per year and the 2005C calculated value of 9.76E-6 per year.

The resulting CDF figure of merit is below the NRC's surrogate safety goal which indicates that Hope Creek poses no undue risk and is within the range of CDFs for other nuclear plants.

---

(1) This category includes some venting sequences where only the noble gases are released.

In addition to the evaluation of accident sequences that could lead to core damage, the Hope Creek PRA also includes the second risk metric specified in RG 1.174, an evaluation of the containment performance by examining the Large Early Release Frequency (LERF) associated with possible radionuclide releases. The large early release frequency (LERF) calculated in the Hope Creek HC108B PRA is 4.76E-07 per year, an increase from the 2005C calculated value of 2.59E-7 per year. The increase in LERF is primarily due to the reassignment of specific Level 2 sequence end states from "No LERF" to "LERF" based on the latest MAAP 4.0.6 deterministic calculations of radionuclide release timing and release magnitude. In addition, the internal flood updated evaluation resulted in additional sequences that lead directly to LERF.

The decrease in the CDF risk metric from 9.76E-6/yr (HC2005C) at 5E-11/yr truncation to 5.11E-06/yr (HC108B) at a 1E-12/yr truncation is primarily due to the incorporation of the following changes into the PRA model:

- Seasonal success criteria for the SSW and SACS heat removal system
- Incorporation of HC.OP-AM.TSC-004 procedure to use the portable power supply for power to the DC chargers.
- Reassessment of HEPs using the latest interviews and HRA Calculation Results led to a reduction in the CDF of approximately 2E-6/yr
- Changes in Basic Event Probabilities based on use of NUREG/CR-6928 latest generic date (Principally affecting EDG logic circuit failures)
- Incorporation of minor changes to flood impact logic in the system models
- Changes to SSW and DFP makeup logic within the long term response actions
- The evaluation of random and common cause data using plant specific and NRC updated data resulted in lower common cause failure probabilities. Specifically, the updated common cause failure probabilities using the latest INEEL updates to NUREG/CR-5497 are lower than those used in the 2003 model.
- The incorporation of a finer structure in the modeling of LOCAs by including location dependent LOCA contributors results in revised success criteria (less conservative) for some LOCAs.
- Improved success criteria using MAAP 4.0.6.
- Changes to the generic initiating event frequencies
- Reductions in the transient initiating event frequencies based on incorporation of recent generic and Hope Creek operating experience.

- Added credit for use of CS from CST
- Added control of vent due to procedure change
- Reassessment of pre-initiator HEPs
- Reassessment of post-initiator HEPs
- Added procedure change to SSW/SACS to allow local manipulation of SSW to SACS heat exchangers under LOOP conditions
  - Improved Inverter Room Cooling logic

Increases in CDF resulted from the following:

- The reassessment of internal floods including the inputs from design engineering, operations, and system managers, as well as the latest EPRI pipe failure rates and internal flooding analysis methodology.
- Modified SW injection to RPV for Level 1 because it is not proceduralized.
- Removed credit for Condensate Transfer as RPV injection source

As can be seen from Figure E.2-1, the top four initiating events contributing to CDF for Hope Creek are loss of offsite power, loss of service water, manual shutdown, and turbine trip. See Table E.2-5 for a complete list of the top initiating event contributors to CDF.

Figure E.2-2 provides a chart of the LERF contributions by initiating event. The top four initiating events contributing to LERF are ISLOCA initiators associated with ECCS discharge paths, turbine trip, loss of offsite power, and loss of service water. See Table E.2-2 for specific LERF contributions listed by initiating event. Table E.2-4 provides a summary of the CET release bins and frequencies.

E.2.3 PRA PEER REVIEW OF THE HC108A MODEL

Because of the significant changes in PRA methods (e.g., HRA, Internal Flooding, Common Cause, LOOP treatment, and Level 2), a complete PRA Peer Review of the Hope Creek PRA model (HC108A) was requested by PSEG. The PRA Peer Review was performed in October 2008 using the ASME PRA Standard (ASME 2005) as endorsed by the NRC in Reg. Guide 1.200, Rev. 1, as well as use of the NEI process (NEI 2007).

The PRA Peer Review process confirmed the adequacy of the Hope Creek PRA model for use in PRA applications based on both the exit interview and the Draft PRA Peer Review Report.

The PRA Peer Review using the ASME PRA Standard resulted in the identification of some minor numerical changes to basic events and several additions to model logic. These are identified above under Section 2.1.12. These changes led to a requantification of the Hope Creek PRA model resulting in the HC108B model which is the model used for the SAMA evaluation. Also, the HC108B model used the FTREX quantification engine, which allowed more efficient quantification at a lower truncation limit, i.e., 1E-12/yr in order to meet MSPI convergence criteria.

E.2.3.1 SUPPORTING REQUIREMENTS ASSESSMENT

The ASME PRA Standard has 331 individual Supporting Requirements; 301 Supporting Requirements are applicable to the Hope Creek PRA. Thirty (30) of the ASME PRA Standard Supporting Requirements are not applicable to Hope Creek (e.g., PWR related, multi-unit related). Of the 301 ASME PRA Standard Supporting Requirements applicable to Hope Creek, based on the draft PRA Peer Review report on HC108A more than 90% are supportive of Capability Category II or greater. Refer to the summary in the below table.

ASME PRA Standard	**Hope Creek Assessment**	
Capability Category	# of SRs	%
Not Met	8	2.7%
I	7	2.3%
I/II	13	4.3%
II	35	11.6%
II/III	22	7.3%
III	9	3.0%
Met (All)	207	68.8%
TOTAL:	**301**	**100%**

Findings were resolved in the update from HC108A to HC108B. The SRs delineated as 'Not Met' in the above table were addressed in the HC108B model so as not to impact the SAMA analysis. Any SRs that were not met would not (numerically) impact the results of this SAMA analysis.

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 Hope Creek Generating Station (HCGS). 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 HCGS 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 HCGS. 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 HCGS site is estimated for the year 2046.

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 2046 population distribution.

The total year 2046 population for the 160 sectors in the region is estimated at 6,634,468. The distribution of the population is given for the 10-mile radius and the 50-mile radius from HCGS in Tables E.3-1 and E.3-2, respectively.

E.3.3 ECONOMY

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 HCGS 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 using the consumer price index was applied to parameters describing cost of evacuating and relocating people, land decontamination, and property condemnation

MACCS2 economic parameters utilized in the HCGS analysis include the following:

HCGS MACCS2 ECONOMIC PARAMETERS

VARIABLE	DESCRIPTION	HCGS 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 HCGS 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 (i.e., dose reduction factors of 3 and 15).
(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 HCGS, 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 2006b). The core inventory corresponds to the end-of-cycle values for HCGS operating at 3917 MWt, 2 percent above the current (EPU) licensed value of 3,840

MWt. Table E.3-3 summarizes the estimated HCGS core inventory used in the MACCS2 analysis.

HCGS 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 the reactor building (61 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 represent 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 (GE) is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. For the HCGS analysis the time of the GE declaration was estimated based on the HCGS emergency action levels (PSEG 2007). 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 HCGS 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 data set was 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, 2006, and 2007 data sets. Given that the 2004 data set was the most complete and resulted in the largest risk results of interest, 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 HCGS 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 HCGS calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). HCGS also used this analysis to establish the maximum benefit that could be achieved if all on-line HCGS risk were eliminated, which is referred to as the Maximum Averted Cost-Risk (MACR). The internal events CDF of 4.44E-06 (at a truncation of 5E-11/yr) was used for the calculations in the following sections. External risk is addressed in Section E.4.6.2.

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 22.86 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 $687,646.

E.4.2 OFF-SITE ECONOMIC COST RISK

The Level 3 analysis showed an annual off-site economic risk of $155,055. 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 $2,331,969.

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) (4.44E-06 (total CDF)) at 5E-11/yr truncation

D_{IO} = immediate occupational dose [3,300 person-rem per accident (NRC estimate)]

$_S$ = subscript denoting status quo (current conditions)

$_A$ = subscript denoting after implementation of proposed action

r = real discount rate (0.03 per year)

t_f = years remaining until end of facility life (20 years).

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

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

$$= 2{,}000 * 4.44E\text{-}06 * 3{,}300 * \{[1 - \exp(-0.03*20)]/0.03\}$$

= \$441

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:

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

$$= 2{,}000*4.44E\text{-}06 *20{,}000*\{ [1 - \exp(-0.03*10)]/0.03\} \{[1 - \exp(-0.03*10)]/0.03*10\}$$

= \$2308

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 = $W_{IO} + W_{LTO}$ = (\$441+\$2,308) = \$2,749 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:

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

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:

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

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 (4.44E-06) to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is \$86,567.

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 Hope Creek's size relative to the "generic" reactor described in NUREG/BR-0184 (NRC 1997) (i.e., 1287 megawatt electric / 910 megawatt electric, the replacement power costs are determined to be 7.81E+09 ($-year). Multiplying 7.81E+09 ($-year) by the CDF (4.44E-06) results in a replacement power cost of $34,709.

E.4.6 MAXIMUM AVERTED COST-RISK

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

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

As described in Section 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 I analysis as a means of screening SAMAs. The following subsections provide a description of how each of these components is calculated and used together to obtain the HCGS 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	$687,646
Off-site economic cost	$2,331,969
On-site exposure cost	$2,749
On-site cleanup cost	$86,567
Replacement power cost	$34,709
Total cost	$3,143,640

This total represents the monetary equivalent of the risk that could be eliminated if all risk associated with on-line internal event hazards (including internal floods) could be eliminated for HCGS. The internal events MACR is rounded to next highest thousand ($3,144,000) for SAMA calculations. It should be noted that the Phase II cost benefit calculations account for the difference between the rounded MACR and the actual MACR by adding the difference to the averted cost-risk calculated for each SAMA.

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, some changes have been made to these models, but they have not been updated to reflect recent plant changes or the full spectrum of current PRA techniques. Therefore, the absolute CDF values that are included in the IPEEE would generally not be considered to be directly comparable to the results of the internal events PRA model. However, the fire model, which is the largest and dominant external event contributor for HCGS, was updated in the year 2003 to reflect more current initiating event frequencies and suppression failure probabilities (among other changes) (PSEG 2003). Generally, these are the areas that are considered to have the largest potential influence on fire CDF apart from the underlying PRA model. Given that HCGS has already adjusted the PRA to reflect these types of changes, supporting a reduced fire CDF for other reasons would be beyond the scope of the SAMA analysis. As a result, the external events CDFs are used directly in the MACR calculation.

The method chosen to account for external events contributions in the SAMA analysis is to use a multiplier on the internal events results. This is simply the ratio of total CDF (including internal and external) to only internal CDF. The internal events CDF is represented by the sum of the Level 2 release category frequencies at a truncation of 5E-11. This ratio is called the External Events multiplier and its value is calculated as follows:

EE Multiplier = (4.44E-06+2.35E-05) / (4.44E-06) = 6.3

The contributions of the external events initiators are summarized in the following table:

IPEEE CONTRIBUTOR SUMMARY EXTERNAL EVENT INITIATOR GROUP CDF

Fire*	1.74E-05
Seismic	1.12E-06
High Winds	1.00E-06
Transportation & Nearby Facility**	1.00E-06
External Flooding	1.00E-06
Detritus***	1.00E-06
Chemical Release	1.00E-06
Total EE CDF	2.35E-05

* HCGS 2003 External Events PRA (PSEG 2003)
** The CDF for accidental aircraft impact was estimated to be 6.7E-8/yr in the HCGS UFSAR, Revision 7, December 29, 1995.
*** Detritus CDF from IPEEE ranged from 5.2E-7 to 9.2E-7.

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 HCGS 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 vulnerabilities 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.

E.4.6.3 HCGS MAXIMUM AVERTED COST-RISK

As stated in Section E.4.6, the MACR is the total of these two components:

Internal Events = $3,144,000

External Events = $16,663,200

Maximum Averted Cost-Risk = $19,807,200

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 HCGS was developed from a combination of resources. These include the following:

- HCGS PRA results and PRA Group Insights
- Industry Phase 2 SAMAs (review of the potentially cost effective Phase 2 SAMAs for selected plants)
- HCGS Individual Plant Examination IPE (HCGS IPE) (PSEG 1994a)
- HCGS IPEEE (PSEG 1997)

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 HCGS.

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 HCGS 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 HCGS 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 HCGS importance list review. For example, if instrument air availability was determined to be an important issue for HCGS, the industry list would be reviewed to determine if a plant enhancement had already been conceived that would address HCGS's needs. If an appropriate SAMA was found to exist, it would be used in the HCGS list to address the Instrument Air issue; otherwise, a new SAMA would be developed that would meet the site's needs. This generic list was compiled as part of the development of multiple industry SAMA analyses and is available in NEI 05-01 (NEI 2005).

It should be noted that the process used to identify HCGS SAMA candidates focuses on plant specific characteristics and is intended to address only those issues important to the site. In this case, the existing capabilities of the plant preclude the need to include many of the potential SAMAs that have been identified for other BWRs. As a result, the types of changes that might be cost effective for HCGS are reduced and the SAMA list is relatively short.

E.5.1.1 LEVEL 1 HCGS IMPORTANCE LIST REVIEW

The HCGS 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 HCGS CDF if the failure probability were set to zero. The events were initially reviewed down to an RRW of 1.01, which corresponds to about 1 percent reduction in the CDF given 100 percent reliability of the event. If the dose-risk and offsite economic cost-risk were also assumed to be reduced by a factor of 1.01, the corresponding averted cost-risk would be about $200,000, which also accounts for the impact of External Events after applying a factor of 6.3. Assuming that the minimum implementation cost (associated with a procedure change) is about $100,000, the Level 1 and 2 events were further reviewed down to a RRW of 1.006 to capture those events with potential averted costs down to $100,000. This review revealed these events were already addressed by previously identified SAMAs, or were identified as part of low probability scenarios, e.g., failure to scram, such that no feasible cost-beneficial SAMAs could be identified.

Table E.5-1 documents the disposition of each event in the Level 1 HCGS RRW list greater than or equal to an RRW of 1.006. Note that no basic events were preemptively screened from the process even if they solely represent sequence flags. Whatever the event, the intent of the process is to determine if insights can be gleaned to reduce the risk of the accident evolutions represented by the events listed. However, unique SAMAs are not identified for all of the events in the RRW list. Previously identified

SAMAs are suggested as mitigating enhancements when those SAMAs (or similarly related changes) would reduce the RRW importance of the identified event. It is recognized that in some cases, additional requirements may need to be imposed on the SAMA to get a reduction in the RRW value for the basic event listed. In these cases, if an existing SAMA can approximate such an impact, then it is considered to address the relevant event and provide a first order indication of the potential benefit. If warranted, a more detailed PRA analysis may then be required to provide a better estimate of the actual potential cost-benefit.

E.5.1.2 LEVEL 2 HCGS IMPORTANCE LIST REVIEW

A review of cutsets representing LERF was conducted to determine if any potential SAMA candidates were feasible. The review included those events with a Risk Reduction Worth (RRW) greater than or equal to 1.006 with respect to Level 2 release categories. Table E.5-2 lists those events and corresponding comments. The HCGS PRA model used to generate Level 1 cutsets also contained information regarding the containment status and Level 2 accident phenomena.

A review of cutsets from all non-intact release categories was made to determine if any dominant basic events or components that had not been identified in the Level 1 review should also be included in the Phase 1 SAMA list. As a result, most items that were dominant contributors to these Release Categories had already been identified in the Level 1 CDF review. If any new events that were considered important (RRW ≥ 1.006) for these Release Categories that were not previously identified would be added to the Phase 1 list in Table E.5-3.

E.5.1.3 INDUSTRY SAMA REVIEW

The SAMA identification process for HCGS is primarily based on the PRA importance listings, the IPE, and the IPEEE. In addition to these plant-specific sources, selected industry SAMA submittals were reviewed to identify any Phase II SAMAs that were determined to be potentially cost beneficial at other plants. These SAMAs were further analyzed and included in the HCGS SAMA list if they were considered to address potential risks not identified by the HCGS 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 HCGS importance ranking should identify the types of changes that would most likely be cost beneficial for HCGS, but review of selected industry Phase II SAMAs may capture potentially important changes not identified for HCGS due to PRA modeling differences or SAMAs that represent alternate methods of addressing risk. Given this potential, it was considered prudent to include a review of selected industry Phase II SAMAs in the HCGS SAMA identification process.

Phase II SAMAs from the following United States nuclear power sites have been reviewed:

- Susquehanna Steam Electric Station (PPL 2006)
- Peach Bottom Atomic Power Station (EXELON 2001)
- James A. Fitzpatrick Nuclear Power Plant (ENTERGY 2008)
- Cooper Nuclear Station (NPPD 2008)
- DAEC (FPL 2008)
- Wolf Creek (WNOC 2006)

One Westinghouse PWR and five General Electric BWR sites were chosen from available documentation to serve as the potential Phase II SAMA sources. Many of the industry Phase II SAMAs were already represented by other SAMAs in the HCGS list, were known not to impact important plant systems or be relevant to the HCGS design, or were judged not to have the potential to be close contenders for HCGS. As a result, they were not added to the HCGS SAMA list. Those unique SAMAs that were considered to have the potential to be cost effective for HCGS 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 HCGS	DISPOSITION FOR HCGS 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 HCGS, this type of enhancement was identified based on the plant specific PRA results review (SAMA 5).	Already included
6	Procure Spare 480V AC Portable Station Generator	HCGS already has a portable generator that can be used to power the station battery chargers. The operator action to align the generator dominates the hardware failure probability and an additional generator would provide limited benefit. HCGS already includes a SAMA to automate alignment of the portable generator.	Already implemented
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 HCGS as part of HCGS SAMA 5.	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 HCGS design.	Not included.
5	Auto Align 480V AC Portable Station Generator	Auto start and alignment of the 480V generator reduces the human error contribution and dependence issues related to providing alternate power. This is addressed by HCGS SAMA 5.	Already included.

E.5.1.3.2 Peach Bottom Atomic Power Station

REVIEW OF PBAPS COST BENEFICIAL SAMAS

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR HCGS	DISPOSITION FOR HCGS SAMA LIST
Phase II SAMA 21	INSTALL SUPPRESSION POOL JOCKEY PUMP FOR ALTERNATE INJECTION TO THE RPV	Peach Bottom proposed the suppression pool jockey pump as a means of improving the reliability of long term, independent injection to the RPV given the complexity of the alignment for the fire water injection method. This type of injection is generally required in loss of containment heat removal cases, but this did not include SBO cases given that it was a low pressure system and would require DC power to maintain the SRVs open. For these types of long term cases, operator reliability is not an issue for HCGS. In addition, the Condensate Storage and Transfer System is available as an injection option and the alignment of this system is not complex. Providing a suppression pool jockey pump similar to the one proposed by Peach Bottom would provide no measurable benefit.	Not included.

E.5.1.3.3 Fitzpatrick

REVIEW OF FITZPATRICK COST BENEFICIAL SAMAS

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR HCGS	DISPOSITION FOR HCGS SAMA LIST
Phase II SAMAs 26, 27, 30, 34, 36, and 61	Multiple Methods to Improve Battery Depletion	Fitzpatrick performed an evaluation of the benefit of improving SBO coping capabilities, primarily through extending the time DC power would be available. HCGS recently installed a portable 480V AC generator to accomplish the task of powering the batter chargers and operator reliability is now the limiting issue for the site with respect to providing alternate DC power. HCGS SAMA 5 addresses loss of offsite power issues and the Fitzpatrick SAMAs would not be beneficial to HCGS.	Already implemented/ included.

REVIEW OF FITZPATRICK COST BENEFICIAL SAMAS

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR HCGS	DISPOSITION FOR HCGS SAMA LIST
62	Develop a procedure to open the door of EDG buildings upon the high temperature alarm	This SAMA was developed to provide an alternate method of room cooling for the EDG rooms. HCGS has redundant sets of room cooling trains for each of the 4 EDG rooms. The SACS system normally supplies cooling water to the room coolers from the same division, but each cooler has a cross-tie to the other SACS division that can be aligned, if required. EDG room cooling issues were not identified on the importance list and are small contributors to HCGS risk.	Not included.

E.5.1.3.4 Cooper Nuclear Station

REVIEW OF COOPER NUCLEAR STATION COST BENEFICIAL SAMAS

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR HCGS	DISPOSITION FOR HCGS SAMA LIST
14	Portable generator for DC power to supply the individual panels.	This SAMA was designed to allow HPCI operation after battery depletion. HCGS already has a portable generator to perform this task.	Already implemented
25	Revise procedure to allow bypass of RCIC turbine exhaust pressure trip	Allows RCIC to operate when suppression pool pressures are high enough to trip the RCIC turbine on high turbine exhaust pressure. This failure mode is not explicitly developed for HCGS and could be examined further.	Added to SAMA list (SAMA I2)

REVIEW OF COOPER NUCLEAR STATION COST BENEFICIAL SAMAS

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR HCGS	DISPOSITION FOR HCGS SAMA LIST
78	Improve training on alternate injection via FPS	The intent of this SAMA is to improve the reliability of the operator action to align alternate injection with the fire protection system, but the SAMA does not identify what problems exist with the current training program, what credible changes could be made to measurably improve reliability, or how any such changes would impact the HRA assessment. The HCGS EOPs direct the use of fire water injection, which is then implemented using system level procedures. The action to align fire water injection has a reasonable low failure rate, an RRW value of 1.006, and a RAW value that is below 1.1. Any SAMAs implemented to improve the reliability of alternate injection with FPS would have a limited impact of risk. Further, it is possible that improved training could increase the operators' proficiency with FPS injection, but current HRA methodologies would estimate little, if any, reduction in the action's HEP based on improved training alone. As a result, no SAMAs are suggested.	Not included
30	Revise procedures to allow manual alignment of the fire water system to RHR heat exchangers	This SAMA was designed to mitigate loss of SW cooling to the RHR heat exchangers. Loss of cooling to the RHR heat exchangers can occur due to an important failure to open the intermediate cooling system's (SACS) heat exchanger valve, but this is an operator action and any additional action to supply alternate cooling to the RHR heat exchangers would be highly or completely dependent on the action to open the SACS heat exchanger valve. For hardware or support system failures that fail SACS, even if cooling water could be supplied to the RHR heat exchangers, the RHR pumps depend on SACS for room cooling (A&B) and lube oil cooling (A, B, C, D) so the availability of water to the HXs is irrelevant. As a result, additional hardware modifications would provide minimal benefit and are not suggested. Other SACS failures are of much lower importance and the inter-division SACS cross-tie is not even credited in the model.	Not included

REVIEW OF COOPER NUCLEAR STATION COST BENEFICIAL SAMAS

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR HCGS	DISPOSITION FOR HCGS SAMA LIST
68	Proceduralize the ability to cross connect the circulating water pumps and the service water going to the TEC heat exchangers	This SAMA is designed to provide an alternate cooling medium to the closed loop cooling system that cools the turbine building loads. For HCGS, the Station Service Water system ultimately provides cooling to the turbine building closed loop cooling system. Station Service Water does not have existing cross-ties to other systems, so a procedure change is not relevant to HCGS. SAMA 10 (use of B.5.b pump for alt injection) provides a lower cost means of maintaining long term injection after a failure of Service Water cooling.	Not included. Not applicable to HCGS.
33	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	This SAMA appears to be aimed at providing a long term supply of water to FW/Condensate. At HCGS, the CST is aligned to the hotwell via a gravity feed mechanism and loss of FW/Condensate due to CST depletion is not a large contributor. LOCA cases can lead to depletion of the CST, but the only LOCA scenario above the RRW review threshold for HCGS is an ISLOCA scenario that leads to a high pressure core melt after successful ASD inhibit. SAMA 1 addresses the elimination of the guidance to use inhibit ADS, which would allow low pressure ECCS to function and provide makeup for 96 percent of the ISLOCA contribution. This is considered to be a lower cost, more appropriate change for HCGS.	Not included. Addressed by a lower cost SAMA.
40	Operator procedure revisions to provide additional space cooling to the EDG room via the use of portable equipment	Addressed in discussion for Fitzpatrick Phase II SAMA 62.	Refer to Fitzpatrick Phase II SAMA 62
45	Provide an alternate means of supplying the instrument air header	This SAMA is intended to improve the reliability of the Instrument Air system by providing an alternate supply to the system header. For HCGS, the Instrument Air system is not an important risk contributor and this type of enhancement is not required.	Not included
64	Proceduralize the use of a fire pumper truck to pressurize the fire water system	Fire water reliability can be enhanced by proceduralizing the use of a fire truck to pressurize the fire water header. HCGS already has this proceduralized.	Already implemented

REVIEW OF COOPER NUCLEAR STATION COST BENEFICIAL SAMAS

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR HCGS	DISPOSITION FOR HCGS SAMA LIST
75	Generation Risk Assessment implementation into plant activities	The intent of this SAMA appears to be the incorporation of risk management tools into work planning practices. This is already performed at HCGS.	Already implemented
79	Modify procedures to allow use of the RHRSW system without a SWBP	Not applicable to HCGS; the Service water system already operates without booster pumps for system cooling.	Not included. Not applicable to HCGS

E.5.1.3.5 Duane Arnold Energy Center

REVIEW OF DUANE ARNOLD ENERGY CENTER COST BENEFICIAL SAMAS

INDUSTRY SITE SAMA ID	SAMA DESCRIPTION	DISCUSSION FOR HCGS	DISPOSITION FOR HCGS SAMA LIST
156	Provide an alternate source of water for the RHRSW/ESW pit.	This SAMA addresses clogging of flow to the RHRSW/ESW pump intake area. This was addressed at DAEC by assuming that a cross connect could be added to allow communication between the Circ Water and RHRSW/ESW pits. HCGS has individual intake bays for each SW pump with lateral connections between each of the bays to allow cross flow in the event that one or more of the intakes becomes clogged.	Already implemented
166	Increase the reliability of the low pressure ECCS RPV low pressure permissive circuitry. Install manual bypass of low pressure permissive	The intent of this SAMA is to reduce the probability that low pressure injection will be failed by the low pressure permissive sensors or logic. This equipment is modeled for HCGS, but is a relatively low contributor. However, adding a key lock bypass would improve the reliability of a bypass action in the event of an interlock failure.	Added to SAMA list (SAMA I3)

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 HCGS	DISPOSITION FOR HCGS 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 HCGS.	Not included
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 has not been identified as an important contributor for HCGS.	Not included
5	Enhance procedures to direct operators to open EDG Room doors for alternate room cooling	Addressed in discussion for Fitzpatrick Phase II SAMA 62.	Refer to Fitzpatrick Phase II SAMA 62
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 provisions to provide high pressure, primary side makeup and is a PWR specific issue. Also, HCGS already has a portable generator to address SBO issues.	Not included
3	AC Cross-tie Capability	This SAMA is designed to improve AC crosstie capability. For HCGS, this type of enhancement was identified based on the plant specific PRA results review (SAMA 5).	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 HCGS, but the relevant failure events are below the review threshold and no cost beneficial changes would result from EDG fuel oil enhancements.	Not included
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 provisions to provide high pressure, primary side makeup and is a PWR specific issue. Also, HCGS already had a portable generator to address SBO issues.	Not included

E.5.1.3.7 Industry SAMA Identification Summary

The important issues for HCGS 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 HCGS based on modeling differences or other factors. For HCGS, the following additional SAMA candidates were identified based on a review of selected industry analyses:

- Develop a procedure to open the door of EDG buildings upon the high temperature alarm (SAMA I1)
- Revise procedure to allow bypass of RCIC turbine exhaust pressure trip (SAMA I2)
- Increase the reliability of the low pressure ECCS RPV low pressure permissive circuitry. Install manual bypass of low pressure permissive. (SAMA I3)

E.5.1.4 HCGS IPE PLANT IMPROVEMENT REVIEW

The HCGS 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.

As a result of the IPE three potential improvements were identified for consideration; however, two of the changes were technically not plant improvements, but improvements to calculations that would allow more credit to be taken for existing plant features. These types of changes do not directly impact plant risk, but they can be used to aid in the management of plant risk and are considered as potential SAMAs. The following table summarizes the status of these improvements:

STATUS OF IPE PLANT ENHANCEMENTS

DESCRIPTION OF POTENTIAL ENHANCEMENT	STATUS OF IMPLEMENTATION	DISPOSITION
Perform further neutronics calculations to demonstrate that reactivity control is possible with a single division of SLC.	Implemented	The current PRA model credits a single SLC pump for providing reactivity control and preventing HCTL depressurization. No further review required.
Perform calculations to show that each SSW/SACS loop can operate with only one pump and that loop cross-tie is a viable recovery mechanism for the systems.	Implemented	Plant calculations have been performed to show that a single SACS pump, SSW-SACS heat exchanger, and SSWS pump can be successful under certain conditions, but not under all conditions. SSWS is operated with the cross-ties open so that either system can provide cooling to the RACS loads, but credit is not taken for one division of SSWS to cool the opposite division's SACS loads. Further analysis could potentially provide a basis for crediting the cross-division cooling of t he SACS loads by SSWS, but this would not result in any actual risk reduction given that the SSWS cross-ties are normally open. No further review required.
Develop operating procedures for the SACS in severe accident conditions.	Implemented	No further review required.

All of the plant changes suggested in the IPE have been implemented at HCGS and no further review of these items is required.

E.5.1.5 HCGS IPEEE PLANT IMPROVEMENT REVIEW

Similar to the IPE, any proposed plant changes that were previously rejected based on non-SAMA criteria should be re-examined as part of this 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
Install a missile shield in front of the Technical Support Center HVAC room (Room 5619, Door 19).	Implemented	No further review required.
Preclude unauthorized shipment and storage of explosives on the Delaware River.	Implemented	No further review required.

While the shipping practices on the Delaware River are not controlled by PSEG, the U.S. Coast Guard stopped explosive shipment and storage near the HCGS site and did not see any need for explosive shipment or storage along the river in the near future. Based on discussions with HCGS security personnel confirming the exclusion zone restrictions are still in place at the site, and have been enhanced in some cases, all of the plant changes suggested in the IPEEE are considered to have been implemented and no further review of these items is required.

An effort was also made to use the IPEEE to develop new SAMAs based on a review of the original results. However, the HCGS 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 the enclosed SAMA analysis, external event contributions are estimated for the reasons described above.

E.5.1.6 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 HCGS staff identified several major changes with the potential to impact the IPEEE results:

- Installation of security enhancements.
  - Installation of the vehicle barrier system
  - Elevation of the security guard bullet resistant enclosures
- Addition of the spent fuel storage facility
- Addition of a liquid oxygen storage tank off the corner of the Unit 2 Reactor Building

These changes are discussed in further detail below.

E.5.1.6.1.1 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 HCGS that could potentially be impacted is the high winds risk. Given that raising the security guard bullet resistant enclosures did not introduce any new materials, no new wind generated missiles would be introduced to the site. Failure of the enclosure themselves does not impact plant risk.

The vehicle barriers are massive concrete blocks and based on engineering judgment, they do not present any wind based hazards that were not addressed in the IPEEE.

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.5.1.6.1.2 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 2007) estimates the probability of a latent cancer fatality from a fuel storage site to be 1.8E-12 during the first year of service, and 3.2E-14 per year during subsequent years of storage. The

NUREG 1864 analysis is not an HCGS 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 wins 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.5.1.6.1.3 Liquid Oxygen Storage Tank

A liquid oxygen (LOX) storage tank has been placed just off the Northwest corner of Unit 2 Reactor Building. This tank is used for recombining H2 in the Radwaste facility. Plant personnel have indicated that the tank is secured to withstand high winds and that the risk associated with the tank in high wind scenarios is negligible. Although not seismically secure, the LOX tank is situated at a distance of approximately 300 ft from safety structures, eliminating it as an interaction hazard. While liquid O2 will support combustion in the presence of combustible materials under the right circumstances, it is not flammable and the consequences of a seismic event on this tank are determined to be negligible.

No SAMAs are suggested to address any risk associated with the liquid oxygen storage tank.

E.5.1.7 USE OF EXTERNAL EVENTS IN THE HCGS SAMA ANALYSIS

The IPEEE was used in the HCGS 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 HCGS external events analysis were identified by Supplement 4 of Generic Letter 88-20 (NRC 1991b) 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 HCGS. The HCGS IPEEE indicates that the guidance in NUREG-1407 and NUREG/CR-5042 was used to identify other potential initiating event (IE) types that could impact safe operation of the HCGS plant. These IEs 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

The HCGS IPEEE site evaluation concluded that the above list constituted a comprehensive list of credible, potential external event hazard initiators and no additional events were identified for evaluation. 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.5.1.7.1)

- Seismic Events (Section E.5.1.7.2)
- High Wind Events (Section E.5.1.7.3)
- External Flooding and Probable Maximum Precipitation (Section E.5.1.7.4)
- Transportation and Nearby Facility Accidents (Section E.5.1.7.5)
- Release of On-site Chemicals (E.5.1.7.6)
- Detritus (E.5.1.7.7)

The type of information available for the initiators that were evaluated by HCGS varied due to the manner in which they were addressed in the IPEEE. For instance, PRAs were developed to evaluate the fire and seismic risk for HCGS while 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. Specifically, the results are not linked to the current Level 2 and 3 PRA models and the consequences of the corresponding core damage scenarios are not available. In 2003, a partial update of the fire and seismic models was performed, but the changes were limited to the reassignment of some initiating event consequences (for fire events), initiating event frequency changes (fire and seismic), and fire severity factor updates. The integration of the fire and seismic models with the internal events PRA was not fully implemented and as a result, the underlying system and plant response models that these analyses rely upon have not been updated since the completion of the IPEEE in 1997.

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

E.5.1.7.1 Internal Fires

As discussed above, the techniques used to model external events vary according to the type of initiator being analyzed. The HCGS Fire Model shares many of the same characteristics as the internal events model and for HCGS, 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 HCGS modeling strategy makes use of PRA techniques, but neither the fire plant response model nor the fire modeling methodology is up to date. The methods are judged to result in overly conservative results. 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 the most recent Level 2 and 3 analyses that are available to support the SAMA analysis, which prevents the evaluation of accident consequences in a manner consistent with the process used for the internal events models.

PRA TOPIC	COMMENT
Initiating Events:	While the fire initiating event methodology is different than what is being used in current analyses, the 2003 HCGS External Events Update included changes to the initiating event frequencies based on the information provided in the 2002 NRC fire database (PSEG 2003).
System Response:	Several conservative assumptions are made with respect to the operation of plant systems due to lack of information and simplifying assumptions, which can increase the overall fire CDF. For example, Feedwater, Condensate, and CRD are assumed to be unavailable. Any fire, including an MCR fire, is assumed to result in a plant trip, even if it is not severe. Fire induced LOOP events are assumed to be unrecoverable as are loss of HVAC events for the class IE panel rooms. Fire suppression is credited, but modeling assumptions almost always result in the inability of the suppression system to extinguish fires before damage occurs to the ignition source.
Sequences:	Sequences in the HCGS fire model are defined in detail. The consequences of any sequence grouping is likely minor.

PRA TOPIC	COMMENT
Fire Modeling:	The 2003 HCGS External Events update (PSEG 2003) included the integration of the EPRI fire severity factors for control room fires, which is a change from the original IPEEE. Otherwise, the fire modeling from the IPEEE model has remained unchanged. In general, fire damage and fire spread are conservatively characterized. For example, Cable damage was calculated assuming all cables were unprotected, even if they were enclosed in cable trays or conduit. When determining damage to target cables from a specific source (in the absence of suppression), if any elevation of cable was calculated to be damaged, all of the cables were assumed to be damaged. When determining whether target cables were damaged from a specific source before extinguishment, if any elevation of cable was calculated to be damaged before extinguishment, all of the cables were assumed to be damaged. Any opening in a wall is assumed to allow fire damage to propagate via a hot gas layer as if the wall below the opening were not there. Exposure fires instantly attain their peak intensities and remain there for the duration of the fire. Targets respond with no delay to temperature changes in the surrounding environment. Heat loss by convection in ventilated room fires is neglected. Plume and hot gas layer temperature effects are superimposed to determine if targets have been damaged. Pump fires are modeled as liquid pool fires of quantity one or two gallons, whichever conservatively bounds the amount of lube oil in the pump.
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 HCGS, all recovery actions other than control of the plant from the remote shutdown panel and recovery of alternate 1E panel room HVAC were set to failure. However, the internal events HEPs for the other post-initiator HFEs and the pre-initiator HFEs were directly used in the fire model.
Level of Detail:	Many fire PRAs may have a reduced level of detail in the mitigation of the initiating events and consequential system damage; however, the HCGS 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:	No peer review similar to what is performed for internal events models using the ASME Standard for PRA was performed on either the IPEEE fire model or the 2003 fire model.

While there are conservative factors included in the fire PRA, the fire PRA is still judged to include more conservative bias than an internal events model, the update of the fire initiating event frequencies and use of the HCGS 2003 External Events update for the CCDPs address a portion of the easily defined conservatisms (PSEG 2003). As a result, the SAMA analysis directly uses the updated fire CDF to develop the external events multiplier, as described in Section E.4.6.2.

The approach taken to identify potential fire-related SAMAs was to review the fire compartments with potential averted cost-risks (PACRs) greater than the minimum expected SAMA implementation cost of $100,000. The fire compartment PACRs were estimated by taking the external events PACR and distributing it among the fire scenarios based on the fire CDFs relative to the total site 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 $100,000, the averted cost-risk would be small (below $100,000) 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 $100,000.

The fire CDFs used to develop the fire scenario PACRs are based on the HCGS 2003 External Events update with the exception of the %IE-FIRE06 scenario. The CDF for this scenario has been reduced by a factor of 3 to reflect the availability of in-console halon suppression that can be initiated by the operators and/or the fire brigade. The factor of 3 reduction is based on the guidance in Appendix M of EPRI-105928 (EPRI 1995), which was used to develop the fire suppression frequency for HCGS in the 2003 External Events update. This results in the reduction of the %IEFIRE06 PACR from about $1,080,000 to $360,000; subsequent analysis demonstrates that this change does not impact the conclusions related to the SAMA identified to address this contributor.

The CDF results from that analysis are presented below for the top 10 contributors; of which only the top 8 have PACRs that are greater than $100,000.

BASIC EVENT ID	DESCRIPTION	FIRE IE FREQUENCY (/YR)	CCDP	FIRE CDF (/YR)	% OF FIRE CDF	COMPARTMENT FIRE MACR
%IE-FIRE03	Control Room Fire Scenario Small Cab_3 (Loss of Emer. Bat.)	2.94E-04	1.80E-02	5.29E-06	30.5%	$3,754,488
%IE-FIRE02	Control Room Fire Scenario Small Cab_2 (Loss of SSWS)	2.45E-04	1.80E-02	4.41E-06	25.4%	$3,128,740
%IE-FIRE01	Control Room Fire Scenario Small Cab_1 (Loss of SACS)	2.10E-04	1.80E-02	3.78E-06	21.8%	$2,681,777
%IE-FIRE28	Cmprtmnt 5339 Fire Scenario 5339_2	1.25E-05	6.00E-02	7.50E-07	4.3%	$532,099
%IE-FIRE37	DG Room (D) Fire Scenario 5304_2	1.00E-04	6.98E-03	6.98E-07	4.0%	$495,206
%IE-FIRE20	DG Room (C) Fire Scenario 5306_2	1.00E-04	6.67E-03	6.67E-07	3.8%	$473,213
%IE-FIRE38	Cmprtmnt 3425/5401 Fire Scenario 5401_1	3.40E-05	1.72E-02	5.85E-07	3.4%	$414,895
%IE-FIRE06	Control Room Fire Scenario Large Cab_1 (MSIV Closure)	2.55E-05	6.00E-02	5.10E-07	2.9%	$361,827
%IE-FIRE21	DG Room (B) Fire Scenario 5305_1	4.00E-03	2.09E-05	8.36E-08	0.5%	$59,311
%IE-FIRE24	Cmprtmnt 5501 Fire Scenario 5501_1	4.20E-04	1.90E-04	7.98E-08	0.5%	$56,615

For each fire compartment with a PACR greater than $100,000, the contributing risk factors were reviewed to determine what measures could be taken to mitigate the fire event and the corresponding core damage sequences. Further discussion is provided for each of these fire compartments below.

E.5.1.7.1.1 %IE-FIRE03: Control Room Fire Scenario Small Cab_3 (Loss of Emer. Bat.)

The definition of a “small” fire in the MCR is one that does not require abandonment to the remote shutdown panel (RSP) and that the damage caused by the fire is limited to the ignition component and the adjacent equipment. The fire addressed by this scenario is small, but a postulated hot short requires abandonment of the MCR and control of the plant at the RSP. In addition to the loss of the MCR, the fire fails the emergency batteries and inverters (related to control cable damage in the MCR). The fire scenario also accounts for the failure of the operator to shut the plant down from the RSP, which results in core damage.

A potential means of reducing the fire frequency is to install incipient fire detectors, which can identify hot points in the cables/circuit before fire ignition. 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. As a result, installation of incipient fire detectors is not suggested as a SAMA.

The information provided for this fire scenario indicates that the required mitigation equipment is available and that it can be operated from the RSP; consequently, no additional hardware changes are required to improve defense-in-depth for the mitigating systems.

One of the factors driving the risk for this scenario is the limited credit that is taken for control of the plant at the RSP. This is due, at least in part, to the broad nature of the action. Current HRA methodologies do not effectively address an action as complex as shutting the reactor down from the RSP when taken as a single action. The failure probability does not provide insight into the factors that may be causing difficulty or even if there are any. While the particular difficulties associated with controlling the plant from the RSP are not well defined, it is clear that preventing MCR abandonment would preclude these challenges. By definition, this fire is small and does not require control room evacuation due to environmental issues; control from the RSP was assumed to be required because both divisions of the emergency batteries and inverters are damaged (even though the controls for the other systems remain available). A full MCR evacuation could be avoided if plant fire procedures were modified to allow the operators to transfer control of a single channel (“B” or “D”) of equipment to the RSP. The RSP could then be used to gain control of a single channel of critical equipment while the MCR is used to govern the other plant systems (SAMA 30). A different permutation of this SAMA would be to direct local control of the DC electrical system using the “A” or “C” trains to avoid use of the RSP altogether (guidance to use the “A” and “C” divisions currently exists as a backup to RSP control). While controlling a single system outside of the control room does present its own challenges, the scope of controlling a single system using an alternate set of controls is limited and could potentially improve the reliability of post fire plant control. It should be noted that the CDF for this scenario includes the assumption that the fire causes a single hot short (with a probability of 0.3) that disables the entire system. Division I and II equipment are generally separate and redundant such that a single hot short could not cause failure of both of the system’s divisions; however, this cannot be demonstrated without a circuit analysis, which is beyond the scope of the SAMA analysis. As a result, the assumption that a single hot short fails both divisions of the emergency batteries and inverters is retained for the SAMA analysis.

E.5.1.7.1.2 %IE-FIRE02: Control Room Fire Scenario Small Cab_2 (Loss of SSWS.)

This fire scenario is similar to %IE-FIRE03 in that a small MCR cabinet fire results in a hot short that forces abandonment to the RSP. In this case, the equipment damaged by the fire is the SSWS rather than the emergency batteries and inverters. The implication is that adequate systems are available to control the plant and that the RSP is operable, but the operators fail to control the plant from the RSP.

As for the %IE-FIRE03, the CDF calculation for this fire scenario also includes the assumption that a single hot short disables both divisions of a redundant plant system.

The same SAMA that is applicable to %IE-FIRE03 is also applicable to this scenario.

E.5.1.7.1.3 %IE-FIRE01: Control Room Fire Scenario Small Cab_1 (Loss of SACS)

This fire scenario is similar to %IE-FIRE03 in that a small MCR cabinet fire results in a hot short that forces abandonment to the RSP. In this case, the equipment damaged by the fire is the SACS rather than the emergency batteries and inverters. The implication is that adequate systems are available to control the plant and that the RSP is operable, but the operators fail to control the plant from the RSP.

As for the %IE-FIRE03, the CDF calculation for this fire scenario also includes the assumption that a single hot short disables both divisions of a redundant plant system.

The same SAMA that is applicable to %IE-FIRE03 is also applicable to this scenario.

E.5.1.7.1.4 %IE-FIRE06: Control Room Fire Scenario Large Cab_1 (MSIV Closure)

The impact of this fire scenario is similar to %IE-FIRE03 in that an MCR cabinet fire forces abandonment to the RSP, but in this case, both environmental factors and equipment damage issues contribute to the need to evacuate the MCR. Multiple systems are damaged by the fire, but the damage is limited to the MCR control consoles/cables and transfer to the RSP isolates the damaged circuits and adequate control is assumed to be available. Failure to control the plant using the RSP is a major contributor to the fire CDF.

Given that an in-console halon system exists in the HCGS MCR that can be quickly initiated by the operators and/or the plant's fire brigade, credit for further manual or automatic fire suppression enhancements beyond what is described in Section E.5.1.7.1 is not considered to be available.

While further suppression improvements are not expected to have a significant impact on the fire CDF, improving the fire barriers in the control consoles containing the MSIV controls is a potential means of preventing fire propagation, which would greatly reduce the damage caused by the fire and prevent the need to evacuate the MCR due to poor environmental conditions (SAMA 31). Success of the fire barriers would effectively reduce the magnitude of the fire to a “small” fire and limit damage to a single console, which appears to only cause an MSIV closure event.

E.5.1.7.1.5 %IE-FIRE28: Cmprtmnt 5339 Fire Scenario 5339_2

The risk significant scenario of Room 5339 is one in which burning liquid fuel from a diesel-generator room fire leaks under the door separating the diesel-generator room from Room 5339. This area contains Division I cables, both sets of 1E 4kV bus bars, and the control power supply cables for diesel generators A and C. The dominant scenario is a large fire, from one of the four diesel-generator rooms, which spreads into this room causing loss of 4kV station power, loss of cables of Division I, and loss of the ability to start diesel-generators A and C. Calculation of the fire frequency for this scenario was taken to be 50% of the frequency of large fires calculated for all of the diesel generator rooms. That is, leakage under the door was assumed to occur for half of the scenarios in which a large pool might collect in any of the diesel generator rooms.

For this fire scenario, the 1E 4kV bus bars are damaged in the original EDG room fire, but it should be noted that these bus bars can be isolated from the division specific emergency 4kV buses that are supplied by the EDGs and feed the plant loads. If the fire does not reach Room 5339, the three remaining EDGs would be capable of starting and loading onto their division specific 4kV emergency buses. Once the fire reaches Room 5339, the A and C EDG control cables are damaged and Division I power is lost. SAMAs could be proposed to mitigate the effects of the fire that would primarily be composed of enhancements to provide alternate means of powering the important Division I equipment (potentially additional) cross-ties. However, a more cost effective means of mitigating this scenario would appear to be the installation of a curb or a diversion channel to ensure liquids from the DG rooms cannot communicate with Room 5339. (SAMA 32)

E.5.1.7.1.6 %IE-FIRE37: DG Room (D) Fire Scenario 5304_2

A large fire in this compartment will fail the D EDG and the 1E 4k emergency bus bars (fails offsite power to the emergency buses), but EDGs A, B, and C would be available to supply their loads, so the consequences of a fire that remains in this room alone are less severe than one that propagates into Room 5339 and fails the other channel of Division II power. Small fires do not damage the 1E 4kV emergency bus bars, but they do fail the EDG. The EDG rooms are equipped with total CO2 flooding systems, but they are not credited with preventing damage to either the EDGs or the bus bars.

The cause of the damage to the bus bars is the large fuel oil fire, which is assumed to be a result of either the plume or the ceiling jet from the fire. While installing an enhanced drain/sump type of a system could divert the majority of the fuel oil out from under the 4kV bus bars, the bars would still be in the ceiling jet and would still be failed by the fire. As a result, this type of a change, which is effective for preventing propagation of fuel oil to other rooms, is not considered to be effective in preventing damage to the 4kV bus bars.

A potential means of addressing the loss of the D EDG would be to install crossties between the Division II 480V AC buses (potentially 10B420 to 10B480 and 10B460 to 10B440). (SAMA 33)

E.5.1.7.1.7 %IE-FIRE20: DG Room (C) Fire Scenario 5306_2

This fire scenario is the same as the D EDG fire in Room 5304, but %IE-FIRE20 impacts the C EDG. Consequently, a similar SAMA is proposed for this scenario, but the crossties would be tailored to the Division I 480V AC bus design: 10B410 to 10B 430 and 10B450 to 10B470. (SAMA 34)

E.5.1.7.1.8 %IE-FIRE38: Cmprtmnt 3425/5401 Fire Scenario 5401_1

The information available in the IPEEE related to this fire is limited, but the fire event appears to be initiated by electrical heaters in the Electrical Access Area of the Auxiliary Building 124’ level that are located within close proximity to some Division II cables. Automatic fire suppression systems are present, but they do not respond in time to prevent cable damage. The result of the fire is a plant trip with a loss of the B and D power divisions.

Inter-divisional cross-ties may be an effective means of mitigating these fires, but preventing the fire by moving or eliminating the electrical heaters is considered to be a more appropriate change. (SAMA 35)

E.5.1.7.1.9 Fire SAMA Identification Summary

Based on the review of the HCGS fire area results, six SAMAs have been identified as potentially cost beneficial methods of reducing fire risk:

- Modify fire procedures to allow partial transfer of controls to the RSP (SAMA 30)
- Install improved fire barriers in the MCR control cabinets containing the primary MSIV control circuits. (SAMA 31)
- Install a curb or a diversion channel to ensure liquids from the DG rooms cannot communicate with Room 5339. (SAMA 32)
- Install crossties between the Division II 480V AC buses (potentially 10B420 to 10B480 and 10B460 to 10B440). (SAMA 33)
- Install crossties between the Division I 480V AC buses (potentially 10B410 to 10B 430 and 10B450 to 10B470). (SAMA 34)
- Move or eliminate the electrical heaters in the electrical access room (Aux Building 124' level) to prevent damage to the Division II power cables. (SAMA 35)

E.5.1.7.2 Seismic Events

In response to Generic Letter 88-20, Supplement 4 (NRC 1991a), PSEG 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 to quantify a CDF using the 1994 version of the HCGS internal events PRA model. The CDF for that internal event PRA model is 1.3E-5/yr, which is about a factor of 3.5 less than the HCGS IPE CDF of 4.58E-5/yr. The baseline case was originally developed using seismic hazard event frequencies developed by Lawrence Livermore National Labs (NRC 1994), but the EPRI seismic hazard curves (EPRI 1989) were also used in parallel as a sensitivity case.

Since completion of the IPEEE, the seismic results have been updated using the following information (PSEG 2003):

- The EPRI seismic hazard curves
- Revised treatment of HEPs under seismic conditions, to eliminate the non-conservative nature of the original seismic analysis
- The HCGS 2003A PRA model (calculates the CCDP)

The resulting CDF is 1.12E-06/yr. While the original intent of the HCGS 2003 External Events update was to facilitate the creation of an integrated PRA model, this change was not fully implemented and the External Events contributors are not maintained as a "living" analysis.

As with the fire analysis, the degree of refinement of the seismic model is not considered to be consistent with the internal events analysis. However, since the estimated CDF is low, effort will not be made in this analysis to detail these issues in order to justify a lower CDF for use in the External Events Multiplier (refer to Section E.4.6.3).

Table E.5.6.4 provides a summary of the changes made to the operator actions to support the 2003 HCGS seismic analysis (PSEG 2003):

The approach taken to identify potential seismic-related SAMAs was to review the seismic contributors with PACRs greater than the minimum expected SAMA implementation cost of $100,000. The seismic PACRs were estimated by taking the external events PACR and distributing it among the seismic damage states (SDSs) based on the seismic CDFs relative to the total site CDF. Review of additional seismic SDSs 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 SDSs with PACRs below $100,000, the averted cost-risk would be small (below $100,000) by definition and would not be a priority for implementation at the site. Consequently, the review effort for this analysis is limited to the SDSs with PACRs greater than $100,000.

The CDFs used to develop the seismic PACRs are based on the HCGS 2003 External Events update (PSEG 2003). The CDF results from that analysis are presented below for the top 10 seismic contributors; only the top 2 scenarios have PACRs that are greater than $100,000.

BASIC EVENT ID	DESCRIPTION	SEISMIC HAZARD FREQUENCY (/YR)	CCDP	SEISMIC CDF (/YR)	% OF SEISMIC CDF	COMPARTMENT SEISMIC MACR
%IE-SET36	Seismic-Induced Equipment Damage State SET-36 (Impacts - 120V PNL481)	6.70E-07	1.00E+00	6.70E-07	5.98E-01	$475,341
%IE-SET18	Seismic-Induced Equipment Damage State SET-18 (Impacts - LOOP)	5.90E-05	5.20E-03	3.07E-07	2.74E-01	$217,806
%IE-SET37	Seismic-Induced Equipment Damage State SET-37 (Impacts - 125V)	5.50E-08	1.00E+00	5.50E-08	4.91E-02	$39,021
%IE-SET35	Seismic-Induced Equipment Damage State SET-35 (Impacts - 120V PNL482, RSP)	4.60E-08	1.00E+00	4.60E-08	4.11E-02	$32,635
%IE-SET38	Seismic-Induced Equipment Damage State SET-38 (Impacts - 1E Panel Room Ventil.)	2.10E-08	1.00E+00	2.10E-08	1.88E-02	$14,899
%IE-SET26	Seismic-Induced Equipment Damage State SET-26 (Impacts - LOOP, 250V)	1.10E-06	9.04E-03	9.94E-09	8.88E-03	$7,052
%IE-SET09	Seismic-Induced Equipment Damage State SET-09 (Impacts - 250V)	4.40E-07	1.04E-02	4.56E-09	4.07E-03	$3,235
%IE-SET34	Seismic-Induced Equipment Damage State SET-34 (Impacts - CR, RSP)	3.70E-09	1.00E+00	3.70E-09	3.30E-03	$2,625
%IE-SET28	Seismic-Induced Equipment Damage State SET-28 (Impacts - LOOP, 250V, CV)	1.00E-07	6.00E-03	6.00E-10	5.36E-04	$426

BASIC EVENT ID	DESCRIPTION	SEISMIC HAZARD FREQUENCY (/YR)	CCDP	SEISMIC CDF (/YR)	% OF SEISMIC CDF	COMPARTMENT SEISMIC MACR
%IE-SET30	Seismic-Induced Equipment Damage State SET-30 (Impacts - LOOP, 250V, CST)	1.00E-07	6.00E-03	6.00E-10	5.36E-04	$426

For each seismic scenario with a PACR greater than $100,000, the contributing risk factors were reviewed determine what measures could be taken to mitigate the seismic event and the corresponding core damage sequences. Further discussion is provided for each of these scenarios below.

E.5.1.7.2.1 %IE-SET36: Seismic-Induced Equipment Damage State SET-36 (Impacts - 120V PNL481)

This seismic damage state represents a seismic-induced failure of all four divisions of 1E 120Vac instrumentation distribution panels 1A/B/C/DJ481. Core damage is assumed to occur given these failures. It is possible to control the plant without class 1E instrumentation power, but it is not proceduralized.

Providing adequate procedural guidance in the MCR to operate the plant after a total loss of class 1E 120V AC power would provide some benefit for these scenarios. (SAMA 36) Guidance is available at the RSP to perform the tasks that would be required without 120V AC power (mainly manually operating equipment that is typically automatically operated), but these functions can be performed directly from the MCR.

An alternate option is to reinforce the 120V AC distribution panels so that they could survive more severe seismic activity. (SAMA 37)

E.5.1.7.2.2 %IE-SET18: Seismic-Induced Equipment Damage State SET-18 (Impacts - LOOP)

This scenario represents a seismic-induced loss of offsite power, with subsequent random failures which result in core damage. No other seismically induced failures are identified for the scenario. The random failures are dominated by Emergency Diesel Generator failures, resulting in a Station Blackout.

A potential means of addressing these contributors would be to provide a 24 hour fuel oil source for the engine driven fire water pump and use the existing portable 480V AC generator to power bus 10B421 to support SRV operation. Use of the portable battery charger provides RPV depressurization capability to allow low pressure injection with fire water (fire water can be aligned manually). In addition, the fire water tanks have HCLPF values of 0.26g and may need to be strengthened to match the engine driven fire pump's HCLPF in order to improve the likelihood that fire water injection will be available in a seismic event. (SAMA 38)

The SDS description does not indicate that the fire water system has failed, but the fire water system is currently not credited in the seismic analysis for RPV injection and information about fire water availability would not be tracked or presented for this SDS.

E.5.1.7.2.3 Seismic SAMA Identification Summary

Based on the review of the HCGS SDS results, three SAMAs have been identified as potentially cost beneficial methods of reducing seismic risk:

- Develop MCR procedures to operate the plant after a loss of all class 1E 120V AC power. (SAMA 36)
- Reinforce the class 1E 120V AC distribution panels. (SAMA 37)
- Enhance the Fire Water system and use the existing portable generator to support SRV operation for long term injection in seismic events. (SAMA 38)

E.5.1.7.3 High Wind Events

The approach taken to analyze the high wind, flood, and "other" external event risk in the HCGS IPEEE was to implement a progressive screening approach. The first three steps included 1) a review of HCGS specific hazard data and licensing basis, 2) identification of significant changes since Operating License issuance, and 3) verification that the HCGS 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.

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 with the exception of the rain hoods on the EDG exhaust pipes and the rain hoods on the EDG fuel oil tank vents. The EDG fuel oil tanks have alternate vent lines that could be used in the event that the primary vents are damaged, which is considered to be adequate redundancy. The EDG exhaust pipes, which could potentially be damaged by a wind generated missile, would have to be first be impacted by a missile and then damaged to the point where they could not function. The IPEEE indicated that the UFSAR evaluated such a strike and concluded that it was very unlikely a wind generated missile strike would adversely impact the function of the exhaust pipes.

Even if the high wind core damage frequency is assumed to be as high as the IPEEE's screening threshold of 1E-06/yr, some high level assumptions can be used to generated a PACR for the EDG exhaust pipes to show that further investigation of this topic is not required. If the same process used in Section E.5.1.8.1 to estimate the fire area PACRs is used for the high wind risk, a high wind CDF of 1E-06/yr can be correlated to a cost-risk of about $590,000. If a missile strike on the EDG exhaust pipes that completely disables one or more EDGs is assumed to account for as much as 10 percent of this risk, the corresponding PACR is only $59,000, which is significantly less than the lower bound cost of a procedure change. No SAMAs are suggested to address this issue.

The only other high wind issue identified in the IPEEE was related to inadequate doors on the TSC, which was addressed through the installation of missile barriers.

In conclusion, no high wind related SAMAs are required for HCGS.

E.5.1.7.4 External Flooding and Probable Maximum Precipitation

Site flooding at HCGS is addressed by the probable maximum hurricane surge with wave run-up coincident with the ten percent exceedance high tide. Safety related systems and components are not affected by a flood when they are located above the postulated maximum flood level. When located below flood level, the HCGS structures were found to be protected against water ingress and no vulnerabilities were identified.

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.5.1.7.5 Transportation and Nearby Facility Accidents

Transportation and nearby facility accidents were included in the HCGS 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 275 times less than the IPEEE internal fire CDF of 1.84E-05 per yr and over 115 times less than the current internal events CDF. If the same process used in Section E.5.1.8.1 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 $48,000 (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 HCGS was analyzed for the IPEEE and it was determined that because no major highway or rail line was located within 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.

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.5.1.7.6 “Other” Events

Because some hazardous chemicals are stored at, delivered to, and used at the HCGS site, it was necessary to examine the impact of chemical releases on plant operations. The IPEEE indicates that HCGS conforms to Regulatory Guide 1.78 and that control room habitability would not be impacted by any postulated accidents. No SAMAs are suggested.

E.5.1.7.7 Detritus

Detritus was also examined for HCGS in the IPEEE given that the site had experienced problems due to mud and grass buildup on the Service Water system traveling screens. While traveling screen clogging was an issue, the IPEEE indicates that a large scale river bottom perturbation would be required to dislodge sufficient detritus to impact all Service Water intakes. A seismically induced detritus event was evaluated for HCGS, but it was screened from the IPEEE based on a 1995 PSEG analysis that estimated the CDF for such an event to range from about 5E-07/yr to about 9E-07/yr. The risk from this type of event was considered to be low and it did not account for all of the changes that had been made to the Service Water system. As a result, no additional changes were considered to be required to reduce the risk of detritus events in the IPEEE. If the same process used in Section E.5.1.7.1 to estimate the fire area PACRs is used for the seismically induced detritus risk, a CDF of 5.2E-07/yr can be correlated to a cost-risk of about $370,000. Based on the information available in the IPEEE related to detritus events, no additional procedure enhancements that would significantly reduce risk have been identified beyond those enhancements that have already been made, 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.

It is noted that events involving SW intake at the site have primarily affected the Salem unit because of the location of the Salem intake and the large intake flow rate required for Salem (no cooling tower). For Hope Creek, the intake is located in a more benign location and the intake flow rate is significantly lower than for Salem because the CW is taken from the cooling tower basin not the river. The river intake is for SW only and is relatively low compared with Salem intake throughput.

E.5.2 PHASE 1 SCREENING PROCESS

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 HCGS design, it is not retained. Similarly, any SAMAs that have already been implemented by PSEG or achieve results that PSEG 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 I 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 1. 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 HCGS specific estimates developed by plant personnel. Table E.5-3 provides implementation costs for each Phase 1 and Phase 2 SAMA.

Sections E.6.1 – E.6.21 describe the simplified cost-benefit analysis that was used for each of the Phase 2 SAMA candidates. It should be noted that the release category results provided for each SAMA do not include contributions from the negligible release category.

E.6.1 SAMA 1: REMOVE ADS INHIBIT FROM NON-ATWS EMERGENCY OPERATING PROCEDURES

In most initiating events the operators are directed to inhibit ADS. This requires them to later manually depressurize to allow low pressure injection from low pressure systems. The ADS feature is inhibited so as to prevent premature depressurization and allow the operator to control the time when depressurization occurs. This SAMA investigates the basis for inhibiting ADS and provides alternatives (e.g., removing the ADS inhibit from the EOP for non-ATWS scenarios). Although this is contrary to the recommendations from the BWROG EOP guidelines, it may have a large impact on the risk reduction. The other alternative would be to install a separate and totally independent high pressure injection system to mitigate those sequences where the normal high pressure injection systems are unavailable. However, due to the large perceived cost with this type of permanent modification, it was decided to analyze the aforementioned lower cost option that involves changing the procedure that directs the operator to inhibit the ADS.

<u>Assumptions:</u>

1. For the purposes of this SAMA, it was assumed that the operator would not inhibit ADS.
2. The ADS inhibit function would still be required for ATWS sequences.

<u>PRA Model Changes to Model SAMA:</u>

The operator action to inhibit ADS (ADS-XHE-OK-INHIB) probability was changed from 1.0 to 1E-1. The 1E-1 represents the HEP for the operator inappropriately inhibiting ADS for non-ATWS scenarios. This high failure rate can later be reduced after training and sufficient experience with this change in place. No other basic events or fault tree structures were affected.

Results of SAMA Quantification:

Implementation of this SAMA yields a large reduction in the CDF, Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for HCGS:

	CDF	Dose-Risk	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	3.28E-06	16.30	$114,734
Percent Change	26.2%	28.7%	26.0%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$Frequency_{BASE}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$Frequency_{SAMA}$	1.26E-07	7.15E-08	3.04E-08	9.67E-07	8.28E-08	1.08E-07	2.15E-07	0.00E+00	2.57E-07	2.36E-07	1.18E-06	**3.28E-06**
$Dose\text{-}Risk_{BASE}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$Dose\text{-}Risk_{SAMA}$	2.29	0.99	0.71	8.46	0.91	1.42	1.36	0.00	0.00	0.16	0.00	**16.30**
$OECR_{BASE}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$OECR_{SAMA}$	$14,454	$6,888	$3,497	$61,971	$7,643	$9,927	$10,178	$0	$0	$175	$0	**$114,734**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 1 NET VALUE

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
Hope Creek	$19,807,200	$14,539,581	$5,267,619

Based on a $200,000 cost of implementation for HCGS, the net value for this SAMA is $5,067,619 ($5,267,619 - $200,000), which results in this SAMA being cost beneficial.

It should be noted that implementation of this SAMA would have a limited impact on external events initiators and that the use of the external events multiplier for the averted cost-risk calculation results in an unrealistically high estimate of the cost benefit. For example, for the three dominant fire scenarios, which account for about 60 percent of the external events risk, the ADS function is irrelevant to the core damage frequency.

The scenarios are dominated by failure to control the plant from the RSP; even if ADS functions, core damage would still occur for those scenarios. In order to assess the importance of the external events contributions on this SAMA's evaluation, the averted cost-risk has been estimated without the use of the external events multiplier. In this case, the internal events based averted cost-risk for SAMA 1 is $836,130, which is greater than the $200,000 cost of implementation.

An additional factor to consider is that implementation of this SAMA would increase the complexity of the EOPs by creating a situation where the use of ADS inhibit is not consistent for all accident scenarios. A potential undesired consequence of such a change would be an increased likelihood that ADS would not be inhibited in ATWS events (or inhibited in non-ATWS events). The quantification performed for this SAMA does not include any detrimental impacts related to implementation; however, any related CDF increases are expected to be small and the SAMA would remain cost beneficial. Even if the negative impacts of implementation were assumed to reduce the benefit of the SAMA by as much as 50 percent, the internal events averted cost-risk would be more than double the cost of implementation at $418,065.

Given that the implementation cost was estimated to be $200,000, this SAMA would be cost beneficial even if any potential negative impacts associated with implementation are accounted for and the averted cost-risk were only based on internal events contributors

E.6.2 SAMA 3: INSTALL BACK-UP AIR COMPRESSOR TO SUPPLY AOVs

Following the loss of the service water system, the PRA includes a recovery action to restore failed equipment, specifically, to restore Service Water and reestablish SACS given a loss of Service Water. Currently, there is no specific procedural direction for this action. This action involves damage repair and recovery as part of Emergency Response Organization (ERO) activities.

This SAMA involves replacing the operator action to repair or restore (NR-IE-SWS) with a backup air compressor. The air compressor would be utilized to allow use of AOVs which would allow operators to mitigate the loss of service water.

Assumptions:

1. For the purposes of this SAMA, it was assumed that this system would require manual initiation.
2. This backup air compressor system would rely upon current AC power sources.
3. A combined HRA and hardware failure probability of 0.5 was selected as a screening

PRA Model Changes to Model SAMA:

It should be noted that the degree of recovery attached to failures of AOV valves is judged to be only a small fraction of the probability for loss of SW. The operator action to recover service water (NR-IE-SWS) probability was changed from 1.0 to 0.5. This event represents a legacy event from previous models, but is no longer credited for recovery of service water in the HC108B model. This change would simulate the addition of an OR gate which would contain the backup air compressor. No other basic events or fault tree structures were affected.

Results of SAMA Quantification:

Implementation of this SAMA yielded an appreciable reduction in CDF and similar changes in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for HCGS:

	CDF	DOSE-RISK	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	3.72E-06	19.26	$128,757
Percent Change	16.3%	15.8%	17.0%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$Frequency_{BASE}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$Frequency_{SAMA}$	1.82E-07	5.15E-08	1.30E-07	6.29E-07	5.75E-08	3.48E-07	2.16E-07	0.00E+00	1.97E-07	1.73E-07	1.73E-06	**3.72E-06**
$Dose\text{-}Risk_{BASE}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$Dose\text{-}Risk_{SAMA}$	3.32	0.71	3.05	5.51	0.63	4.55	1.37	0.00	0.00	0.12	0.00	**19.26**
$OECR_{BASE}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$OECR_{SAMA}$	$20,973	$4,959	$14,975	$40,334	$5,307	$31,881	$10,200	$0	$0	$128	$0	**$128,757**

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**
Hope Creek	$19,807,200	$16,505,055	$3,302,145

Based on a $700,000 cost of implementation for HCGS, the net value for this SAMA is $2,602,145 ($3,302,145 - $700,000), which results in this SAMA being cost beneficial.

E.6.3 SAMA 4: PROVIDE PROCEDURAL GUIDANCE TO CROSS-TIE RHR TRAINS

The ability to repair or recover RHR equipment that is failed or out of service can have a dramatic impact on the course of postulated accident sequences. For example, the loss of containment heat removal sequences may evolve over extended times of 15 - 50 hours. During this time frame, there can be extensive repair activities accomplished to restore equipment to service. The PRA includes these repair activities (RHS-REPAIR-TR). Currently only one pump within the loop is capable of being aligned to perform the torus cooling function.

This SAMA involves replacing recovery activity to repair or restore RHR (NR-IE-SWS) with an operator action to cross tie the existing RHR pumps to allow either to perform the heat removal functions. This change requires procedure and operator training to realize the benefit of this SAMA.

Assumptions:

1. For the purposes of this SAMA, it was assumed that this system would require manual operation.
2. This motor operator valve manipulation would rely upon current AC power sources.
3. A combined HRA and hardware failure probability of 1E-1 was selected as a screening

PRA Model Changes to Model SAMA:

The operator action to recover RHR (RHS-REPAIR-TR) probability was changed from 3.5E-1 to 1E-1.This change would simulate the conditional probability that RHR could be recovered by crosstying pumps within the loop. No other basic events or fault tree structures were affected.

Results of SAMA Quantification:

Implementation of this SAMA yielded a slight reduction in the CDF with larger reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for HCGS:

	CDF	**DOSE-RISK**	**OECR**
Base Value	4.44E-06	22.86	$155,055
SAMA Value	3.89E-06	18.04	$119,730
Percent Change	12.4%	21.1%	22.8%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$Frequency_{BASE}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$Frequency_{SAMA}$	1.83E-07	7.15E-08	1.30E-07	4.19E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**3.89E-06**
$Dose\text{-}Risk_{BASE}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$Dose\text{-}Risk_{SAMA}$	3.33	0.99	3.05	3.66	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**18.04**
$OECR_{BASE}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$OECR_{SAMA}$	$21,045	$6,888	$14,975	$26,834	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$119,730**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 4 NET VALUE

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
Hope Creek	$19,807,200	$15,449,074	$4,358,126

Based on a $100,000 cost of implementation for HCGS, the net value for this SAMA is $4,258,126 ($4,358,126 - $100,000), which results in this SAMA being cost beneficial.

E.6.4 SAMA 5: RESTORE AC POWER WITH ONSITE GAS TURBINE GENERATOR

After a loss of offsite power with a failure of all EDGs or failure of some EDGs combined with failure of EDG supported equipment (i.e., ECCS trains) operators may wish to cross-tie certain equipment. This action can link electrical supply with otherwise operational equipment. Currently there is no operational capability or procedural guidance to cross-tie 4.160 kv loads between Hope Creek electrical divisions. Repair of damaged equipment is considered separately from procedurally guided operator action. As such, these actions involve damage repair and recovery as part of Emergency Response Organization (ERO) activities. During operator interviews the operators confirmed that they would not cross the EDGs from one division to another. Based on this input this recovery action (NR-XTIE-EDG) is set to 1.0.

A 40 MWe gas turbine generator is located adjacent to the Hope Creek plant, inside the Salem Generating Station's protected area. This equipment is capable of supplying power to the Hope Creek 13.8kv system via the local Salem 500kv system. The gas turbine is operated by Salem personnel. Hope Creek operators must coordinate its use with Salem Plant Staff. This task involves requesting alignment of the gas turbine and coordinating electrical system manipulations with Salem staff as well as regional power control staff.

This SAMA involves replacing the EDG cross tie activity (NR-XTIE-EDG) with an operator action to take more advantage of the existing Salem Gas Generator. This change requires procedure and operator training to realize the benefit of this SAMA.

Assumptions:

1. For the purposes of this SAMA, it was assumed that this system would require manual operation.
2. The additional breaker manipulation would rely upon current AC power equipment.
3. A combined HRA and hardware failure probability of 1E-1 was selected as a screening

PRA Model Changes to Model SAMA:

The operator action cross tie emergency diesels (NR-XTIE-EDG) probability was changed from 9.9E-1 to 1E-1.This change would simulate improvement of increasing the use of the Salem Gas Generator. No other basic events or fault tree structures were affected.

Results of SAMA Quantification:

Implementation of this SAMA yielded a significant reduction in the CDF, Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for HCGS:

	CDF	DOSE-RISK	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	4.10E-06	22.08	$149,815
Percent Change	7.7%	3.4%	3.4%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$Frequency_{BASE}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$Frequency_{SAMA}$	1.57E-07	7.15E-08	1.30E-07	9.45E-07	8.34E-08	3.47E-07	2.04E-07	0.00E+00	2.56E-07	2.39E-07	1.67E-06	**4.10E-06**
$Dose\text{-}Risk_{BASE}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$Dose\text{-}Risk_{SAMA}$	2.86	0.99	3.05	8.27	0.92	4.54	1.30	0.00	0.00	0.16	0.00	**22.08**
$OECR_{BASE}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$OECR_{SAMA}$	$18,045	$6,888	$14,975	$60,590	$7,694	$31,782	$9,664	$0	$0	$177	$0	**$149,815**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 5 NET VALUE

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
Hope Creek	$19,807,200	$19,102,652	$704,548

Based on a $2,050,000 cost of implementation for HCGS, the net value for this SAMA is -$1,345,452 ($704,548 - $2,050,000), which results in this SAMA <u>not</u> being cost beneficial.

E.6.5 SAMA 7: INSTALL BETTER FLOOD DETECTION INSTRUMENTATION FOR RACS COMPARTMENT

The Service Water system has two trains (A and B). The A and B trains are normally isolated from each other and supply loads that are dedicated to their train. As such, a rupture of one train will in general be isolable to terminate the discharge of flow to the Reactor Building. There is an exception for short runs of unisolable SW discharge pipe located in the Reactor Building. For certain postulated unisolated breaks in the SW discharge inside the RACS room, SW will continue to discharge to the RACS room because of either (1) continued operation of the opposite SW train which results in continued back flow through the break from the discharge; or, (2) reverse flow from the Cooling Tower Basin.

The SW discharge to the Cooling Tower Basin traverses the HCGS yard. There are valves located in 4 ft. deep pits in the HCGS yard (within the Protected Area). The internal flood walkdown identified that these valves are located in a “confined space” underground in the HCGS yard within the Protected Area. These isolation valves are located below grade and are accessed via man-ways in the yard between the plant buildings and the cooling tower. These are large valves and are difficult to manipulate. Operations staff interviewed indicated that closing the valves would require at least 1-2 hours if remote operation of the valves was unavailable. Further, during a plant walkdown in March 2008, the man-ways were observed to be flooded with ground water making accessibility especially difficult if not unachievable within a reasonable amount of time. These valves are the only way to isolate a small portion of the SW pipe within the Reactor Building (RACS compartment) if they rupture. Flooding from the Cooling Tower basin to the RACS room can occur due to reverse flow. It is determined that these valves do not represent viable methods of isolating the relatively large leaks that are postulated as part of the internal flood analysis. This is principally due to the following:

- Located in the yard
- Located in a confined space (requires special consideration)
- Under water
- Difficult to turn (under these time limited conditions)

Remote operation is not guaranteed

Assumptions:

1. For the purposes of this SAMA, it was assumed that this system would require manual operation from the control room.
2. Failure of the new MOV to close on demand is negligible.
3. A HRA failure probability of 1E-1 was selected as a screening value

PRA Model Changes to Model SAMA:

The operator action “FAILURE TO ISOLATE LOCALLY A SW RUPTURE IN RACS COMPARTMENT” (SWS-XHE-RACS-UNI) probability was changed from 1 to 1.0E-1. This change would simulate a motor operated valve failure combined with the failure of the operator to isolate the break. No other basic events or fault tree structures were affected.

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 HCGS:

	CDF	DOSE-RISK	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	4.27E-06	22.52	$152,597
Percent Change	3.8%	1.5%	1.6%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$Frequency_{BASE}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$Frequency_{SAMA}$	1.83E-07	6.36E-08	1.30E-07	9.70E-07	6.54E-08	3.48E-07	2.16E-07	0.00E+00	2.27E-07	1.96E-07	1.87E-06	**4.27E-06**
$Dose\text{-}Risk_{BASE}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$Dose\text{-}Risk_{SAMA}$	3.33	0.88	3.05	8.49	0.72	4.55	1.37	0.00	0.00	0.13	0.00	**22.52**
$OECR_{BASE}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$OECR_{SAMA}$	$21,045	$6,121	$14,975	$62,159	$6,035	$31,881	$10,235	$0	$0	$145	$0	**$152,597**

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
Hope Creek	$19,807,200	$19,480,262	$326,939

Based on a $3,070,000 cost of implementation for HCGS, the net value for this SAMA is -$2,743,062 ($326,939 - $3,070,000), which results in this SAMA not being cost beneficial.

E.6.6 SAMA 8: CONVERT SELECTED FIRE PROTECTION PIPING FROM WET TO DRY PIPE SYSTEM

A corridor outside the control room (and similarly, the lower Control Equipment Room) includes fire protection system equipment. A line rupture could quickly flood the corridor. Since the corridor includes a door that opens to the control room, water could enter the control room if the door should fail. The PRA currently models the probability of operators' failing to secure the fire system locally in order to isolate the leak (FPS-XHE-CRISOL).

This SAMA involves reducing the need for isolating the fire protection header (FPS-XHE-CRISOL). Converting the fire protection piping from wet to dry piping would reduce the need for this operator action. This change requires design changes to the fire protection system to realize the benefit of this SAMA.

Assumptions:

1. For the purposes of this SAMA, it is assumed that operator intervention would still be required to mitigate inadvertent filling of system.

PRA Model Changes to Model SAMA:

The operator action to isolate the fire protection header leak (FPS-XHE-CRISOL) probability was changed from 1.0 to 0.1. This represents the conversion of fire protection from wet to dry pipe system but still requiring operator intervention for inadvertent filling of the system.

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 HCGS:

	CDF	DOSE-RISK	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	4.28E-06	22.55	$152,798
Percent Change	3.7%	1.4%	1.5%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$Frequency_{BASE}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$Frequency_{SAMA}$	1.83E-07	6.62E-08	1.30E-07	9.69E-07	6.55E-08	3.48E-07	2.16E-07	0.00E+00	2.32E-07	1.96E-07	1.87E-06	**4.28E-06**
$Dose\text{-}Risk_{BASE}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$Dose\text{-}Risk_{SAMA}$	3.33	0.91	3.05	8.48	0.72	4.55	1.37	0.00	0.00	0.13	0.00	**22.55**
$OECR_{BASE}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$OECR_{SAMA}$	$21,013	$6,375	$14,975	$62,138	$6,046	$31,881	$10,223	$0	$0	$145	$0	**$152,798**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 8 NET VALUE

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
Hope Creek	$19,807,200	$19,505,644	$301,556

Based on a $600,000 cost of implementation for HCGS, the net value for this SAMA is -$298,444 ($301,556 - $600,000), which results in this SAMA not being cost beneficial.

E.6.7 SAMA 10: PROVIDE PROCEDURAL GUIDANCE TO USE B.5.b LOW PRESSURE PUMP FOR NON-SECURITY EVENTS

During certain loss of offsite power scenarios (e.g. SBO resulting in a recirculation seal LOCA) where loss of steam driven high pressure systems is postulated to occur. For these types of scenarios it is desirable to have an independently powered pump for injection into the RPV.

This SAMA involves adding a diesel driven pump that takes suction from outside containment (e.g. CST). This includes improving procedures and adding a new pump.

Assumptions:

1. For the purposes of this SAMA, it is assumed that the procedures and training would change to allow make use of these new injection methods.
2. This alternate injection system would rely upon an independent AC power source (i.e. diesel driven pump).
3. A combined HRA and hardware failure probability of 1E-1 was selected as a screening value for this SAMA.

PRA Model Changes to Model SAMA:

The operator action to align RHRSW to for injection into the RPV probability (RHR-XHE-RHR-INJ) was changed from 1.0E-1 to 1.0E-2. This represents the failure probability of this SAMA modification combined with the nominal operator action failure rate (RHR-XHE-RHR-INJ). The model was requantified with this change. This represents the pump reliability, availability and procedure improvement related to the alternate injection system. No other basic events or fault tree structures were affected.

Results of SAMA Quantification:

Implementation of this SAMA yields a small reduction in the CDF and larger reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for HCGS:

	CDF	DOSE-RISK	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	4.39E-06	22.65	$153,467
Percent Change	1.1%	0.9%	1.0%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$Frequency_{BASE}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$Frequency_{SAMA}$	1.83E-07	7.15E-08	1.30E-07	9.60E-07	8.34E-08	3.48E-07	1.96E-07	0.00E+00	2.64E-07	2.39E-07	1.92E-06	**4.39E-06**
$Dose\text{-}Risk_{BASE}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$Dose\text{-}Risk_{SAMA}$	3.33	0.99	3.05	8.40	0.92	4.55	1.24	0.00	0.00	0.16	0.00	**22.65**
$OECR_{BASE}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$OECR_{SAMA}$	$21,045	$6,888	$14,975	$61,519	$7,694	$31,881	$9,288	$0	$0	$177	$0	**$153,467**

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
Hope Creek	$19,807,200	$19,607,622	$199,578

Based on a $100,000 cost of implementation for HCGS, the net value for this SAMA is $99,578 ($199,578 - $100,000), which results in this SAMA being cost beneficial.

E.6.8 SAMA 15: ALTERNATE DESIGN OF CSS SUCTION STRAINER TO MITIGATE PLUGGING

This SAMA involves improving the reliability of the Core Spray suction strainers (CSS-STR-PL-(A thru D)). This would improve Core Spray injection reliability.

Assumptions:

1. For the purposes of this SAMA, this is a hardware change only.
2. This assumes that the reliability of all these strainers is the same.

PRA Model Changes to Model SAMA:
The operator action to open the SW valve(s) locally (CSS-STR-PL-(A thru D)) probability was changed from 8.36E-3 to 8.36E-4. This factor of 10 reduction was applied to all 4 basic events to simulate strainer improved reliability. The model with this change was then requantified to obtain the SAMA CDF value. No other basic events or fault tree structures were affected.

Results of SAMA Quantification:

Implementation of this SAMA yields a small reduction in the CDF and negligible reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for HCGS:

	CDF	DOSE-RISK	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	4.33E-06	22.74	$154,166
Percent Change	2.4%	0.5%	0.6%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$Frequency_{BASE}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$Frequency_{SAMA}$	1.83E-07	6.94E-08	1.30E-07	9.70E-07	7.61E-08	3.48E-07	2.16E-07	0.00E+00	2.47E-07	2.19E-07	1.88E-06	**4.33E-06**
$Dose\text{-}Risk_{BASE}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$Dose\text{-}Risk_{SAMA}$	3.33	0.96	3.05	8.49	0.84	4.55	1.37	0.00	0.00	0.15	0.00	**22.74**
$OECR_{BASE}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$OECR_{SAMA}$	$21,045	$6,681	$14,975	$62,159	$7,026	$31,881	$10,235	$0	$0	$162	$0	**$154,166**

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
Hope Creek	$19,807,200	$19,680,797	$126,403

Based on a $1,000,000 cost of implementation for HCGS, the net value for this SAMA is -$873,597 ($126,403 - $1,000,000), which results in this SAMA not being cost beneficial.

E.6.9 SAMA 16: USE OF DIFFERENT DESIGNS FOR SWITCHGEAR ROOM COOLING FANS

This SAMA considers replacing one of four Switchgear room cooling fans (FANS AVH401 through DVH401) with a different design so as to eliminate common cause failure of all fans. An alternate means of cooling could involve multiple portable fans placed strategically in or near the switchgear doorway(s) to provide maximum air flow.

Assumptions:

1. For the purposes of this SAMA, this is a hardware change only.
2. This assumes that the reliablity of all these fans is the same.
3. The replacement fan is assumed to eliminate common cause fan failure for the system

PRA Model Changes to Model SAMA:

All failure to start and failure to run for switchgear room fans common cause events were set to zero. The following table provides a list of the basic events that were set to zero.

SAMA 16 BASIC EVENTS

NAME	DESC
VSW-FAN-FR-DF12	CCF FAILURE FANS A THRU DVH401 FAIL TO RUN
VSW-FAN-FR-DF13	CCF FAILURE FANS A -B AND CVH401 FAIL TO RUN
VSW-FAN-FR-DF14	CCF FAILURE FANS A -B AND DVH401 FAIL TO RUN
VSW-FAN-FR-DF15	CCF FAILURE FANS A -C AND DVH401 FAIL TO RUN
VSW-FAN-FR-DF16	CCF FAILURE FANS B -C AND DVH401 FAIL TO RUN
VSW-FAN-FR-DF17	CCF FAILURE FANS A AND BVH401 FAIL TO RUN
VSW-FAN-FR-DF18	CCF FAILURE FANS A AND CVH401 FAIL TO RUN
VSW-FAN-FR-DF19	CCF FAILURE FANS A AND DVH401 FAIL TO RUN
VSW-FAN-FR-DF20	CCF FAILURE FANS B AND CVH401 FAIL TO RUN
VSW-FAN-FR-DF21	CCF FAILURE FANS B AND DVH401 FAIL TO RUN
VSW-FAN-FR-DF22	CCF FAILURE FANS C AND DVH401 FAIL TO RUN
VSW-FAN-FS-DF01	CCF FAILURE FANS A THRU DVH401 FAIL TO START
VSW-FAN-FS-DF02	CCF FAILURE FANS A -B AND CVH401 FAIL TO START
VSW-FAN-FS-DF03	CCF FAILURE FANS A -B - AND DVH401 FAIL TO START
VSW-FAN-FS-DF04	CCF FAILURE FANS A -C AND DVH401 FAIL TO START
VSW-FAN-FS-DF05	CCF FAILURE FANS B -C AND DVH401 FAIL TO START
VSW-FAN-FS-DF06	CCF FAILURE FANS A AND BVH401 FAIL TO START
VSW-FAN-FS-DF07	CCF FAILURE FANS A AND CVH401 FAIL TO START
VSW-FAN-FS-DF08	CCF FAILURE FANS A AND DVH401 FAIL TO START
VSW-FAN-FS-DF09	CCF FAILURE FANS B AND CVH401 FAIL TO START
VSW-FAN-FS-DF10	CCF FAILURE FANS B AND DVH401 FAIL TO START
VSW-FAN-FS-DF11	CCF FAILURE FANS C AND DVH401 FAIL TO START

No other basic events or fault tree structures were affected.

<u>Results of SAMA Quantification:</u>

Implementation of this SAMA yielded a small reduction in the CDF and negligible reductions in Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for HCGS:

	CDF	DOSE-RISK	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	4.34E-06	22.73	$154,142
Percent Change	2.4%	0.6%	0.6%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$\text{Frequency}_{\text{BASE}}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$\text{Frequency}_{\text{SAMA}}$	1.83E-07	6.67E-08	1.30E-07	9.70E-07	7.89E-08	3.48E-07	2.16E-07	0.00E+00	2.56E-07	2.27E-07	1.86E-06	**4.34E-06**
$\text{Dose-Risk}_{\text{BASE}}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$\text{Dose-Risk}_{\text{SAMA}}$	3.33	0.92	3.05	8.49	0.87	4.55	1.37	0.00	0.00	0.16	0.00	**22.73**
$\text{OECR}_{\text{BASE}}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$\text{OECR}_{\text{SAMA}}$	$21,035	$6,419	$14,975	$62,159	$7,279	$31,881	$10,225	$0	$0	$169	$0	**$154,142**

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
Hope Creek	$19,807,200	$19,678,151	$129,049

Based on a $400,000 cost of implementation for HCGS, the net value for this SAMA is -$270,951 ($129,049 - $400,000), which results in this SAMA <u>not</u> being cost beneficial.

E.6.10 SAMA 17: REPLACE A SUPPLY FAN WITH A DIFFERENT DESIGN IN SERVICE WATER PUMP ROOM

This SAMA considers replacing one of four Service Water Pump Room Supply fans (FANS AV503 through DV503) with a different design so as to eliminate common cause failure of all fans.

Assumptions:

1. For the purposes of this SAMA, this is a hardware change only.
2. This assumes that the reliablity of all these fans is the same.
3. The replacement fan is assumed to eliminate common cause fan failure for the system

PRA Model Changes to Model SAMA:

All failure to start and failure to run for service water pump room supply fans common cause events were set to zero. The following table provides a list of the basic events that were set to zero.

SAMA 17 BASIC EVENTS

NAME	DESC
VIS-FAN-FR-DF01	CCF FAILURE FANS A THRU DV503 FAIL TO RUN
VIS-FAN-FR-DF02	CCF FAILURE FANS A -B AND CV503 FAIL TO RUN
VIS-FAN-FR-DF03	CCF FAILURE FANS A -B AND DV503 FAIL TO RUN
VIS-FAN-FR-DF04	CCF FAILURE FANS A -C AND DV503 FAIL TO RUN
VIS-FAN-FR-DF05	CCF FAILURE FANS B -C AND DV503 FAIL TO RUN
VIS-FAN-FR-DF06	CCF FAILURE FANS A AND BV503 FAIL TO RUN
VIS-FAN-FR-DF07	CCF FAILURE FANS A AND CV503 FAIL TO RUN
VIS-FAN-FR-DF08	CCF FAILURE FANS A AND DV503 FAIL TO RUN
VIS-FAN-FR-DF09	CCF FAILURE FANS B AND CV503 FAIL TO RUN
VIS-FAN-FR-DF10	CCF FAILURE FANS B AND DV503 FAIL TO RUN
VIS-FAN-FR-DF11	CCF FAILURE FANS C AND DV503 FAIL TO RUN
VIS-FAN-FS-DF01	CCF FAILURE FANS A THRU DV503 FAIL TO START
VIS-FAN-FS-DF02	CCF FAILURE FANS A -B AND CV503 FAIL TO START
VIS-FAN-FS-DF03	CCF FAILURE FANS A -B AND DV503 FAIL TO START

SAMA 17 BASIC EVENTS

NAME	DESC
VIS-FAN-FS-DF04	CCF FAILURE FANS A -C AND DV503 FAIL TO START
VIS-FAN-FS-DF05	CCF FAILURE FANS B -C AND DV503 FAIL TO START
VIS-FAN-FS-DF06	CCF FAILURE FANS A AND BV503 FAIL TO START
VIS-FAN-FS-DF07	CCF FAILURE FANS A AND CV503 FAIL TO START
VIS-FAN-FS-DF08	CCF FAILURE FANS A AND DV503 FAIL TO START
VIS-FAN-FS-DF09	CCF FAILURE FANS B AND CV503 FAIL TO START
VIS-FAN-FS-DF10	CCF FAILURE FANS B AND DV503 FAIL TO START
VIS-FAN-FS-DF11	CCF FAILURE FANS C AND DV503 FAIL TO START

No other basic events or fault tree structures were affected.

Results of SAMA Quantification:

Implementation of this SAMA yielded a marginal reduction in the CDF, Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for HCGS:

	CDF	DOSE-RISK	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	4.21E-06	21.81	$147,407
Percent Change	5.2%	4.6%	4.9%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
Frequency_{BASE}	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
Frequency_{SAMA}	1.83E-07	7.12E-08	1.30E-07	8.65E-07	8.25E-08	3.48E-07	2.00E-07	0.00E+00	2.55E-07	2.30E-07	1.85E-06	**4.21E-06**
Dose-Risk_{BASE}	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
Dose-Risk_{SAMA}	3.33	0.98	3.05	7.57	0.91	4.55	1.27	0.00	0.00	0.16	0.00	**21.81**
OECR_{BASE}	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
OECR_{SAMA}	$21,045	$6,855	$14,975	$55,432	$7,611	$31,876	$9,443	$0	$0	$170	$0	**$147,407**

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
Hope Creek	$19,807,200	$18,843,754	$963,446

Based on a $600,000 cost of implementation for HCGS, the net value for this SAMA is $363,446 ($963,446 - $600,000), which results in this SAMA being cost beneficial.

E.6.11 SAMA 18: REPLACE A RETURN FAN WITH A DIFFERENT DESIGN IN SERVICE WATER PUMP ROOM

This SAMA considers replacing one of four Service Water Pump Room Return fans (FANS AV504 through DV504) with a different design so as to eliminate common cause failure of all fans.

Assumptions:

1. For the purposes of this SAMA, this is a hardware change only.
2. This assumes that the reliablity of all these fans are the same.
3. The replacement fan is assumed to eliminate common cause fan failure for the system

PRA Model Changes to Model SAMA:

All Service Water Pump Room Return fan's failure to start and failure to run common cause events were set to zero. The following table provides a list of the basic events that were set to zero.

SAMA 18 BASIC EVENTS

NAME	DESC
VIS-FAN-FR-DF12	CCF FAILURE FANS A THRU DV504 FAIL TO RUN
VIS-FAN-FR-DF13	CCF FAILURE FANS A -B AND CV504 FAIL TO RUN
VIS-FAN-FR-DF14	CCF FAILURE FANS A -B AND DV504 FAIL TO RUN
VIS-FAN-FR-DF15	CCF FAILURE FANS A -C AND DV504 FAIL TO RUN
VIS-FAN-FR-DF16	CCF FAILURE FANS B -C AND DV504 FAIL TO RUN
VIS-FAN-FR-DF17	CCF FAILURE FANS A AND BV504 FAIL TO RUN
VIS-FAN-FR-DF18	CCF FAILURE FANS A AND CV504 FAIL TO RUN

SAMA 18 BASIC EVENTS

NAME	DESC
VIS-FAN-FR-DF19	CCF FAILURE FANS A AND DV504 FAIL TO RUN
VIS-FAN-FR-DF20	CCF FAILURE FANS B AND CV504 FAIL TO RUN
VIS-FAN-FR-DF21	CCF FAILURE FANS B AND DV504 FAIL TO RUN
VIS-FAN-FR-DF22	CCF FAILURE FANS C AND DV504 FAIL TO RUN
VIS-FAN-FS-DF12	CCF FAILURE FANS A THRU DV504 FAIL TO START
VIS-FAN-FS-DF13	CCF FAILURE FANS A -B ANDCV504 FAIL TO START
VIS-FAN-FS-DF14	CCF FAILURE FANS A -B AND DV504 FAIL TO START
VIS-FAN-FS-DF15	CCF FAILURE FANS A -C AND DV504 FAIL TO START
VIS-FAN-FS-DF16	CCF FAILURE FANS B -C AND DV504 FAIL TO START
VIS-FAN-FS-DF17	CCF FAILURE FANS A AND BV504 FAIL TO START
VIS-FAN-FS-DF18	CCF FAILURE FANS A AND CV504 FAIL TO START
VIS-FAN-FS-DF19	CCF FAILURE FANS A AND DV504 FAIL TO START
VIS-FAN-FS-DF20	CCF FAILURE FANS B AND CV504 FAIL TO START
VIS-FAN-FS-DF21	CCF FAILURE FANS B AND DV504 FAIL TO START
VIS-FAN-FS-DF22	CCF FAILURE FANS C AND DV504 FAIL TO START

No other basic events or fault tree structures were affected.

Results of SAMA Quantification:

Implementation of this SAMA yielded a marginal reduction in the CDF, Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for HCGS:

	CDF	DOSE-RISK	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	4.21E-06	21.81	$147,407
Percent Change	5.2%	4.6%	4.9%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$Frequency_{BASE}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$Frequency_{SAMA}$	1.83E-07	7.12E-08	1.30E-07	8.65E-07	8.25E-08	3.48E-07	2.00E-07	0.00E+00	2.55E-07	2.30E-07	1.85E-06	**4.21E-06**
$Dose\text{-}Risk_{BASE}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$Dose\text{-}Risk_{SAMA}$	3.33	0.98	3.05	7.57	0.91	4.55	1.27	0.00	0.00	0.16	0.00	**21.81**
$OECR_{BASE}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$OECR_{SAMA}$	$21,045	$6,855	$14,975	$55,432	$7,611	$31,876	$9,443	$0	$0	$170	$0	**$147,407**

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
Hope Creek	$19,807,200	$18,843,754	$963,446

Based on a $600,000 cost of implementation for HCGS, the net value for this SAMA is $363,446 ($963,446 - $600,000), which results in this SAMA being cost beneficial.

E.6.12 SAMA 30 PROVIDE PROCEDURAL GUIDANCE FOR PARTIAL TRANSFER OF CONTROL FUNCTIONS FROM CONTROL ROOM TO THE REMOTE SHUTDOWN PANEL

SAMAs 30 through 35 address fire-related scenarios from the external events analysis. Although the methodology delineated below deals with specific events associated with the Remote Shutdown Panel (RSP), it has been applied to all fire SAMAs.

Human performance associated with the RSP accounts for a significant contribution to fire CDF at HCGS. For fires that cause catastrophic damage to the controls of a single critical system, the reliability of controling the plant may be improved by allowing the operators to transfer only a single division of controls to the RSP to recover a channel of the critical system while the MCR is maintained as the primary control center. A permutaiton of this SAMA would be to use local system controls rather than the RSP.

It is assumed that if the portion of the HCGS CDF and release consequences related to RSP operator reliability 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 MACR attributable to external events
- Determine the component of the external events cost-risk attributable to fire events
- Determine the component of the fire-based cost-risk attributable to RSP operator reliability
- Calculate the percent reduction in fire CDF that would occur for the RSP if the SAMA is implemented and reduce the cost-risk for the RSP by the same percent. The reduction in cost-risk is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the HCGS SAMA is that they are a little more than 5 times the internal events contributions (see Section 4.6). Given that the internal events contribution to the MACR is $3,144,000, a value of $16,663,200 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 process established in Section 5.1.7 to calculate the fire-based contributions for the SAMAs requiring PRA model quantification is considered to be appropriate for HCGS and is used here. The fire contribution to the MACR is therefore $12,319,700.

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 D.5.1.7.1):

BASIC EVENT ID	PERCENT OF FIRE RISK	CORRESPONDING COST-RISK
%IE-FIRE03	30.5%	$3,754,488
%IE-FIRE02	25.4%	$3,128,740
%IE-FIRE01	21.8%	$2,681,777

The risk reduction possible for each of these areas is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. Based on the large cost-risk contributions from these fire compartments, and the fact this SAMA involves maintaining MCR habitability (and thereby improving operator reliability) via revised fire procedures , it was assumed that this SAMA eliminates as much as 90% of the risk associated with these compartments to simplify the calculations. The cost-risk calculation for this SAMA is straightforward and is equal to 0.90 times the total cost-risk from the fire compartments, or $8,600,000 after rounding.

SAMA 30 NET VALUE

COST OF IMPLEMENTATION	TOTAL AVERTED COST-RISK	NET VALUE
$100,000	$8,600,000	$8,500,000

Based on a $100,000 cost of implementation for HCGS, the net value for this SAMA is $8,500,000 ($8,600,000 - $100,000), which results in this SAMA being cost beneficial.

E.6.13 SAMA 31 INSTALL IMPROVED FIRE BARRIERS IN THE MCR CONTROL CABINETS CONTAINING THE PRIMARY MSIV CONTROL CIRCUITS

MCR fires that propagate from the originating cabinets result in widespread control damage and induce environmental conditions that would require abandonment even if the controls were not damaged. IPEEE insights suggest that improving the fire barriers in the console containing the primary MSIV controls would reduce the probability of these types of fire events.

BASIC EVENT ID	PERCENT OF FIRE RISK	CORRESPONDING COST-RISK
%IE-FIRE06	2.9%	$361,827

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. Based on the nominal cost-risk contribution associated with this fire compartment, and the fact this SAMA involves a substantial hardware modification, it was assumed that this SAMA eliminates 100% of the risk associated with this compartment to simplify the calculations. The cost-risk calculation for this SAMA is straightforward and is equal to 1.0 times the total cost-risk from the fire compartments, or $360,000 after rounding.

SAMA 31 NET VALUE

COST OF IMPLEMENTATION	TOTAL AVERTED COST-RISK	NET VALUE
$1,200,000	$360,000	-$840,000

Based on a $1,200,000 cost of implementation for HCGS, the net value for this SAMA is -$840,000 ($360,000 - $1,200,000), which results in this SAMA not being cost beneficial.

E.6.14 SAMA 32 INSTALL ADDITIONAL PHYSICAL BARRIERS TO LIMIT DISPERSION OF FUEL OIL FROM DG ROOMS

For compartment 5339 fire scenario 5339_2, install a curb or a diversion channel to ensure liquids from the DG rooms cannot communicate with Room 5339.

BASIC EVENT ID	PERCENT OF FIRE RISK	CORRESPONDING COST-RISK
%IE-FIRE28	4.3%	$532,099

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. Due to the small cost-risk contributions from this fire compartment, and the fact this SAMA involves a hardware modification, it was conservatively assumed that this SAMA eliminates 90% of the risk associated with this compartment to simplify the calculations. The cost-risk calculation for this SAMA is straightforward and is equal to 0.90 times the total cost-risk from the fire compartment, or $480,000 after rounding.

SAMA 32 NET VALUE

COST OF IMPLEMENTATION	TOTAL AVERTED COST-RISK	NET VALUE
$800,000	$480,000	-$320,000

Based on a $800,000 cost of implementation for HCGS, the net value for this SAMA is -$320,000 ($480,000 - $800,000), which results in this SAMA not being cost beneficial.

E.6.15 SAMA 33 INSTALL DIVISION II 480VAC BUS CROSSTIES

For DG room (D) fire scenario 5304_2, install cross-ties between the Division II 480VAC buses (potentially 10B420 to10B480 and 10B460 to 10B440).

BASIC EVENT ID	PERCENT OF FIRE RISK	CORRESPONDING COST-RISK
%IE-FIRE37	4.0%	$495,206

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. Due to the small cost-risk contributions from this fire compartment, and the fact this SAMA involves a hardware modification, it was conservatively assumed that this SAMA eliminates 90% of the risk associated with this compartment to simplify the calculations. The cost-risk calculation for this SAMA is straightforward and is equal to 0.90 times the total cost-risk from the fire compartment, or $370,000 after rounding.

These model changes do not account for any negative risk factors associated with implementation of an AC cross-tie, such as failing to isolate a fault before completing the cross-tie or improperly placing two separate divisions in parallel during power operation. Excluding these factors inflates the averted cost-risk for the SAMA; however, the effects are considered to be small relative to the reduction in risk associated with implementation.

SAMA 33 NET VALUE

COST OF IMPLEMENTATION	TOTAL AVERTED COST-RISK	NET VALUE
$1,320,000	$450,000	-$870,000

Based on a $1,320,000 cost of implementation for HCGS, the net value for this SAMA is -$870,000 ($450,000 - $1,320,000), which results in this SAMA <u>not</u> being cost beneficial.

E.6.16 SAMA 34 INSTALL DIVISION I 480VAC BUS CROSSTIES

For DG room (C) fire scenario 5306_2, install cross-ties between the Division I 480VAC buses (potentially 10B410 to10B430 and 10B450 to 10B470).

BASIC EVENT ID	PERCENT OF FIRE RISK	CORRESPONDING COST-RISK
%IE-FIRE20	3.8%	$473,312

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. Due to the small cost-risk contributions from this fire compartment, and the fact this SAMA involves a hardware modification, it was conservatively assumed that this SAMA eliminates 90% of the risk associated with this compartment to simplify the calculations. The cost-risk calculation for this SAMA is straightforward and is equal to 0.90 times the total cost-risk from the fire compartment, or $430,000 after rounding.

These model changes do not account for any negative risk factors associated with implementation of an AC cross-tie, such as failing to isolate a fault before completing the cross-tie or improperly placing two separate divisions in parallel during power operation. Excluding these factors inflates the averted cost-risk for the SAMA; however, the effects are considered to be small relative to the reduction in risk associated with implementation.

SAMA 34 NET VALUE

COST OF IMPLEMENTATION	TOTAL AVERTED COST-RISK	NET VALUE
$1,320,000	$430,000	-$890,000

Based on a $1,320,000 cost of implementation for HCGS, the net value for this SAMA is -$890,000 ($430,000 - $1,320,000), which results in this SAMA not being cost beneficial.

E.6.17 SAMA 35 RELOCATE, MINIMIZE AND/OR ELIMINATE ELECTRICAL HEATERS IN ELECTRICAL ACCESS ROOM

For compartment 3425/5401 fire scenario 5401_1, move or eliminate the electrical heaters in the electrical access room (Aux Building 124’ level) to prevent damage to the Division II power cables.

BASIC EVENT ID	PERCENT OF FIRE RISK	CORRESPONDING COST-RISK
%IE-FIRE38	3.4%	$414,895

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. Due to the small cost-risk contributions from this fire compartment, and the fact this SAMA involves elimination of the risk condition, it was conservatively assumed that this SAMA eliminates 99% of the risk associated with this compartment to simplify the calculations. The cost-risk calculation for this SAMA is straightforward and is equal to 0.99 times the total cost-risk from the fire compartment, or $340,000 after rounding.

SAMA 35 NET VALUE

COST OF IMPLEMENTATION	TOTAL AVERTED COST-RISK	NET VALUE
$270,000	$370,000	$100,000

Based on a $270,000 cost of implementation for HCGS, the net value for this SAMA is $100,000 ($370,000 - $270,000), which results in this SAMA being cost beneficial.

E.6.18 SAMA 36 PROVIDE PROCEDURAL GUIDANCE FOR LOSS OF ALL 1E 120VAC POWER

SAMAs 36, 37 and 38 address seismic-induced scenarios from the external events analysis. The same methodology utilized for fire SAMAs (30 through 35) is applied here. The only notable exception is the seismic contribution to the MACR is much less than that for fire, and calculated to be $794,644 (see Section 5.7.1).

For Seismic-Induced Equipment Damage State SET-36 (Impacts - 120V PNL481), develop MCR procedures to operate the plant after a loss of all class 1E 120V AC power.

BASIC EVENT ID	PERCENT OF SEISMIC RISK	CORRESPONDING COST-RISK
%IE-SET36	59.8%	$475,341

The risk reduction possible for this scenario is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. Due to the large cost-risk contributions from this scenario, and the fact this SAMA involves improving operator reliability, it was conservatively assumed that this SAMA eliminates 50% of the risk associated with this seismic event to simplify the calculations. The cost-risk calculation for this SAMA is straightforward and is equal to 0.50 times the total cost-risk from the fire compartment, or $200,000 after rounding.

SAMA 36 NET VALUE

COST OF IMPLEMENTATION	TOTAL AVERTED COST-RISK	NET VALUE
$270,000	$240,000	-$30,000

Based on a $270,000 cost of implementation for HCGS, the net value for this SAMA is -$30,000 ($240,000- $270,000), which results in this SAMA not being cost beneficial.

E.6.19 SAMA 37 REINFORCE 1E 120V AC DISTRIBUTION PANELS

For Seismic-Induced Equipment Damage State SET-36 (Impacts - 120V PNL481), reinforce the class 1E 120V AC distribution panels.

BASIC EVENT ID	PERCENT OF SEISMIC RISK	CORRESPONDING COST-RISK
%IE-SET36	59.8%	$475,341

The risk reduction possible for this scenario is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. Due to the large cost-risk contributions from this scenario, and the fact this SAMA involves a hardware modification, it was conservatively assumed that this SAMA eliminates 90% of the risk associated with this seismic event to simplify the calculations. The cost-risk calculation for this SAMA is straightforward and is equal to 0.90 times the total cost-risk from the fire compartment, or $360,000 after rounding.

SAMA 37 NET VALUE

COST OF IMPLEMENTATION	TOTAL AVERTED COST-RISK	NET VALUE
$500,000	$430,000	-$70,000

Based on a $500,000 cost of implementation for HCGS, the net value for this SAMA is -$70,000 ($430,000 - $500,000), which results in this SAMA not being cost beneficial.

E.6.20 SAMA 39 PROVIDE PROCEDURAL GUIDANCE TO BYPASS RCIC TURBINE EXHAUST PRESSURE TRIP

Revise procedure to allow bypass of RCIC turbine exhaust pressure trip.

This SAMA was generated as a result of the industry SAMA list review and upon detailed review by the PRA group, was considered to be applicabile to HCGS.

Results of SAMA Quantification:

Implementation of this SAMA yields a marginal reduction in the CDF, Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for HCGS:

	CDF	DOSE-RISK	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	4.01E-06	22.79	$154,593
Percent Change	9.8%	0.3%	0.3%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$Frequency_{BASE}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$Frequency_{SAMA}$	1.81E-07	7.15E-08	1.30E-07	9.70E-07	8.09E-08	3.48E-07	2.16E-07	0.00E+00	2.52E-07	2.29E-07	1.53E-06	**4.01E-06**
$Dose\text{-}Risk_{BASE}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$Dose\text{-}Risk_{SAMA}$	3.29	0.99	3.04	8.49	0.89	4.56	1.37	0.00	0.00	0.16	0.00	**22.79**
$OECR_{BASE}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$OECR_{SAMA}$	$20,815	$6,885	$14,950	$62,177	$7,467	$31,912	$10,217	$0	$0	$170	$0	**$154,593**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 39 NET VALUE

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
Hope Creek	$19,807,200	$19,673,514	$133,686

Based on a $120,000 cost of implementation for HCGS, the net value for this SAMA is $13,686 ($133,686 - $120,000), which results in this SAMA being (marginally) cost beneficial.

E.6.21 SAMA 40 INCREASE RELIABILITY / INSTALL MANUAL BYPASS OF LP PERMISSIVE

Increase the reliability of the low pressure ECCS RPV low pressure permissive circuitry. Install manual bypass of low pressure permissive.

This SAMA was generated as a result of the industry SAMA list review and upon detailed review by the PRA group, was considered to be applicabile to HCGS.

Results of SAMA Quantification:

Implementation of this SAMA yields a marginal reduction in the CDF, Dose-Risk and Offsite Economic Cost-Risk. The results are summarized in the following table for HCGS:

	CDF	DOSE-RISK	OECR
Base Value	4.44E-06	22.86	$155,055
SAMA Value	4.38E-06	22.63	$153,373
Percent Change	1.4%	1.0%	1.1%

A further breakdown of the Dose-Risk and OECR information is provided in the below table according to release category:

RELEASE CATEGORY	ST1	ST2	ST3	ST4	ST5	ST6	ST7	ST8	ST9	ST10	ST11	TOTAL
$Frequency_{BASE}$	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06	**4.44E-06**
$Frequency_{SAMA}$	1.83E-07	7.13E-08	1.30E-07	9.48E-07	8.26E-08	3.46E-07	2.16E-07	0.00E+00	2.65E-07	2.37E-07	1.90E-06	**4.38E-06**
$Dose\text{-}Risk_{BASE}$	3.33	0.99	3.05	8.49	0.92	4.55	1.37	0.00	0.00	0.16	0.00	**22.86**
$Dose\text{-}Risk_{SAMA}$	3.33	0.98	3.04	8.30	0.91	4.53	1.37	0.00	0.00	0.16	0.00	**22.63**
$OECR_{BASE}$	$21,045	$6,888	$14,975	$62,159	$7,694	$31,881	$10,235	$0	$0	$177	$0	**$155,055**
$OECR_{SAMA}$	$21,045	$6,866	$14,950	$60,767	$7,624	$31,728	$10,217	$0	$0	$176	$0	**$153,373**

This information was used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 40 NET VALUE

UNIT	BASE CASE COST-RISK	REVISED COST-RISK	AVERTED COST-RISK
Hope Creek	$19,807,200	$19,592,698	$214,502

Based on a $620,000 cost of implementation for HCGS, the net value for this SAMA is -$405,498 ($214,502 - $620,000), which results in this SAMA <u>not</u> being cost beneficial.

E.6.22 SUMMARY

All of the SAMAs reviewed showed at least some benefit with respect to the traditional CDF and LERF risk metrics. Nearly 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: Remove ADS Inhibit from Non-ATWS Emergency Operating Procedures

SAMA 3: Install Back-Up Air Compressor to Supply AOVs

SAMA 4: Provide Procedural Guidance to Cross-Tie RHR Trains

SAMA 10: Provide Procedural Guidance to Use B.5.b Low Pressure Pump for Non-Security Events

SAMA 17: Replace a Supply Fan with a Different Design in Service Water Pump Room

SAMA 18: Replace a Return Fan with a Different Design in Service Water Pump Room

SAMA 30: Provide Procedural Guidance for Partial Transfer of Control Functions from the Control Room to the Remote Shutdown Panel

SAMA 35: Relocate, Minimize, and/or Eliminate Electrical Heaters in Electrical Access Room

SAMA 39: Provide Procedural Guidance to Bypass RCIC Turbine Exhaust Pressure Trip

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 95th 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.

Phase 1 SAMAs are not impacted by use of the 7 percent RDR. Refer to Section E.5 and Table E.5-3 for a detailed analysis of each Phase 1 SAMA that was screened from further analysis.

The Phase 2 analysis was re-performed using the 7 percent RDR. Implementation of the 7 percent RDR reduced the MMACR by 28 percent compared with the case where a 3 percent RDR was used. This corresponds to a decrease in the MMACR from $19,807,200 to $14,263,200.

The Phase 2 SAMAs are dispositioned based on PRA insights or detailed analysis. All of the PRA insights used to screen the SAMAs are still applicable given the use of the 7 percent real discount rate as the change only strengthens the factors used to screen them. The SAMA candidates screened based on these insights are considered to be addressed and are not further investigated.

The remaining Phase 2 SAMAs were dispositioned based on the results of a SAMA specific cost-benefit analysis. This step has been re-performed using the 7 percent real discount rate to calculate the net values for the SAMAs.

As shown below, the determination of cost effectiveness changed for only one of the Phase 2 SAMAs (SAMA 39) when the 7 percent RDR was used in lieu of 3 percent.

SUMMARY OF THE IMPACT OF THE RDR VALUE ON THE DETAILED SAMA ANALYSES

SAMA ID	COST OF IMPLEMENTATION	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?
1	$200,000	$5,267,619	$5,067,619	$3,792,915	$3,592,915	No
3	$700,000	$3,302,145	$2,602,145	$2,377,626	$1,677,626	No
4	$100,000	$4,358,126	$4,258,126	$3,129,878	$3,029,878	No
5	$2,050,000	$704,548	($1,345,452)	$511,043	($1,538,957)	No
7	$3,070,000	$326,939	($2,743,062)	$237,397	($2,832,603)	No
8	$600,000	$301,556	($298,444)	$219,108	($380,892)	No
10	$100,000	$199,578	$99,578	$143,791	$43,791	No
15	$1,000,000	$126,403	($873,597)	$92,604	($907,396)	No
16	$400,000	$129,049	($270,951)	$94,443	($305,557)	No
17	$600,000	$963,446	$363,446	$694,090	$94,090	No
18	$600,000	$963,446	$363,446	$694,090	$94,090	No
30	$100,000	$8,600,000	$8,500,000	$6,200,000	$6,100,000	No
31	$1,200,000	$360,000	($840,000)	$260,000	($940,000)	No
32	$800,000	$480,000	($320,000)	$340,000	($460,000)	No
33	$1,320,000	$450,000	($870,000)	$320,000	($1,000,000)	No
34	$1,320,000	$430,000	($890,000)	$310,000	($1,010,000)	No
35	$270,000	$370,000	$100,000	$270,000	$0	No
36	$270,000	$240,000	($30,000)	$170,000	($100,000)	No
37	$500,000	$430,000	($70,000)	$310,000	($190,000)	No
39	$120,000	$133,686	$13,686	$104,328	($15,672)	Yes
40	$620,000	$214,502	($405,498)	$154,766	($465,234)	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 HCGS. The availability and use of Level 2 uncertainties is unique since most plants incorporate only Level 1 analyses in their SAMA reports. The reason Level 2 analyses are not typically used is due to the differing degree of development and uncertainties between the two models. Specifically, the Level 1 model tends to represent the plant in a more thorough and comprehensive manner as opposed to the Level 2 model. Furthermore, there are more release contributors beyond those captured by LERF. As such, for the purposes of the 95th percentile analysis, only Level 1 results are used in the uncertainty process. The results of the Level 1 calculation are provided below.

In performing the sensitivity analysis, only the base case was used in determining the appropriate value for the 95th percentile. For those SAMAs that required the addition of new basic events, no new uncertainty distributions were assigned since the design and implementation of each SAMA was arbitrary and was defined by the analysis assumptions. The results of this uncertainty analysis, therefore, show the expected statistical uncertainty of the CDF risk metrics under the assumption that each SAMA was designed and implemented as it was specified in this analysis. 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 CDF point estimate of 4.44E-06.

SUMMARY OF UNCERTAINTY DISTRIBUTION

MEAN	5%	50%	95%	FACTOR > CDF_{PE}	STD DEV
5.41E-06	1.91E-06	3.85E-06	1.26E-05	2.84	8.77E-06

The above table reveals a factor that is 2.84 greater than the respective point estimate CDF, which is in agreement with industry experience. Therefore, for this analysis, the 95th percentile for 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 involved qualitative disposition of (2) SAMAs, and hence, no PRA requantification data was necessary for these SAMAs. Refer to Table E.5-3 for a discussion of each Phase 1 SAMA that was screened from further analysis. It is not necessary to perform any sensitivity analysis on these (2) SAMAs. All other Phase 1 SAMAs transitioned to the Phase 2 analysis and were subject to the sensitivity analyses in the following sections.

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 be not cost beneficial due to implementation costs exceeding their associated nominal averted cost risk may be potentially cost beneficial at the revised 95th percentile averted cost risk. In this case, four additional Phase 2 SAMAs become cost beneficial.

As explained in Section E.7.2.1 above, no Phase 1 SAMAs were retained in the Phase 2 analysis when utilizing the 95th percentile PRA results, since these SAMAs were dispositioned independently of implementation cost.

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.

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 EFFECTIVE-NESS?
1	$200,000	$5,267,619	$5,067,619	$14,943,264	$14,743,264	No
3	$700,000	$3,302,145	$2,602,145	$9,367,576	$8,667,576	No
4	$100,000	$4,358,126	$4,258,126	$12,363,199	$12,263,199	No
5	$2,050,000	$704,548	($1,345,452)	$1,998,672	($51,328)	No
7	$3,070,000	$326,939	($2,743,062)	$927,464	($2,142,536)	No
8	$600,000	$301,556	($298,444)	$855,458	$255,458	Yes
10	$100,000	$199,578	$99,578	$566,165	$466,165	No
15	$1,000,000	$126,403	($873,597)	$358,583	($641,417)	No
16	$400,000	$129,049	($270,951)	$366,089	($33,911)	No
17	$600,000	$963,446	$363,446	$2,733,120	$2,133,120	No
18	$600,000	$963,446	$363,446	$2,733,120	$2,133,120	No
30	$100,000	$8,600,000	$8,500,000	$24,396,614	$24,296,614	No
31	$1,200,000	$360,000	($840,000)	$1,021,254	($178,746)	No
32	$800,000	$480,000	($320,000)	$1,361,671	$561,671	Yes
33	$1,320,000	$450,000	($870,000)	$1,276,567	($43,433)	No
34	$1,320,000	$430,000	($890,000)	$1,219,831	($100,169)	No
35	$270,000	$370,000	$100,000	$1,049,622	$779,622	No
36	$270,000	$240,000	($30,000)	$680,836	$410,836	Yes
37	$500,000	$430,000	($70,000)	$1,219,831	$719,831	Yes
39	$120,000	$133,686	$13,686	$379,243	$259,243	No

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 EFFECTIVE-NESS?
40	$620,000	$214,502	($405,498)	$608,504	($11,496)	No

When the 95th percentile PRA results are used, four of the Phase 2 SAMAs (8, 32, 36 and 37) 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.7.3 MACCS2 INPUT VARIATIONS

The MACCS2 model was developed using the best information available for the HCGS 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.7.3.7, 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 HCGS BASELINE RISK TO PARAMETER CHANGES

PARAMETER	DESCRIPTION	POP. DOSE RISK Δ BASE (%)	COST RISK Δ BASE (%)
Meteorology	Year 2005 Meteorology	-1%	-2%
	Year 2006 Meteorology	-2%	-1%
	Year 2007 Meteorology	-3%	-7%
Evacuation Time	Evacuation delay time increased from 65 minutes to 130 minutes (factor of 2)	+1%	0%
Evacuation Speed	Average evacuation speed decreased 50% from 2.8 m/sec to 1.4 m/sec.	+2%	0%
Release Height	Release height set to ground level (in lieu of top of containment).	-6%	-7%
Release Heat	Buoyant plume assumed (10 MW for each plume segment, except for intact containment release).	-1%	-1%
Population	Year 2046 population uniformly increased 30%	+29%	+30%
Resettlement Planning	No “Intermediate Phase” resettlement planning (in lieu of 6 months)	+14%	-37%
	1 year “Intermediate Phase” resettlement planning (in lieu of 6 months)	-11%	+39%
Rate of Return	3% expected rate of return (in lieu of 7%)	+2%	-9%
	12% expected rate of return (in lieu of 7%)	-1%	+10%

E.7.3.1 METEOROLOGICAL SENSITIVITIES

In addition to the year 2004 base case meteorological data, years 2005, 2006, and 2007 were also analyzed. Analysis of year 2005, 2006, and 2007 data sets yielded population dose-risks and cost risks that were 1% to 7% less than 2004 results. As no particular criteria have been defined by the industry related to determining which meteorological data set should be used as a base case for a site, the year 2004 data is chosen for HCGS given that it represents the most complete data set and results in higher results than 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 very minor impact (approximately 1% 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 2% 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 reactor building (61m) 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 6% 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 very minor dose-risk and 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 2046 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 dose risk and cost risk by 29% and 30%, 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 of interdicted individuals 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 (14% 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 39% increase in cost risk estimates compared with the base case selection of 6 months. The population dose decreased by 11% 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 1990b), shows an increase cost risk of approximately 10%. For both sensitivity cases the dose risk changes are minor (1% to 2%).

E.7.3.7 IMPACT ON SAMA ANALYSIS

Several different Level 3 input parameters are examined as part of the HCGS MACCS2 sensitivity analysis. The primary reason for performing these sensitivity runs is to identify any reasonable changes that could be made to the Level 3 input parameters that would impact the conclusions of the SAMA analysis. While the table in Section E.7.3 summarizes the changes to the dose-risk and OECR estimates for each sensitivity case, it is prudent to consider if any of these changes would result in the retention of the SAMAs that were screened using the baseline results.

Of all the MACCS2 sensitivity cases, the largest dose-risk increase, 29%, occurred in the Population (Year 2046 population uniformly increased 30%) case. The largest OECR increase, 39%, occurred in the Resettlement Planning (1 year "Intermediate Phase" resettlement planning in lieu of 6 months). Subsequently, the HCGS MMACR was recalculated using these results to determine the impact of using the worst case for each parameter simultaneously. The resulting MMACR is a factor of 1.35 greater than the base case, which is significantly less than the average factor of 2.84 calculated in Section E.7.2 for the 95th percentile individual SAMA PRA model results. Therefore, the 95th percentile PRA results sensitivity is considered to bound this case and no SAMAs would be retained based on this sensitivity that were not already identified in Section E.7.2.

E.8 CONCLUSIONS

The benefits of revising the operational strategies in place at HCGS and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. However, use of the PRA in conjunction with cost-benefit analysis methodologies provides an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on a larger future population. The results of this study indicate that several potential improvements were identified that warrant further review for potential implementation at HCGS.

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 HCGS. 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 the existing Plant Health Committee processes.

SAMA 1: Remove ADS Inhibit from Non-ATWS Emergency Operating Procedures

SAMA 3: Install Back-Up Air Compressor to Supply AOVs

SAMA 4: Provide Procedural Guidance to Cross-Tie RHR Trains

SAMA 8: Convert Selected Fire Protection Piping from Wet to Dry Pipe System

SAMA 10: Provide Procedural Guidance to Use B.5.b Low Pressure Pump for Non-Security Events

SAMA 17: Replace a Supply Fan with a Different Design in Service Water Pump Room

SAMA 18: Replace a Return Fan with a Different Design in Service Water Pump Room

SAMA 30: Provide Procedural Guidance for Partial Transfer of Control Functions from the Control Room to the Remote Shutdown Panel

SAMA 32: Install Additional Physical Barriers to Limit Dispersion of Fuel Oil from DG Rooms

SAMA 35: Relocate, Minimize, and/or Eliminate Electrical Heaters in Electrical Access Room

SAMA 36: Provide Procedural Guidance for Loss of All 1E 120V AC Power

SAMA 37: Reinforce 1E 120V AC Distribution Panels

SAMA 39: Provide Procedural Guidance to Bypass RCIC Turbine Exhaust Pressure Trip

E.9 TABLES

TABLE E.2-1
HOPE CREEK PRA MODEL SUMMARY

MODEL REVISION DATE	MODEL NAME	INTERNAL EVENTS EXCLUDING INTERNAL FLOODING (1/YR)	INTERNAL FLOODING (1/YR)	TOTAL CDF (1/YR)	TOTAL LERF (1/YR)	TRUNC. LIMIT (1/YR)	REFERENCE (SECTION E.11)	NOTES
May 1994	IPE	4.59E-05	5.50E-07	4.65E-05	9.42E-6	1E-10	PSEG 1994a	1
Sep. 1994	Model 0	1.29E-05	5.50E-07	1.34E-05	9.42E-6	1E-10	PSEG 1994b	2
July 1999	Model 1.0	1.80E-05	5.50E-07	1.85E-05	8.95E-07	1E-10	PSEG 1999	3
March 2000	Model 1.1	1.05E-05	5.50E-07	1.11E-05	NR	1E-10	PSEG 2000a	4
June 2000	Model 1.2	8.70E-06	5.50E-07	9.25E-05	1.00E-06	1E-10	PSEG 2000b	5
Oct. 2000	Model 1.3	8.66E-06	5.50E-07	9.25E-05	1.00E-06	1E-10	PSEG 2000c	6
Aug. 2003	Model 2003A	3.13E-05	1.17E-07	3.14E-05	1.05E-6	5E-11	PSEG 2003	7
Oct. 2004	Rev. 2.0	1.66E-05	8.13E-08	1.67E-05	NR	1E-10	PSEG 2004	8
Oct. 2005	Model 2005A	--	--	--	--	--	PSEG 2006a	9
Nov. 2005	Model 2005B	1.00E-5	7.45E-08	1.01E-05	--	5E-11	PSEG 2006a	10
Feb. 2006	Model 2005C	9.69E-6	7.45E-08	9.76E-06	2.59E-07	5E-11	PSEG 2006a	11
Aug. 2008	HC108A	--	--	7.60E-06	8.63E-07	5E-11	PSEG 2008a	12
Dec. 2008	HC108B	4.99E-06	1.19E-07	5.11E-06	4.76E-07	1E-12	PSEG 2008b	13

Notes:

1. Note that the internal flooding analysis is retained from the IPE.
2. Note that the internal flooding analysis is retained from the IPE.
3. Note that the internal flooding analysis is retained from the IPE.
4. Note that the internal flooding analysis is retained from the IPE.
5. Note that the internal flooding analysis is retained from the IPE.
6. Note that the internal flooding analysis is retained from the IPE. It is also important to note that even though the LERF value was the same as the previous model, it was recalculated in Model 1.3.
7. The main change in this model is the conversion from NUPRA to CAFTA. The 2003A model is the result of a regularly scheduled update.
8. This model includes PSEG modifications on 480 VAC dependencies, SACS, success criteria, and SACS-SW HEPs.
9. This PRA model revision addresses conservatism in the Rev. 2.0 model. The above table does not include values for this Model revision. This revision is addressed in the above table to provide a complete history of the Hope Creek PRA. See 2005B for values.
10. This PRA model was used as input for the EPU submittal. It removes conservatism introduced in the Rev. 2.0 model (e.g. SACS heat load manipulation HEPs). The 2005B and C models included a modified SACS/SSW success criteria based on detailed PSEG calculations, which accounted for the removal of excess conservatism in the 2003A PRA model.

11. This revision modifies the 2005B EPU model to support online maintenance evaluations and MSPI calculations. The only PRA model change from the 2005B EPU PRA model to the 2005C Base PRA model is to reduce the turbine trip initiating event frequency from 1.25/yr to 1.03/yr to reflect plant specific operating history. The 2005B and C models included a modified SACS/SSW success criteria based on detailed PSEG calculations. This accounted for the removal of excess conservatism in the 2003A PRA model.
12. The HC108A model has been peer-reviewed against the ASME PRA Standard (see Section E.2.3)
13. Note that the current HC108B CAFTA model truncation limit has decreased compared to the previous HC108A model. This lower truncation limit was used with the FTREX quantification engine, which allowed more efficient quantification at a lower truncation limit (1E-12/yr) in order to meet MSPI convergence criteria.

TABLE E.2-2
HOPE CREEK 2008 PRA LEVEL 2 LERF CONTRIBUTION BY INITIATING EVENT (HC108B)

BASIC EVENT ID	DESCRIPTION	FREQUENCY (/YR)	F-V	LERF (/YR)	CLERP
%IE-ISLOCAD	ISLOCA INITIATOR FOR ECCS DISCHARGE PATHS	1.63E-05	2.34E-01	1.11E-07	6.83E-03
%IE-TT	TURBINE TRIP WITH BYPASS	7.03E-01	1.54E-01	7.32E-08	1.04E-07
%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT	2.37E-02	1.37E-01	6.52E-08	2.75E-06
%IE-SWS	LOSS OF SERVICE WATER INITIATING EVENT	1.79E-04	6.74E-02	3.21E-08	1.79E-04
%IE-S2-ST	SMALL LOCA - STEAM (ABOVE TAF)	6.20E-04	6.40E-02	3.04E-08	4.91E-05
%IE-S2-WA	SMALL LOCA - WATER (BELOW TAF)	6.20E-04	6.10E-02	2.90E-08	4.68E-05
%FLTORUS	TORUS RUPTURE IN TORUS ROOM	2.80E-06	3.24E-02	1.54E-08	5.50E-03
%IE-MS	MANUAL SHUTDOWN INITIATING EVENT	1.46E+00	2.77E-02	1.32E-08	9.02E-09
%IE-TC	LOSS OF CONDENSER VACUUM	9.33E-02	2.69E-02	1.28E-08	1.37E-07
%IE-SORV2	2 or More SORVs	2.44E-04	2.09E-02	9.94E-09	4.07E-05
%FLFPS-CR	FPS RUPTURE OUTSIDE CONTROL ROOM	1.10E-05	1.76E-02	8.37E-09	7.61E-04
%IE-TM	MSIV CLOSURE	5.62E-02	1.56E-02	7.42E-09	1.32E-07
%FLTORUSRB	TORUS SUCTION LINE RUPTURE IN ECCS ROOM	2.70E-06	1.25E-02	5.95E-09	2.20E-03
%IE-TF	LOSS OF FEEDWATER	4.49E-02	1.23E-02	5.85E-09	1.30E-07
%FL-FPS-5302	INT. FLOOD OUTSIDE LOWER RELAY ROOM	6.62E-06	9.50E-03	4.52E-09	6.83E-04
%IE-ISLOCAS	ISLOCA INITIATOR FOR SDC SUCTION PATH	5.01E-07	8.15E-03	3.88E-09	7.74E-03
%FLSWAB-RACS-U	FREQ OF COMMON HEADER TO RACS RUPTURE (UNISOLABLE)	7.60E-08	7.83E-03	3.72E-09	4.90E-02
%FLSWA-RACS-U	FREQ. OF UNISOLABLE SW A PIPE RUPT IN RACS ROOM	5.70E-08	5.87E-03	2.79E-09	4.90E-02
%FLSWB-RACS-U	FREQ. OF UNISOLABLE SW B PIPE RUPT. IN RACS ROOM	5.70E-08	5.87E-03	2.79E-09	4.90E-02
%IE-BOCMSA	Main Steam Line A Break outside Containment	9.66E-09	5.29E-03	2.52E-09	2.60E-01
%IE-BOCMSB	Main Steam Line B Break outside	9.66E-09	5.29E-03	2.52E-09	2.60E-01

TABLE E.2-2
HOPE CREEK 2008 PRA LEVEL 2 LERF CONTRIBUTION BY INITIATING EVENT (HC108B)

BASIC EVENT ID	DESCRIPTION	FREQUENCY (/YR)	F-V	LERF (/YR)	CLERP
%IE-BOCMSC	Main Steam Line C Break outside	9.66E-09	5.29E-03	2.52E-09	2.60E-01
%IE-BOCMSD	Main Steam Line D Break outside	9.66E-09	5.29E-03	2.52E-09	2.60E-01
%IE-SACS	LOSS OF SACS INITIATING EVENT	1.16E-04	4.02E-03	1.91E-09	1.65E-05
%IE-TI	INADVERTENTLY OPEN SRV INITIATING EVENT	1.44E-02	3.77E-03	1.79E-09	1.25E-07
%IE-LLRHR	Large LOCA – RHR	9.69E-06	2.92E-03	1.39E-09	1.43E-04
%IE-LLMS	Large LOCA – Main Steam	1.00E-05	2.91E-03	1.38E-09	1.38E-04
%IE-BOCHPCI	HPCI Steam Line Break outside Containment	5.11E-09	2.80E-03	1.33E-09	2.61E-01
%IE-BOCRCIC	RCIC Steam Line Break outside Containment	5.11E-09	2.80E-03	1.33E-09	2.61E-01
%IE-BOCRWCU	RWCU Line Break outside Containment	5.11E-09	2.80E-03	1.33E-09	2.61E-01
%IE-LLRECIRC	Large LOCA – Reactor Recirculation	8.74E-06	2.64E-03	1.26E-09	1.44E-04
%IE-LLADS	Large LOCA - Spurious ADS Actuation	8.48E-06	2.46E-03	1.17E-09	1.38E-04
%IE-MLRHR	Medium LOCA – RHR	1.44E-05	2.32E-03	1.10E-09	7.66E-05
%IE-IAS	LOSS OF INSTRUMENT AIR INITIATOR	6.17E-03	2.17E-03	1.03E-09	1.67E-07
%IE-MLRECIRC	Medium LOCA – Reactor Recirculation	1.18E-05	1.90E-03	9.04E-10	7.66E-05
%FLFPS-RBU	FPS RUPTURE IN RB UPPER LEVELS	6.60E-05	1.81E-03	8.61E-10	1.30E-05
%FLSWA-RACS-I	FREQ. OF ISOLABLE SW A PIPE RUPTURE IN RACS ROOM	1.43E-06	1.77E-03	8.42E-10	5.89E-04
%FLSWB-RACS-I	FREQ. OF ISOLABLE SW B PIPE RUPTURE IN RACS ROOM	1.43E-06	1.77E-03	8.42E-10	5.89E-04
%IE-TE-REC	LOSS OF OFFSITE POWER INITIATING EVENT (RECOVERED LOOP EVENT)	2.37E-02	1.58E-03	7.51E-10	3.17E-08
%IE-LLCS	Large LOCA - Core Spray	5.40E-06	1.56E-03	7.42E-10	1.37E-04
%IE-MLRWCU	Medium LOCA – RWCU	8.63E-06	1.37E-03	6.52E-10	7.55E-05
%IE-LLFW	Large LOCA – Feedwater	4.53E-06	1.35E-03	6.42E-10	1.42E-04

TABLE E.2-2
HOPE CREEK 2008 PRA LEVEL 2 LERF CONTRIBUTION BY INITIATING EVENT (HC108B)

BASIC EVENT ID	DESCRIPTION	FREQUENCY (/YR)	F-V	LERF (/YR)	CLERP
%IE-LLRWCU	Large LOCA – RWCU	4.53E-06	1.35E-03	6.42E-10	1.42E-04
%FLFPS-5537	FPS RUPTURE OUTSIDE 125V DC ROOMS	1.34E-05	1.34E-03	6.37E-10	4.76E-05
%IE-ACD	LOSS OF AC BUS D INITIATING EVENT	2.07E-03	1.25E-03	5.95E-10	2.87E-07
%IE-BOCFWA	Feedwater Line A Break outside	2.23E-09	1.22E-03	5.80E-10	2.60E-01
%IE-BOCFWB	FEEDWATER LINE B BREAK OUTSIDE CONTAINMENT	2.23E-09	1.22E-03	5.80E-10	2.60E-01
%IE-MLMS	Medium LOCA – Main Steam	1.54E-05	1.21E-03	5.75E-10	3.74E-05
%IE-MLFW	Medium LOCA – Feedwater	7.22E-06	1.14E-03	5.42E-10	7.51E-05
%IE-MLNBINST	Medium LOCA – Nuclear Boiler Instrumentation	5.24E-06	8.11E-04	3.86E-10	7.36E-05
%IE-MLCS	Medium LOCA – Core Spray	9.34E-06	7.29E-04	3.47E-10	3.71E-05
%FLSACS-A	SACS A RUPTURE	2.70E-04	6.06E-04	2.88E-10	1.07E-06
%FLSW-SACS-B	SW RUPTURE IN SACS B ROOM	4.80E-07	3.54E-04	1.68E-10	3.51E-04
%IE-MLHPCI	Medium LOCA – HPCI	1.80E-06	3.28E-04	1.56E-10	8.67E-05
%FLTB-CW	TURBINE BUILDING FLOOD	1.50E-03	3.23E-04	1.54E-10	1.02E-07
%IE-LLHPCI	Large LOCA – HPCI	1.13E-06	3.21E-04	1.53E-10	1.35E-04
%IE-ACA	LOSS OF AC BUS A INITIATING EVENT	2.89E-04	2.89E-04	1.37E-10	4.76E-07
%IE-ACB	LOSS OF AC BUS B INITIATING EVENT	2.89E-04	2.82E-04	1.34E-10	4.64E-07
%IE-MLRCIC	Medium LOCA – RCIC	3.27E-06	2.38E-04	1.13E-10	3.46E-05
%FLSW-SACS-A	SW RUPTURE IN SACS A ROOM	4.80E-07	2.23E-04	1.06E-10	2.21E-04
%IE-R	EXCESSIVE LOCA EVENT	6.38E-09	1.79E-04	8.51E-11	1.33E-02
%FLSACS-B	SACS B RUPTURE	2.70E-04	1.75E-04	8.32E-11	3.08E-07
%IE-DCAB	LOSS OF DCA & DCB	7.14E-07	9.01E-05	4.29E-11	6.00E-05
%FLFPS-CD	FPS RUPTURE IN CONTROL DIESEL BUILDING	8.20E-05	7.21E-05	3.43E-11	4.18E-07

TABLE E.2-2
HOPE CREEK 2008 PRA LEVEL 2 LERF CONTRIBUTION BY INITIATING EVENT (HC108B)

BASIC EVENT ID	DESCRIPTION	FREQUENCY (/YR)	F-V	LERF (/YR)	CLERP
%IE-ACC	LOSS OF AC BUS C INITIATING EVENT	2.89E-04	2.92E-05	1.39E-11	4.81E-08
%FLSWAB-RACS-I	FREQ. OF ISOLABLE SW A & B PIPE RUPTURE IN RACS ROOM (TO RACS HX)	5.70E-07	2.42E-05	1.15E-11	2.02E-05

TABLE E.2-3
RELEASE SEVERITY AND TIMING CLASSIFICATION SCHEME[1]

RELEASE SEVERITY		RELEASE TIMING	
CLASSIFICATION CATEGORY	**CS IODIDE % IN RELEASE**	**CLASSIFICATION CATEGORY**	**TIME OF INITIAL RELEASE(2) RELATIVE TO TIME FOR GENERAL EMERGENCY DECLARATION**
High (H)	Greater than 10	Late (L)	Greater than 24 hours
Medium or Moderate (M)	1 to 10	Intermediate (I)	4 to 24 hours
Low (L)	0.1 to 1	Early (E)	Less than 4 hours
Low-low (LL)	Less than 0.1		
No iodine (OK)	0		

(1) The combinations of severity and timing classifications results in one OK release category and 12 other release categories of varying times and magnitudes.

(2) The cue for the General Emergency declaration is taken to be the time when EALs are exceeded. The declaration of the General Emergency begins the time for evacuation.

TABLE E.2-4
SUMMARY OF CONTAINMENT EVALUATION

INPUT		OUTPUT	
LEVEL 1 PRA		**CET EVALUATION**	
CORE DAMAGE FREQUENCY	**CHARACTERIZE RELEASE**	**RELEASE BIN[(1)]**	**RELEASE FREQUENCY (PER YEAR)[(4)]**
	Little or No Release	OK	2.12E-06
	Low Public Risk Impact	LL and Late	3.90E-08
		LL and I	2.87E-07
		LL and E	9.30E-08
		L and Late[(2)]	2.88E-07
		L and I	7.71E-09
		L and E	5.95E-10
	Moderate Public Risk Impact	M and Late [(2)]	0.00E+00
		M and I	3.17E-07
		M and E	3.57E-07
	High Release	H and Late[(2)]	1.26E-07
		H and I	1.15E-06
		H and E	4.72E-07[(3)]

(1) See Table E.2-3 for nomenclature on the release bins.

(2) One of the areas that PRA tools are somewhat limited is in the estimation of recovery or repair during extended times such as 24 hours. Some estimates would indicate that response over such an extended time could be very extensive and highly successful. Therefore, it can be argued that virtually no accidents that take beyond 24 hours to release should be considered to be a significant potential contributor to public risk.

(3) The accident class LERF total of 4.72E-7/yr is slightly lower than the base Level 2 LERF total of 4.76E-7/yr from the single top model. This may be due to the assumption that all Class IV end states were decreased proportionally due to the success branch probability issue. The Level 2 LERF total of 4.76E-7/yr from the single top model is judged to be the appropriate LERF result.

(4) Release frequencies were calculated at a truncation limit of 1E-12/yr.

TABLE E.2-5
HCGS HC108B LEVEL 1 CDF CONTRIBUTION BY INITIATING EVENT
(CDF = 5.11E-6/YR AT 1E-12/YR TRUNCATION)

BASIC EVENT ID	DESCRIPTION	Frequency (/yr)	F-V	CDF (/yr)	CCDP
%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT	2.37E-02	1.82E-01	9.31E-07	3.93E-05
%IE-SWS	LOSS OF SERVICE WATER INITIATING EVENT	1.79E-04	1.59E-01	8.13E-07	4.54E-03
%IE-MS	MANUAL SHUTDOWN INITIATING EVENT	1.46E+00	1.50E-01	7.67E-07	5.25E-07
%IE-TT	TURBINE TRIP WITH BYPASS	7.03E-01	1.22E-01	6.24E-07	8.87E-07
%IE-S2-WA	SMALL LOCA - WATER (BELOW TAF)	6.20E-04	5.40E-02	2.76E-07	4.45E-04
%IE-S2-ST	SMALL LOCA - STEAM (ABOVE TAF)	6.20E-04	4.45E-02	2.28E-07	3.67E-04
%IE-TC	LOSS OF CONDENSER VACUUM	9.33E-02	3.98E-02	2.03E-07	2.18E-06
%FLFPS-CR	FPS RUPTURE OUTSIDE CONTROL ROOM	1.10E-05	3.62E-02	1.85E-07	1.68E-02
%IE-ISLOCAD	ISLOCA INITIATOR FOR ECCS DISCHARGE PATHS	1.63E-05	2.22E-02	1.14E-07	6.96E-03
%IE-TM	MSIV CLOSURE	5.62E-02	2.16E-02	1.10E-07	1.97E-06
%FL-FPS-5302	INT. FLOOD OUTSIDE LOWER RELAY ROOM	6.62E-06	1.90E-02	9.71E-08	1.47E-02
%IE-TF	LOSS OF FEEDWATER	4.49E-02	1.72E-02	8.79E-08	1.96E-06
%IE-SACS	LOSS OF SACS INITIATING EVENT	1.16E-04	1.54E-02	7.87E-08	6.79E-04
%FLSWAB-RACS-U	FREQ OF COMMON HEADER TO RACS RUPTURE (UNISOLABLE)	7.60E-08	1.49E-02	7.62E-08	1.00E+00
%FLSWA-RACS-U	FREQ. OF UNISOLABLE SW A PIPE RUPT IN RACS ROOM	5.70E-08	1.11E-02	5.68E-08	9.96E-01
%FLSWB-RACS-U	FREQ. OF UNISOLABLE SW B PIPE RUPT. IN RACS ROOM	5.70E-08	1.11E-02	5.68E-08	9.96E-01
%IE-ACD	LOSS OF AC BUS D INITIATING EVENT	2.07E-03	7.78E-03	3.98E-08	1.92E-05
%IE-SORV2	2 or More SORVs	2.44E-04	6.19E-03	3.16E-08	1.30E-04
%FLFPS-RBU	FPS RUPTURE IN RB UPPER LEVELS	6.60E-05	5.60E-03	2.86E-08	4.34E-04
%FLSWA-RACS-I	FREQ. OF ISOLABLE SW A PIPE RUPTURE IN RACS ROOM	1.43E-06	5.14E-03	2.63E-08	1.84E-02
%FLSWB-RACS-I	FRQ. OF ISOLABLE SW B PIPE RUPTURE IN RACS ROOM	1.43E-06	4.87E-03	2.49E-08	1.74E-02
%IE-TI	INADVERTENTLY OPEN SRV INITIATING EVENT	1.44E-02	4.82E-03	2.46E-08	1.71E-06
%IE-IAS	LOSS OF INSTRUMENT AIR INITIATOR	6.17E-03	4.50E-03	2.30E-08	3.73E-06
%IE-MLRHR	Medium LOCA – RHR	1.44E-05	4.08E-03	2.09E-08	1.45E-03
%IE-MLRECIRC	Medium LOCA – Reactor Recirculation	1.18E-05	3.34E-03	1.71E-08	1.45E-03
%FLTORUS	TORUS RUPTURE IN TORUS ROOM	2.80E-06	3.32E-03	1.70E-08	6.06E-03
%IE-ACA	LOSS OF AC BUS A INITIATING EVENT	2.89E-04	2.96E-03	1.51E-08	5.24E-05
%FL-FPS-5537	FPS RUPTURE OUTSIDE 125V DC ROOMS	1.34E-05	2.62E-03	1.34E-08	1.00E-03

TABLE E.2-5
HCGS HC108B LEVEL 1 CDF CONTRIBUTION BY INITIATING EVENT
(CDF = 5.11E-6/YR AT 1E-12/YR TRUNCATION)

BASIC EVENT ID	DESCRIPTION	Frequency (/yr)	F-V	CDF (/yr)	CCDP
%IE-MLRWCU	Medium LOCA – RWCU	8.63E-06	2.44E-03	1.25E-08	1.45E-03
%IE-TE-REC	LOSS OF OFFSITE POWER INITIATING EVENT (RECOVERED LOOP EVENT)	2.37E-02	2.28E-03	1.17E-08	4.92E-07
%IE-MLFW	Medium LOCA – Feedwater	7.22E-06	2.04E-03	1.04E-08	1.44E-03
%FLFPS-CD	FPS RUPTURE IN CONTROL DIESEL BUILDING	8.20E-05	1.79E-03	9.15E-09	1.12E-04
%IE-MLNBINST	Medium LOCA – Nuclear Boiler Instrumentation	5.24E-06	1.48E-03	7.57E-09	1.44E-03
%FLTORUSRB	TORUS SUCTION LINE RUPTURE IN ECCS ROOM	2.70E-06	1.28E-03	6.54E-09	2.42E-03
%IE-ACB	LOSS OF AC BUS B INITIATING EVENT	2.89E-04	1.22E-03	6.24E-09	2.16E-05
%FLSW-SACS-A	SW RUPTURE IN SACS A ROOM	4.80E-07	1.06E-03	5.42E-09	1.13E-02
%FLSACS-A	SACS A RUPTURE	2.70E-04	7.97E-04	4.07E-09	1.51E-05
%IE-ISLOCAS	ISLOCA INITIATOR FOR SDC SUCTION PATH	5.01E-07	7.58E-04	3.88E-09	7.74E-03
%FLSW-SACS-B	SW RUPTURE IN SACS B ROOM	4.80E-07	7.03E-04	3.59E-09	7.49E-03
%IE-LLRHR	Large LOCA – RHR	9.69E-06	6.26E-04	3.20E-09	3.30E-04
%IE-MLHPCI	Medium LOCA – HPCI	1.80E-06	5.92E-04	3.03E-09	1.68E-03
%FLSACS-B	SACS B RUPTURE	2.70E-04	5.66E-04	2.89E-09	1.07E-05
%IE-ACC	LOSS OF AC BUS C INITIATING EVENT	2.89E-04	5.60E-04	2.86E-09	9.91E-06
%IE-LLRECIRC	Large LOCA – Reactor Recirculation	8.74E-06	5.50E-04	2.81E-09	3.22E-04
%FLTB-CW	TURBINE BUILDING FLOOD	1.50E-03	5.27E-04	2.69E-09	1.80E-06
%IE-BOCMSA	Main Steam Line A Break outside Containment	9.66E-09	4.92E-04	2.52E-09	2.60E-01
%IE-BOCMSB	Main Steam Line B Break outside	9.66E-09	4.92E-04	2.52E-09	2.60E-01
%IE-BOCMSC	Main Steam Line C Break outside	9.66E-09	4.92E-04	2.52E-09	2.60E-01
%IE-BOCMSD	Main Steam Line D Break outside	9.66E-09	4.92E-04	2.52E-09	2.60E-01
%IE-MLMS	Medium LOCA – Main Steam	1.54E-05	3.78E-04	1.93E-09	1.25E-04
%FLSWAB-RACS-I	FREQ. OF ISOLABLE SW A & B PIPE RUTPURE IN RACS ROOM (TO RACS HX)	5.70E-07	3.37E-04	1.72E-09	3.02E-03
%IE-LLMS	Large LOCA – Main Steam	1.00E-05	3.36E-04	1.72E-09	1.72E-04
%IE-MLCS	Medium LOCA – Core Spray	9.34E-06	3.15E-04	1.61E-09	1.72E-04
%IE-LLFW	Large LOCA – Feedwater	4.53E-06	2.85E-04	1.46E-09	3.22E-04
%IE-LLRWCU	Large LOCA – RWCU	4.53E-06	2.85E-04	1.46E-09	3.22E-04

TABLE E.2-5
HCGS HC108B LEVEL 1 CDF CONTRIBUTION BY INITIATING EVENT
(CDF = 5.11E-6/YR AT 1E-12/YR TRUNCATION)

BASIC EVENT ID	DESCRIPTION	Frequency (/yr)	F-V	CDF (/yr)	CCDP
%IE-LLADS	Large LOCA - Spurious ADS Actuation	8.48E-06	2.84E-04	1.45E-09	1.71E-04
%IE-BOCHPCI	HPCI Steam Line Break outside Containment	5.11E-09	2.60E-04	1.33E-09	2.60E-01
%IE-BOCRCIC	RCIC Steam Line Break outside Containment	5.11E-09	2.60E-04	1.33E-09	2.60E-01
%IE-BOCRWCU	RWCU Line Break outside Containment	5.11E-09	2.60E-04	1.33E-09	2.60E-01
%IE-LLCS	Large LOCA - Core Spray	5.40E-06	2.30E-04	1.18E-09	2.18E-04
%IE-DCAB	LOSS OF DCA & DCB	7.14E-07	1.44E-04	7.36E-10	1.03E-03
%IE-R	EXCESSIVE LOCA EVENT	6.38E-09	1.39E-04	7.11E-10	1.11E-01
%IE-BOCFWA	Feedwater Line A Break outside	2.23E-09	1.14E-04	5.83E-10	2.61E-01
%IE-BOCFWB	FEEDWATER LINE B BREAK OUTSIDE CONTAINMENT	2.23E-09	1.14E-04	5.83E-10	2.61E-01
%IE-MLRCIC	Medium LOCA – RCIC	3.27E-06	7.67E-05	3.92E-10	1.20E-04
%IE-LLHPCI	Large LOCA – HPCI	1.13E-06	3.63E-05	1.86E-10	1.64E-04
%IE-RACS	LOSS OF RACS	1.56E-05	5.86E-07	3.00E-12	1.92E-07

TABLE E.3-1
ESTIMATED POPULATION DISTRIBUTION WITHIN A 10-MILE RADIUS OF HCGS, YEAR 2046

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(2)
N	0	0	0	0	0	1830	1830
NNE	0	0	0	0	105	15854	15959
NE	0	0	0	0	176	4512	4688
ENE	0	0	0	187	571	3500	4258
E	0	0	0	0	220	1734	1954
ESE	0	0	0	0	0	1674	1674
SE	0	0	0	0	0	0	0
SSE	0	0	0	0	0	129	129
S	0	0	0	90	0	1193	1283
SSW	0	0	0	0	0	1299	1299
SW	0	0	0	27	0	4706	4733
WSW	0	0	15	0	904	5183	6102
W	0	0	0	23	566	17065	17654
WNW	0	0	0	304	2138	6172	8614
NW	0	0	75	0	940	5686	6701
NNW	0	0	145	160	158	44577	45040
Total(2)	0	0	235	790	5778	115114	121917

(1) Radial ten year population growth factor applied successively to year 2000 census data to develop year 2046 estimate. Radial growth factor is based upon radial population growth from 1990 to year 2000.
(2) Population projections developed in electronic spreadsheet calculation and totals may differ slightly due to rounding of individual values.

TABLE E.3-2
ESTIMATED POPULATION DISTRIBUTION WITHIN A 50-MILE RADIUS OF HCGS, YEAR 2046

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(2)
N	1830	246483	205299	162261	203948	819820
NNE	15959	26708	169874	969326	1326997	2508865
NE	4688	16670	98321	418531	531046	1069256
ENE	4258	8618	47490	80249	45510	186125
E	1954	65843	108963	22328	51820	250908
ESE	1674	17688	22482	9994	28862	80700
SE	0	141	835	0	48631	49607
SSE	129	108	1845	1413	7822	11317
S	1283	27990	88978	27767	18930	164948
SSW	1299	32553	16178	9882	17231	77143
SW	4733	7140	7738	6343	12701	38655
WSW	6102	7138	5135	11206	36303	65885
W	17654	9607	5916	55881	212030	301089
WNW	8614	42406	36834	30575	28271	146698
NW	6701	193335	42694	28418	52573	323721
NNW	45040	238574	113728	76381	66009	539732
Total(2)	121917	941003	972310	1910554	2688683	6634468

(1) Radial ten year population growth factor applied successively to year 2000 census data to develop year 2046 estimate. Radial growth factor is based upon radial population growth from 1990 to year 2000.

(2) Population projections developed in electronic spreadsheet calculation and totals may differ slightly due to rounding of individual values.

TABLE E.3-3
HCGS MACCS2 END OF CYCLE CORE INVENTORY

ENTRY	NUCLIDE	ACTIVITY (BQ)	ENTRY	NUCLIDE	ACTIVITY (BQ)
1	Co-58	2.22E+16	31	Te-131m	4.01E+18
2	Co-60	2.65E+16	32	Te-132	5.52E+18
3	Kr-85	4.78E+16	33	I-131	3.87E+18
4	Kr-85m	1.07E+18	34	I-132	5.61E+18
5	Kr-87	2.06E+18	35	I-133	7.99E+18
6	Kr-88	2.90E+18	36	I-134	8.78E+18
7	Rb-86	9.20E+15	37	I-135	9.01E+18
8	Sr-89	3.90E+18	38	Xe-133	7.68E+18
9	Sr-90	3.83E+17	39	Xe-135	2.64E+18
10	Sr-91	7.68E+18	40	Cs-134	7.75E+17
11	Sr-92	5.23E+18	41	Cs-136	2.70E+17
12	Y-90	4.07E+17	42	Cs-137	9.80E+17
13	Y-91	4.99E+18	43	Ba-139	7.17E+18
14	Y-92	5.25E+18	44	Ba-140	6.93E+18
15	Y-93	6.03E+18	45	La-140	7.36E+18
16	Zr-95	7.03E+18	46	La-141	6.54E+18
17	Zr-97	2.13E+19	47	La-142	6.33E+18
18	Nb-95	7.06E+18	48	Ce-141	6.58E+18
19	Mo-99	7.39E+18	49	Ce-143	6.12E+18
20	Tc-99m	6.46E+18	50	Ce-144	1.08E+19
21	Ru-103	1.12E+19	51	Pr-143	5.91E+18
22	Ru-105	3.91E+18	52	Nd-147	2.62E+18
23	Ru-106	4.26E+18	53	Np-239	7.57E+19
24	Rh-105	3.67E+18	54	Pu-238	1.31E+16
25	Sb-127	4.06E+17	55	Pu-239	1.58E+15
26	Sb-129	1.23E+18	56	Pu-240	2.04E+15
27	Te-127	4.03E+17	57	Pu-241	5.93E+17
28	Te-127m	5.38E+16	58	Am-241	6.67E+14
29	Te-129	1.21E+18	59	Cm-242	1.58E+17
30	Te-129m	1.80E+17	60	Cm-244	7.59E+15

TABLE E.3-4
MACCS2 RELEASE CATEGORIES VS. HCGS RELEASE CATEGORIES

MACCS2 RELEASE CATEGORIES	HCGS 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

SOURCE TERM	RELEASE CATEGORY	MAAP CASE	REPRESENTATIVE CASE DESCRIPTION	CSI RF(1)	TCD (HRS)(2)	TVF (HRS)(3)	TCF (HRS)(4)	TEND (HRS)(5)
ST1	H/E-HP	HC070500 IA-L2-NSPR	Loss of makeup at high pressure. No containment sprays.	0.57	0.60	3.0	3.2	38
ST2	H/E-LP	HC070504 ID-L2-NSPR	Loss of makeup at low pressure. No containment sprays.	0.15	0.47	4.7	4.8	38
ST3	H/E-BOC	HC070524 V-L2-17	Main steam line break outside containment. No injection. Release to environment begins at core damage.	0.69	0.13	6.8	6.9	38
ST4	H/I	HC070509 IIT-L2-WWW	Loss of containment heat removal and subsequent wetwell failure. RCIC and core spray provide injection. SRVs reclose at 50 psid. No containment sprays.	0.30	29.1	38.6	29.8	72
ST5	H/L	HC070515 IIA-L2-WWW	Loss of containment heat removal and subsequent wetwell failure. CRD, RCIC, and core spray provide injection. SRVs reclose at 50 psid. No containment sprays.	0.36	35.4	46.4	34.4	84
ST6	M/E	HC070519 IVA-L2-ED-WWA	ATWS event with SLC failure and emergency depressurization. FW, HPCI, and LPCI provide injection until containment failure.	0.070	0.77	5.4	0.58	38

TABLE E.3-5
REPRESENTATIVE MAAP LEVEL 2 CASE DESCRIPTIONS AND KEY EVENT TIMINGS

SOURCE TERM	RELEASE CATEGORY	MAAP CASE	REPRESENTATIVE CASE DESCRIPTION	CSI RF(1)	TCD (HRS)(2)	TVF (HRS)(3)	TCF (HRS)(4)	TEND (HRS)(5)
ST7	M/I	HC070516 IIA-L2-DW	Loss of containment heat removal and subsequent drywell failure. CRD, RCIC, and core spray provide injection. SRVs reclose at 50 psid. No containment sprays.	0.057	35.4	46.5	34.4	84
ST8	M/L	HC070502 IA-L2-SPRY-A	Loss of makeup at high pressure. Containment sprays fail at containment failure.	0.040	0.58	3.0	21.8	38
ST9	L / E, LL / E, L / I LL / I	HC070503 IA-L2-SPRY-B	Loss of makeup at high pressure. Containment sprays operate past containment failure.	2.3E-6	0.58	3.0	21.8	38
ST10	L / L, LL / L	HC070505 ID-L2-SPRY	Loss of makeup at low pressure. Containment sprays fail at containment failure.	9.8E-5	0.47	4.8	32.2	38
ST11	Intact	HC070525A OK-L2-A	Loss of makeup at high pressure. Containment sprays and suppression pool cooling operate. Intact containment with technical specification leakage.	1.7E-6	0.58	3.1	NA	38

Notes:

(1) CsI RF – Cesium Iodide release fraction to the environment
(2) Tcd - Time of core damage (maximum core temperature >1800°F)
(3) Tvf - Time of vessel breach
(4) Tcf – Time of containment failure
(5) Tend – Time at end of run

TABLE E.3-6
HCGS SOURCE TERM SUMMARY

	RELEASE CATEGORY										
	H/E-HP	H/E-LP	H/E-BOC	H / I	H / L	M / E	M / I	M / L	L/E LL/E L/I LL/I	L/L LL/L	INTACT
Bin Frequency	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06
MAAP Case	HC070500	HC070504	HC070524	HC070509	HC070515	HC070519	HC070516	HC070502	HC070503	HC070505	HC070525A
Run Duration	38 hr	38 hr	38 hr	72 hr	84 hr	38 hr	84 hr	38 hr	38 hr	38 hr	38 hr
Time after Scram when GE is declared (1)	30 min.	30 min.	30 min.	20 hr	20 hr	50 min.	20 hr	30 min.	30 min.	30 min.	30 min.
Fission Product Group:											
1) Noble											
Total Release Fraction	8.70E-01	7.70E-01	9.80E-01	9.90E-01	9.90E-01	9.90E-01	9.10E-01	5.00E-01	8.90E-01	9.80E-01	1.20E-02
Total Plume 1 Release Fraction	8.10E-01	6.50E-01	9.65E-01	8.40E-01	9.30E-01	9.50E-01	8.00E-01	4.70E-01	0.00E+00	0.00E+00	1.00E-03
Start of Plume 1 Release (hr)	3.10	4.75	0.17	30.00	36.00	1.00	35.00	22.00			3.00
End of Plume 1 Release (hr)	4.00	6.00	1.50	32.00	40.00	2.50	45.00	25.00			4.50
Total Plume 2 Release Fraction	3.00E-02	4.00E-02	5.00E-03	1.40E-01	4.00E-02	3.00E-02	2.00E-02	0.00E+00	0.00E+00	9.80E-01	1.00E-03
Start of Plume 2 Release (hr)	4.00	6.00	1.50	32.00	46.00	2.50	45.00			32.00	4.50
End of Plume 2 Release (hr)	6.00	14.00	4.00	34.00	50.00	7.00	50.00			38.00	8.00
Total Plume 3 Release Fraction	3.00E-02	8.00E-02	1.00E-02	1.00E-02	2.00E-02	1.00E-02	9.00E-02	3.00E-02	8.90E-01	0.00E+00	1.00E-02
Start of Plume 3 Release (hr)	6.00	14.00	6.90	38.00	50.00	7.00	50.00	32.00	22.00		8.00
End of Plume 3 Release (hr)	16.00	24.00	7.90	45.00	60.00	17.00	60.00	38.00	32.00		18.00
2) CsI											
Total Release Fraction	5.70E-01	1.50E-01	7.00E-01	3.00E-01	3.60E-01	7.00E-02	5.70E-02	4.00E-02	2.30E-06	9.80E-05	1.70E-06
Total Plume 1 Release Fraction	2.50E-01	2.00E-03	4.10E-01	1.00E-02	2.60E-01	1.50E-02	4.00E-03	0.00E+00	1.50E-06	0.00E+00	1.60E-06
Start of Plume 1 Release (hr)	3.10	4.75	0.17	30.00	36.00	1.00	35.00		3.00		3.00
End of Plume 1 Release (hr)	4.00	6.00	1.50	32.00	40.00	2.50	45.00		4.00		4.50
Total Plume 2 Release Fraction	8.00E-02	1.10E-01	2.70E-01	2.20E-01	5.00E-02	1.10E-02	8.00E-03	3.10E-02	2.00E-07	9.80E-05	1.00E-07
Start of Plume 2 Release (hr)	4.00	6.00	1.50	32.00	46.00	2.50	45.00	28.00	4.00	32.00	4.50
End of Plume 2 Release (hr)	6.00	14.00	4.00	34.00	50.00	7.00	50.00	32.00	6.00	38.00	8.00
Total Plume 3 Release Fraction	2.40E-01	3.80E-02	2.00E-02	7.00E-02	5.00E-02	4.40E-02	4.50E-02	9.00E-03	6.00E-07	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)	6.00	14.00	6.90	38.00	50.00	7.00	50.00	32.00	22.00		
End of Plume 3 Release (hr)	16.00	24.00	7.90	45.00	60.00	17.00	60.00	38.00	32.00		

TABLE E.3-6
HCGS SOURCE TERM SUMMARY

	RELEASE CATEGORY										
	H/E-HP	**H/E-LP**	**H/E-BOC**	**H / I**	**H / L**	**M / E**	**M / I**	**M / L**	**L/E LL/E L/I LL/I**	**L/L LL/L**	**INTACT**
Bin Frequency	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06
MAAP Case	HC070500	HC070504	HC070524	HC070509	HC070515	HC070519	HC070516	HC070502	HC070503	HC070505	HC070525A
Run Duration	38 hr	38 hr	38 hr	72 hr	84 hr	38 hr	84 hr	38 hr	38 hr	38 hr	38 hr
Time after Scram when GE is declared (1)	30 min.	30 min.	30 min.	20 hr	20 hr	50 min.	20 hr	30 min.	30 min.	30 min.	30 min.
Fission Product Group:											
3) TeO2											
Total Release Fraction	2.40E-01	4.50E-02	4.70E-01	7.90E-02	1.10E-01	3.50E-02	1.50E-02	2.20E-02	4.60E-07	4.90E-05	5.20E-07
Total Plume 1 Release Fraction	3.00E-02	1.00E-03	4.60E-01	2.60E-02	9.00E-02	8.00E-03	1.20E-03	0.00E+00	2.20E-07	0.00E+00	3.50E-07
Start of Plume 1 Release (hr)	3.10	4.75	0.17	30.00	36.00	1.00	35.00		3.00		3.00
End of Plume 1 Release (hr)	4.00	6.00	1.50	32.00	40.00	2.50	45.00		4.00		4.50
Total Plume 2 Release Fraction	2.10E-01	2.30E-02	1.00E-02	4.50E-02	1.00E-02	1.00E-03	2.00E-04	1.20E-02	2.00E-07	4.90E-05	1.50E-07
Start of Plume 2 Release (hr)	4.00	6.00	1.50	32.00	46.00	2.50	45.00	28.00	4.00	32.00	4.50
End of Plume 2 Release (hr)	6.00	14.00	4.00	34.00	50.00	7.00	50.00	32.00	6.00	38.00	8.00
Total Plume 3 Release Fraction	0.00E+00	2.10E-02	0.00E+00	8.00E-03	1.00E-02	2.60E-02	1.36E-02	1.00E-02	4.00E-08	0.00E+00	2.00E-08
Start of Plume 3 Release (hr)		14.00		38.00	50.00	7.00	50.00	32.00	22.00		8.00
End of Plume 3 Release (hr)		24.00		45.00	60.00	17.00	60.00	38.00	32.00		18.00
4) SrO											
Total Release Fraction	1.70E-02	1.40E-02	2.00E-02	5.90E-03	8.00E-03	1.40E-02	6.10E-03	2.10E-03	3.60E-11	7.20E-10	3.00E-11
Total Plume 1 Release Fraction	6.00E-03	1.30E-02	5.00E-03	0.00E+00	4.00E-04	0.00E+00	0.00E+00	0.00E+00	3.50E-11	7.20E-10	3.00E-11
Start of Plume 1 Release (hr)	3.10	4.75	0.17		36.00				3.00	4.75	3.00
End of Plume 1 Release (hr)	4.00	6.00	1.50		40.00				4.00	5.50	4.50
Total Plume 2 Release Fraction	1.10E-02	1.00E-03	0.00E+00	1.00E-04	7.60E-03	1.40E-02	6.10E-03	1.70E-03	0.00E+00	0.00E+00	0.00E+00
Start of Plume 2 Release (hr)	4.00	6.00		32.00	46.00	2.50	45.00	28.00			
End of Plume 2 Release (hr)	6.00	14.00		34.00	50.00	7.00	50.00	32.00			
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	1.50E-02	5.80E-03	0.00E+00	0.00E+00	0.00E+00	4.00E-04	1.00E-12	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)			6.90	38.00				32.00	22.00		
End of Plume 3 Release (hr)			7.90	45.00				38.00	32.00		

TABLE E.3-6
HCGS SOURCE TERM SUMMARY

	RELEASE CATEGORY										
	H/E-HP	**H/E-LP**	**H/E-BOC**	**H / I**	**H / L**	**M / E**	**M / I**	**M / L**	**L/E LL/E L/I LL/I**	**L/L LL/L**	**INTACT**
Bin Frequency	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06
MAAP Case	HC070500	HC070504	HC070524	HC070509	HC070515	HC070519	HC070516	HC070502	HC070503	HC070505	HC070525A
Run Duration	38 hr	38 hr	38 hr	72 hr	84 hr	38 hr	84 hr	38 hr	38 hr	38 hr	38 hr
Time after Scram when GE is declared (1)	30 min.	30 min.	30 min.	20 hr	20 hr	50 min.	20 hr	30 min.	30 min.	30 min.	30 min.
Fission Product Group:											
5) MoO2											
Total Release Fraction	2.60E-06	8.10E-07	2.20E-02	1.60E-03	8.20E-04	8.60E-05	7.90E-06	3.60E-09	3.50E-11	1.10E-11	2.40E-11
Total Plume 1 Release Fraction	2.10E-06	4.20E-07	2.20E-02	1.10E-03	2.00E-04	7.90E-05	7.50E-06	2.00E-10	3.20E-11	2.00E-12	2.40E-11
Start of Plume 1 Release (hr)	3.10	4.75	0.17	30.00	36.00	1.00	35.00	22.00	3.00	4.75	3.00
End of Plume 1 Release (hr)	4.00	6.00	1.50	32.00	40.00	2.50	45.00	25.00	4.00	5.50	4.50
Total Plume 2 Release Fraction	0.00E+00	3.00E-08	0.00E+00	5.00E-04	6.20E-04	7.00E-06	4.00E-07	1.00E-10	0.00E+00	9.00E-12	0.00E+00
Start of Plume 2 Release (hr)		6.00		32.00	46.00	2.50	45.00	28.00		32.00	
End of Plume 2 Release (hr)		14.00		34.00	50.00	7.00	50.00	32.00		38.00	
Total Plume 3 Release Fraction	5.00E-07	3.60E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.30E-09	3.00E-12	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)	6.00	14.00						32.00	22.00		
End of Plume 3 Release (hr)	16.00	24.00						38.00	32.00		
6) CsOH											
Total Release Fraction	3.30E-01	1.40E-01	4.20E-01	6.40E-02	1.30E-01	1.50E-01	4.50E-02	6.50E-02	2.80E-06	1.10E-03	9.30E-07
Total Plume 1 Release Fraction	6.00E-02	8.00E-04	3.70E-01	8.00E-03	6.00E-02	6.00E-03	1.00E-03	0.00E+00	2.00E-07	0.00E+00	3.70E-07
Start of Plume 1 Release (hr)	3.10	4.75	0.17	30.00	36.00	1.00	35.00		3.00		3.00
End of Plume 1 Release (hr)	4.00	6.00	1.50	32.00	40.00	2.50	45.00		4.00		4.50
Total Plume 2 Release Fraction	2.20E-01	1.10E-01	4.00E-02	3.20E-02	1.00E-02	2.00E-03	3.00E-03	3.80E-02	4.00E-07	1.10E-03	3.50E-07
Start of Plume 2 Release (hr)	4.00	6.00	1.50	32.00	46.00	2.50	45.00	28.00	4.00	32.00	4.50
End of Plume 2 Release (hr)	6.00	14.00	4.00	34.00	50.00	7.00	50.00	32.00	6.00	38.00	8.00
Total Plume 3 Release Fraction	5.00E-02	2.92E-02	1.00E-02	2.40E-02	6.00E-02	1.42E-01	4.10E-02	2.70E-02	2.20E-06	0.00E+00	2.10E-07
Start of Plume 3 Release (hr)	6.00	14.00	6.90	38.00	50.00	7.00	50.00	32.00	22.00		8.00
End of Plume 3 Release (hr)	16.00	24.00	7.90	45.00	60.00	17.00	60.00	38.00	32.00		18.00

TABLE E.3-6
HCGS SOURCE TERM SUMMARY

	RELEASE CATEGORY										
	H/E-HP	**H/E-LP**	**H/E-BOC**	**H / I**	**H / L**	**M / E**	**M / I**	**M / L**	**L/E LL/E L/I LL/I**	**L/L LL/L**	**INTACT**
Bin Frequency	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06
MAAP Case	HC070500	HC070504	HC070524	HC070509	HC070515	HC070519	HC070516	HC070502	HC070503	HC070505	HC070525A
Run Duration	38 hr	38 hr	38 hr	72 hr	84 hr	38 hr	84 hr	38 hr	38 hr	38 hr	38 hr
Time after Scram when GE is declared (1)	30 min.	30 min.	30 min.	20 hr	20 hr	50 min.	20 hr	30 min.	30 min.	30 min.	30 min.
Fission Product Group:											
7) BaO											
Total Release Fraction	7.50E-03	6.00E-03	3.90E-02	3.40E-03	5.20E-03	6.30E-03	2.70E-03	1.00E-03	9.50E-11	3.20E-10	7.20E-11
Total Plume 1 Release Fraction	2.40E-03	5.70E-03	3.30E-02	3.00E-04	9.00E-04	2.00E-04	0.00E+00	0.00E+00	8.90E-11	3.10E-10	7.20E-11
Start of Plume 1 Release (hr)	3.10	4.75	0.17	30.00	36.00	1.00			3.00	4.75	3.00
End of Plume 1 Release (hr)	4.00	6.00	1.50	32.00	40.00	2.50			4.00	5.50	4.50
Total Plume 2 Release Fraction	5.10E-03	3.00E-04	0.00E+00	6.00E-04	4.30E-03	6.10E-03	2.70E-03	8.00E-04	0.00E+00	1.00E-11	0.00E+00
Start of Plume 2 Release (hr)	4.00	6.00		32.00	46.00	2.50	45.00	28.00		32.00	
End of Plume 2 Release (hr)	6.00	14.00		34.00	50.00	7.00	50.00	32.00		38.00	
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	6.00E-03	2.50E-03	0.00E+00	0.00E+00	0.00E+00	2.00E-04	6.00E-12	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)			6.90	38.00				32.00	22.00		
End of Plume 3 Release (hr)			7.90	45.00				38.00	32.00		
8) La2O3											
Total Release Fraction	1.20E-03	1.50E-03	3.10E-03	6.90E-04	4.70E-04	1.60E-03	3.10E-04	1.40E-05	2.60E-12	7.60E-11	1.70E-12
Total Plume 1 Release Fraction	4.00E-04	1.50E-03	4.00E-04	0.00E+00	1.00E-05	0.00E+00	0.00E+00	0.00E+00	2.40E-12	7.60E-11	1.70E-12
Start of Plume 1 Release (hr)	3.10	4.75	0.17		36.00				3.00	4.75	3.00
End of Plume 1 Release (hr)	4.00	6.00	1.50		40.00				4.00	5.50	4.50
Total Plume 2 Release Fraction	8.00E-04	0.00E+00	0.00E+00	5.00E-05	4.60E-04	1.60E-03	3.10E-04	1.00E-05	0.00E+00	0.00E+00	0.00E+00
Start of Plume 2 Release (hr)	4.00			32.00	46.00	2.50	45.00	28.00			
End of Plume 2 Release (hr)	6.00			34.00	50.00	7.00	50.00	32.00			
Total Plume 3 Release Fraction		0.00E+00	2.70E-03	6.40E-04	0.00E+00	0.00E+00	0.00E+00	4.00E-06	2.00E-13	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)			6.90	38.00				32.00	22.00		
End of Plume 3 Release (hr)			7.90	45.00				38.00	32.00		

TABLE E.3-6
HCGS SOURCE TERM SUMMARY

	RELEASE CATEGORY										
	H/E-HP	**H/E-LP**	**H/E-BOC**	**H / I**	**H / L**	**M / E**	**M / I**	**M / L**	**L/E LL/E L/I LL/I**	**L/L LL/L**	**INTACT**
Bin Frequency	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06
MAAP Case	HC070500	HC070504	HC070524	HC070509	HC070515	HC070519	HC070516	HC070502	HC070503	HC070505	HC070525A
Run Duration	38 hr	38 hr	38 hr	72 hr	84 hr	38 hr	84 hr	38 hr	38 hr	38 hr	38 hr
Time after Scram when GE is declared (1)	30 min.	30 min.	30 min.	20 hr	20 hr	50 min.	20 hr	30 min.	30 min.	30 min.	30 min.
Fission Product Group:											
9) CeO2											
Total Release Fraction	1.60E-02	1.30E-02	2.30E-02	8.20E-03	5.00E-03	1.50E-02	3.70E-03	6.80E-04	2.10E-11	6.50E-10	1.40E-11
Total Plume 1 Release Fraction	4.00E-03	1.30E-02	1.00E-03	0.00E+00	1.00E-04	0.00E+00	0.00E+00	0.00E+00	2.00E-11	6.50E-10	1.40E-11
Start of Plume 1 Release (hr)	3.10	4.75	0.17		36.00				3.00	4.75	3.00
End of Plume 1 Release (hr)	4.00	6.00	1.50		40.00				4.00	5.50	4.50
Total Plume 2 Release Fraction	1.20E-02	0.00E+00	0.00E+00	1.00E-04	4.90E-03	1.50E-02	3.70E-03	5.10E-04	0.00E+00	0.00E+00	0.00E+00
Start of Plume 2 Release (hr)	4.00			32.00	46.00	2.50	45.00	28.00			
End of Plume 2 Release (hr)	6.00			34.00	50.00	7.00	50.00	32.00			
Total Plume 3 Release Fraction	0.00E+00	0.00E+00	2.20E-02	8.10E-03	0.00E+00	0.00E+00	0.00E+00	1.70E-04	1.00E-12	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)			6.90	38.00				32.00	22.00		
End of Plume 3 Release (hr)			7.90	45.00				38.00	32.00		
10) Sb											
Total Release Fraction	4.10E-01	8.10E-02	7.30E-01	7.60E-02	8.30E-02	1.00E-01	2.90E-02	5.00E-02	1.00E-06	9.70E-06	4.90E-09
Total Plume 1 Release Fraction	3.00E-02	4.10E-02	5.80E-01	1.00E-04	4.00E-02	1.00E-02	1.00E-03	0.00E+00	0.00E+00	0.00E+00	4.90E-09
Start of Plume 1 Release (hr)	3.10	4.75	0.17	30.00	36.00	1.00	35.00				3.00
End of Plume 1 Release (hr)	4.00	6.00	1.50	32.00	40.00	2.50	45.00				4.50
Total Plume 2 Release Fraction	1.50E-01	2.00E-02	8.00E-02	1.00E-04	2.90E-02	5.00E-02	2.30E-02	1.80E-02	0.00E+00	9.70E-06	0.00E+00
Start of Plume 2 Release (hr)	4.00	6.00	1.50	32.00	46.00	2.50	45.00	28.00		32.00	
End of Plume 2 Release (hr)	6.00	14.00	4.00	34.00	50.00	7.00	50.00	32.00		38.00	
Total Plume 3 Release Fraction	2.30E-01	2.00E-02	7.00E-02	7.58E-02	1.40E-02	4.00E-02	5.00E-03	3.20E-02	1.00E-06	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)	6.00	14.00	6.90	38.00	50.00	7.00	50.00	32.00	22.00		
End of Plume 3 Release (hr)	16.00	24.00	7.90	45.00	60.00	17.00	60.00	38.00	32.00		
11) Te2											
Total Release Fraction	5.00E-02	2.50E-03	1.30E-03	1.70E-03	9.20E-04	2.80E-03	2.40E-04	3.30E-02	4.10E-09	1.00E-08	1.70E-10
Total Plume 1 Release Fraction	1.70E-02	2.20E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.00E-10	0.00E+00	1.70E-10
Start of Plume 1 Release (hr)	3.10	4.75							3.00		3.00

TABLE E.3-6
HCGS SOURCE TERM SUMMARY

	RELEASE CATEGORY										
	H/E-HP	**H/E-LP**	**H/E-BOC**	**H / I**	**H / L**	**M / E**	**M / I**	**M / L**	**L/E LL/E L/I LL/I**	**L/L LL/L**	**INTACT**
Bin Frequency	1.83E-07	7.15E-08	1.30E-07	9.70E-07	8.34E-08	3.48E-07	2.16E-07	0.00E+00	2.68E-07	2.39E-07	1.93E-06
MAAP Case	HC070500	HC070504	HC070524	HC070509	HC070515	HC070519	HC070516	HC070502	HC070503	HC070505	HC070525A
Run Duration	38 hr	38 hr	38 hr	72 hr	84 hr	38 hr	84 hr	38 hr	38 hr	38 hr	38 hr
Time after Scram when GE is declared (1)	30 min.	30 min.	30 min.	20 hr	20 hr	50 min.	20 hr	30 min.	30 min.	30 min.	30 min.
Fission Product Group:											
End of Plume 1 Release (hr)	4.00	6.00							4.00		4.50
Total Plume 2 Release Fraction	1.30E-02	2.00E-04	0.00E+00	0.00E+00	8.50E-04	2.40E-03	2.30E-04	1.60E-02	0.00E+00	1.00E-08	0.00E+00
Start of Plume 2 Release (hr)	4.00	6.00			46.00	2.50	45.00	28.00		32.00	
End of Plume 2 Release (hr)	6.00	14.00			50.00	7.00	50.00	32.00		38.00	
Total Plume 3 Release Fraction	2.00E-02	1.00E-04	1.30E-03	1.70E-03	7.00E-05	4.00E-04	1.00E-05	1.70E-02	3.90E-09	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)	6.00	14.00	6.90	38.00	50.00	7.00	50.00	32.00	22.00		
End of Plume 3 Release (hr)	16.00	24.00	7.90	45.00	60.00	17.00	60.00	38.00	32.00		
12) UO2											
Total Release Fraction	8.40E-05	9.40E-05	1.70E-04	4.60E-05	2.80E-05	1.00E-04	2.00E-05	2.30E-06	1.40E-14	4.90E-12	1.20E-14
Total Plume 1 Release Fraction	2.30E-05	9.00E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.40E-14	4.90E-12	1.20E-14
Start of Plume 1 Release (hr)	3.10	4.75							3.00	4.75	3.00
End of Plume 1 Release (hr)	4.00	6.00							4.00	5.50	4.50
Total Plume 2 Release Fraction	5.90E-05	4.00E-06	0.00E+00	0.00E+00	2.70E-05	9.80E-05	2.00E-05	1.00E-06	0.00E+00	0.00E+00	0.00E+00
Start of Plume 2 Release (hr)	4.00	6.00			46.00	2.50	45.00	28.00			
End of Plume 2 Release (hr)	6.00	14.00			50.00	7.00	50.00	32.00			
Total Plume 3 Release Fraction	0.00	0.00E+00	1.70E-04	4.60E-05	1.00E-06	2.00E-05	0.00E+00	1.30E-06	0.00E+00	0.00E+00	0.00E+00
Start of Plume 3 Release (hr)			6.90	38.00	50.00	7.00		32.00			
End of Plume 3 Release (hr)			7.90	45.00	60.00	17.00		38.00			

(1) General Emergency declaration estimated from Hope Creek Emergency Classification Guide (PSEG 2007).

TABLE E.3-7
MACCS2 BASE CASE MEAN RESULTS

SOURCE TERM	RELEASE CATEGORY	DOSE (P-REM)	OFFSITE ECONOMIC COST ($)	FREQ. (/YR)[1]	DOSE-RISK (P-REM/YR)	OECR ($/YR)
ST1	H / E – HP	1.82E+07	1.15E+11	1.830E-07	3.33E+00	2.10E+04
ST2	H / E – LP	1.38E+07	9.63E+10	7.152E-08	9.87E-01	6.89E+03
ST3	H / E – BOC	2.34E+07	1.15E+11	1.302E-07	3.05E+00	1.50E+04
ST4	H / I	8.75E+06	6.41E+10	9.697E-07	8.49E+00	6.22E+04
ST5	H / L	1.10E+07	9.23E+10	8.336E-08	9.17E-01	7.69E+03
ST6	M / E	1.31E+07	9.17E+10	3.477E-07	4.55E+00	3.19E+04
ST7	M / I	6.34E+06	4.73E+10	2.164E-07	1.37E+00	1.02E+04
ST8	M / L	6.38E+06	5.35E+10	0.000E+00	0.00E+00	0.00E+00
ST9	L/E, L/I, LL/E, LL/I	6.44E+03	2.54E+05	2.677E-07	1.72E-03	6.80E-02
ST10	L/L, LL/L	6.87E+05	7.41E+08	2.392E-07	1.64E-01	1.77E+02
ST11	INTACT	1.01E+03	3.63E+04	1.933E-06	1.95E-03	7.02E-02
			FREQUENCY WEIGHTED TOTALS	**4.44E-06**	**2.29E+01**	**1.55E+05**

[1] Release frequencies were calculated at a truncation limit of 5E-11/yr.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
ADS-XHE-OK-INHIB	1.00E+00	1.399	OPERATOR SUCCESSFULLY INHIBITS ADS WITH NO HP INJECTION (NON-ATWS)	BWROG recommends inhibiting ADS during normal operation, therefore, install alternate injection system capable of operating at high pressures. (SAMA 1)
%IE-SWS	1.79E-04	1.220	LOSS OF SERVICE WATER INITIATING EVENT	This initiator event is a compilation of industry and plant-specific data. (No specific SAMA identified)
NR-IE-SWS	1.00E+00	1.220	NONRECOVERY OF %IE-SWS	Provide a back-up air compressor to supply AOVs with an alternate air source. (SAMA 3) Provide the ability to cross-tie RHR pumps trains. (SAMA 4)
NR-U1X-DEP-SRV	3.00E-04	1.215	FAILURE TO DEPRESSURIZE WITH SRV W/O HIGH PRES. INJ.	This event is tied to a similar scenario that involves inhibiting ADS. Consider installing alternate injection system capable of operating at high pressures. This particular event may be mitigated via SAMA 1.
RHS-REPAIR-TR	3.50E-01	1.204	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (TRANSIENT EVENTS)	See SAMA 4
%IE-TE	2.37E-02	1.188	LOSS OF OFFSITE POWER INITIATING EVENT	This initiator event is a compilation of industry and plant-specific data. (No specific SAMA identified)
%IE-MS	1.46E+00	1.161	MANUAL SHUTDOWN INITIATING EVENT	This initiating event is tied to plant-specific operating experience. (No specific SAMA identified)

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
%IE-TT	7.03E-01	1.130	TURBINE TRIP WITH BYPASS	This initiator event represents a protective trip based on transients associated with balance of plant systems that are generally not safety-related. The maintenance rule process and other performance indicators provide a method for minimizing this initiator frequency. (No specific SAMA identified)
NR-XTIE-EDG	1.00E+00	1.088	FAILURE TO CROSS-TIE DIESEL GENERATOR	Improve procedural use of gas turbine generator to restore onsite emergency AC power sources. (SAMA 5)
LOOP-IE-SW	2.10E-01	1.085	COND. PROBABILITY DUE TO WEATHER RELATED LOOP EVENT	See SAMA 5
%IE-S2-WA	6.20E-04	1.064	SMALL LOCA - WATER (BELOW TAF)	This initiator event is a compilation of industry and plant-specific data. (No specific SAMA identified)
SAC-XHE-MC-DF01	8.00E-05	1.058	DEPENDENT FAILURE OF MISCAL. OF TEMP CONTROLLER HV-2457S	The miscalibration of temp controller HV-2457S during a LOOP event may result in SW bypass of the SACS heat exchangers. Bypassing the SACS heat exchangers would increase temperatures in the SACS system and compromise the ability of the RHR HXs to remove heat from the RPV, leading to core damage. The low probability of this event combined with existing procedural guidance for calibrating this controller suggests very limited opportunity for improvement. (No specific SAMA identified)

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
%IE-S2-ST	6.20E-04	1.053	SMALL LOCA - STEAM (ABOVE TAF)	This initiator event is a compilation of industry and plant-specific data. (No specific SAMA identified)
OSPR20HR-SW	1.33E-01	1.052	FAILURE TO RECOVER OSP WITHIN 20 HRS (SW RELATED LOOP EVENT)	This event appears in conjunction with failure to cross-tie diesel event and is addressed by SAMA 5.
NR-S1X-DEP-SRV	3.20E-02	1.049	FAILURE TO MAN. DEPRESS. FOR A MED. LOCA W/NO HI PRESS. INJ.	Although operator training can be emphasized to reduce human error probability, based on the HEP analysis, significant credit is currently given to procedures and training, no further HEP enhancements are considered to lower event probability. (No specific SAMA identified)
RHS-MDP-TM-PB	1.58E-02	1.048	RHS PUMP TRAIN B IN TEST AND MAINT	This event can be mitigated through use of SAMAs 1, 4, and 8, since it appears with those related accident sequences.
SWS-XHE-RACS-UNI	1.00E+00	1.045	FAILURE TO ISOLATE LOCALLY A SW RUPTURE IN RACS COMPARTMENT	Replace existing manual valves with remotely-operated, auto-isolating MOVs to enhance isolation capability and eliminate the source of flooding. (SAMA 7)
%FLFPS-CR	1.10E-05	1.043	FPS RUPTURE OUTSIDE CONTROL ROOM	See SAMA 8
DW-SHELL-RUPT	4.50E-01	1.043	DRYWELL SHELL RUPTURE DISRUPTS INJECTION LINES AND FAILS RB SYS	This initiator event is a compilation of industry and plant-specific data. (No specific SAMA identified)

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
FPS-XHE-CRISOL	1.00E+00	1.043	Operator fails to secure FPS given CR area rupture	This HRE represents an internal flooding scenario that disables various safety-related components. Mitigation of this event can be accomplished by changing the existing FPS to a dry-pipe system. (SAMA 8)
MCR-PHE-DOOR	5.00E-01	1.043	MCR DOOR FAILS DUE TO WATER PRESSURE	See SAMA 8
HPI-TDP-FS-OP204	1.39E-02	1.042	HPCI TDP FAILS TO START	See SAMA 1
RPCDRPS-MECHFCC	2.10E-06	1.042	MECHANICAL SCRAM FAILURE	This is a low probability event based on sparse industry data. (No specific SAMA identified)
XHOS-RIVER-LT70	6.90E-01	1.042	RIVER TEMPERATURE IS LESS THAN 70 F	This event is based on environmental conditions specific to the plant site. (No specific SAMA identified)
%IE-TC	9.33E-02	1.040	LOSS OF CONDENSER VACUUM	This initiator event is a compilation of industry and plant-specific data. (No specific SAMA identified)
DCP-XHE-PORTA	6.20E-02	1.031	FAILURE TO CROSS TIE BUS TO BATTERY CHARGER PORTABLE SUPPLY	See SAMA 5
RX-FWR-POR	2.30E-03	1.029	DEP OP ACT: FAIL TO INITIATE FW CNTRL AND PORTABLE GENERATOR ALIGNMENT	See SAMA 5
CAC-AOV-CC-11541	1.11E-03	1.028	PNUEMATIC SUPPLY TO HV-11541 FAILS	See SAMA 4
CAC-AOV-CC-4964	1.11E-03	1.028	PNEUMATIC SUPPLY TO HV-4964 FAILS	See SAMA 4

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
CAC-XHE-FO-LVENT	6.20E-02	1.028	LOCAL VENTING THRU 12" LINE FAILS	See SAMA 4
CSS-STR-PL-A	8.36E-03	1.027	CSS PUMP A SUCTION STRAINERS PLUGGED IN STANDBY	Consider alternate design of CSS suction strainer to mitigate plugging. (SAMA 15)
CSS-STR-PL-B	8.36E-03	1.027	CSS PUMP B SUCTION STRAINERS PLUGGED IN STANDBY	See SAMA 15
CSS-STR-PL-C	8.36E-03	1.027	CSS PUMP C SUCTION STRAINERS PLUGGED IN STANDBY	See SAMA 15
CSS-STR-PL-D	8.36E-03	1.027	CSS PUMP D SUCTION STRAINERS PLUGGED IN STANDBY	See SAMA 15
NRHVCSWGR24-01	4.10E-03	1.027	Fail to restore SWGR room cooling	Consider replacing one of the SWGR room cooling fans with a different design so as to eliminate common cause failure of all fans. (SAMA 16)
QUVISL	1.00E+00	1.027	ALTERNATE MAKEUP SOURCES INADEQUATE (ISLOCA)	See SAMA 1
VIS-FAN-FS-DF01	1.08E-05	1.027	CCF FAILURE FANS A THRU DV503 FAIL TO START	Consider replacing one of the SW pump room supply fans with a different design so as to eliminate common cause failure of all fans. (SAMA 17)
VIS-FAN-FS-DF12	1.08E-05	1.027	CCF FAILURE FANS A THRU DV504 FAIL TO START	Consider replacing one of the SW pump room return fans with a different design so as to eliminate common cause failure of all fans. (SAMA 18)

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
VISL	1.00E+00	1.027	LOW PRESSURE MAKEUP UNAVAILABLE (ISLOCA)	See SAMA 1
XHOS-STBY-AP502LT	5.00E-01	1.027	PUMP SSW AP502 IN STANDBY WITH 2 PUMPS OPERATING	This event represents the normal configuration of SSW pumps. Specific SAMAs associated with this system are addressed elsewhere. (No specific SAMA identified)
XHOS-STBY-CP502LT	5.00E-01	1.027	PUMP SSW CP502 IN STANDBY WITH 2 PUMPS OPERATING	This event represents the normal configuration of SSW pumps. Specific SAMAs associated with this system are addressed elsewhere. (No specific SAMA identified)
%IE-ISLOCAD	1.63E-05	1.026	ISLOCA INITIATOR FOR ECCS DISCHARGE PATHS	This initiator event is a compilation of industry and plant-specific data. (No specific SAMA identified)
UISLOCA	1.00E+00	1.026	HPCI/RCIC UNAVAILABLE FOR ISLOCA (LARGE RUPTURE OR NO EARLY ISOLATION)	See SAMA 1
IS1L	4.20E-01	1.025	SYSTEM ISOLATION FAILS GIVEN LEAKAGE	This is a conditional probability based on an initial failure mechanism. The probability is based on industry and operating experience. (No specific SAMA identified)
LEAKD	5.00E-01	1.025	PIPE LEAKAGE GIVEN OVERPRESSURIZATION IN SDC DISCHARGE LINES	This is a conditional probability based on an initial failure mechanism. The probability is based on industry and operating experience. (No specific SAMA identified)
VIS-FAN-FR-DF01	9.90E-06	1.025	CCF FAILURE FANS A THRU DV503 FAIL TO RUN	See SAMA 17

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
VIS-FAN-FR-DF12	9.90E-06	1.025	CCF FAILURE FANS A THRU DV504 FAIL TO RUN	See SAMA 18
CAC-SOV-CC-11541	9.54E-04	1.024	SOLENOID VALVE SV-11541 FAILS TO OPEN.	See SAMA 4
CAC-SOV-CC-4964	9.54E-04	1.024	SOLENOID VALVE 4964 FAILS TO OPEN.	See SAMA 4
DGS-DGN-FS-BG400	1.31E-02	1.024	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (LOCA EVENTS)	See SAMA 5
SLC-XHE-E-LVL	4.60E-01	1.024	FAIL TO CONTROL LEVEL EARLY DURING ATWS SEQUENCE	Adequate training and procedures already exist. High failure probability is due to the short response time involved. Further training and/or procedure enhancement will not reduce the failure probability. (No specific SAMA identified)
ACP-BAC-HV-RMCLG	9.00E-01	1.023	FAILURE OF EQUIPMENT GIVEN NO SWG ROOM COOLING	Although this is a conditional probability based on an initial failure mechanism, SAMA 16 may help mitigate the associated accident sequence.
DGS-DGN-FS-DG400	1.31E-02	1.023	DIVISION D DIESEL 1DG400 FAILS TO START	See SAMA 5
%FL-FPS-5302	6.62E-06	1.022	INT. FLOOD OUTSIDE LOWER RELAY ROOM	This initiator event is a compilation of industry and plant-specific data. (No specific SAMA identified)
FPS-XHE-5302IS	5.00E-01	1.022	OP. FAILS TO SECURE FPS GIVEN LCER AREA RUPTURE (EARLY)	See SAMA 8

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
HPI-TDP-TM-OP204	1.09E-02	1.022	FAILURE TO ISOLATE LOCALLY A SW RUPTURE IN RACS COMPARTMENT	See SAMA 1
LCER-PHE-DOOR	1.00E+00	1.022	LCER DOOR FAILS DUE TO WATER PRESSURE	See SAMA 8
DCP-BDC-ST-DF01	3.87E-08	1.021	CCF FAILURE 125VDC BUSES 10D410 - 20 - 30 - & 40	Based on low contribution to L1 and L2 and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
%IE-TM	5.62E-02	1.020	MSIV CLOSURE	This initiating event is tied to plant-specific operating experience. (No specific SAMA identified)
RX-FW-ADS	5.10E-05	1.020	COND. PROB. OF SMALL RECIRC SEAL LOCA GIVEN SBO	See SAMA 1
VSW-FAN-FR-DF12	9.90E-06	1.020	CCF FAILURE FANS A THRU DVH401 FAIL TO RUN	Consider replacing one of the SWGR room cooling fans with a different design so as to eliminate common cause failure of all fans. (SAMA 16)
XHOS-STBY-DP502LT	5.00E-01	1.020	PUMP SSW DP502 IN STANDBY WITH 2 PUMPS OPERATING	This event represents the normal configuration of SSW pumps. Specific SAMAs associated with this system are addressed elsewhere. (No specific SAMA identified)

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
CSS-MDP-TM-PAC	1.36E-02	1.018	CSS PUMP TRAINS A AND C IN TEST AND MAINT	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
CSS-MDP-TM-PBD	1.36E-02	1.018	CSS PUMP TRAINS B AND D IN TEST AND MAINT	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
NR-VENT-5-03	4.10E-04	1.018	FAILURE TO INITIATE CONT. VENT. GIVEN SPC HARDWARE FAILURE	Although adequate training and procedures already exist, SAMA 4 would help to mitigate the associated accident sequence. Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
RX-ADS-SW	2.25E-05	1.018	DEP OP ACT: FAIL TO INITIATE ADS AND START SW	This basic event appears in conjuction with ADS-XHE-OK-INHIB, therefore SAMA 1 applies to this event as well.
%FLSWAB-RACS-U	7.60E-08	1.017	FREQ OF COMMON HEADER TO RACS RUPTURE (UNISOLABLE)	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
%IE-SACS	1.16E-04	1.017	LOSS OF SACS INITIATING EVENT	This initiating event is tied to plant-specific operating experience. Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
NR-%IE-SACS	1.00E+00	1.017	NONRECOVERY OF %IE-SACS	Although contribution to L1 risk is low, SAMA 4 may provide some benefit in mitigating the associated accident sequence.Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
OSPR7HR-SW	2.80E-01	1.017	FAILURE TO RECOVER OSP WITHIN 7 HRS (SW RELATED LOOP EVENT)	Since this involves loss of long-term RHR, provide an independent means of alternate makeup to RPV. Possible suction sources are CST, RST and FPS. Possible use of an alternate diesel-driven pump combined with rapid depressurization. (SAMA 10)
%IE-TF	4.49E-02	1.016	FAILURE TO CNTRL PLANT USING REMOTE SHTDWN PANEL FLLWNG FPS RUPTURE OUTSIDE LWR	This initiator event is a compilation of industry and plant-specific data. (No specific SAMA identified)
DCP-EDG-PORTGEN	2.50E-02	1.016	FAILURE TO INITIATE RHR FOR DECAY HEAT REMOVAL WITHIN 20 HRS	See SAMA 5 Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
NR-RHR-INIT-L	2.10E-06	1.016	FAILURE TO INITIATE RHR FOR DECAY HEAT REMOVAL WITHIN 20 HRS	Adequate training and procedures already exist. Further training and/or procedure enhancement will not reduce the failure probability. (No specific SAMA identified)
NR-RHRVENT-INIT	2.40E-01	1.016	FAIL TO INITIATE VENT GIVEN FAILURE TO INITIATE RHR IN SPC	This is a conditional failure probability based on HEP dependency analysis. Further training and/or procedure enhancement will not reduce the failure probability. (No specific SAMA identified)
RCI-TDP-FS-OP203	1.11E-02	1.016	CCF FAILURE OF HV-2457A AND B VALVES	See SAMA 1 Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
ESF-XHE-MC-DF01	8.00E-05	1.015	COMMON CAUSE MISCALIBRATION OF ALL ECCS PRESSURE TRANS.	This is a low probability event. Further training and/or procedure enhancement will not reduce the failure probability. (No specific SAMA identified)
MSOP-LVL1--H--	5.00E-01	1.015	RPV WATER LEVEL REQUIRED TO BE LOWERED BELOW LEVEL 1	This event represents a requirement (alignment flag) to lower RPV level below Level 1 to reduce reactor power during ATWS condition. (No specific SAMA identified)
MSOPMSIVINLKH--	9.20E-01	1.015	FAIL TO BYPASS THE LOW LEVEL INTERLOCK AT LVL 1 (-129")	Failure probability is based on HEP dependency analysis. Further training and/or procedure enhancement will not reduce the failure probability. This is an EOP-directed action that is practiced in the simulator as well as trained in the classroom. (No specific SAMA identified)

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
SAC-AOV-OO-DF01	2.26E-05	1.015	CCF FAILURE OF HV-2457A AND B VALVES	Consider replacing one AOV with an MOV to eliminate the CCF contribution of this event. However, based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
XHOS-STBY-BP502LT	5.00E-01	1.015	PUMP SSW BP502 IN STANDBY WITH 2 PUMPS OPERATING	This event represents a normal plant configuration lineup. (No specific SAMA identified)
DGS-DGN-TM-BG400	1.30E-02	1.014	DGS TRAIN BG400 IN TEST AND MAINT	See SAMA 5 Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
RHS-STR-PL-PB	4.21E-03	1.014	RHR SUCTION STRAINER B PLUGGED IN STANDBY	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
RPT-PIP-RP-SEALS	9.50E-01	1.014	COND. PROB. OF SMALL RECIRC SEAL LOCA GIVEN SBO	Consider replacing recirc seals with those of a more robust design that can withstand higher temps caused by loss of cooling. Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
%FLSWA-RACS-U	5.70E-08	1.013	FREQ. OF UNISOLABLE SW A PIPE RUPT IN RACS ROOM	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
%FLSWB-RACS-U	5.70E-08	1.013	FREQ. OF UNISOLABLE SW B PIPE RUPT. IN RACS ROOM	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
DGS-DGN-TM-DG400	1.30E-02	1.013	DGS TRAIN DG400 IN TEST AND MAINT	See SAMA 5 Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
HPI-TDP-FS-DFP01	3.17E-04	1.013	CCF FAILURE OF HPCI AND RCIC TDP TO START	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified) SAMA 1 may provide some benefit. Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
IE-LOOP-CND-L	2.40E-02	1.013	INADVERTENTLY OPEN SRV INITIATING EVENT	See SAMA 3 and 5Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
RHR-XHE-RHR-INJ	1.00E-01	1.012	FAILURE TO ALIGN RHR MOV 17B LOCALLY FOR INJECTION	See SAMA 10 Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
CAC-LOG-NO-AC652	3.33E-03	1.011	LATE RPV WATER LEVEL CONTROL (CONDITIONAL)	See SAMA 4 Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
CAC-LOG-NO-DC652	3.33E-03	1.011	LOGIC CIRCUIT TO HV-4978 FAILS.	See SAMA 4 Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
NR-CSC-VSS-INIT	3.90E-02	1.011	SRVs SUCCESSFULLY RECLOSE ON REDUCED PRESSURE	See SAMA 1 Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
OSPR4HR-SW	3.61E-01	1.011	FAILURE TO RECOVER OFFSITE POWER WITHIN 4.5 HRS (SW RELATED EVENT)	See SAMA 5 Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
RHS-REPAIR-L	4.30E-01	1.011	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (LOCA EVENTS)	See SAMA 4 Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
SRV-TNK-LK-TRANS	1.00E-04	1.011	FAILURE OF 13/14 ACCUMULATORS (LEAKAGE) (NON-SBO)	Based on engineering judgment, there would be no practical cost-beneficial SAMA capable of mitigating this particular low-probability event. (No specific SAMA identified)

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
CSS-MDP-TM-PA	7.51E-03	1.010	CSS PUMP TRAIN A IN TEST AND MAINT	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
CSS-MDP-TM-PC	7.51E-03	1.010	CSS PUMP TRAIN C IN TEST AND MAINT	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
LOOP-IE-SWYD	4.03E-01	1.010	COND. PROBABILITY LOOP DUE TO SWYD EVENT	Although this is a conditional probability based on an initial failure mechanism, SAMA 5 may help mitigate the associated LOOP sequence. Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
CSS-MDP-TM-PB	7.51E-03	1.009	CSS PUMP TRAIN B IN TEST AND MAINT	Similar event that was previously addressed in L1 importance list.
CSS-MDP-TM-PD	7.51E-03	1.009	CSS PUMP TRAIN D IN TEST AND MAINT	Similar event that was previously addressed in L1 importance list.
RCI-TDP-TM-OP203	9.84E-03	1.009	RCI TURBINE TRAIN OP203 IN TEST AND MAINT	SAMA 1 applies to this event.
SLC-XHE-L-LVLCND	3.91E-02	1.009	LATE RPV WATER LEVEL CONTROL (CONDITIONAL)	This event was addressed in the L2 importance list.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
SAC-MDP-TM-SSWA	2.30E-05	1.009	SAC-B IN MAINT. COINCIDENT WITH SSW A	This event appears with LOOP sequences; addressed by SAMA 5.
XHOS-RIVER-70TO80	1.90E-01	1.008	RIVER TEMPERATURE IS 70 TO 80 DEG F	This event is based on environmental data (no specific SAMA identified).
CAC-AOV-CC-DF01	2.00E-04	1.008	COMMON CAUSE FAILURE OF AIR OPERATED BUTTERFLY VALVES TO OPEN	This event appears in conjunction with RHS-REPAIR, which is addressed by SAMA 4.
RSP-XHE-CBFLD	4.00E-03	1.008	FAILURE TO CNTRL PLANT USING REMOTE SHTDWN PANEL FLLWNG FPS RUPTURE OUTSIDE LWR	SAMA 8 applies to this event.
NR-UV-WTLVL-20M	2.10E-02	1.008	FAILURE TO CONTROL RPV WATER LVL W/HIGH PRESS. INJ. SYS.	SAMA 1 applies to this event.
DGS-DGN-TM-ABCD	2.30E-05	1.007	COINCIDENT MAINTENANCE UNAVAILABILITY OF DG A, DG B, DG C, AND DG D	This event appears with LOOP sequences; addressed by SAMA 5.
HPI-STR-PL-DFLOC	1.00E-04	1.007	CCF PLUGGING OF ECCS SUCTION STRAINERS (LOCA)	SAMA 15 applies to this event.
DGS-DGN-FS-AG400	1.31E-02	1.007	DIVISION A DIESEL 1AG400 FAILS TO START	SAMA 5 applies to this event.
%IE-SORV2	2.44E-04	1.007	2 or More SORVs	SAMA 1 applies to this event.
RX-ADS-SW-HXDISH	1.50E-05	1.007	DEP HEP: FAILURE TO INITIATE ADS, SW PUMP, SWS HX VALVE	SAMA 1 applies to this event.
RCI-MOV-LK-ROOM	1.00E-01	1.007	PROBABILITY OF STEAM LEAK INTO RCI ROOM	This event appears with LOOP sequences; addressed by SAMA 5.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
FPS-XHE-ALIGN	5.80E-02	1.006	FAILURE TO ALIGN FPS FOR INJECTION IN TIME	This event was addressed in the L2 importance list.
OSPR30MIN-GR	8.25E-01	1.006	FAILURE TO RECOVER GRID LOOP W/IN 30 MIN.	SAMA 5 applies to this event.
RHS-MDP-TM-PA	1.58E-02	1.006	RHS PUMP TRAIN A IN TEST AND MAINT	SAMA 4 applies to this event.
NR-U1X-DEP-10M	3.20E-02	1.006	FAILURE TO MANUALLY DEPRESSURIZE THE RPV WITHIN 10 MIN.	This event appears in cutsets related to ATWS scenarios. No cost-beneficial SAMA was feasible based on low probability of mechanical scram failure. (No specific SAMA identified).
SWS-STR-FR-DF01	2.78E-06	1.006	CCF FAILURE TO RUN ALL SWS STRNR MOTORS	This event is associated with those cutsets that can be mitigated via SAMAs 4, 5 and 15.
%FLFPS-RBU	6.60E-05	1.006	FPS RUPTURE IN RB UPPER LEVELS	SAMA 8 applies to this event.
FPS-XHE-RB-E	1.00E+00	1.006	FAILURE TO ISOLATE FPS PIPE RUPTURE IN THE REACTOR BUILDING (EARLY)	SAMA 8 applies to this event.
SWS-MOV-VF-SPRAY	1.00E-01	1.006	Flood - SPRAY CAUSES MOV FAILURE IN RACS COMPARTMENT	This is associated with a low probability scenario that conservatively assumes failure of MOVs due to spray damage; there is no feasible SAMA identified for this type of event.
LPI-XHE-AT-LVL	4.00E-02	1.006	FAILURE TO CONTROL LP ECCS TO PREVENT OVERFILL	This event appears in cutsets related to ATWS scenarios. No cost-beneficial SAMA was feasible based on low probability of mechanical scram failure. (No specific SAMA identified).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
SWS-PHE-PMP-HD	9.00E-01	1.006	SW HEAD INADEQUATE	This event appears in conjunction with RHS-REPAIR, which is addressed by SAMA 4.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
CGS-PHE-FF-INERT	9.90E-01	7.759	CONTAINMENT INERTED; VENTING NOT REQUIRED	Indication of plant configuration / condition. (No specific SAMA identified)
CNT-MDL-FF-SCTRM	1.00E+00	2.484	REACTOR BUILDING INEFFECTIVE IN REDUCING SOURCE TERM	This event assumes no credit for source term scrubbing. There was no feasible SAMA identified for this event.
RX-NOCREDIT	1.00E+00	2.439	FAILURE OF IN-VESSEL RECOVERY	This event assumes no credit for in-vessel recovery. There was no feasible SAMA identified for this event.
CNT-MDL-FF-LVL1F	1.00E+00	1.747	LG CONT. FAILURE GIVEN CONT. FAILED IN LEVEL 1 (CLASS II, IIID, IV)	This is conditional probability based on plant damage state. (No specific SAMA identified)
CNT-DWV-FF-MLTFL	1.00E+00	1.731	DW SHELL MELT-THROUGH FAILURE DUE TO CONT. FAILURE	This event assumes immediate failure of containment due to core melt-through, which implies that as soon as molten corium contacts the DW inner liner, containment failure is guaranteed. There was no feasible SAMA identified for this event.
DIA	9.78E-01	1.518	DRYWELL FAILURE (CLASS IIA)	This is a split fraction used in the CET for condition of DW. (No specific SAMA identified)
OP6-IIA-NOT	8.80E-01	1.427	0	This is a split fraction for success path in CET. (No specific SAMA identified)
RHR-MCU-FF-MSIVS	1.00E+00	1.279	PCS UNAVAILABLE AS HEAT SINK	This event appears in combination with RHS-REPAIR-TR. See SAMA 4 (L1 List).

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
RHR-MDL-FF-EOPCM	1.00E+00	1.279	CONTINGENCY METHODS INADEQUATE (NOT CREDITED)	This is a place holder event for contingency methods that are not credited in the PRA model. See SAMA 4 (L1 List).
1RXPH-CRDINJ-F--	1.00E+00	1.264	CRD INJECTION INADEQUATE	This is a flag event representing the inability to inject water into the vessel. SAMA 1 (L1 List) would provide some benefit.
1RXPH-HPCIRVLF--	1.00E+00	1.264	HPCI UNAVAILABLE	This is a flag event representing the inability to inject water into the vessel. SAMA 1 (L1 List) would provide some benefit.
1RXPH-MNFDWTRF--	1.00E+00	1.264	MAIN FEEDWATER SYSTEM UNAVAILABLE	This is a flag event representing the inability to inject water into the vessel. SAMA 1 (L1 List) would provide some benefit.
1RXPH-RCICINAF--	1.00E+00	1.264	RCIC SYSTEM INADEQUATE	This is a flag event representing the inability to inject water into the vessel. SAMA 1 (L1 List) would provide some benefit.
VF--XHE-L2-INREC	9.00E-01	1.264	OPERATOR FAIL TO RECOVER INJECTION BEFORE RPV BREACH	This event is also associated with flooding scenarios previously identified in the L1 list. SAMAs 7 and 8 (L1 List) will provide some benefit.
IS1-IA-NOT	8.00E-01	1.238	0	This is a split fraction for success path in CET. (No specific SAMA identified)
CNT-MDL-SC-MDTMP	1.00E+00	1.143	SM CONT. FAILURE AT INTER DW TEMP. (CLASS I, III WITH RPV BREACH)	This is a flag event tied to a type of accident sequence. (No specific SAMA identified)
FC5-3B-NOT	5.90E-01	1.125	CONTAINMENT FLOODING INITIATED (IIIB)	This is a split fraction for success path in CET. (No specific SAMA identified)

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
1RXRX-ONEACL-F--	1.00E+00	1.111	ONSITE EMERGENCY AC POWER NOT RECOVERED	See SAMA 5 (L1 list)
OP5-NOT	8.80E-01	1.109	0	This is a split fraction for success path in CET. (No specific SAMA identified)
1RXRX-OFFACL-F--	6.00E-01	1.109	OFFSITE AC POWER NOT RECOVERED	See SAMA 5 (L1 list)
OP--XHE-ALT-DEP	1.00E+00	1.099	ALTERNATE DEPRESS. METHODS NOT CREDITED	See SAMA 4 (L1 List)
UV1-XHE-ALDHR-RX	1.00E+00	1.099	Op. Fails to Align Alternate Inj. Flow Paths to Recover In-Vessel Core Damage	This event appears in combination with RHS-REPAIR-L which was identified in the L1 SAMA List. See SAMA 4 (L1 List).
1OPPH-PRESBK-F--	8.00E-01	1.099	PRESSURE TRANSIENT DOES NOT FAIL MECHANICAL SYSTEMS	This is a split fraction for success path in CET. (No specific SAMA identified)
1OPPH-TEMPBK-F--	7.00E-01	1.099	HIGH PRIM SYS TEMP DOES NOT CAUSE FAIL OF RCS PRESS. BOUND	This is a split fraction for success path in CET. (No specific SAMA identified)
1OPPH-SORV---F--	5.50E-01	1.099	SRVs DO NOT FAIL OPEN DURING CORE MELT PROGRESSION	This is a split fraction for success path in CET. (No specific SAMA identified)
CMS-MDL-SC-LFLMT	1.00E+00	1.098	LG. CONT. FAILURE DOES NOT COMPROMISE M/U SOURCES (INTERMED. TEMP)	This is a flag event tied to other Level 2 plant phenomena. (No specific SAMA identified)
CMS-MDL-SC-MDTMP	5.00E-01	1.087	CONT. LEAK. OR VENT DOES NOT COMPROMISE M/U SOURCES (INTERMED. TEMP)	This is a flag event tied to other Level 2 plant phenomena. (No specific SAMA identified)

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
CGS-XHE-L2-VENT	2.51E-01	1.086	OPERATOR FAILS TO VENT (HC.OP.EO-ZZ.0318)	This event appears in combination with RHS-REPAIR-L which was identified in the L1 SAMA List. See SAMA 4 (L1 List).
VC1-ID-NOT	6.70E-01	1.075	0	This is a split fraction for success path in CET. (No specific SAMA identified)
1RX-PHE-SUBSUME	1.00E+00	1.072	ACCIDENT TIME DOES NOT EXCEED 4 HRS TO CORE DAMAGE	This is a flag event tied to other Level 2 plant phenomena. (No specific SAMA identified)
DIATWS-NOT	9.90E-01	1.062	DW INTACT ATWS	This is a split fraction for success path in CET. (No specific SAMA identified)
CND-SYS-FF-LERF	1.00E+00	1.055	0	This is a flag event tied to other Level 2 plant phenomena. (No specific SAMA identified)
OP6-NOT	9.00E-01	1.055	0	This is a split fraction for success path in CET. (No specific SAMA identified)
SWS-XHE-RACS-UNI	1.00E+00	1.051	FAILURE TO ISOLATE LOCALLY A SW RUPTURE IN RACS COMPARTMENT	See SAMA 7 (L1 List)
1OPPH-CNTFAD-F--	4.50E-01	1.051	STRUCTURAL BREACH IN CONT. CUASES FAILURE OF ADS	This is a conditional probability based on structural failure of containment. No feasible method of reinforcing ADS supply to preclude this event. (No specific SAMA identified)
FPS-XHE-CRISOL	1.00E+00	1.047	Operator fails to secure FPS given CR area rupture	See SAMA 8 (L1 List)
MCR-PHE-DOOR	5.00E-01	1.047	MCR DOOR FAILS DUE TO WATER PRESSURE	See SAMA 8 (L1 List)

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
PCV-XHE-L2-VENT	1.30E-01	1.047	OPERATOR FAILS TO VENT (HC.OP-EO-ZZ.0318)	This event appears in combination with RHS-REPAIR-L which was identified in the L1 SAMA List. See SAMA 4 (L1 List).
%FLFPS-CR	1.10E-05	1.047	FPS RUPTURE OUTSIDE CONTROL ROOM	See SAMA 8 (L1 List)
L2-OSP-24H-SW	8.57E-01	1.043	COND PROB OF FAILURE TO RESTORE AC IN L2 W/IN 24 HRS. NODE SI	Same as SAMA 5 (L1 list)
CIS-DRAN-L2-OPEN	1.00E+00	1.038	VALVES OPEN AUTOMATICALLY FOR DRAINAGE NORMALLY OPEN	The major contributor is loss of power to these valves. SAMA 5 (L1 List) will provide benefit. Another means to address this, although more costly, is to replace the MOVs with FC AOVs.
SWS-PHE-PMP-HD	9.00E-01	1.037	SW HEAD INADEQUATE	See SAMA 4 (L1 list)
PCS-SYS-RP-DWFAIL	4.30E-01	1.037	LARGE DW CONTAINMENT FAILURE CAUSES LOSS OF INJECTION	This is a conditional probability based on structural failure of containment. No feasible method of reinforcing injection piping to preclude this event. (No specific SAMA identified)
RHS-MDP-TM-PB	1.58E-02	1.035	RHS PUMP TRAIN B IN TEST AND MAINT	See SAMAs 1, 4 and 8 (L1 List)
WWATWS	5.00E-01	1.03	WW FAILURE ATWS	L2 phenomenology probability. (No specific SAMA identified)
WWATWS-NOT	5.00E-01	1.03	WW FAILURE ATWS	This is a split fraction for success path in CET. (No specific SAMA identified)

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
L2-OSP-11H-SW	7.46E-01	1.025	COND. PROB. OF FAILURE TO RESTORE AC IN L2 W/IN 11 HRS IN NODE SI	See SAMA 5 (L1 List)
1RXRX-ONEACE-F--	1.00E+00	1.023	ONSITE EMERGENCY AC POWER NOT RECOVERED	See SAMA 5 (L1 list)
1RXRX-OFFACE-F--	6.30E-01	1.023	OFFSITE AC POWER NOT RECOVERED	See SAMA 5 (L1 list)
DIT	1.00E+00	1.022	DRYWELL FAILURE (CLASS IIT AND IIID)	This is a flag event tied to a type of accident sequence. (No specific SAMA identified)
CGS-PHE-FF-STMIN	9.90E-01	1.022	COMBUSTIBILE GAS VENTING NOT REQUIRED (STEAM INERTED - CLASS IIID)	L2 phenomenology probability. (No specific SAMA identified)
L2-OSP-8H-SW	6.75E-01	1.022	COND. PROB. OF FAILURE TO RESTORE AC IN L2 W/IN 8 HRS IN NODE SI	See SAMA 5 (L1 List)
CIS-XHE-FO-DRN-E	1.00E+00	1.021	OP FAILS TO LOCALLY CLOSE EQ. DRN AND FLR DRN MOV IN RB-EARLY	The major contributor is loss of power to these valves. SAMA 5 (L1 List) will provide benefit. Another means to address this, although more costly, is to replace the MOVs with FC AOVs.
ACP-XHE-L2-OP	5.00E-01	1.021	OPERATOR FAILS TO RESTORE AC POWER DURING BOIL-OFF	See SAMA 5 (L1 List)
CSS-STR-PL-A	8.36E-03	1.021	CSS PUMP A SUCTION STRAINERS PLUGGED IN STANDBY	See SAMA 15 (L1 List)

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
CSS-STR-PL-B	8.36E-03	1.021	CSS PUMP B SUCTION STRAINERS PLUGGED IN STANDBY	See SAMA 15 (L1 List)
CSS-STR-PL-C	8.36E-03	1.021	CSS PUMP C SUCTION STRAINERS PLUGGED IN STANDBY	See SAMA 15 (L1 List)
CSS-STR-PL-D	8.36E-03	1.021	CSS PUMP D SUCTION STRAINERS PLUGGED IN STANDBY	See SAMA 15 (L1 List)
DCP-BDC-ST-DF01	3.87E-08	1.021	CCF FAILURE 125VDC BUSES 10D410 - 20 - 30 - & 40	Based on low contribution to L1 and L2 and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
NR-CSC-VSS-INIT	3.90E-02	1.02	OPERATOR FAILS TO INITIATE DRYWELL SPRAYS	Although this HEP was analyzed in detail and operator training and procedures were deemed adequate, the relatively high failure rate was attributed to short time available to perform action. Further training and/or procedure enhancement will not reduce the failure probability. However, this event appears in conjunction with XHE-OK-INHIB and therefore SAMA 1 (L1 List) would apply.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
%FLSWAB-RACS-U	7.60E-08	1.02	FREQ OF COMMON HEADER TO RACS RUPTURE (UNISOLABLE)	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
CAC-LOG-NO-AC652	3.33E-03	1.019	LOGIC CIRCUIT AT AC652 FAILS.	See SAMA 4 (L1 list)Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
CAC-LOG-NO-DC652	3.33E-03	1.019	LOGIC CIRCUIT TO HV-4978 FAILS.	See SAMA 4 (L1 list) Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
OP1-IA-NOT	8.40E-01	1.018	RPV DEPRESSURIZATION SUCCESSFUL (IA)	This is a split fraction for success path in CET. (No specific SAMA identified)
CIS-XHE-FO-DRN-L	1.30E-01	1.018	OP FAILS TO LOCALLY CLOSE EQ. DRN AND FLR DRN MOV IN RB-LATE	See SAMA 5 (L1 List) Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
NRHVCSWGR24-01	4.10E-03	1.017	Fail to restore SWGR room cooling	SAMA 16 (L1 List) will provide some benefit since this event appears most of the time with common cause failure of the room cooling fans. Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
SLC-XHE-L-LVLCND	3.91E-02	1.016	LATE RPV WATER LEVEL CONTROL (CONDITIONAL)	This is a conditional probability based on sequence of events related to ATWS. No cost-beneficial SAMA was feasible based on low probability of mechanical scram failure. (No specific SAMA identified) Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
L2-OSP-10H-SW	7.26E-01	1.015	COND PROB OF FAILURE TO RESTORE AC IN L2 W/IN 10 HRS IN NODE SI	See SAMA 5 (L1 list) Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
OSP65HR-SW	3.07E-01	1.015	FAILURE TO RECOVER OSP WITHIN 6 HOURS (SEVERE WEATHER LOOP EVENT)	See SAMA 5 (L1 list)Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
DCP-EDG-PORTGEN	2.50E-02	1.015	PORTABLE GENERATOR FAILS	See SAMA 5 (L1 list) Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
CSS-MDP-TM-PAC	1.36E-02	1.015	CSS PUMP TRAINS A AND C IN TEST AND MAINT	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
CSS-MDP-TM-PBD	1.36E-02	1.015	CSS PUMP TRAINS B AND D IN TEST AND MAINT	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
%FLSWA-RACS-U	5.70E-08	1.015	FREQ. OF UNISOLABLE SW A PIPE RUPT IN RACS ROOM	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
%FLSWB-RACS-U	5.70E-08	1.015	FREQ. OF UNISOLABLE SW B PIPE RUPT. IN RACS ROOM	Based on low contribution to L1 risk and engineering judgment, the anticipated implementation cost of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit. (No specific SAMA identified)
RHR-XHE-RHR-INJ	1.00E-01	1.014	FAILURE TO ALIGN RHR MOV 17B LOCALLY FOR INJECTION	See SAMA 10 (L1 List) Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
CAC-AOV-CC-DF01	2.00E-04	1.014	COMMON CAUSE FAILURE OF AIR OPERATED BUTTERFLY VALVES TO OPEN	See SAMA 4 (L1 list)Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
SAC-MDP-TM-SSWA	2.30E-05	1.014	SAC-B IN MAINT. COINCIDENT WITH SSW A	This is a low probability event that is not part of routine maintenance. This type of situation is monitored via the online maintenance (a4) process. (No specific SAMA identified)
ACP-BAC-HV-RMCLG	9.00E-01	1.013	FAILURE OF EQUIPMENT GIVEN NO SWG ROOM COOLING	See SAMA 16 (L1 List) Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
FC1-IA-NOT	2.80E-01	1.013	0	This is a split fraction for success path in CET. (No specific SAMA identified)
ESF-XHE-MC-DF01	8.00E-05	1.013	COMMON CAUSE MISCALIBRATION OF ALL ECCS PRESSURE TRANS.	This is a low probability event. Further training and/or procedure enhancement will not reduce the failure probability. (No specific SAMA identified)
ESF-XHE-MC-DF01	8.00E-05	1.013	COMMON CAUSE MISCALIBRATION OF ALL ECCS PRESSURE TRANS.	This is a low probability event. Further training and/or procedure enhancement will not reduce the failure probability. (No specific SAMA identified)
DGS-DGN-TM-ABCD	2.30E-05	1.013	COINCIDENT MAINTENANCE UNAVAILABILITY OF DG A, DG B, DG C, AND DG D	This is a low probability event that is not part of routine maintenance. This type of situation is monitored via the online maintenance (a4) process. (No specific SAMA identified)
VSW-FAN-FR-DF12	9.90E-06	1.013	CCF FAILURE FANS A THRU DVH401 FAIL TO RUN	See SAMA 16 (L1 List) Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
IE-LOOP-CND-L	2.40E-02	1.012	CONDITIONAL LOOP GIVEN TRANSIENT WITH LOCA SIGNAL	See SAMA 3 and 5 (L1 List) Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
HPI-STR-PL-DFLOC	1.00E-04	1.012	CCF PLUGGING OF ECCS SUCTION STRAINERS (LOCA)	This event is addressed by various NRC documents (GSI-191, others) for all nuclear sites, and therefore, no further work is deemed necessary. (No specific SAMA identified)
VC1-IA-NOT	8.00E-01	1.01	0	This is a split fraction for success path in CET. (No specific SAMA identified)
VC1-IBL-NOT	7.50E-01	1.01	0	This is a split fraction for success path in CET. (No specific SAMA identified)
XHOS-STBY-DP502LT	5.00E-01	1.01	PUMP SSW DP502 IN STANDBY WITH 2 PUMPS OPERATING	This event represents the normal configuration of SSW pumps. Specific SAMAs associated with this system are addressed elsewhere. (No specific SAMA identified)
CMS-MDL-SC-LOOPL	5.00E-01	1.01	CONT. LEAK OR VNT DOES NOT COMPROMISE MU SOURCES (INTER. TMP)	This is a flag event tied to other Level 2 plant phenomena. (No specific SAMA identified)
FPS-XHE-ALIGN	5.80E-02	1.01	FAILURE TO ALIGN FPS FOR INJECTION IN TIME	This HEP was analyzed in detail. Operator training and procedures were deemed adequate. Relatively high failure rate attributed to short time available to perform action. Further training and/or procedure enhancement will not reduce the failure probability. (No specific SAMA identified)

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
LPI-XHE-AT-LVL	4.00E-02	1.01	FAILURE TO CONTROL LP ECCS TO PREVENT OVERFILL	This HEP was analyzed in detail. Operator training and procedures were deemed adequate. Relatively high failure rate attributed to short time available to perform action. Further training and/or procedure enhancement will not reduce the failure probability. (No specific SAMA identified)
DGS-DGN-FS-BG400	1.31E-02	1.01	DIVISION B DIESEL 1BG400 FAILS TO START	See SAMA 5 (L1 List) Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
HPI-TDP-TM-OP204	1.09E-02	1.01	HPI TURBINE TRAIN OP204 IN TEST AND MAINT	See SAMA 1 (L1 List) Given the low RRW value of <1.02, this modification may not be cost beneficial if implementation costs are greater than $500K.
%IE-TF	4.49E-02	1.009	LOSS OF FEEDWATER	This initiating event is tied to plant-specific operating experience. (No specific SAMA identified).
CGS-PHE-SC-INERT	1.00E-02	1.009	CONTAINMENT NOT INERTED; VENTING REQUIRED	This is a plant condition not related to any specific failure; this event appears in those cutsets addressed by SAMAs 1, 4, and 8.
WW-DW-LK-RUPT	1.00E-01	1.009	RB SYS FAIL DUE TO ENVRON. STRESS WW RUPT/LK	This event appears in conjunction with RHS-REPAIR, which is addressed by SAMA 5.
OSPR30MIN-GR	8.25E-01	1.009	FAILURE TO RECOVER GRID LOOP W/IN 30 MIN.	SAMA 5 applies to this event.
RHS-STR-PL-PB	4.21E-03	1.009	RHR SUCTION STRAINER B PLUGGED IN STANDBY	SAMA 4 applies to this event.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
RCI-MOV-LK-ROOM	1.00E-01	1.009	PROBABILITY OF STEAM LEAK INTO RCI ROOM	This event appears with LOOP sequences; addressed by SAMA 5.
%IE-SORV2	2.44E-04	1.009	2 or More SORVs	SAMA 1 applies to this event.
IAS-MDC-FR-K100	6.09E-02	1.009	EIA COMPRESSOR FAILS TO RUN	SAMA 3 applies to this event.
NR-ATWS-ADS-INH	1.50E-02	1.008	FAILURE TO INHIBIT ADS DURING AN ATWS (W/O FW)	This event appears in cutsets related to ATWS scenarios. No cost-beneficial SAMA was feasible based on low probability of mechanical scram failure. (No specific SAMA identified).
1CZPH-EXVSLSTF--	1.00E-02	1.008	EX-VESSEL STEAM EXPLOSION	Even though this is an event related to L2 phenemonology, SAMAs 1, 4, and 8 will provide some benefit.
%FL-FPS-5302	6.62E-06	1.008	INT. FLOOD OUTSIDE LOWER RELAY ROOM	This event was addressed in the L1 importance list.
FPS-XHE-5302IS	5.00E-01	1.008	OP. FAILS TO SECURE FPS GIVEN LCER AREA RUPTURE (EARLY)	This event was addressed in the L1 importance list.
LCER-PHE-DOOR	1.00E+00	1.008	LCER DOOR FAILS DUE TO WATER PRESSURE	This event was addressed in the L1 importance list.
DGS-DGN-FS-DG400	1.31E-02	1.008	DIVISION D DIESEL 1DG400 FAILS TO START	This event was addressed in the L1 importance list.
RSP-XHE-CBFLD	4.00E-03	1.007	FAILURE TO CNTRL PLANT USING REMOTE SHTDWN PANEL FLLWNG FPS RUPTURE OUTSIDE LWR	SAMA 8 applies to this event.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
CSS-MDP-TM-PA	7.51E-03	1.007	CSS PUMP TRAIN A IN TEST AND MAINT	This event was addressed in the L1 importance list.
CSS-MDP-TM-PB	7.51E-03	1.007	CSS PUMP TRAIN B IN TEST AND MAINT	Similar event that was previously addressed in L1 importance list.
CSS-MDP-TM-PC	7.51E-03	1.007	CSS PUMP TRAIN C IN TEST AND MAINT	This event was addressed in the L1 importance list.
CSS-MDP-TM-PD	7.51E-03	1.007	CSS PUMP TRAIN D IN TEST AND MAINT	Similar event that was previously addressed in L1 importance list.
LPI-XHE-AT-LVLF	1.00E-01	1.007	FAILURE TO CNTRL LP ECCS TO PRVNT OVERFILL GIVEN HPI FAILS	This event appears in cutsets related to ATWS scenarios. No cost-beneficial SAMA was feasible based on low probability of mechanical scram failure. (No specific SAMA identified).
SLC-TNK-LO-10204	7.55E-03	1.006	SLC STORAGE TANK CONCENTRATION OUT OF SPEC.	This event appears in cutsets related to ATWS scenarios. No cost-beneficial SAMA was feasible based on low probability of mechanical scram failure. (No specific SAMA identified).
LOOP-IE-SWYD	4.03E-01	1.006	COND. PROBABILITY LOOP DUE TO SWYD EVENT	This event was addressed in the L1 importance list.
%FLTORUS	2.80E-06	1.006	TORUS RUPTURE IN TORUS ROOM	This is a low probability event with no feasible cost-beneficial SAMA identified; SAMA 1 may provide some benefit.
DGS-DGN-FS-AG400	1.31E-02	1.006	DIVISION A DIESEL 1AG400 FAILS TO START	SAMA 5 applies to this event.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RISK REDUCTION WORTH	DESCRIPTION	POTENTIAL SAMAS
SRV-TNK-LK-TRANS	1.00E-04	1.006	FAILURE OF 13/14 ACCUMULATORS (LEAKAGE) (NON-SBO)	This event was addressed in the L1 importance list.
SWS-STR-FR-DF01	2.78E-06	1.006	CCF FAILURE TO RUN ALL SWS STRNR MOTORS	This event is associated with those cutsets that can be mitigated via SAMAs 4, 5 and 15.
HPI-XHE-AT-CS	1.10E-01	1.006	CREW BLOWS DOWN BEFORE LVL IS CONTROLLED BY HPCI (3600 GPM)	This event appears in cutsets related to ATWS scenarios. No cost-beneficial SAMA was feasible based on low probability of mechanical scram failure. (No specific SAMA identified).
DGS-DGN-TM-BG400	1.30E-02	1.006	DGS TRAIN BG400 IN TEST AND MAINT	This event was addressed in the L1 importance list.
SAC-MDP-TM-SSWB	2.30E-05	1.006	SAC A IN MAINT. COINCIDENT WITH SSW B	SAMA 3 applies to this event.
DIA-NOT	2.20E-02	1.006	DRYWELL INTACT (CLASS IIA)	This is a split fraction for success path in CET. (No specific SAMA identified).
WWA	1.00E+00	1.006	WETWELL AIRSPACE FAILURES (CLASS IIA)	SAMA 4 applies to this event.

TABLE E.5-3
HCGS PHASE 1 SAMA LIST SUMMARY

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE (1)	RETAINED	PHASE 1 BASELINE DISPOSITION
1	Remove ADS inhibit from non-ATWS emergency operating procedures	Investigate the design basis for inhibiting ADS. If ADS does not have to be inhibited except for ATWS, it can be credited for reducing pressure in more scenarios. Susquehanna and LaSalle have taken this approach. An alternative solution is to install an injection system capable of operating at high pressures. However, this solution is a much costlier option and may likely prove not be a practical approach to mitigating this event.	HCGS Level 1 Importance List	$200,000	Yes	See Section E.6.1
3	Install Back-Up air compressor to Supply AOVs	Provide a back-up air compressor to supply AOVs with an alternate air source.	HCGS Level 1 Importance List	$700,000	Yes	See Section E.6.2
4	Provide procedural guidance to cross-tie RHR trains	Provide the ability to cross-tie RHR pumps trains. Although the piping network exists, it is not allowed by procedure.	HCGS Level 1 Importance List	$100,000	Yes	See Section E.6.3
5	Restore AC power with onsite gas turbine generator	Improve procedural use of gas turbine generator to restore onsite emergency AC power sources.	HCGS Level 1 Importance List	$2,050,000	Yes	See Section E.6.4

TABLE E.5-3
HCGS PHASE 1 SAMA LIST SUMMARY

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE (1)	RETAINED	PHASE 1 BASELINE DISPOSITION
7	Install better flood detection instrumentation for RACS compartment	This HRE represents an internal flooding scenario that disables various safety-related components. Mitigation of this event can be accomplished by replacing manual isolation valves with remotely-operated MOVs with automatic isolation capability.	HCGS Level 1 Importance List	$3,070,000	Yes	See Section E.6.5
8	Convert selected fire protection piping from wet pipe to dry pipe system	This HRE represents an internal flooding scenario that disables various safety-related components. Mitigation of this event can be accomplished by changing the existing FPS to a dry-pipe system. Limerick took this approach.	HCGS Level 1 Importance List	$600,000	Yes	See Section E.6.6
10	Provide procedural guidance to use B.5.b low pressure pump for non-security events	Since this involves loss of long-term RHR, provide an independent means of alternate makeup to RPV. Possible suction sources are CST, RST and FPS. Possible use of an alternate diesel-driven pump combined with rapid depressurization.	HCGS Level 1 Importance List	$100,000	Yes	See Section E.6.7
14	Alternate room cooling for SW rooms	Provide an alternate means of opening the Torus Vent valves when remote operation fails. Adequate time is available given this is a long term sequence.	HCGS Level 1 Importance List	$500,000	No	SAMA 14 has been subsumed into SAMA 4 (Cross-tie RHR pump trains).

TABLE E.5-3
HCGS PHASE 1 SAMA LIST SUMMARY

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE [1]	RETAINED	PHASE 1 BASELINE DISPOSITION
15	Alternate design of CSS suction strainer to mitigate plugging	Consider alternate design of CSS suction strainer to mitigate plugging.	HCGS Level 1 Importance List	$1,000,000	Yes	See Section E.6.8
16	Use of different designs for switchgear room cooling fans	Consider replacing one of the SWGR room cooling fans with a different design so as to eliminate common cause failure of all fans.	HCGS Level 1 Importance List	$400,000	Yes	See Section E.6.9
17	Replace a supply fan with a different design in service water pump room	Consider replacing one of the SW pump room supply fans with a different design so as to eliminate common cause failure of all fans.	HCGS Level 1 Importance List	$600,000	Yes	See Section E.6.10
18	Replace a return fan with a different design in service water pump room	Consider replacing one of the SW pump room return fans with a different design so as to eliminate common cause failure of all fans.	PRA Group Insight	$600,000	Yes	See Section E.6.11
30	Provide procedural guidance for partial transfer of control functions from the control room to the remote shutdown panel	For fires that cause catastrophic damage to the controls of a single critical system, the reliability of controling the plant may be improved by allowing the operators to transfer only a single division of controls to the RSP to recover a channel of the critical system while the MCR is maintained as the primary control center. A permutaiton of this SAMA would be to use local system controls rather than the RSP.	IPEEE (Fire)	$100,000	Yes	See Section E.6.12

TABLE E.5-3
HCGS PHASE 1 SAMA LIST SUMMARY

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE (1)	RETAINED	PHASE 1 BASELINE DISPOSITION
31	Install improved fire barriers in the MCR control cabinets containing the primary MSIV control circuits	MCR fires that propagate from the originating cabinets result in widespread control damage and induce environmental conditions that would require abandonment even if the controls were not damaged. IPEEE insights suggest that improving the fire barriers in the console containg the primary MSIV controls would reduce the probability of these types of fire events.	IPEEE (Fire)	$1,200,000	Yes	See Section E.6.13
32	Install additional physical barriers to limit dispersion of fuel oil from DG rooms	For compartment 5339 fire scenario 5339_2, install a curb or a diversion channel to ensure liquids from the DG rooms cannot communicate with Room 5339.	IPEEE (Fire)	$800,000	Yes	See Section E.6.14
33	Install Division II 480VAC bus cross-ties	For DG room (D) fire scenario 5304_2, install cross-ties between the Division II 480VAC buses (potentially 10B420 to10B480 and 10B460 to 10B440).	IPEEE (Fire)	$1,320,000	Yes	See Section E.6.15
34	Install Division I 480VAC bus cross-ties	For DG room (C) fire scenario 5306_2, install cross-ties between the Division I 480VAC buses (potentially 10B410 to10B430 and 10B450 to 10B470).	IPEEE (Fire)	$1,320,000	Yes	See Section E.6.16

TABLE E.5-3
HCGS PHASE 1 SAMA LIST SUMMARY

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE [(1)]	RETAINED	PHASE 1 BASELINE DISPOSITION
35	Relocate, minimize, and/or eliminate electrical heaters in electrical access room	For compartment 3425/5401 fire scenario 5401_1, move or eliminate the electrical heaters in the electrical access room (Aux Building 124' level) to prevent damage to the Division II power cables.	IPEEE (Fire)	$270,000	Yes	See Section E.6.17
36	Provide procedural guidance for loss of all 1E 120V AC power	For Seismic-Induced Equipment Damage State SET-36 (Impacts - 120V PNL481), develop MCR procedures to operate the plant after a loss of all class 1E 120V AC power.	IPEEE (Seismic)	$270,000	Yes	See Section E.6.18
37	Reinforce 1E 120V AC distribution panels	For Seismic-Induced Equipment Damage State SET-36 (Impacts - 120V PNL481), reinforce the class 1E 120V AC distribution panels.	IPEEE (Seismic)	$500,000	Yes	See Section E.6.19
38	Enhance FWS and ADS for long term injection	For Seismic-Induced Equipment Damage State SET-36 (Impacts - LOOP), enhance the Fire Water system and use the existing portable generator to support SRV operation for long term injection in seismic events.	IPEEE (Seismic)	N/A	No	Subsequent to the IPEEE, procedure HC.OP-AM.TSC-0024 was developed to address the actions associated with this SAMA. Therefore, this SAMA is screened from further analysis.
39	Provide procedural guidance to bypass RCIC turbine exhaust trip	Revise procedure to allow bypass of RCIC turbine exhaust pressure trip.	Industry SAMA List	$120,000	Yes	See Section E.6.20

TABLE E.5-3
HCGS PHASE 1 SAMA LIST SUMMARY

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE [1]	RETAINED	PHASE 1 BASELINE DISPOSITION
40	Increase reliability / install manual bypass of LP permissive	Increase the reliability of the low pressure ECCS RPV low pressure permissive circuitry. Install manual bypass of low pressure permissive.	Industry SAMA List	$620,000	Yes	See Section E6.21

Notes:

[1] Cost estimates provided / validated by HCGS

TABLE E.5.4
SUMMARY OF HCGS PRA MODELING OF SEISMIC IMPACT ON BASELINE HEPS

OPERATOR ACTION DESCRIPTION (1)	HCGS PRA BASELINE HEP (BASIC EVENT ID)	HCGS IPE HEP	HCGS SEISMIC IPEEE HEP	HEP MODIFICATIONS IN HCGS PRA FOR SEISMIC INITIATORS
Failure to Provide Alternate Ventilation Within 12 Hours After Loss of Class 1E Panel Room HVAC	2.9E-3 (NR-HVC-PNRM-12) (6)	3.0E-4	3.0E-3	The frequency of seismic initiator %IE-SET38, as taken from the HCGS Seismic IPEEE, incorporates the increased HEP (3E-3) due to the seismic event. No HEP adjustment necessary in the HCGS PRA modeling. For other seismic initiators, operator action basic event NR-HVC-PNRM-SET, with a value of 3.0E-3, is used in the fault tree logic to replace the baseline 2.9E-3 HEP.
Failure to Provide Alternate Ventilation Within 24 Hours After Loss of Switchgear Room Ventilation	1.4E-2 (NRHVCSWGR24-01)	1.6E-4	1.0E-1	Operator action basic event NRHVCSWGR24-SET, with a value of 1.0E-1, is used in the fault tree logic to replace the baseline 1.4E-2 HEP.
Failure to Initiate RHR for Decay Heat Removal (Early)	3.1E-4 (NR-RHR-INIT)	5.0E-5	5.0E-4	Operator action basic event NR-RHR-INIT-SET, with a value of 5.0E-4, is used in the fault tree logic to replace the baseline 3.1E-4 HEP. Operator action basic event NR-RHR-INIT-SET also is used in the fault tree logic to replace basic event NR-RHR-INIT-L (Failure to Initiate RHR for DHR – Late) to replace the baseline 2.1E-6 HEP.
Failure to Align SACS for Long-Term Operation with One Operating SACS Pump in Each Loop	4.32E-3 (SAC-XHE-FO-XTIE) (5)	1.0E-2	1.0E-1	Operator action basic event SAC-XHE-FO-XTIE, with a value of 1.0E-1, is used in the fault tree logic to replace the baseline 4.32E-3 HEP.
Failure to Depressurize with SRVs	3.6E-4 (NR-U1X-DEP-SRV) (2)	(2)	(2)	Operator action basic event NR-U1X-DEP-SET, with a value of 1.0E-2, is used in the fault tree logic to replace the baseline 3.6E-4 HEP.

TABLE E.5.4
SUMMARY OF HCGS PRA MODELING OF SEISMIC IMPACT ON BASELINE HEPS

OPERATOR ACTION DESCRIPTION (1)	HCGS PRA BASELINE HEP (BASIC EVENT ID)	HCGS IPE HEP	HCGS SEISMIC IPEEE HEP	HEP MODIFICATIONS IN HCGS PRA FOR SEISMIC INITIATORS
Failure to Manually Initiate ECCS Within 1 Hour	3.8E-4 (NR-UV-ECCS-T)	3.9E-2	3.9E-1	Operator action basic event NR-UV-ECCS-SET, with a value of 3.9E-1, is used in the fault tree logic to replace the baseline 3.8E-4 HEP.
Failure to Control RPV Level With HPCI/RCIC – Not ATWS	8.27E-3 (NR-UV-WTLVL-20M)	4.3E-2	4.3E-1	Operator action basic event NR-UV-WTLVL-SET, with a value of 4.3E-1, is used in the fault tree logic to replace the baseline 8.27E-3 HEP.
Failure to Initiate Containment Venting	2.58E-3 (NR-VENT-5-03)	2.0E-3	3.0E-2	Operator action basic event NR-VENT-5-03, with a value of 3.0E-2, is used in the fault tree logic to replace the baseline 2.58E-3 HEP.
Failure to Manually Start SACS or SSWS Pumps	(3)	(3)	1.6E-1	Operator action basic event NR-WW1-SACSW-SET, with a value of 1.6E-1, is used in the fault tree logic to replace the baseline HEPs.
Failure to Recover Offsite Power	(4)	(4)	1.0	Operator action basic event NR-LOSP-SET, with a value of 1.0, is used in the fault tree logic to replace baseline HEPs for offsite power recovery in the shorter time frames (less than 4 hours). Operator action basic event NR-LOSP-SET4, with a value of 5.0E-1, is used in the fault tree logic to replace the baseline HEPs for offsite power recovery in the longer time frames (4 or more hours).
Failure to Safely Shutdown Plant Using Remote Shutdown Panel	N/A	N/A	6.3E-2	The frequencies of seismic initiators %IE-SET34 and %IE-SET35, as taken from the HCGS Seismic IPEEE, incorporate the Remote Shutdown Panel HEP (6.3E-2). No HEP adjustment necessary in the HCGS PRA modeling.

NOTES TO TABLE E.5.4:

(1) The list of operator action HEPs identified for potential modification for seismic initiators is based on the HCGS IPEEE seismic analysis.

(2) The HCGS Seismic IPEEE makes the following RPV emergency depressurization HEP modifications:

- NR-U1X-DEP-40M: HEP increased from 5.2E-3 to 5.2E-2
- NR-U1X-DEP-60M: HEP increased from 4.6E-3 to 4.6E-2

However, the two operator actions above are not used as the baseline RPV Emergency Depressurization HEP in the current HCGS PRA. The HCGS PRA currently uses basic event NR-U1X-DEP-SRV (with an HEP of 3.6E-4) to model RPV Emergency Depressurization for non-ATWS scenarios. As such, basic event NR-U1X-DEP-SRV is the event replaced in the PRA with a higher HEP for seismic initiators.

(3) There are four operator action basic events for failure to manually start a SACS or SSWS pumps:

- NR-WW1-SAC-02 (Replaced by basic event SAC-XHE-FS-AP210 in current HCGS PRA)
- NR-WW1-SAC-03 (Replaced by basic event SAC-XHE-FS-AP210 in current HCGS PRA)
- NR-WW1-SWP-02
- NR-WW1-SWP-03

In the HCGS IPEEE Table 3-9, these four actions are listed as having HEPs in the HCGS IPE ranging from 7.4E-5 to 1.6E-2, and are each increased to 1.6E-1 for the HCGS Seismic IPEEE. In the current HCGS PRA, the first two actions have been replaced by basic event SAC-XHE-FS-AP210. These actions have baseline HEPs of 8.28E-4, 2.16E-3, and 2.16E-3, respectively. Each of these three actio**ns** are replaced in the HCGS PRA with an HEP of 1.6E-2 (consistent with the HCGS IPEEE) for seismic initiators.

(4) Although offsite power recovery failure probability modifications are not described in the text of the HCGS IPEEE, review of the HCGS Seismic IPEEE supporting documentation (Report H-07, Seismic System Analysis/Quantification Report) shows no offsite power recovery basic events in the cutsets (indicating offsite power recovery was assumed to have a 1.0 failure probability for the HCGS Seismic IPEEE). The following five offsite power recovery actions are included in the current HCGS PRA models and filter up into seismic sequences:

- NR-LOSP-15M (6.8E-1): 15 minute time frame
- NR-LOSP-45M (3.9E-1): 45 minute time frame
- NR-LOSP-25 (1.3E-1): 2.5 hour time frame
- NR-LOSP-5 (5.3E-2): 5 hour time frame

For the seismic sequences, these offsite power recovery actions are increased as follows: The current HCGS PRA model credits long term offsite AC power recovery in the 4 and 20 hour time frames. The 5 hour time frame value of 5.0E-1 from the IPEEE is conservatively used for both the 4 and 20 hour time frames; and the values for the lesser time frames are replaced with an event with a value of 1.0.

(5) The HCGS Seismic IPEEE makes the following SACS alignment HEP modification:

- NR-SACS-SHED-01: HEP increased from 1.0E-3 to 1.0E-1

However, the operator action above is not used in the current HCGS PRA. The HCGS PRA currently uses basic event SACS-XHE-FO-XTIE (with an HEP of 4.32E-3) to SACS alignment and crosstie failure. As such, basic event SACS-XHE-FO-XTIE is the event replaced in the PRA with a higher HEP for seismic initiators.

(6) Operator action basic event NR-HVC-PNRM-SET is not modeled as a failure mode in the current HCGS PRA. It is included in this table for consistency with the IPEEE.

TABLE E.6-1
HCGS PHASE 2 SAMA LIST SUMMARY

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION
1	Remove ADS inhibit from non-ATWS emergency operating procedures	Investigate the design basis for inhibiting ADS. If ADS does not have to be inhibited except for ATWS, it can be credited for reducing pressure in more scenarios. Susquehanna and LaSalle have taken this approach. An alternative solution is to install an injection system capable of operating at high pressures. However, this solution is a much costlier option and may likely prove not be a practical approach to mitigating this event.	HCGS Level 1 Importance List	The averted cost-risk for this SAMA is **greater** than the cost of implementation, therefore the SAMA is **cost beneficial**.
3	Install back-Up air compressor to supply AOVs	Provide a back-up air compressor to supply AOVs with an alternate air source.	HCGS Level 1 Importance List	The averted cost-risk for this SAMA is **greater** than the cost of implementation, therefore the SAMA is **cost beneficial**.
4	Provide procedural guidance to cross-tie RHR trains	Provide the ability to cross-tie RHR pumps trains. Although the piping network exists, it is not allowed by procedure.	HCGS Level 1 Importance List	The averted cost-risk for this SAMA is **greater** than the cost of implementation, therefore the SAMA is **cost beneficial**.
5	Restore AC power with onsite gas turbine generator	Improve procedural use of gas turbine generator to restore onsite emergency AC power sources.	HCGS Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.
7	Install better flood detection instrumentation for RACS compartment	This HRE represents an internal flooding scenario that disables various safety-related components. Mitigation of this event can be accomplished by replacing manual isolation valves with remotely-operated MOVs with automatic isolation capability.	HCGS Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.
8	Convert selected fire protection piping from wet pipe to dry pipe system	This HRE represents an internal flooding scenario that disables various safety-related components. Mitigation of this event can be accomplished by changing the existing FPS to a dry-pipe system. Limerick took this approach.	HCGS Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.

TABLE E.6-1
HCGS PHASE 2 SAMA LIST SUMMARY

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION
10	Provide procedural guidance to use B.5.b low pressure pump for non-security events	Since this involves loss of long-term RHR, provide an independent means of alternate makeup to RPV. Possible suction sources are CST, RST and FPS. Possible use of an alternate diesel-driven pump combined with rapid depressurization.	HCGS Level 1 Importance List	The averted cost-risk for this SAMA is **greater** than the cost of implementation, therefore the SAMA is **cost beneficial**.
15	Alternate design of CSS suction strainer to mitigate plugging	Consider alternate design of CSS suction strainer to mitigate plugging.	HCGS Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.
16	Use of different designs for switchgear room cooling fans	Consider replacing one of the SWGR room cooling fans with a different design so as to eliminate common cause failure of all fans.	HCGS Level 1 Importance List	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.
17	Replace a supply fan with a different design in service water pump room	Consider replacing one of the SW pump room supply fans with a different design so as to eliminate common cause failure of all fans.	HCGS Level 1 Importance List	The averted cost-risk for this SAMA is **greater** than the cost of implementation, therefore the SAMA is **cost beneficial**.
18	Replace a return fan with a different design in service water pump room	Consider replacing one of the SW pump room return fans with a different design so as to eliminate common cause failure of all fans.	PRA Group Insight	The averted cost-risk for this SAMA is **greater** than the cost of implementation, therefore the SAMA is **cost beneficial**.
30	Provide procedural guidance for partial transfer of control functions from control room to the remote shutdown panel	For fires that cause catastrophic damage to the controls of a single critical system, the reliability of controling the plant may be improved by allowing the operators to transfer only a single division of controls to the RSP to recover a channel of the critical system while the MCR is maintained as the primary control center. A permutaiton of this SAMA would be to use local system controls rather than the RSP.	IPEEE (Fire)	The averted cost-risk for this SAMA is **greater** than the cost of implementation, therefore the SAMA is **cost beneficial**.

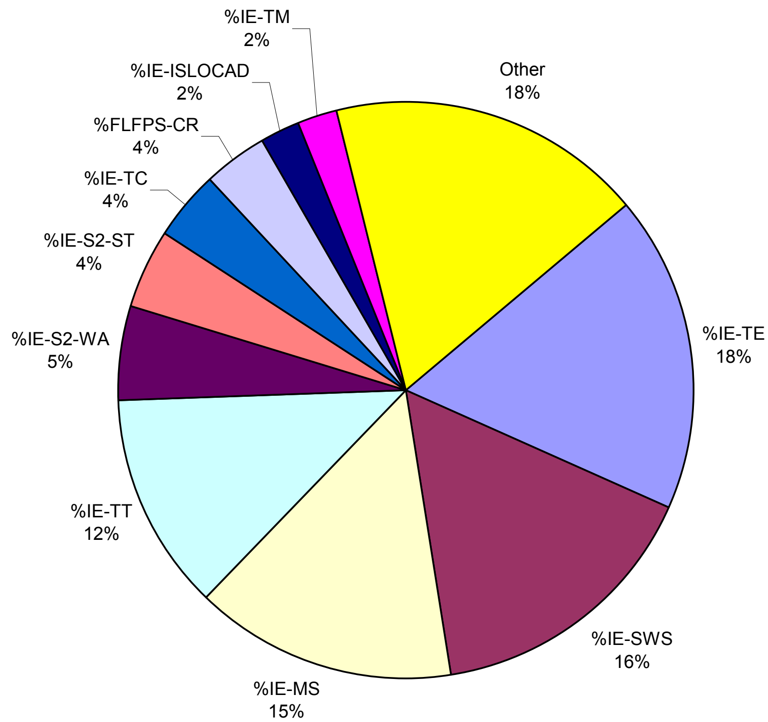
TABLE E.6-1
HCGS PHASE 2 SAMA LIST SUMMARY

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION
31	Install improved fire barriers in the MCR control cabinets containing the primary MSIV control circuits	MCR fires that propagate from the originating cabinets result in widespread control damage and induce environmental conditions that would require abandonment even if the controls were not damaged. IPEEE insights suggest that improving the fire barriers in the console containg the primary MSIV controls would reduce the probability of these types of fire events.	IPEEE (Fire)	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.
32	Install additional physical barriers to limit dispersion of fuel oil from DG rooms	For compartment 5339 fire scenario 5339_2, install a curb or a diversion channel to ensure liquids from the DG rooms cannot communicate with Room 5339.	IPEEE (Fire)	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.
33	Install Division II 480VAC bus crossties	For DG room (D) fire scenario 5304_2, install cross-ties between the Division II 480VAC buses (potentially 10B420 to10B480 and 10B460 to 10B440).	IPEEE (Fire)	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.
34	Install Division I 480VAC bus crossties	For DG room (C) fire scenario 5306_2, install cross-ties between the Division I 480VAC buses (potentially 10B410 to10B430 and 10B450 to 10B470).	IPEEE (Fire)	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.
35	Relocate, minimize, and/or eliminate electrical heaters in electrical access room	For compartment 3425/5401 fire scenario 5401_1, move or eliminate the electrical heaters in the electrical access room (Aux Building 124' level) to prevent damage to the Division II power cables.	IPEEE (Fire)	The averted cost-risk for this SAMA is **greater** than the cost of implementation, therefore the SAMA is **cost beneficial**.
36	Provide procedural guidance for loss of all 1E 120V AC power	For Seismic-Induced Equipment Damage State SET-36 (Impacts - 120V PNL481), develop MCR procedures to operate the plant after a loss of all class 1E 120V AC power.	IPEEE (Seismic)	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is <u>not</u> cost beneficial.

TABLE E.6-1
HCGS PHASE 2 SAMA LIST SUMMARY

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE 2 BASELINE DISPOSITION
37	Reinforce 1E 120V AC distribution panels	For Seismic-Induced Equipment Damage State SET-36 (Impacts - 120V PNL481), reinforce the class 1E 120V AC distribution panels.	IPEEE (Seismic)	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.
39	Provide procedural guidance to bypass RCIC turbine exhaust pressure trip	Revise procedure to allow bypass of RCIC turbine exhaust pressure trip.	Industry SAMA List	The averted cost-risk for this SAMA is **greater** than the cost of implementation, therefore the SAMA is **cost beneficial**.
40	Increase reliability / install manual bypass of LP permissive	Increase the reliability of the low pressure ECCS RPV low pressure permissive circuitry. Install manual bypass of low pressure permissive.	Industry SAMA List	The averted cost-risk for this SAMA is less than the cost of implementation and therefore the SAMA is not cost beneficial.

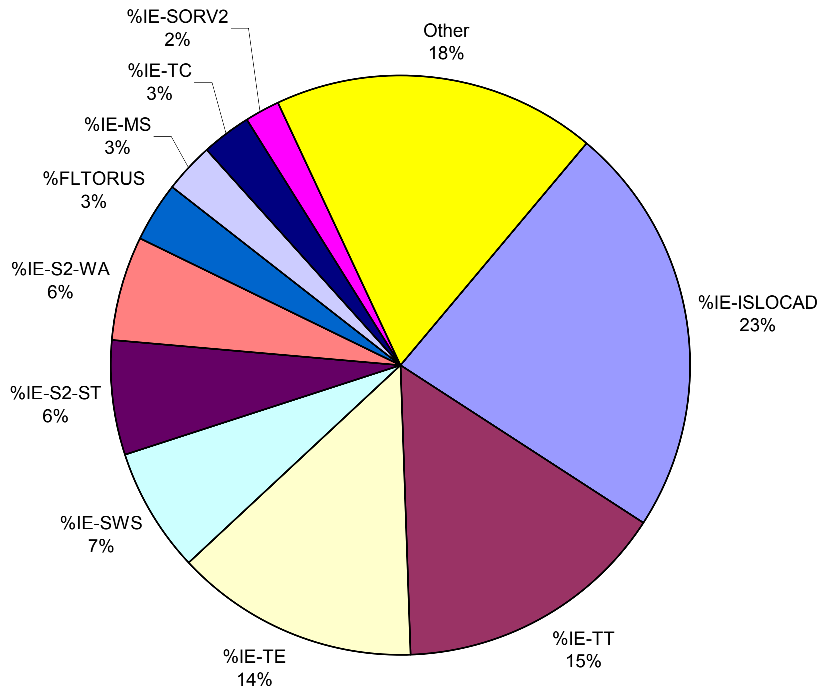
E.10 FIGURES



Basic Event ID	Description
%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
%IE-SWS	LOSS OF SERVICE WATER INITIATING EVENT
%IE-MS	MANUAL SHUTDOWN INITIATING EVENT
%IE-TT	TURBINE TRIP WITH BYPASS
%IE-S2-WA	SMALL LOCA - WATER (BELOW TAF)
%IE-S2-ST	SMALL LOCA - STEAM (ABOVE TAF)
%IE-TC	LOSS OF CONDENSER VACUUM
%FLFPS-CR	FPS RUPTURE OUTSIDE CONTROL ROOM
%IE-ISLOCAD	ISLOCA INITIATOR FOR ECCS DISCHARGE PATHS
%IE-TM	MSIV CLOSURE

Note: For complete listing of IEs contributing to CDF, see Table E.2-5

FIGURE E.2-1
HC108B CONTRIBUTION TO CDF BY INITIATING EVENT



Basic Event ID	Description
%IE-ISLOCAD	ISLOCA INITIATOR FOR ECCS DISCHARGE PATHS
%IE-TT	TURBINE TRIP WITH BYPASS
%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
%IE-SWS	LOSS OF SERVICE WATER INITIATING EVENT
%IE-S2-ST	SMALL LOCA - STEAM (ABOVE TAF)
%IE-S2-WA	SMALL LOCA - WATER (BELOW TAF)
%FLTORUS	TORUS RUPTURE IN TORUS ROOM
%IE-MS	MANUAL SHUTDOWN INITIATING EVENT
%IE-TC	LOSS OF CONDENSER VACUUM
%IE-SORV2	2 or More SORVs

Note: For complete listing of IEs contributing to LERF, see Table E.2-2

FIGURE E.2-2
HC108B CONTRIBUTION TO LERF BY INITIATING EVENT

E.11 REFERENCES

ASME 2005	ASME (The American Society of Mechanical Engineers). 2005. ASME RA-Sb-2005, *Addenda to ASME RA-S-2002 Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications*. December.
BEA 2008	BEA (Bureau of Economic Analysis). 2008. Regional Economic Accounts, accessed June 20 at http://www.bea.gov/regional/reis/.
ENTERGY 2008	Entergy (Entergy Corporation). James A. Fitzpatrick Nuclear Power Plant. 2008. *License Renewal Application. Environmental Report. Appendix G: Severe Accident Mitigation Alternatives*. January.
EPA 1972	EPA (U.S. Environmental Protection Agency). 1972. *Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States*. AP-101. Holzworth, George C. January.
EPRI 1989	EPRI (Electric Power Research Institute). 1989. *Probabilistic Seismic Hazard Evaluation at Nuclear Plant Sites in the Central and Eastern United States: Resolution of the Charleston Issue*. April.
EPRI 1995	EPRI (Electric Power Research Institute). 1995. *Fire PRA Implementation Guide*. EPRI TR-105928, Final Report. W.J. Parkinson. December
EXELON 2001	Exelon (Exelon Corporation). Peach Bottom Atomic Power Station. 2001. *License Renewal Application. Environmental Report. Appendix G: Severe Accident Mitigation Alternatives (SAMA)*. July.
FPL 2008	FPL (Florida Power and Light Energy). Duane Arnold Energy Center. 2008. *License Renewal Application. Environmental Report. Appendix F: SAMA Analysis*. September.
IDCOR 1984	IDCOR (Industrial Degraded Core Rulemaking Program). 1984. Nuclear Power Plant Response to Severe Accidents. Technology for Energy Corp. Knoxville, Tennessee. November.
KLD 2004	KLD (KLD Associates, Inc.) 2004. *Salem / Hope Creek Nuclear Generating Stations Development of Evacuation Time Estimates.* KLD TR-356. February.
NEI 2005	NEI (Nuclear Energy Institute). 2005. Severe Accident Mitigation Alternatives (SAMA) Analysis. NEI 05-01, Rev. A. November.
NEI 2007	NEI (Nuclear Energy Institute). 2007. Process for Performing Follow-on PRA Peer Reviews Using the ASME PRA Standard (Internal Events). NEI 05-04, Rev. 1. December.

NPPD 2008	NPPD (Nebraska Public Power District). Cooper Nuclear Station. 2008. *License Renewal Application. Environmental Report. Appendix E: Severe Accident Mitigation Alternatives Analysis*. September.
NRC 1975	NRC (U.S. Nuclear Regulatory Commission). 1975. Reactor Safety Study – *An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants.* WASH-1400 (NUREG-75/014). Washington, D.C. October.
NRC 1983	NRC (U.S. Nuclear Regulatory Commission). 1983. *PRA Procedures Guide.* NUREG/CR-2300. Washington, D.C. January.
NRC 1985	NRC (U.S. Nuclear Regulatory Commission). 1985. *Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications.* NUREG/CR-1278. Washington, D.C. October.
NRC 1987	NRC (U.S. Nuclear Regulatory Commission). 1987. *Accident Sequence Evaluation Program Human Reliability Analysis Procedure.* Sandia National Laboratories. NUREG/CR-4772. Washington, D.C. February.
NRC 1988	NRC (U.S. Nuclear Regulatory Commission). 1988. *Assessment of Severe Accident Prevention and Mitigation Features: BWR, Mark I Containment Design*. NUREG/CR-4920. Washington, D.C. July.
NRC 1989	NRC (U.S. Nuclear Regulatory Commission). 1989. *Individual Plant Examination: Submittal Guidance.* NUREG-1335. Washington, D.C. August.
NRC 1990a	NRC (U.S. Nuclear Regulatory Commission). 1990a. *Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants. Final Summary Report.* NUREG-1150. Vol. 1. Washington, D.C. December.
NRC 1990b	NRC (U.S. Nuclear Regulatory Commission). 1990b. *Evaluation of Severe Accident Risks: Quantification of Major Input Parameters*, NUREG/CR-4551, SAND86-1309, Vol. 2, Rev. 1, Part 7. Sprung, J.L., Rollstin, J.A., Helton, J.C., Jow, H-N. Washington, D.C. December.
NRC 1991a	NRC (U.S. Nuclear Regulatory Commission). 1991. Generic Letter 88-20, Supplement 4, June 28.
NRC 1991b	NRC (U.S. Nuclear Regulatory Commission). 1991. *Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities*. Final Report. NUREG-1407. June.
NRC 1994	NRC (U.S. Nuclear Regulatory Commission). 1994. *Revised Livermore Seismic Hazard Estimates for 69 Nuclear Power Plant Sites East of the Rocky Mountains*. NUREG-1488. May.

NRC 1997	NRC (U.S. Nuclear Regulatory Commission). 1997. *Regulatory Analysis Technical Evaluation Handbook*. NUREG/BR-0184. January.
NRC 1998a	NRC (U.S. Nuclear Regulatory Commission). 1998. *Code Manual for MACCS2: User's-Guide*. NUREG/CR-6613, Volume 1, SAND 97-0594. Chanin, D. and Young, M. May.
NRC 1998b	NRC (U.S. Nuclear Regulatory Commission). 1998. *Guidelines on Modeling Common-Cause Failures in Probabilistic Risk Assessment*. NUREG/CR-5485. November.
NRC 1998c	NRC (U.S. Nuclear Regulatory Commission). 1998. *Common-Cause Failure Parameter Estimations*. NUREG/CR-5497. October.
NRC 2000	NRC (U.S. Nuclear Regulatory Commission). 2000. *Component Performance Study 1987-1998, Commercial Power Reactors*. NUREG-1715. April.
NRC 2002	NRC (U.S. Nuclear Regulatory Commission). 2002. *An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-specific Changes to Licensing Basis*. Regulatory Guide 1.174. Revision 1. November.
NRC 2003	NRC (U.S. Nuclear Regulatory Commission). 2003. *Sector Population, Land Fraction, and Economic Estimation Program.* SECPOP2000: NUREG/CR-6525, Washington, D.C., Rev. 1, August.
NRC 2004	NRC (U.S. Nuclear Regulatory Commission). 2004. *Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission.* NUREG/BR-0058, Washington, D.C., Rev 4, September.
NRC 2005	NRC (U.S. Nuclear Regulatory Commission). 2005. *Reevaluation of Station Blackout Risk at Nuclear Power Plants - Analysis of Loss of Offsite Power Events: 1986-2004.* NUREG/CR-6890, Washington, D.C. December.
NRC 2007	NRC (U.S. Nuclear Regulatory Commission). 2007. A Pilot Probabilistic Risk Assessment of a Dry Cask Storage System at a Nuclear Power Plant. NUREG-1864. March.
PPL 2006	PPL (Pennsylvania Power and Light). Susquehanna Steam Generating Station. 2006. *License Renewal Application. Environmental Report. Attachment E: Severe Accident Mitigation Alternatives*. September.
PSEG 1993	PSEG (Public Service Electric and Gas Company). 1993. Generic Letter 88-20; Schedule Revision for Hope Creek Generating Station. Letter from PSEG to NRC, NLR-N93-118. July.
PSEG 1994a	PSEG (Public Service Electric and Gas Company). 1994. Hope Creek Generating Station Individual Plant Examination. April.
PSEG 1994b	PSEG (Public Service Electric and Gas Company). 1994. Hope Creek PRA Model 0. September.

PSEG 1997	PSEG (Public Service Electric and Gas Company). 1997. Hope Creek Generating Station Individual Plant Examination of External Events. July.
PSEG 1999	PSEG (Public Service Electric and Gas Company). 1999. Hope Creek PRA Model 1.0. July.
PSEG 2000a	PSEG (Public Service Electric and Gas Company). 2000. Hope Creek PRA Model 1.1. March.
PSEG 2000b	PSEG (Public Service Electric and Gas Company). 2000. Hope Creek PRA Model 1.2. June.
PSEG 2000c	PSEG (Public Service Electric and Gas Company). 2000. Hope Creek PRA Model 1.3. November.
PSEG 2003	PSEG (Public Service Electric and Gas Company). 2003. Hope Creek External Events PRA. HC PRA-021. August.
PSEG 2004	PSEG (Public Service Electric and Gas Company). 2004. Hope Creek PRA Model 2.0. October.
PSEG 2006a	PSEG (Public Service Electric and Gas Company). 2006. Hope Creek PRA Model 2005C. February.
PSEG 2006b	PSEG (Public Service Electric and Gas Company). 2006. *Post-LOCA EAB, LPZ, and CR Doses*, H-1-ZZ-MDC-1880, August.
PSEG 2007	PSEG (Public Service Electric and Gas Company). 2007. Hope Creek Emergency Classification Guide. Rev. 10. December.
PSEG 2008a	PSEG (Public Service Electric and Gas Company). 2008. Hope Creek PRA Model HC108A. August.
PSEG 2008b	PSEG (Public Service Electric and Gas Company). 2008. Hope Creek PRA Model HC108B. December.
PSEG 2008c	PSEG (Public Service Electric and Gas Company). 2008. Hope Creek Generating Station PRA. HC PSA-015. Level 2 Analysis. August.
USDA 2004	USDA (U.S. Department of Agriculture). 2004. *2002 Census of Agriculture - Volume 1, Geographic Area Series, Census, State-County Data*. June. http://www.nass.usda.gov/Census/Create_Census_US_CNTY.jsp.
WNOC 2006	WNOC (Wolf Creek Nuclear Operating Corporation). Wolf Creek Generating Station. 2006. *License Renewal Application. Environmental Report. Attachment F: Severe Accident Mitigation Alternatives Analysis*. October.

Appendix F

401 Water Quality Certification

This Page Intentionally Left Blank

12958

State of New Jersey

DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF WATER RESOURCES
P. O. BOX 2809
TRENTON, NEW JERSEY 08625

May 1, 1974

Public Service Electric and Gas Co.
80 Park Place
Newark, New Jersey 07101

Re: Nos. 1 and 2 Units, Hope Creek Generating Station
Lower Alloways Creek Township, Salem County, N.J.
Applicant - Public Service Electric and Gas Co.

Gentlemen:

This is to certify in accordance with the provisions of Section 401 (a) (1), "Federal Water Pollution Control Act Amendments of 1972" that there is reasonable assurance as determined by the Department of Environmental Protection of the State of New Jersey that the proposed activity, as described above, will be conducted in a manner which will not violate applicable water quality standards of the State of New Jersey.

The foregoing applies only and exclusively to the effect the proposed work would have on water quality as defined in the regulations establishing certain classifications to be assigned to the waters of this State and standards of quality to be maintained in waters so classified. The certification does not apply to broader ecological, biological, or environmental effects which may result from the project, nor does this certificate evaluate the degree of public interest the project may further.

Very truly yours,

Ernest R. Segesser (BR)

Ernest R. Segesser
Assistant Director for Water Quality

6E11:A1

cc: Mr. Paul McDowell
Bureau of Navigation

State of New Jersey
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF WATER RESOURCES
P. O. BOX ~~XXXX~~ 2809
TRENTON, NEW JERSEY 08625

May 8, 1974

RECEIVED LIC-ENV.
JUN 4 1979

F.W. Schneider, Manager of Engineering
Public Service Electric and Gas Company
80 Park Place
Newark, New Jersey 07101

Re: Hope Creek Generating Station
Units No. 1 & 2
Lower Alloways Creek Township
Salem County, New Jersey

Dear Mr. Schneider:

The following is offered as an amendment to the water quality certificate issued by this Department on May 1, 1974:

> This is to further certify that to our knowledge there are no applicable Federal effluent limitations established pursuant to the Federal Water Pollution Control Act Amendments of 1972 under Sections 301(b) and 302 nor are there any applicable Federal standards under Sections 306 and 307 of the Act.

Very truly yours,

Thomas F. Harding
Project Manager, Permits
Bureau of Water Pollution Control

E36:C:A21