HOPE CREEK GENERATING STATION
ENVIRONMENTAL REPORT
FOR EXTENDED POWER UPRATE

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EXECUTIVE SUMMARY

This report presents an evaluation of the environmental impacts of the proposed Hope Creek Generating Station (HCGS or Station) thermal power uprate from 3,339[1] megawatts-thermal (MWt) to a maximum of 3,952 MWt. The intent of this report is to provide sufficient information for the Nuclear Regulatory Commission (NRC) to evaluate the environmental impacts of the Extended Power Uprate (EPU) in accordance with the requirements of 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions."

The environmental impacts of EPU are identified and compared against the environmental impacts that have been previously evaluated by the NRC (1984) in the Final Environmental Statement (FES) (1984) associated with the issuance of the HCGS operating license and in other related docketed correspondence. The environmental impacts identified by the NRC in the FES were based on conservative assumptions for source terms and other environmental parameters. Since initial operations, a variety of systematic environmental improvements have been implemented at HCGS that have further increased the margin of conservatism associated with these assumptions. By adjusting current plant operating parameters for extended power uprate effects, it will be readily demonstrated that the previous assumptions and conclusions concerning the environmental impact of HCGS operation continue to bound plant operation at EPU conditions. Plant activities involving design, construction, maintenance, and operation are conducted in strict compliance with environmental regulations and careful consideration of environmental consequences.

The HCGS extended power uprate is being implemented without consequential changes to the

[1] Hope Creek Operating License NPF-57 authorizes operation up to a maximum power level of 3,339 MWt, an increase granted in 2001 for which a Finding Of No Significant Impact was issued by NRC. This Environmental Assessment was conducted to include an evaluation of the cumulative environmental impacts of the 1.4% licensed power level increase from 3,293 MWt to 3,339 MWt granted in 2001 and the proposed Extended Power Uprate to 3,952 MWt.

plant systems that directly or indirectly interface with the environment. This evaluation demonstrates that the changes in environmental impacts of plant operation that will result from extended power uprate are not significant. The environmental impacts associated with extended power uprate are either well bounded by previously evaluated environmental impact analyses and criteria established by the NRC in the Final Environmental Statement or well bounded by other applicable regulatory criteria. As a result, approval of the extended power uprate will not significantly affect the environment.

1.0 INTRODUCTION

PSEG Nuclear LLC (PSEG) is committed to operating HCGS in an environmentally sound manner. Plant activities involving design, construction, maintenance, and operation are conducted in strict compliance with environmental regulations and careful consideration of environmental consequences. Numerous controls and modifications have been implemented to prevent and reduce impacts to the environment, and extensive environmental monitoring programs have been instituted at HCGS. In keeping with this important commitment and in accordance with regulatory requirements, PSEG has conducted a comprehensive environmental evaluation of the proposed extended power uprate, including the prior 1.4% rerate, from 3,293 MWt to 3,952 MWt.

This environmental evaluation is provided pursuant to 10 CFR 51.41, "Requirement to Submit Environmental Information," and is intended to fully support the NRC in complying with the requirements of Section 102(2) of the National Environmental Policy Act (NEPA), as amended, for the proposed change to the authorized operating power level at HCGS. Environmental report general requirements are outlined in 10 CFR 51.45. The evaluation provides information necessary to determine the environmental impact of those particular changes associated with the extended power uprate at HCGS to 3,952 MWt.

The environmental impact of operation at the present power level has been reviewed and determined to be acceptable by the NRC. In 1983, an Environmental Report (ER) was submitted by Public Service Electric and Gas Company (PSEG, 1983) to the NRC as part of the application for an operating license for HCGS. This report addressed the environmental impacts of construction and operation of the HCGS. In 1984, the ER was utilized by the NRC (1984) in preparing a Final Environmental Statement (FES) in fulfillment of the requirements of NEPA. The NRC subsequently issued operating license NPF-57 to HCGS authorizing operation up to a maximum power level of 3,293 MWt. In 2001, NRC authorized a licensed thermal power increase to 3,339 MWt and issued an "Environmental Assessment and Finding of No Significant Impact for Increase in Allowable Thermal Power Level".

This evaluation demonstrates that the extended power uprate will not result in a significant increase in the environmental impacts of operation of the HCGS. This evaluation was performed against the originally licensed thermal power of 3,293 MWt as reviewed by the NRC to the EPU maximum of 3,952 MWt. The environmental impacts of HCGS operation with extended power uprate continue to be bounded by the FES or bounded by other appropriate and applicable regulatory criteria. This evaluation is submitted, in part, to fulfill the NRC (1996a) requirement to submit a "Supplement to the Applicant's Environmental Report" as documented in the Staff Position concerning the GE BWR EPU Program dated February 8, 1996.

This environmental report will assess the impact of EPU on the environment, compare changes to those presented in the FES or in more recent environmental reports, identify reasonable alternatives to the proposed EPU, and recommend a course of action.

2.0 PROPOSED ACTION AND NEED

2.1 DESCRIPTION OF PROPOSED ACTION

The proposed action is an amendment to the HCGS Operating License to increase the licensed core thermal power level to 3,952 MWt. The operational goal of this amendment is to increase electrical generating capacity. PSEG in conjunction with the plant designer, General Electric, has comprehensively evaluated the effects of an extended power uprate at HCGS. This environmental assessment was performed at a maximum increase in core thermal power of 3,952 MWt to ensure the conclusions bound the final power uprate. This evaluation concluded that sufficient safety and design margins exist such that an increase in the rated core thermal power to 3,952 MWt can be accomplished without adverse impact on the health and safety of the public and without significant impact on the environment.

Although the maximum authorized power level proposed by this action and evaluated for environmental impact herein is 3,952 MWt, the intent is to raise power level in increments. The final power level of HCGS will not exceed 3,952 MWt but may be less than that value.

HCGS is a Boiling Water Reactor (BWR) that operates in a direct thermodynamic cycle between the reactor and the turbine. Under extended power uprate conditions, thermodynamic processes are changed to extract additional work from the turbine. Simply put, extended power uprate involves installation of a higher efficiency turbine and an increase in the heat output of the reactor. This will support increased turbine inlet steam flow requirements and an increase in the heat dissipated by the condenser to support increased turbine exhaust steam flow requirements. In the turbine portion of the heat cycle, increases in the turbine throttle pressure and steam flow will result in a small increase in the heat rejected to the cooling tower. The environmental impacts of these operational changes are discussed herein.

Due to design and safety margins inherent in plant equipment, the proposed extended power uprate can be accomplished with relatively few modifications. The most significant changes involve replacement of the high pressure and low pressure turbines and replacement of the main transformers. Other minor modifications to support extended power uprate are routine in nature and are being conducted within the existing plant boundary.

The modifications are being accomplished by standard maintenance and modification processes that are similar to those performed during normal outages. The majority of plant systems will not require any significant modifications.

2.2 NEED FOR PROPOSED ACTION

Once per year, the North American Electric Reliability Council (NAERC) performs a forecast reliability assessment using information provided by the regional reliability councils such as Mid-Atlantic Area Council (MAAC) and the PJM Interconnection, L.L.C. (PJM). The 2004 net peak demand growth rate in the MAAC was 1.7% (NAERC, 2004) and the most current assessment includes a U.S. forecasted increase in expected customer peak demand, based on historical increases, of approximately 2.0% per year through the 2002 - 2011 planning period. The 2004 PJM Load Forecast Report forecasts normalized winter and summer increases of 1.5 to 1.7%, respectively, per year over the next ten years (PJM, 2004). These annual changes amount to an increased need of 8,300 to 10,700 MW over the next decade. The additional generating capacity provided by the EPU will help ensure that a reasonable operating margin for reliability is maintained in the MAAC and the PJM.

PSEG has determined the need for additional generation resources in its territory through a comparison of the projected load growth to the generation and possible power purchases. There are two significant aspects of maintaining a flexible and robust supply portfolio. The first is to obtain low cost power. The second is to maintain a portfolio with sufficient diversity to allow utilities to respond to changes in the underlying cost of power, owned or purchased. The increase in generating capacity of HCGS provides PSEG with lower cost power than can be obtained in the current and anticipated energy market. In addition, the increased generating capacity reduces exposure to potential cost increases in fossil fuel based alternatives. In a deregulated arena, the proposed EPU will displace approximately two 100 MWe gas turbines and the associated emissions impacts as discussed in Section 6.

Extended power uprate is an important step in improving the economic performance of HCGS under utility deregulation. The improved performance is accomplished by cost reductions in production and total bus bar cost per kilowatt hour (kWh). Therefore, extended power uprate should enhance the value of HCGS as a generating asset. The extended uprate will help PSEG meet a projected need for additional capacity. The increased HCGS capacity when compared to new combustion turbine units, combined cycle units, and purchased power agreements, is a low cost option for maintaining a highly reliable power supply.

3.0 SOCIOECONOMIC IMPACTS

Extended power uprate does not affect the size of the HCGS workforce and does not have a material effect upon the labor force required for future outages. The HCGS contributions to local, state, and school taxes, both directly through taxation of PSEG and indirectly through taxation of the employees, vendors, and contractors, are of significant value to the local economy. The socioeconomic effects of implementing EPU at HCGS are, in part, dependent on the ability of PSEG to remain competitive in a deregulated market. Implementation of EPU is not the primary factor affecting the overall competitiveness of PSEG, but it is a factor that must be considered. PSEG has determined that, notwithstanding the uncertainty associated with deregulation, the favorable capital cost of the proposed EPU compared to new generating capacity, and the reduction in incremental costs that result from EPU as compared to new generation facilities, make the EPU project attractive. In addition, the investment associated with the proposed EPU will result in increased revenues, thus enhancing the value of HCGS as a provider of electricity and allow PSEG to remain a strong partner within the community and the State of New Jersey. The direct benefit of an extended power uprate to PSEG customers is that the program will supply up to an additional 213 MWe of reliable electrical generating capacity.

A quantitative study of environmental costs of alternatives is not necessary to recognize that significant environmental benefits can be derived from extended power uprate when compared to other options of adding capacity. As demonstrated herein, extended power uprate does not result in significant environmental costs. Unlike fossil fuel plants, HCGS does not routinely emit significant amounts of Sulfur Dioxide ($S0_2$), Nitrogen Oxide (NOx), Carbon Dioxide (CO_2) or other atmospheric pollutants during normal operation. Routine operation of HCGS at extended power uprate conditions will not contribute to greenhouse gas emissions, ground level ozone (smog), or acid rain.

The environmental effects of the fuel cycle and of transportation of fuel and waste are very small as discussed in Section 5.0. While the project will produce additional spent nuclear fuel, the added amount is not appreciable and can be accommodated by the facility.

Based upon the discussion above, it is reasonable to conclude the HCGS extended power uprate project provides an economic advantage to other alternatives for added generation. Extended power uprate involves effective utilization of an existing asset with negligible environmental impact and is the preferable option to secure additional generation.

4.0 NON-RADIOLOGICAL ENVIRONMENTAL IMPACTS

4.1 TERRESTRIAL RESOURCES

4.1.1 Threatened and Endangered Species

The FES (NRC, 1984) noted that the geographic range of several species listed as endangered by the Federal Government include the state of New Jersey. Some terrestrial species (e.g., small whorled pogonia) are known to occur in New Jersey but not on or near the HCGS and its associated transmission facilities. However, the state endangered bald eagle and peregrine falcon occasionally occur as non-breeding visitors near the HCGS, while the state endangered osprey commonly nests on transmission towers near HCGS (NRC, 1984). Bald eagles and peregrine falcons do nest in other areas of Salem County. Table 4-1 presents a current list of threatened and endangered species potentially occurring near HCGS and their status (NJDEP, 2005; PSEG, 2003).

The generic assessment of power plants showed that neither cooling system operations nor electric power transmission lines associated with nuclear power plants have significant adverse impacts on any threatened or endangered species (NRC, 1996b). The FES (NRC, 1984) concluded that the operation of HCGS will not have any adverse impacts on terrestrial endangered and threatened species. An assessment conducted my the National Marine Fisheries Service (NMFS, 1993) in consultation with the Nuclear Regulatory Commission (NRC, 1993) under Section 7 of the Endangered Species Act (ESA) determined that "continued operation of the Hope Creek Generating Station will not affect listed species" under the ESA. The extended power uprate will not change the physical location or dimensions of HCGS's structures. The conclusion for the extended power uprate is the same since it will not have any additional impact on these species or their habitats.

4.1.2 Terrestrial Biota

The terrestrial biota of the HCGS and surrounding area were described in the ER (PSEG, 1983) and FES (NRC, 1984). The FES identified that HCGS is located on Artificial Island, which consists of dredge spoils, has only low quality habitats for wildlife, and thus is not an important natural resource area. Vegetation near the HCGS is predominately found in tidal marsh, upland field, and upland woodland habitats.

The proposed extended power uprate will not produce a significant increase (approximately 9%) in existing cooling tower salt drift. An NJDEP (1980) study estimated that the two cooling towers proposed at that time for the two units at HCGS might annually add up to an additional 0.2 lb/acre of salt deposition on the nearest farm. Subsequently, only one unit and one cooling tower were built at HCGS. To put the cooling tower salt deposition rate for one tower (0.1 lb/acre) into perspective, NJDEP stated that the annual rate of deposition due to crop fertilization is about 4.0 lb/acre, and approximately 375 lb/acre due to natural seasalt deposition along the New Jersey ocean coast. Salt deposition studies performed in the vicinity of HCGS during 1987-1989 confirmed that the highest salt deposition rates were well below the threshold to reduce agricultural plant productivity (WCC, 1989). The activities associated with the extended power uprate will not change the terrestrial flora and fauna and associated habitats in the vicinity of HCGS because the estimated 9% increase in the salt deposition rates from the HCGS cooling tower as a result of the extended power uprate is well below salt deposition rates that cause adverse effects (NJDEP, 1980; WCC, 1989). Therefore, the conclusion reached in the FES (NRC, 1984) that the operation of HCGS would not have any adverse impacts on terrestrial biota remains valid for the extended power uprate.

Table 4-1

Threatened and Endangered Species Potentially Occurring near HCGS.

Common Name	Scientific Name	State Status[2]	Federal Status[3]
Bald eagle	*Haliaeetus leucocephalus*	E/T	LE/LT[4]
Peregrine falcon	*Falco peregrinus*	E	LE/SA
Osprey	*Pandion haliaetus*	T/U	
Northern harrier	*Circus cyaneus*	E/S	
Red shouldered hawk	*Buteo lineatus*	E/T	
Grasshopper sparrow	*Ammodramus savannarum*	T	
Savannah sparrow	*Passerculus sandwichenis*	T	
Vesper sparrow	*Pooectes gramineus*	E/T	
Sedge wren	*Cistothorus platenis*	E	
Pied-billed grebe	*Podilymbus podiceps*	E	
Yellow-crowned night heron	*Nyctanassa violacea*	T	
Shortnose sturgeon	*Acipenser brevirostrum*	E	E
Atlantic loggerhead turtle	*Caretta caretta*	E	T
Atlantic green turtle	*Chelonia mydas*	T	T
Kemp's ridley turtle	*Lepidochelys kempi*	E	E

[2] State status codes: E = Endangered; T = Threatened; S = Stable; U = Undetermined; / = indicates dual status, first status refers to state breeding population and second status refers to non-breeding population.
[3] Federal status codes: LE = Taxa formerly listed as endangered; LT = Taxa formerly listed as threatened; LE/SA = Listed Endangered/Similarity of Appearance.
[4] Federal Status as listed in the New Jersey Department of Environmental Protection Natural Heritage Program (NHP) database. A Final Rule reclassifying the status of the bald eagle from endangered to threatened was published by FWS in the Federal Register on July 12, 1995 with an effective date of August 11, 1995.

4.1.3 Land Use

The extended power uprate does not change the present HCGS land use. Based on the U.S Census reports, the population in Salem County has declined slightly from 1980 to 2000 with a shift in population from the City of Salem to other areas in the county like Lower Alloways Creek (Table 4-2). However, there are no plans to build facilities or materially alter the land use to support extended power uprate activities. Except for transportation of equipment and routine disposal of waste, extended power uprate maintenance activities are confined to the area within the site boundary. Extended power uprate does not affect the storage requirements for above ground or below ground tanks. Lands located outside the site boundary will not be affected by extended power uprate activities. Consistent with the FES the extended power uprate does not involve changes to any aesthetic resources and does not involve any impacts to lands with historical or archaeological significance.

The extended power uprate is not expected to require additional low-level radioactive waste storage facilities. The replaced turbine components will be decontaminated as necessary, and recycled to the extent possible, or transferred to an approved disposal facility.

4.1.4 Transmission Facilities

At present, three transmission lines serve HCGS. Two pre-existing transmission lines were disconnected from the Salem Generating Station and routed into the HCGS (i.e., Hope Creek-New Freedom and Hope Creek-Red Lion). A third line approximately 1,000 feet long connects HCGS to the Salem Generating Station within the PSEG site boundary. No changes in operating transmission or power line right of way are required to support extended power uprate. However, higher main transformer capacity will be necessary to deliver the additional power to the offsite grid. This will be accomplished by replacing the existing transformers that do not meet these capacity requirements.

Extended power uprate does not increase the probability of "corona" or electrical shock from primary or secondary currents. In addition, the transmission lines are designed in accordance with the applicable shock prevention provisions of the National Electric Safety Code (NESC).

There is no scientific consensus regarding the health effects, if any, of exposure to electric and magnetic fields, collectively referred to as electromagnetic fields (EMF) produced by operating transmission lines. Chronic effects of EMF on humans are not quantified at this time and no significant impacts to terrestrial biota have been identified (NRC, 1996b). Subsequent review of the potential health effects of EMF by organizations such as the American Conference of Governmental Industrial Hygienists (ACGIH), the International Commission on Non-Ionizing Radiation Protection (ICNIRP), and the International Agency for Research on Cancer (IARC) have identified no deleterious human effects.

The increased generator output at HCGS will cause a corresponding current, and thus magnetic field, increase in the onsite transmission line between the HCGS main generator and the plant substation. This transmission line is located within the outer fenced boundary of the plant where public access is prohibited. Furthermore, the extended power uprate does not involve significant increases in exposure to electromagnetic fields from transmission lines and therefore, the conclusions in the FES (NRC, 1984) relative to the effects of EMF remain valid.

4.1.5 Noise

The extended power uprate will not result in significant changes to the character, sources, or energy of noise generated at HCGS. The new equipment necessary to implement extended power uprate will be installed within existing plant buildings. No significant increase in ambient noise levels is expected within the plant. This includes the upgraded turbines, which will operate at the same speed as the original equipment. The nearest resident is over 3 miles from HCGS. The NRC staff concluded that area residents would not be adversely affected by noise resulting from Station operation (NRC, 1984). The Environmental Report and FES conclusions for noise levels remain relevant for extended power uprate conditions.

Table 4-2. Population Changes in the Project Area[a]

	1980	**2000**	**% Change**

New Jersey	7,364,823	8,414,350	14.2
Salem County	64,676	64,285	-0.6
Lower Alloways Creek (LAC)	1,547	1,851	19.7
City of Salem	6,959	5,857	-15.8
HOUSING UNITS			
Salem County	22,476	26,158	16.4
LAC	572	730	27.6
City of Salem	2,830	2,863	1.2
[a] United States Census Reports 1980 and 2000.			

4.2 AQUATIC RESOURCES

4.2.1 Threatened and Endangered Species

Table 4-1 presents a current list of threatened and endangered species potentially occurring near HCGS and their status (PSEG, 2003). The shortnose sturgeon (*Acipenser brevirostrum*) is listed as endangered by both the United States Fish and Wildlife Service (FWS) and the State of New Jersey. A significant portion of New Jersey's shortnose sturgeon occurs in the upper tidal Delaware River, which is a substantial distance from HCGS. NRC (1980) and National Marine Fisheries Service (NMFS) staff (Leitzell, 1980) concluded that the operation of HCGS would not jeopardize the continued existence of the shortnose sturgeon.

Sea turtles have been observed and captured in the vicinity of HCGS, including two federally listed threatened species, the Atlantic loggerhead turtle (*Caretta caretta*) and the Atlantic green turtle (*Chelonia mydas*), and one endangered species, the Kemp's ridley turtle (*Lepidochelys kempi*). The three turtle species spend almost their entire lives in the sea and their occurrence in the vicinity of HCGS is relatively infrequent.

The FES (NRC, 1984) concluded that the operation of HCGS will not have any adverse impacts on aquatic endangered and threatened species. More recently, the NMFS (1993), in consultation with NRC, concluded in its Section 7 Biological Opinion that "...No impingements have been recorded at the Hope Creek Generating Station. Thus, besides the normal cleanings, monitoring is no longer necessary." The conclusion for the extended power uprate is consistent with the conclusions presented above since it will not have any additional impact on these species or their habitats.

4.2.2 Cooling Water Withdrawal

The volume of water withdrawn by the service water system for cooling and ultimately providing makeup to HCGS's closed cycle cooling system are relatively low, approximately 67 million gallons per day (MGD) during normal operations. Water usage at HCGS during normal operations accounts for less than 0.03 percent of the average tidal flow of the estuary of about 259,000 MGD. Based on these factors, the number of organisms susceptible to impingement and entrainment is relatively low. Impingement and entrainment effects were evaluated in the FES for full power operation as having minimal impact to the aquatic community of the Delaware River. In addition, the New Jersey Department of Environmental Protection (NJDEP, 2002) determined that that the location, design, construction, and capacity of HCGS's cooling water intake structure continues to reflect the best technology available (BTA) for minimizing adverse environmental impact. This conclusion is consistent with USEPA's final section 316(b) rule for existing facilities (Federal Register, July 9, 2004). Extended power uprate does not increase the intake flow requirements of the plant nor change the construction of the cooling water intake structure and, therefore, these evaluations remains valid.

4.3 AIR QUALITY

4.3.1 Cooling Tower Air Contaminant Emissions

PSEG has been issued an Air Operating Permit from NJDEP in accordance with New Jersey Administrative Code (N.J.A.C.) 7:27-22 and Title V of the Clean Air Act for operation of the HCCT. The Permit limits emissions of particulates to no greater than 29.4 pounds per hour. PSEG provides annual reports to the NJDEP demonstrating compliance with this limitation.

As discussed in section 4.3.2 below, the emission rate of PM from the cooling tower is dependent on the circulating water flow rate, the drift rate, and the concentration of total dissolved solids (TDS) in the circulating water. The circulating flow rate and the drift rate are not being changed by the EPU. The concentration of TDS in the makeup water is highly variable and depends primarily on the tidal hydrodynamics of the Delaware Estuary, hydrological conditions (namely, precipitation and runoff), meteorological conditions and the salinity of the Delaware Estuary. Salinity usually is between 0 and 20 parts per thousand (ppt) and typically exceeds 6 ppt during periods of low freshwater inflow in summer. Evaporation rates are seasonally variable and tend to be highest in the summer (approximately 13,000 gpm) and lowest in the winter (approximately 10,000 gpm). The wide variability in the concentration of TDS in the makeup water and of the evaporation rate can introduce considerable variability in the short-term emissions of particulate matter from HCCT.

Calculations indicate that particulate emissions from the HCCT could increase as a result of the extended power uprate to a maximum of 42.0 pounds per hour. This maximum potential emission rate exceeds the emissions rate specified in the air permit for the facility and is in excess of the standards set at N.J.A.C. 7:27-6.2, which limits the emissions of particulate matter from any process to 30 pounds per hour. Increased particulate air emissions, however, will not occur until the phase of the EPU where reactor thermal power is increased. PSEG has discussed this with the NJDEP and is primarily pursuing two parallel paths.

First, NJDEP is in the process of a regulatory revision to the N.J.A.C. 7:27-6.2 limit. The current limit of 30 pounds per hour is based on the emission of 0.02 grains per standard cubic foot and a maximum air flow of 175,000 standard cubic feet per minute (scfm). The regulatory revision is anticipated to allow a limitation based on the air flow, substituting a 0.015 grains per standard cubic foot basis or a similar metric, and require atmospheric modeling to demonstrate a lack of negative impact. The air flow from the HCCT is approximately 44 million scfm and atmospheric modeling indicates that an emission rate of 42.0 pounds per hour would not have a negative impact. The regulatory revision is currently anticipated to be issued in 2006.

In parallel, PSEG has submitted a request for a variance from the 30 pound per hour limitation. The New Jersey regulations at N.J.A.C. 7:27-6.5 allow for a request for a variance from the 30 pounds per hour limitation when the applicant believes that advances in the art of control for the kind and amount of particles emitted has not developed to a degree that would enable the 30 pounds per hour to be achieved. PSEG has determined from discussions with a manufacturer of cooling towers that the state of the art for emissions control has not developed beyond that installed in the HCCT. Research of the USEPA's RACT/BACT/LAER Database identified that the HCCT emission rate is 59% lower than the typical result in the database and 18% lower than the lowest entry in the database. Therefore, the HCCT meets the requirements of N.J.A.C. 7:27-6.5 for obtaining a variance from the 30 pound per hour particulate emission limitation. PSEG will not operate the HCCT above the particulate emission limitations imposed by NJDEP.

Additionally, the initial evaluation of cooling tower air contaminant emissions from HCGS was conducted considering two cooling towers and found no adverse environmental effects. HCGS was constructed with only one cooling tower, the other unit was cancelled. This provides additional conservatisms in demonstrating the air emissions after the EPU will be bounded by the FES.

4.3.2 Prevention of Significant Deterioration

The USEPA's Prevention of Significant Deterioration (PSD) regulations are codified at 40 CFR 52.21. Because, HCGS is more than 10 km from a Class I area, the actual increases that trigger a PSD review are defined at 40 CFR 52.21(b)(23)(i). These regulations would apply if the extended power uprate were a physical change or change in the method of operation that resulted in a significant net emissions increase of a criteria pollutant. A significant net emissions increase of total suspended particulates (TSP) or PM_{10} (equivalent aerodynamic particle sizes less than 10 microns in diameter) occurs when comparison of the baseline actual emissions with the projected-actual emissions yields an emissions increase of 15 tons or more per year (tpy)of PM_{10} or 25 tons or more per year of TSP. PM_{10} is characterized by equivalent aerodynamic particle sizes less than 10 microns in diameter. TSP is characterized by all particulate matter, including PM_{10}. PSEG has concluded that the PSD regulations do not apply to the EPU and the United Stated Environmental Protection Agency (USEPA) has concurred with that determination (USEPA 2004b).

HCGS is a major existing source that is located in an area that is designated "attainment" or "unclassified" for TSP and PM_{10}. Therefore, annual particulate increases resulting from physical changes or changes in the method of operation at HCGS must be evaluated with respect to PSD regulations.

The EPU is expected to increase emissions of particulate matter (PM) from the existing natural draft cooling tower. The PM is assumed to be characterized by equivalent aerodynamic particle sizes less than 10 microns in diameter (PM_{10}). That is, all emissions are conservatively assumed to be PM_{10} for the purpose of the PSD non-applicability determination. The PSD significant emission increase threshold for TSP is greater than that for PM_{10} (25 tpy for TSP versus 15 tpy for PM_{10}). If the particulate emission increase resulting from the EPU, considering the entire particulate mass emitted without respect to particle size, is less than the PM_{10} threshold, there is no possibility of exceeding the 25 tpy threshold for TSP.

HCGS uses a closed cycle cooling water system (CWS) to dissipate waste heat to the atmosphere. The CWS consists of a natural draft cooling tower (HCCT), circulating water pumps, condensers, service water pumps, a circulating water line, and a blowdown line. Circulating water pumps force a large cooling water flow through the condensers, which raise the temperature of the cooling water. The heated water is passed to the HCCT, which lowers the temperature primarily through evaporation. A very small percentage (< 0.0005%) of the circulating water is lost as drift that is carried out of the tower by the natural draft. The drift contains dissolved solids that are present in the circulating water.

The emission rate of PM from the cooling tower is dependent on the circulating water flow rate, the drift rate, and the concentration of total dissolved solids (TDS) in the circulating water. The total design flow rate of the circulating water pumps is 552,000 gpm. The design drift rate is

0.0005% of the circulating water flow rate. Test data and other measurements show that the actual circulating water flow rate is approximately 612,000 gpm while the drift rate is only 0.00041% of the circulating water flow. The concentration of TDS in the circulating water varies with the concentration of TDS in the makeup water, the service water (or makeup) flow rate, and the evaporation from the tower. The concentration of TDS in the makeup water is highly variable and depends primarily on the tidal hydrodynamics of the Delaware Estuary, hydrological conditions (namely, precipitation and runoff), meteorological conditions, and the salinity of the Delaware Estuary. Salinity usually is between 0 and 20 parts per thousand (ppt) and typically exceeds 6 ppt during periods of low freshwater inflow in summer. Service water flow rates typically range from approximately 36,500 gpm (when intake temperatures are less than 70°F) to 51,500 gpm when the estuarine water is warmer. Evaporation rates are seasonally variable and tend to be highest in the summer (approximately 13,000 gpm) and lowest in the winter (approximately 10,000 gpm). The concentration of TDS in the circulating water increases as the evaporation rate increases and/or the service water flow rate decreases. The wide variability in the concentration of TDS in the makeup water and of the evaporation rate can introduce considerable variability in the short-term and annual emissions of particulate matter from HCCT.

The comparison of baseline PM_{10} actual emissions (53.5 tpy) with the projected-actual emissions (63.7 tpy) yields an emissions increase of 10.2 tpy for PSD applicability purposes. Actual emissions of other criteria pollutants to the atmosphere will not change as a result of the EPU. Therefore, the planned EPU does not trigger Prevention of Significant Deterioration regulations.

4.4 HYDROLOGY EFFECTS

HCGS operates under New Jersey Pollutant Discharge Elimination System (NJPDES) Permit No. NJ 0025411, with an effective date of March 1, 2003, that covers the following discharges and typical daily average flows, as depicted on Figure 4-1:

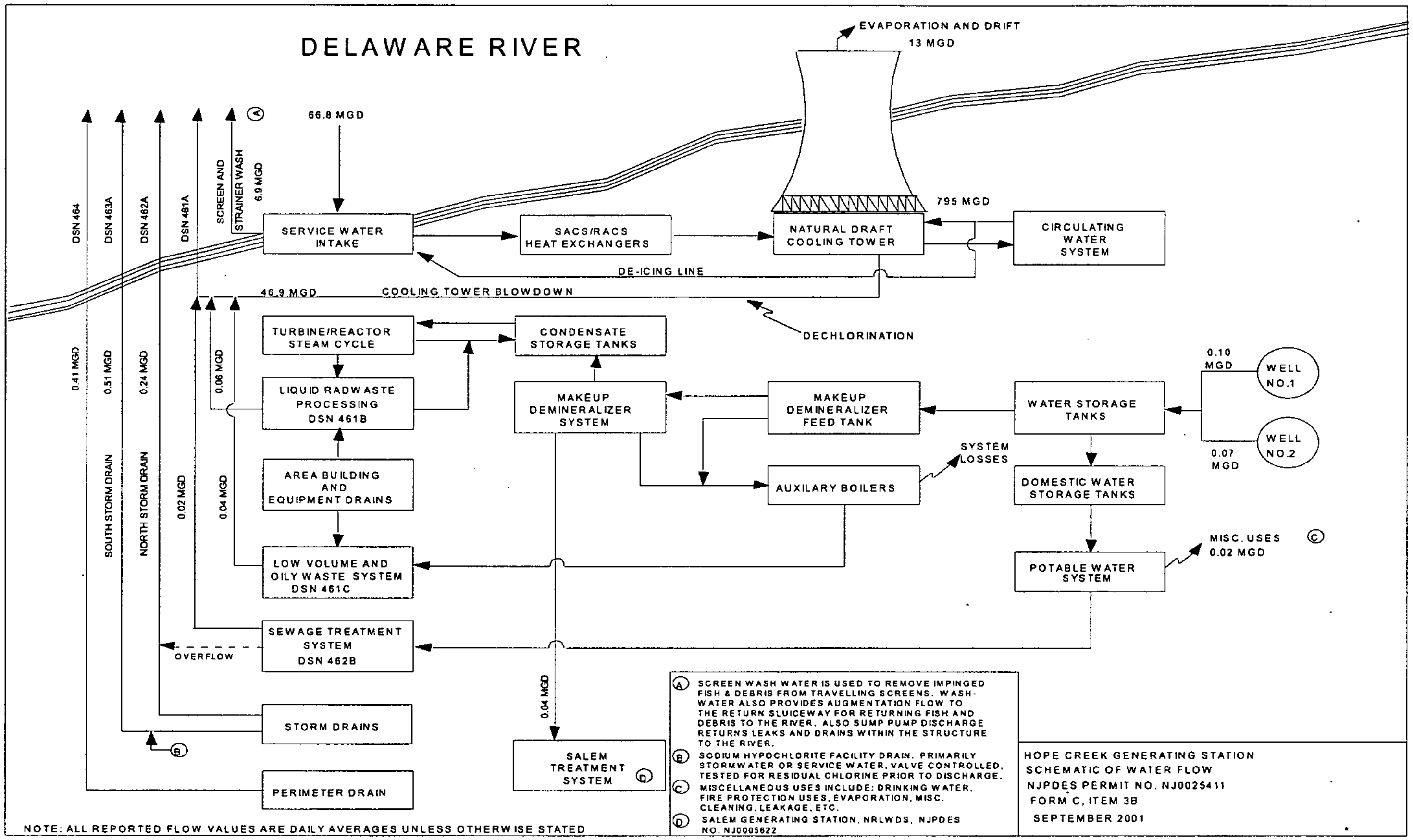
- DSN 461A, combination of all non-stormwater wastewater components, primarily cooling tower blowdown (46.9 MGD)
- DSN 461C, internal monitoring point for low volume and oily waste system (0.04 MGD)

- DSN 462B, internal monitoring point for sewage treatment system (0.02 MGD)
- DSN 465A (formerly 462A), north stormwater drain (0.24 MGD)
- DSN 463A, south stormwater drain (0.51 MGD)
- DSN 464A, perimeter stormwater drain (0.41 MGD)

All of these discharges ultimately flow to the Delaware River.

4.4.1 Cooling Tower Effluent

The HCGS circulating water system (CWS) transports excess heat from the condensers to the cooling tower for dissipation. The CWS is a closed cycle cooling water system and the circulating water is re-circulated within the CWS. The CWS provides an operating volume of about 11 million gallons of water and about 9 million gallons resides in the cooling tower basin. There is an evaporative loss of approximately 10 to 13 MGD (See Figure 4-1) from the natural draft cooling tower and a continuous blowdown is used to control the solids concentration. Makeup water to replace the evaporative loss and continuous blowdown is provided by the service water system (See Section 4.2.2 above).



DELAWARE RIVER
EVAPORATION AND DRIFT
13 MGD
66.8 MGD
795 MGD
DSN 464
DSN 463A
DSN 462A
DSN 461A
SCREEN AND STRAINER WASH
6.9 MGD
SERVICE WATER INTAKE
SACS/RACS HEAT EXCHANGERS
NATURAL DRAFT COOLING TOWER
CIRCULATING WATER SYSTEM
DE-ICING LINE
46.9 MGD
COOLING TOWER BLOWDOWN
DECHLORINATION
0.41 MGD
0.51 MGD
0.24 MGD
0.06 MGD
TURBINE/REACTOR STEAM CYCLE
CONDENSATE STORAGE TANKS
LIQUID RADWASTE PROCESSING DSN 461B
MAKEUP DEMINERALIZER SYSTEM
MAKEUP DEMINERALIZER FEED TANK
WATER STORAGE TANKS
0.10 MGD
WELL NO.1
WELL NO.2
0.07 MGD
SYSTEM LOSSES
AUXILARY BOILERS
DOMESTIC WATER STORAGE TANKS
SOUTH STORM DRAIN
NORTH STORM DRAIN
0.02 MGD
0.04 MGD
AREA BUILDING AND EQUIPMENT DRAINS
MISC. USES
0.02 MGD
LOW VOLUME AND OILY WASTE SYSTEM DSN 461C
POTABLE WATER SYSTEM
SEWAGE TREATMENT SYSTEM DSN 462B
OVERFLOW
0.04 MGD
STORM DRAINS
SALEM TREATMENT SYSTEM
PERIMETER DRAIN
A SCREEN WASH WATER IS USED TO REMOVE IMPINGED FISH & DEBRIS FROM TRAVELLING SCREENS. WASH-WATER ALSO PROVIDES AUGMENTATION FLOW TO THE RETURN SLUICEWAY FOR RETURNING FISH AND DEBRIS TO THE RIVER. ALSO SUMP PUMP DISCHARGE RETURNS LEAKS AND DRAINS WITHIN THE STRUCTURE TO THE RIVER.
B SODIUM HYPOCHLORITE FACILITY DRAIN. PRIMARILY STORMWATER OR SERVICE WATER. VALVE CONTROLLED. TESTED FOR RESIDUAL CHLORINE PRIOR TO DISCHARGE.
C MISCELLANEOUS USES INCLUDE: DRINKING WATER, FIRE PROTECTION USES, EVAPORATION, MISC. CLEANING, LEAKAGE, ETC.
D SALEM GENERATING STATION, NRLWDS, NJPDES NO. NJ0005622
HOPE CREEK GENERATING STATION
SCHEMATIC OF WATER FLOW
NJPDES PERMIT NO. NJ0025411
FORM C, ITEM 3B
SEPTEMBER 2001
NOTE: ALL REPORTED FLOW VALUES ARE DAILY AVERAGES UNLESS OTHERWISE STATED

Figure 4-1

The cooling tower effluent (DSN 461A) is monitored for flow, temperature, heat rate, pH, chlorine produced oxidants (CPOs), and total organic carbon (TOC) as required by the NJPDES permit. NRC (1984) noted that dilution by river and tidal flow as well as CPO demand by the river could reduce the amount of CPOs released to the Delaware River below the NJPDES permit limits. HCGS has also installed a dechlorination system, utilizing ammonium bisulfite, to further reduce CPO concentrations and ensure compliance with the NJPDES permit. Toxic amounts of other chemicals in the effluent are not permitted and the non-toxic effect of the discharges has been confirmed by acute and chronic toxicity tests performed during 1998 through 2001 (see Attachment A).

Thermal effluent limitations imposed by the Delaware River Basin Commission (DRBC) in the NJPDES permit require that the net temperature increase of the Delaware River not be greater than 2.2°C from September to May and not greater than 0.8°C from June to August. These limitations apply outside a heat dissipation area (HDA) no larger than 2,500 ft upstream or downstream or 1,500 ft outshore from the point where the effluent enters the river. The FES (NRC, 1984) concluded that the shoreline discharge should not adversely affect shore zone biota because of the large tidal influence (amplitude of 6.6.- 8.5 ft and high tidal flow of about 400,000 cfs), which dilutes, mixes, and rapidly dissipates the thermal discharges from HCGS. Mobile resident and migratory fish that come in contact with any portion of the thermal plume with temperatures higher than their preference temperatures should be able to readily avoid the plume. Cold shock to aquatic organisms results when the warm water discharge from a plant abruptly stops due to an unplanned shutdown. The probability of an unplanned shutdown is independent of extended power uprate. Although extended power uprate will slightly increase the discharge temperature, HCGS will continue to be operated within and not exceed the current NPDES 24-hour average temperature limitation of 97.1° F. The recent hydrothermal modeling analysis for the HCGS EPU project (Najarian Associates, 2003), illustrates that discharge will be in compliance with the DRBC water quality standards for water temperature at the edge of the associated seasonal HDAs. An analysis conducted by PSEG and appended to the hydrothermal modeling analysis report demonstrates that the 97.1° F effluent limitation of the NJPDES Permit will be met. Consequently, the increase in thermal impacts to aquatic organisms will not be significant, and the total impact will continue to be bounded by the FES.

4.4.2 Other Effluents

The discharge flow from DSN 461A also consists of other minor non-radiological waste stream contributions from the Low Volume and Oily Waste System (DSN 461C, 0.04 MGD) and the Sewage Treatment System (DSN 462B, 0.02 MGD), as well as the radioactive liquid waste system. The low volume oily waste system collects and treats potentially oily wastewater from the area, building, and equipment drains throughout the site as well as auxiliary boiler blowdown, and miscellaneous stormwater sources. The sewage treatment system treats domestic wastewater from HCGS and the adjacent Salem Generating Station. The NJPDES permit specifies internal effluent limitations and monitoring for these systems before discharge via DSN 461A.

The North Yard Drain (DSN 465A, 0.24 MGD) collects and discharge site drainage from the facility parking lots, warehouse roof drain, loading ramp catch basins, auxiliary boiler roof drains, fire water pumphouse, No.2 Reactor Building roof and area drains, materials center area and roof drains, construction and excavation dewatering, and runoff from miscellaneous sources.

The South Yard Drain (DSN 463A, 0.51 MGD) collects and discharges site drainage from the Security Center roof, drain, and parking lot, roof and area drains from the Administration Building, Auxiliary Boiler, Turbine Building, Reactor Building, Materials Center, and Services Facility Building, safety shower, as well as the Chlorine Structure drains, service water valve pit, dewatering sump, construction and excavation dewatering, and runoff from other miscellaneous sources.

The Perimeter Drain (DSN 464A, 0.41 MGD) collects and discharges site drainage from the access road area, Administration Building roof drains and parking lots, Combo Shop roof drains, catch basins in undeveloped portions of the site, groundwater, and natural drainage from the adjacent marshes and immediate areas external to HCGS.

The NJPDES permit specifies the required controls for these three stormwater outfalls to include a Stormwater Pollution Prevention Plan containing Best Management Practices, which helps to ensure that the discharges will not have an adverse impact on Delaware River water quality.

As noted by the NRC (1996b), the impacts of discharges should be considered of small significance if water quality criteria (e.g., NPDES permits) are not consistently violated. The EPU will not create any condition that would cause a violation of the NJPDES Permit.

4.4.3 Groundwater

Two, approximately 815 ft deep wells provide domestic and process water to the HCGS. The wells are permitted by NJDEP (2000) and DRBC to supply groundwater from the Raritan aquifer at a maximum withdrawal rate of 700 gpm or 30.2 million gallons per month (mgm) per well. The NJDEP Staff Report (2000) accompanying the most recent permit states that PSEG is currently in compliance with all permit conditions. No wastes from HCGS are disposed of through underground injection to ground water. The proposed extended power uprate will not increase the use of groundwater or change the limits in the current water allocation permit. Therefore, the conclusions of the FES relative to groundwater remain valid for the extended power uprate.

4.4.4 Surface Water

HCGS cooling and service water supply is obtained from the Delaware River. The Station's service water system withdraws about 67 MGD. Approximately 7 MGD is used for intake screen wash water and strainer backwash. The Service Water is used as makeup water for the cooling tower. The cooling tower system evaporates approximately 13 MGD and returns about 47 MGD through the cooling tower blowdown. The EPU will not increase the amount of water withdrawn from the Delaware River. Consumptive use of surface water is regulated by the DRBC under a water use contract and will not substantively change as a result of the EPU. Based on over 16 years of monitoring, Operation of HCGS has not been reported to have adversely affected the water quality or water quantity of the Delaware River. Furthermore, there is no indication that water withdrawals or discharges from the once-through cooling Salem Generating Station and adjacent HCGS have caused any detrimental effects to the aquatic biota in the Delaware River (PSEG, 1999).

Water quality monitoring programs have been established in accordance with the NJPDES permit. There are no modifications to the nonradiological drain systems required for the extended power uprate, and biocide/chemical discharges will be consistent with existing permit limits. Extended power uprate will not introduce any new contaminants or pollutants and will not significantly increase the amount of any potential contaminants presently allowed for discharge by the NJDEP.

5.0 RADIOLOGICAL ENVIRONMENTAL IMPACTS

5.1 Radioactive Waste Streams

The radioactive waste systems at HCGS are designed to collect, process, and dispose of radioactive wastes in a controlled and safe manner. The design bases for these systems during normal operation are to limit discharges in accordance with 10 CFR 20 and satisfy the design objectives of Appendix I to 10 CFR 50. These limits and objectives will continue to be adhered to under the EPU.

In addition, operation at EPU conditions does not result in any changes in the operation or design of equipment in the radioactive solid waste, liquid waste, or gaseous waste management systems. The safety and reliability of these systems are unaffected by the power uprate. Neither the environmental monitoring of any of these waste streams, nor the radiological monitoring requirements of the HCGS Technical Specifications and/or Offsite Dose Calculation Manual, will be affected by the EPU. Furthermore, the EPU does not introduce any new or different radiological release pathways, nor does it increase the probability of either an operator error or an equipment malfunction, that would result in an uncontrolled radioactive release. The specific effects of the EPU on each of the radioactive waste management systems are evaluated below.

5.1.1 Solid Waste

The Solid Waste Management System (SWMS) collects and processes wet and dry radioactive wastes generated by the plant, packages and monitors the resultant solid radioactive product, and provides temporary storage facilities prior to offsite shipment and permanent disposal. The SWMS does not have any safety-related function. The SWMS is designed to package the wet and dry types of radioactive solid waste for offsite shipment and burial, in accordance with the requirements of applicable United States Nuclear Regulatory Commission (NRC) and Department of Transportation (DOT) regulations, including 10 CFR 61, 10 CFR 71 and 49 CFR 170 through 178. This results in radiation exposures to individuals and the general population well within the limits of 10 CFR 20 and 10 CFR 50. HCGS continually tracks the volume of solid radwaste generated, and reports annually to the Staff by generating Annual Radioactive Effluent Release

Reports (ARERRs) (Ref. 5-18). The annual low-level solid radwaste volumes generated at the HCGS are obtained from Reference 5-18 and shown in Table 5-1.

The post-EPU total solid radwaste increase from spent resin solids radwaste is due to the increased resin replacements from the reactor water cleanup system filter/demineralizer (RWCU F/D) and the condensate pre-filter demineralizers (Ref. 5-6, Section 3.3.2). The total solid radwaste consists of the spent resin, filter sludges, and evaporator bottoms. Average total solid radwaste shipped offsite for burial is 51.2 m^3 (Table 5-1). The increase in demineralizer/filter backwashes at EPU conditions will result in 14.7% increase in the solid radwaste (Ref. 5-6, Section 3.3.1.1), which will yield no more than an additional 7.53 m^3 of solid waste per year (51.2 $m^3 \times 0.147 = 7.53$ m^3). This would result in an increase of total waste generation rate from 51.2 m^3 to 58.8 m^3 (See Table 5-1 below).

The insignificantly small increase in total solid radwaste from the condensate demineralizer/filter backwashes will not result in waste volumes substantially above present level. Therefore, the offsite doses resulting from the post-EPU solid radwaste shipments and compliance with the DOT regulations, including 10 CFR 61, 10 CFR 71 and 49 CFR 170 through 178 requirements will not be impacted by the EPU. The additional solid waste volume due to EPU condition is well within the system design capacity of 945,944 lbs/year (Ref. 5-6, Section 3.3.2.2). In light of the HCGS ongoing efforts to reduce radioactive waste, which can be seen from Table 5-1 waste quantities, the waste reduction program will compensate for the insignificant increase in solid radwaste. The environmental impact of transportation of solid radwaste and spent fuel is discussed in Section 5.6.

Table 5-1
Annual Solid Waste Volume Shipped and Curie Content

Annual Radioactive Effluent Release Report (ARERR) No.	Annual Solid Radwaste Shipped To Burial Site	
	Volume (M^3) A	Activity (Ci) B
HCGS RERR-23 2000	36	141
HCGS RERR-24 2001	85	591
HCGS RERR-25 2002	90.4	533
HCGS RERR-26 2003	11.7	1.04
HCGS RERR-27 2004	33.1	420.5
Pre-Uprate Average	51.2	337.3
Post-EPU Average	58.8	386.9

A & B From Reference 5-18

Post-EPU Value = (1.147 × Average Volume or Activity)

5.1.2 Liquid Waste

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 three process subsystems, each for collecting, storing, processing, monitoring, and disposal of specific types of liquid wastes in accordance with their conductivity, chemical composition, and radioactivity. These systems are:

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

Sufficient treatment capability is available to process liquid waste to meet demineralized water quality requirements for plant reuse. Liquid wastes that are not processed to meet the quality requirement for reuse are released as excess water. Excess water is released in a controlled and monitored manner into the cooling tower blowdown line for dilution, and then discharged to the Delaware River. The LWMS has no safety-related function. The system is designed so that no potentially radioactive liquids can be discharged to the environment unless they have been processed, monitored, and diluted by mixing with the cooling tower blowdown release. This results in offsite radiation exposures within the limits of 10 CFR 20 and 10 CFR 50.

The increased frequency of RWCU F/D and Condensate Pre-Filter Demineralizer backwashes due to the EPU conditions will increase the total liquid radwaste volume (Ref. 5-6, Section 3.3.2). The RWCU F/D backwashes are expected to increase in proportion to the increase in reactor water iron concentration due to EPU (Ref. 5-6, Section 3.2.2.4). The condensate F/D backwashes are expected to increase in proportion to the increase in the condensate system flow due to EPU (Ref. 5-6, Section 3.2.2.6). Average historical total liquid radwaste prior to dilution is 1.898E+08 liters (Table 5-2). The total liquid radwaste volume increase as a result of the EPU is due to the increased frequency of RWCU F/D and Condensate Pre-Filter Demineralizer backwashes. The increase in liquid radwaste due to the EPU is estimated to be 2.2% (Ref. 5-6, Section 3.3.1.1), which will yield no more than an additional 4.173E+6 liters of liquid waste per year (1.897E+08 liters × 0.022 = 4.173E+06 liters). This would result in an increase of total liquid waste generation from 1.897E+08 liters to 1.94E+08 liters (See Table 5-2). The 2.2% increase is insignificant.

Table 5-2
Annual Liquid Waste Volume Prior To Dilution

Annual Radioactive Effluent Release Report (ARERR) No.	Annual Liquid Radwaste Prior To Dilution	
	Volume (Liter) A	Activity (Ci) B
HCGS RERR-23 2000	**1.625E+08**	**2.333E-02**
HCGS RERR-24 2001	**1.970E+08**	**3.204E-02**
HCGS RERR-25 2002	**1.997E+08**	**2.630E-03**
HCGS RERR-26 2003	**2.072E+08**	**6.754E-02**
HCGS RERR-27 2004	**1.823E+08**	**3.233E-02**
Pre-Uprate Average	**1.897E+08**	**3.157E-02**
Post-EPU Average	**1.939E+08**	**3.226E-02**

A & B From Reference 5-18

Post-EPU Value = (1.022 x Average Volume or Activity)

B = Total Fission & Activation Products Excluding Tritium

5.1.3 Gaseous Waste

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 plant ventilation systems. These systems reduce radioactive gaseous releases from the plant by filtration or delay. Delay allows natural decay of radioisotopes prior to release. The function of the off-gas system is to collect and delay the release of non-condensable radioactive gases removed from the main condenser by the air ejectors during normal plant operation. 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.

The continuous releases via the south plant vent are for the containment and auxiliary building exhaust, including the radwaste area and turbine building exhaust. The off-gas system releases are continuous via the north plant vent. The intermittent drywell purge releases and mechanical vacuum pump releases are via the south plant vent. The GWMS are designed to limit offsite doses from routine plant releases to significantly less than the limits specified in 10 CFR 20 and to operate within the dose objectives established in 10 CFR 50 Appendix I. Continuous monitoring is provided for pathways of airborne radioactive releases, with main control room annunciation prior to exceeding Technical Specification allowed limits. The off-gas system is designed to provide at least 35 days and 36 hours of delay time for xenon and krypton, respectively, at a 75 scfm airflow rate. The post-EPU radioactive release through the off-gas system is mainly a function of:

1. Radioactive Off-gas Release Rate;
2. Off-gas System Air Flow Rate; and,
3. Holdup Times In the Off-gas Charcoal Delay System.

5.1.3.1 Radioactive Off-gas Release Rate

The HCGS off-gas system normal noble gases release rates are based on sufficient fuel cladding defects to result in a total off-gas release rate of 100,000 μCi/sec after 30 minutes decay (Ref. 5-9, Table V). The isotopic noble gas release rates bound the resulting EPU noble gas release rates (Ref. 5-10, Appendix A, Class 1). Therefore, the normal radioactive release rate of noble gas is bounding for the EPU condition.

5.1.3.2 Off-gas System Air Flow Rate

The off-gas system air flow rate of 75 scfm is primarily a function of the condenser inleakage, which is independent of the power level (Ref. 5-12, Section 3.2.2.2). The condenser inleakage is primarily a function of material condition, which is not affected by the EPU condition. Therefore, the existing off-gas flow rate of 75 scfm remains bounding for the EPU condition.

5.1.3.3 Holdup Times in Off-gas Charcoal Delay System

The holdup time required for noble gas in the charcoal adsorbers can be determined by the decontamination factor described as follows (Ref. 5-13, Section 4.10):

$T = (K_d \times M) / F$

Where:

- T = average delay time, sec
- K_d = dynamic adsorption coefficient, cm^3/g
- M = mass of absorbent, g
- F = flow rate of noble gas, cm^3/sec
- All values are those at operating conditions.

Dynamic adsorption coefficients for xenon and krypton are based on the charcoal type, relative humidity, temperature, pressure, and other effects (Ref. 5-13, Section 4.10). The factors affecting a dynamic adsorption coefficient are not expected to change during the EPU when the recombiner temperature is at or below the bounding 693^0F value. Therefore, the off-gas charcoal delay system holdup time remains bounding for the EPU.

The reactor coolant source terms have been determined to remain bounding for the EPU condition (Ref. 10, Appendix A). The plant ventilation systems radionuclide concentrations are based on the reactor coolant system source terms. Consequently, the potential airborne activities resulting from the reactor coolant system leakages remain bounding for the EPU condition. Therefore, the gaseous effluent releases and resulting offsite doses from the ventilation systems, which process and control the potential airborne sources of radioactive materials, will not be impacted by the EPU condition.

The radioactive release rate of the gaseous effluent is administratively controlled by the HCGS Offsite Dose Calculation Manual (ODCM) (Ref. 5-14, Control 3/4.11.2 and Appendices C & D). The annual gaseous effluent releases are assessed in the ARERR (Ref. 5-18) using the actual measured or sampled isotopic activities listed in Table 5-3. Table 5-3 show that the 5-year average total annual noble gases and iodine (I-131), and particulate activities are less than the

FES annual average values. Although, the annual particulate activity release in year 2000 was larger than the FES value, per Tables 5-7 through 5-10, the resulting offsite doses from this release for year 2000 were considerably less than the allowable dose limits of 10 CFR 20 and 10 CFR 50, Appendix I.

Table 5-3
Annual Gaseous Effluent Activity Released To Environment

Annual Radioactive Effluent Release Report (ARERR) No.	Annual Gaseous Effluent Activity Release		
	Noble Gases (Ci) A	Iodine (Ci) B	Particulate (Ci) C
HCGS RERR-23 2000	2.990E+01	1.914E-04	5.910E-02
HCGS RERR-24 2001	7.518E-04	2.848E-03	5.853E-04
HCGS RERR-25 2002	4.312E+00	3.438E-03	2.177E-04
HCGS RERR-26 2003	6.300E+01	1.348E-02	2.655E-05
HCGS RERR-27 2004	9.251E+00	5.840E-03	6.768E-05
Pre-Uprate Average	2.129E+01	5.160E-03	1.200E-02
HCGS FES Value	7.329E+03	2.500E-01	4.184E-02

A, B & C From Reference 5-18
HCGS FES Value From Reference 5-5, Table D-1

5.2. Normal In-Plant and Annual Occupational Exposures and Offsite Doses

5.2.1 Normal Operation In-Plant Radiation

During reactor operation, the coolant passing through the core region becomes radioactive as a result of nuclear reactions. Coolant activation products, primarily Nitrogen-16, are the dominant source of gamma radiation fields in the turbine building. Because these sources are produced by activation of coolant in the core region, their rates of production are proportional to power. However, while the magnitude of the source production increases in proportion to power, the concentration in the steam remains nearly constant. This is because the increase in activation production is balanced by the increase in steam flow. Nevertheless, the radiation field resulting from activation products will increase with the EPU primarily due to the increased steam flow and the resultant decrease in transit time for the activation products as they flow from the reactor pressure vessel to the turbine complex. Since these activation products typically have extremely short half-lives, on the order of seconds, the decrease in transit time will result in a measurable increase in radiation exposures in various steam components. The HCGS has implemented a Hydrogen Water Chemistry (HWC) program with a hydrogen injection rate of 35 scfm, which increased the main steam system and subsystem N-16 concentration by a factor of 4.3 over pre-HWC N-16 concentration.

The N-16 concentration of 50 μCi/g at the Reactor Pressure Vessel (RPV) nozzle remains bounding for the EPU because the increase in the N-16 production rate is balanced by the increase in the steam flow. The N-16 transit time of interest is the first 10 seconds, because during this period the main steam has already traveled through the major steam components including the steam headers, high pressure (HP) turbine inlet and outlet piping, cross-over and cross-under piping, moisture separators, and feedwater heaters, which contribute to the major in-plant (direct dose) and skyshine dose. An analysis of post-EPU N-16 transit times in various steam components indicates that the increase in N-16 source strength is approximately 16% for a 20% increase in steam flow (Ref. 5-15, Section 8.0).

A post-EPU radiation exposure assessment in the turbine complex is performed in Reference 5-15 (Tables 3A and 3B) using the likelihood of radiological conditions based on operational data obtained during the implementation of the HWC with a hydrogen injection rate of 35 scfm. Due to conservatisms in the original design, higher-than-expected radiation source terms, and analytical techniques employed for the design of plant shielding to maintain the plant exposure As Low AS Reasonably Achievable (ALARA), the increase in post-EPU radiation levels does not affect the existing radiation zoning or shielding in the various areas of the plant.

5.2.2 Annual Occupational Exposure – Person-Rem

The EPU impact on the annual plant radiation exposure (Person-Rem) is assessed in Reference 5-15, Table 7 with the post-HWC exposure. The EPU related increase is insignificant. Although the implementation of HWC with a hydrogen injection rate of 35 scfm has substantially increased the N-16 contribution to in-plant and skyshine radiation exposures, the average annual radiation exposure measured during with the HWC implemented was substantially lower than the previous average annual exposures as shown Table 5-4, primarily due to strict adherence to good ALARA practices, conservatively designed shielding, and administrative controls. EPU will increase the in-plant occupational exposure by 16%. In addition, the downward trend in occupational exposures at HCGS is expected to continue (Table 5-8) due to the effectiveness of the ALARA Program. The NRC used the collective occupational exposure of 920 person-rem (Ref. 5-5, Appendix D, Table D-8) in the HCGS FES to assess the risks to nuclear-power-plant workers, which is substantially higher than the projected post-EPU occupational exposure of 146 person-rem (Table 5-4). Therefore, the NRC assessment of potential health risk to the exposed work-force at the Hope Creek facility based on the 920 person-rem is bounding for the EPU condition (Ref. 5-5, Section 5.9.3.1.1).

Table 5-4 INPO Occupational Exposure Data for Hope Creek Site	
Actual Occupational Exposure Data - Person-Rem	
Year	**Hope Creek** **A**
1990	209.2
1991	366.9
1992	437.2
1993	97.6
1994	342.5
1995	199.2
1996	171.7
1997	351.8
1998	56.3
1999	281.5
2000	***199.3***
2001	***154.7***
2002	***22.5***
Total Person-Rem	**2890.4**
Pre-EPU Average Person-Rem During HWC Years 2000 to 2002	**126**
Post-EPU Person-Rem	**146**
HCGS FES Person-Rem	**920**
A From Reference 5-15, Table 8	
HCGS FES Person-Rem From Reference 5-5, Table D-8	

5.2.3 Post-EPU Offsite Doses

5.2.3.1 Compliance with 10 CFR 20.1302(a) Requirement

The accessibility to the Station perimeter for members of the public (MOP) changed on September 11, 2001. The definition of members of the public now includes the members of the New Jersey National Guard, which augment the security force at the site. Their typical patrol spans the site. In accordance with the requirements of ODCM 6.9.1.8 (SGS) and 6.9.1.7 (HCGS), the dose to the public inside the site boundary has been calculated based on the assumption that the National Guard works a 40 hour week, therefore, all doses are conservatively multiplied by 0.25 to assess their dose. For the 12-month reporting period the calculated dose is 2.29E-01 mrem total body (Ref. 5-18.a, page 14). The combined post-EPU total body dose to the MOP is 1.43 mrem/year [(0.229 mrem/year + 1.0 mrem/year due to the effluent releases) x 1.16 (projected increased exposure due to EPU)], which is substantially less than the allowable limit of 100 mrem/year.

5.2.3.2 Compliance with 10 CFR 20.1302(b)(ii) Requirement

The site boundary locations were reviewed on the basis of continuous occupancy. The south and west site boundaries are adjacent to the Delaware River, where personnel occupancy will be very low. Therefore, only north and east site boundaries are considered for continuous occupancy at an unrestricted area. The dose survey results indicate that the dose rate at the east site boundary is higher than at the north site boundary. Therefore, the annual dose to the MOP continuously present at the east site boundary is calculated in Reference 5-15, Section 6.3 to be 9.3 mrem/year due to EPU. As shown in Table 5-5, this annual dose is much less than the allowable limit of 50 mrem/year.

5.2.3.3 Compliance with 40 CFR 190.10(a) Requirement

To assess compliance with 40 CFR 190.10(a), direct radiation exposures from the following principal sources are considered:

1. The activity stored outside the plant structures in the condensate storage tank (CST);

2. Turbine shine due to the Nitrogen-16 present in the reactor steam; and,
3. Radiation shine during transport of drummed radwaste and spent fuel assemblies to offsite facilities.

The dose contributions from the CST, the radwaste transport casks, and the spent fuel shipping casks at the site boundaries are considered negligible when compared to the post-EPU N-16 shine from the turbine building. The N-16 present in the reactor steam in the primary steam lines, HP turbine inlet and exhaust headers, cross-over and cross-under piping, and moisture separators provides a major dose contribution to locations outside the plant enclosure as a result of the high energy gamma rays that are emitted as the N-16 decays. The maximum dose rate for areas with potentially high occupancy occurs at the east site boundary. Therefore, the assessment for this limit applicable to unrestricted areas is bounded by the assessment in the preceding Section 5.2.3.2 (i.e., the annual dose to the MOP continuously present at the site boundary is expected to be 9.3 mrem/year due to EPU). Per Table 5-5, this annual dose is much less than the allowable limit of 25 mrem/year. The N-16 only contributes to the whole body dose. The inhaled dose from the gaseous effluent and direct dose from the liquid effluent are included in the annual site boundary dose.

The EPU creates neither new nor different sources of offsite dose from HCGS operation nor does the EPU significantly increase present offsite radiation levels. Therefore, the post-EPU offsite doses shown in Table 5-5 will remain within a fraction of the regulatory limits.

Table 5-5 Annual Post-EPU Offsite Doses		
Regulatory Compliance Required	Post-EPU Dose To MOP (mrem/yr)	Regulatory Allowable Limit (mrem/yr)
20 CFR 20.1301/1302(a)	1.43	100
20 CFR 20.1302(b)(ii)	9.3	50
49 CFR 190, Subpart B	9.3	25

5.2.3.4 Compliance with 10 CFR 50, Appendix I Requirement

Liquid effluents are monitored in accordance with Table 4.11.1.1.1-1 of the HCGS ODCM (Ref. 5-14). The estimated doses for the current licensed power level in Table 5-6 represent the maximum total body and organ radiation doses that could be received by a member of the general public, which are small fractions of allowable limits. The doses were calculated using methods described in Regulatory Guide 1.109 and represent calculations for the 12 month reporting interval. The increase in the general public and population doses due to the post-EPU liquid effluent releases is 2.2% (Ref. 5-6, Section 3.3.1.1), which is insignificant and results in a negligible increase in the post-EPU total doses. Therefore, the existing doses due to the liquid effluents are considered bounding for the EPU condition.

The gaseous effluents are monitored in accordance with Table 4.11.2.1.2-1 of the HCGS ODCM. The estimated doses for the current licensed power level listed in Tables 5-7 and 5-8 represent the maximum gamma and beta radiation doses that could be received by a member of the general public. These doses are small fractions of the allowable limits. The gaseous effluent releases are not impacted by the EPU (Ref. 5-8, Section 7.2). Therefore, the existing general public and population doses from the gaseous effluents remain bounding for the EPU.

Radiation doses to members of the public from the proposed EPU operation have been examined from a variety of perspectives and the impacts were found to be well within design objectives and regulations (Tables 5-9 and 5-10). Both maximum individual and average doses are expected to remain within regulatory limits during the continued EPU operation.

Table 5-6
Annual Total Body & Organ Doses From Liquid Effluent Release

Dose Category	Annual Dose (mrem) Liquid Effluent Release			Annual Maximum Dose			Annual Dose Limit	Percent of Allowable Limit
				Pre-EPU	Post-EPU	HCGS FES		
	2000 A	2001 B	2002 C	(mrem) D	(mrem) E=Dx1.017	(mrem) F1	(mrem) F	G=(E/F)*100
Total Body	2.73E-03	5.26E-05	2.68E-03	2.73E-03	2.78E-03	< 0.1	3	0.093
Any Organ	1.33E-02	4.24E-04	9.35E-03	1.33E-02	1.35E-02	1.40E-01	10	0.135
D = Max of A, B, & C								
A, B, & C From Reference 5-18								
F1 From Reference 5-5, Appendix D, Table D-7								

Table 5-7
Annual Air Gamma Dose From Gaseous Effluent Release

Year	Cumulative Air Gamma Dose Per Quarter Gaseous Effluent Release				Annual Air Gamma Dose Gaseous Effluent Release				Percent of Allowable Limit
	1st Quarter (mrad) A	2nd Quarter (mrad) B	3rd Quarter (mrad) C	4th Quarter (mrad) D	Pre-EPU Dose (mrad) E=A+B+C+D	Post-EPU Dose (mrad) F=E	HCGS FES (mrad) F1	Dose Limit (mrad) G	H=(F/G)*100
2000	1.56E-02	2.30E-04	2.18E-03	2.36E-03	2.04E-02	2.04E-02	4.70E+00	10.0	0.204
2001	0.00E+00	2.04E-08	0.00E+00	1.18E-08	3.22E-08	3.22E-08		10.0	0.000
2002	0.00E+00	1.97E-04	5.65E-05	0.00E+00	2.54E-04	2.54E-04		10.0	0.003
A, B, C, & D From Reference 5-18									
F1 From Reference 5-5, Appendix D, Table D-7									

Table 5-8 Hope Creek Annual Air Beta Dose From Gaseous Effluent Release									
Year	Cumulative Air Beta Dose Per Quarter Gaseous Effluent Release				Annual Airborne Beta Dose Gaseous Effluent Release				Percent of Allowable Limit
	1st Quarter (mrad) A	2nd Quarter (mrad) B	3rd Quarter (mrad) C	4th Quarter (mrad) D	Pre-EPU Dose (mrad) E=A+B+C+D	Post-EPU Dose (mrad) F=E	HCGS FES (mrad) F1	Dose Limit (mrad) G	H=(F/G)*100
2000	1.64E-02	2.41E-04	2.29E-03	2.47E-03	2.14E-02	2.14E-02	6.90E+00	20.0	0.107
2001	0.00E+00	6.05E-08	0.00E+00	1.52E-08	7.57E-08	7.57E-08		20.0	0.000
2002	0.00E+00	4.17E-04	7.59E-05	0.00E+00	4.93E-04	4.93E-04		20.0	0.002
A, B, C, & D From Reference 5-18									
F1 From Reference 5-5, Appendix D, Table D-7									

Table 5-9 Annual Total Body & Population Doses at Site Boundary Gaseous Effluent Pathways - 10 CFR 20			
Dose Type	**Year**	**Annual Total Body Dose (mrem)**	**Allowable Regulatory Limit (mrem)**
Total Body Dose	2002	2.29E-04	500.00
	2001	2.82E-08	
	2000	1.95E-02	
Average Total Body Dose		**6.58E-03**	
Post-EPU Total Body Dose		**6.58E-03**	
Total Population Dose	2002	3.90E-01	N/A
	2001	1.32E+00	
	2000	1.41E+00	
Average Total Population Dose (person-rem)		**1.04E+00**	
Post-EPU Total Population Dose (person-rem)		**1.06E+00**	
Average Population Dose	2002	8.66E-05	N/A
	2001	2.22E-06	
	2000	2.36E-04	
Average Ave Population Dose		**1.08E-04**	
Post-EPU Avg Population Dose		**1.10E-04**	
Dose Information From Reference 5-18			

Table 5-10
Annual Thyroid Dose at Unrestricted Area
Gaseous Effluent Pathways - 10 CFR 50, Appendix I Compliance

Dose Type	Year	Annual Organ Dose Pre-EPU (mrem)	Annual Organ Dose HCGS FES* (mrem)	Allowable Regulatory Limit (mrem)
Organ Dose (Thyroid)	2002	3.60E-02	3.10E+00	15
	2001	3.16E-02		
	2000	4.27E-03		
Average Organ Dose (Thyroid)		**2.40E-02**		
Post-EPU Organ Dose (Thyroid)		**2.40E-02**		
Pre-EPU Organ Dose Information From Reference 5-18				
* Annual Organ Dose From Reference 5-5, Appendix D, Table D-7				

5.3 Radiological Consequences of Accidents

To demonstrate that certain features important to the safety of the HCGS meet acceptable design and performance criteria, both PSEG and the Staff have analyzed the potential consequences of a number of postulated accidents. Section 5.9.4.5(1) of the HCGS Final Environmental Statement (FES) (Ref. 5-5) indicates that in the HCGS safety analysis and evaluation, three classes of postulated accidents have been considered based on probability of occurrence. These classes are (1) incidents of moderate frequency (events that can be reasonably be expected to occur during any year of operation), (2) infrequent incidents (events that might occur once during the life time of the plant), and (3) limiting faults (accidents not expected to occur, but that have potential for significant releases of radioactivity). The following subsections address the impact of the EPU on the assumptions and conclusions for these accident classes.

5.3.1 Class 1 – Incidents of Moderate Frequency

Incidents of moderate frequency are analyzed to ensure that they will not cause damage to either the fuel or the reactor coolant pressure boundary, and to ensure that the radiological dose is maintained within 10 CFR 20 guidelines (Ref. 5-19, page 15-1). Anticipated operational occurrences are those transients resulting from single equipment failures or single operator errors that might be expected to occur during normal or planned modes of plant operation. The acceptance criteria for these incidents require that the reactor core and associated control, instrumentation, and protection systems be designed with appropriate margin to ensure that acceptable fuel design limits and that the design condition of reactor coolant pressure boundary are not exceeded during normal operation including anticipated operational occurrences. The FES concludes that the radiological consequences of moderate frequency incidents are similar to the consequences from normal operation effluent releases previously discussed in Section 5.1.2. Because of improved fuel integrity and the increased effectiveness of the gaseous and liquid treatment systems, the post-EPU radiological consequences will be considerably less than that predicted by the FES and will remain within the allowable regulatory limits (See Tables 5-3, 5-4, 5-5, & 5-7 for comparison of the post-EPU doses with FES doses).

5.3.2 Class 2 – Infrequent Incidents

Class 2 events are those events that might occur once during the life of the plant. The EPU does not increase the probability of a fuel handling accident (FHA). The following section discusses the FHA.

The HCGS operating license (OL) was amended by the Staff on October 3, 2001 (Ref. 5-22), to adopt the Alternative Source Term (AST) for HCGS design basis analyses. The OL was subsequently amended to modify the secondary containment integrity during a refueling outage and to remove the filtration, recirculation, and ventilation system (FRVS) recirculation subsystem charcoal filters from the Technical Specifications (Ref. 5-23). The FHA was re-analyzed using the AST and EPU core inventory.

The post-FHA EAB and Low Population Zone (LPZ) doses in Table 5-11 are within the allowable limits, which demonstrate that removal of the charcoal from the FRVS recirculation filters does not adversely impact the dose mitigation system compliance with the acceptable design objectives. Although, the resulting environmental impact following a FHA is higher than that predicted in the HCGS FES due to the plant modifications implemented after the FES was issued, the environmental impact will remain within the allowable limits for the FHA incident. The environmental impact is not expected to differ significantly for EPU operation because it is analyzed in a fashion consistent with the regulatory limit set for the incident.

Table 5-11
Post-FHA EAB, LPZ, & CR Doses

	Fuel Handling Accident Occurring in Reactor TEDE Dose (rem) Receptor Location		
	Control Room	**EAB**	**LPZ**
Calculated Dose*	3.31E+00	5.27E-01	5.27E-02
Allowable TEDE Limit	5.00E+00	6.30E+00	6.30E+00

*From Reference 5-24, Section 7.0

5.3.3 Class 3 – Limiting Faults

Class 3 limiting fault accidents are those events that are not expected to occur, but have the potential for significant releases of radioactivity. The HCGS FES evaluated the loss of coolant accident (LOCA) as a Class 3 accident (Ref. 5-5, Section 5.9.4.5 and Table 5-13). In addition to the LOCA, the results of other limiting fault accidents – control rod drop accident (CRDA) and main steam line break accident (MSLBA) – are provided in the following subsections to cover the entire spectrum of limiting faults. However, the resulting post-EPU radiological consequences will be higher than that predicted by the FES (Ref. 5-5, Table 13) due to various plant modifications and TEDE dose criteria implemented after the FES was issued, they will remain within the allowable regulatory limits (See Tables 5-12, 5-13, 5-14, & 5-15 for comparison of the post-EPU doses with allowable limits).

5.3.3.1 Loss of Coolant Accident (LOCA)

The post-LOCA EAB, LPZ, and CR doses are analyzed using the guidance in Regulatory Guide 1.183, Appendix A (Ref. 5-25) with removal of Main Steam Isolation Valve Sealing System

(MSIVSS), charcoal from the FRVS recirculation filters, increase of total MSIV leakage from 46 scfh to 250 scfh, EPU core inventory, and TEDE dose criteria in Table 6 of Reference 5-25. The results are summarized in Table 5-12.

Table 5-12
Post-LOCA EAB, LPZ, and CR Doses

Post-LOCA Activity Release Path	Post-LOCA TEDE Dose (Rem) Receptor Location		
	Control Room	EAB	LPZ
Containment Leakage	1.05E+00	3.73E-01	1.62E-01
ESF Leakage	1.25E+00	1.91E-01	9.79E-02
MSIV Leakage	2.13E+00	2.63E+00	4.56E-01
CR Filter Shine	2.46E-03	0.00E+00	0.00E+00
Total	**4.43E+00**	**3.19E+00**	**7.16E-01**
Allowable TEDE Limit	**5.00E+00**	**2.50E+01**	**2.50E+01**

5.3.3.2 Control Rod Drop Accident (CRDA)

The post-CRDA EAB, LPZ, and CR doses are analyzed using the guidance in Regulatory Guide 1.183, Appendix C (Ref. 5-25), EPU core inventory, and TEDE dose criteria in Table 6 of Reference 5-25. The results are summarized in Table 5-13.

Table 5-13
Post-Control Rod Drop Accident EAB, LPZ, and CR Doses

	Control Rod Drop Accident TEDE Dose (Rem) Receptor Location		
	Control Room	EAB	LPZ
Calculated Dose*	1.37E-01	2.92E-02	6.23E-03
Allowable TEDE Limit	**5.00 E+00**	**6.30E+00**	**6.30E+00**

* From Reference 5-27, Section 7.0

5.3.3.3 Main Steam Line Break Accident (MSLBA)

The post-MSLBA EAB, LPZ, and CR doses are analyzed using the guidance in Regulatory Guide 1.183, Appendix D (Ref. 5-25), EPU core inventory, and TEDE dose criteria in Table 6 of Reference 5-25 with a pre-accident iodine spike (4.0 μCi/g DE I-131) and the maximum equilibrium iodine concentration (0.2 μCi/g DE I-131). The results are summarized in Tables 5-14 and 5-15.

Table 5-14
Post-MSLB Accident EAB, LPZ, CR Doses with Pre-accident Iodine Spike

	Main Steam Line Break Accident with Pre-accident Iodine Spike TEDE Dose (rem)		
	Receptor Location		
	Control Room	**EAB**	**LPZ**
Calculated Dose*	3.60E+00	9.42E-01	9.45E-02
Allowable TEDE Limit	**5.00E+00**	**2.50E+01**	**2.50E+01**

* From Reference 5-28, Section 7.1

Table 5-15
Post-MSLB Accident EAB, LPZ, CR Doses with Maximum Equilibrium Iodine Concentration

	Main Steam Line Break Accident with Maximum Equilibrium Iodine Concentration for Continued Full Power Operation TEDE Dose (rem)		
	Receptor Location		
	Control Room	**EAB**	**LPZ**
Calculated Dose*	1.81E-01	5.61E-02	5.63E-03
Allowable TEDE Limit	**5.00E+00**	**2.50E+00**	**2.50E+00**

* From Reference 5-28, Section 7.2

5.4 Severe Accidents

The severe accidents, frequently called Class 9 accidents, are considered less likely to occur than DBA, but their consequences could be more severe for both the plant itself and for the environment. PSEG analyzed the severe accident in Reference 5-30 (Section 7.1 and Appendix C) and concluded that some of the environmental impacts could be severe, but the likelihood of their occurrence, and hence, the public risk, were judged to be small. The NRC independently analyzed the Class 9 accidents in Reference 5-5, Section 5.9.4.5(2). The NRC concluded in the HCGS FES that the severe accident risks from HCGS are expected to be a small fraction of the risks the general public incurs from other natural sources. Further, the best estimate calculations show that the risks of potential reactor accidents at HCGS are within the range of such risks from other power plants. Based on the analyses of environmental impact of Class 9 accidents, the NRC concluded that there were no special or unique circumstances about the HCGS site and environs that would warrant consideration of alternatives for HCGS (Ref. 5-5, Section 5.9.4.6). The post-EPU severe accident risks to the general public are still expected to be a small fraction of the risks incurred from natural background sources and are bounded by the FES analyses.

5.5 Environmental Effects Of Uranium Fuel Cycle Activities (Summary Table S-3)

Summary Table S-3 of 10 CFR 51.51 was adopted for the HCGS licensing process, and used by the Staff to assess the environmental impacts from the uranium fuel cycle as related to the operation of HCGS in Reference 5-5, Appendix C. The radiological environmental impact of the uranium fuel cycle for the EPU operation has been reviewed and assessed (Ref. 5-31). The assessment of health effects was based on the values presented in Summary Table S-3, regulatory standards including 10 CFR 20, 10 CFR 61, 10 CFR 71 and 49 CFR 170 through 178, the gaseous and liquid releases from uranium mining, milling and active tailings, and radon-222 and technetium-99 releases from the un-reclaimed open-pit mines and stabilized tailings piles, to support the post-EPU operation of HCGS (Ref. 5-31). Based on the evaluation, it is concluded that the radiological environmental impact of HCGS EPU operation on the U.S. population from radioactive gaseous and liquid releases (including Rn-222 and Tc-99) resulting from the uranium fuel cycle is very small when compared with the impact of natural background radiation. Therefore, the HCGS post-EPU operation is bounded by the radiological environmental assessment of Table S-3.

5.6 Environmental Impact of Transportation of Fuel and Waste (Summary Table S-4)

Summary Table S-4 of 10 CFR 51.52 was adopted for the HCGS licensing process and used by the Staff to assess the environmental impacts from the transportation of fuel and waste as related to the operation of HCGS in Reference 5-5, Section 5.9.3.1.2. The radiological and non-radiological environmental impacts of transportation of fuel and waste due to the EPU operation have been reviewed and assessed in Reference 5-31. Per the assessment, the following conditions in paragraph (a) of 10 CFR 51.52 will not be met during the EPU operation, however, they are acceptable as explained in the following sections:

Table 5-16

Plant Parameter	10 CFR 51.52(a) Criteria	EPU Parameter Value
Reactor Core Thermal Power Level	3,800 MW_t	3,952 MW_t[1]
Uranium-235 Enrichment Percent	$\leq 4\%$	$\leq 4.6\%$[2]
Average Level of Irradiation	33,000 MWD/MTU	$\leq$ 35,000 MWD/MTU[2]
1. From Reference 5-7, Section 1.1, Project Summary		
2. From Reference 5-7, Section 1.3, Results Summary		

5.6.1 Reactor Thermal Power Level

The WASH-1238 environmental impact analysis for the transportation of spent fuel and radwaste is based on shipments of fresh fuel, irradiated fuel, and solid radioactive waste from a boiling water or pressurized water reactor with design ratings in the range of 3,000 to 5,000 MWt or 1,000 to 1,500 MWe (Ref. 5-29, page 3). This range bounds the EPU power level of 3,952 MWt. The radiation exposure to transportation workers and the MOP are calculated in Appendix D of WASH-1238 based on the regulatory limit of 10 mrem/hr at 6 feet from the surface of the vehicle (Ref. 5-29, page 107), which is independent of power level. Although the increase in the transportation exposure due to the EPU is negligible, adherence to the regulatory dose rate limit during the transportation of post-EPU spent fuel and solid radioactive waste will result in the transport workers and MOP radiation exposures in compliance with the exposure values in Summary Table S-4.

5.6.2 U-235 Enrichment and Fuel Burnup

The data presented in Summary Tables S-3 and S-4 are, in part, based on an average burnup assumption of 33,000 MWD/MTU and a Uranium-235 enrichment assumption of 4 wt.%. Under extended power uprate conditions, fuel consumption is expected to increase such that the batch average burnup of the fuel assemblies will be in excess of 33,000 MWD/MTU but less than 60,000 MWD/MTU. To support extended burnup, the U-235 enrichments levels will also increase to greater than 4 wt.% but less than 5 wt.%. The NRC has previously evaluated the impact of increased burnup to 60,000 MWD/MTU with U-235 fuel enrichment to 5 wt.% on the conclusions of Summary Table S-4 (Ref. 5-11). Although some radionuclide inventory levels and activity levels are projected to increase, the NRC noted that little or no increase in the amount of radionuclides released to the environment during normal operation was expected. The NRC determined that the incremental environmental effects of increased enrichment and burnup on transportation of fuel, spent fuel, and waste were not significant. In addition, the NRC recognized the salient environmental benefits of extended burnup such as reduced occupational dose, reduced public dose, reduced fuel requirements per unit electricity, and reduced shipments. The NRC concluded that the environmental impacts described by Summary Table S-4 were bounding and were also applicable for burnup levels to 60,000 MWD/MTU and U-235 enrichment levels up to 5 wt.%. Therefore, the environmental impacts described by Summary Table S-4 are bounding for the HCGS EPU operations.

5.6.3 Non-radiological Impact of Transportation of Fuel and Waste

The non-radiological environmental impacts associated with the transportation of spent fuel and radioactive waste include the heat per irradiated fuel cask in transit, weight, traffic density, fatal and non-fatal injuries, and property damage.

The weight of shipment by truck must meet State restrictions on gross weight of the vehicle, which ensure against damage to bridges or highways. The limited number of shipments per reactor year is too small to have any measurable effect on the environment due to the resultant increase in traffic density. The weights of rail and barge shipments are too small to result in any measurable effects on the environment.

The effect of a heat output of 250,000 Btu/hr from an irradiated fuel cask in transit in Summary Table S-4 is based on an actual design of a shipping cask for LWR fuel (Ref. 5-21, page 2). At the time of discharge from the reactor, the radioactivity and the decay heat of high burnup fuel may be higher, but this heat output increase diminishes as the cooling time is lengthened. Since the spent fuel is cooled more than a year before it is shipped to a burial site, the shipping cask heat dissipation rate would be substantially lower than 250,000 Btu/hr. With the existing inventory of spent fuel that has accumulated, the age of any spent fuel that is reprocessed or transported to a repository is likely to be many years. At the conclusion of the hearings on reprocessing and waste management (Dockets 50-277, 50-278, 50-320, 50-354, and 50-355, Consolidated Hearing on Radon Before the Appeal Board), the Hearing Board concluded that 5 years would be a reasonable value to use in making estimates (Ref. 5-20, Section 6.2.3, pages 310 & 311). The scenario that is visualized today for emplacement of spent fuel and high-level waste in a geologic repository calls for this final disposal to occur after the spent fuel or waste is at least 10 or more years old. Longer cooling times on site reduce the impact on the environment and increase the margin of safety once the fuel is being transported.

5.7 Emergency Planning Impacts

The emergency preparedness plan at the HCGS is established for an accident including the protective action measures for the public to ensure that the condition of on- and off-site emergency preparedness provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. In the event of a release of radioactive material from the plant, protective actions can be taken to move or shelter members of the public in the projected path of the material. The success of these actions in preventing exposure of members of the public to released radioactive material is dependent upon the warning time available prior to the release and the time it takes to carry out the protective actions. In general, this latter item (the time to carry out the protective action) is mostly influenced by the size of the population around the plant. Other measures include provisions for dissemination to the public of basic emergency planning information; provisions for rapid notification of the public during a serious reactor emergency; and methods, systems, and equipment for assessing and monitoring actual or potential off-site consequences in the event of a radiological emergency condition. These protective measures and various emergency levels are independent of the licensed power level. Therefore, the post-EPU operation of HCGS will not impact the existing emergency preparedness plan adversely.

5.8 Environmental Effects of Decommissioning

HCGS has developed a Decommissioning Cost Analysis (DCA) (Ref. 5-32) to present the cost to promptly decommission HCGS following a scheduled cessation of plant operations. Additional costs of decommissioning are only associated with the increased activity levels in the plant and the increase in fuel activity. Effects on the DCA related to the EPU are negligible.

The HCGS Decommissioning Cost Analysis (DCA) (Ref. 5-32) was developed analyzing the DECON alternative. The DECON alternative is defined as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations." (Ref. 5-33) Decommissioning costs are analyzed considering the preparation period, the actual decommissioning operations, and the site restoration.

The preparation period is undertaken to ensure a smooth transition from plant operations to decommissioning. This period includes planning, permitting, submittal of the license termination plan, determination of staff requirements, characterization of the site, and development of the post-shutdown decommissioning activities report (PSDAR). The EPU will have no impact on the costs determined for the preparation period in the DCA.

The decommissioning operations period includes the dismantling, decontamination, and disposal of components and equipment. The increased radiation and activity levels associated with the EPU will slightly increase the costs of disposal of radioactive materials. Any increase in cost attributable to the EPU would be negligible because the calculated increase in plant solid waste and resin activity is less than 0.5% (see Section 5.1) and the total cost for radwaste disposal during this phase is only 16% of the estimated cost.

The site restoration period includes the demolition and removal of site structures and facilities and extensive radiological surveys. The EPU will have no effect on the estimated costs of the site restoration phase.

The spent fuel management costs, prior to disposal, are included in the DCA. These costs are approximately 7.24% of the total cost in the DCA. Therefore, the costs associated with spent fuel management after cessation of operations related to the EPU will be negligible.

The cost to dispose of spent fuel generated from plant operations is not included in the DCA. Ultimate disposal of spent fuel is within the province of the Department of Energy's (DOE's) Waste Management System. As such, the disposal cost is financed by a kilowatt-hour surcharge paid into the DOE's waste fund during operations. Any increase in the costs of spent fuel disposal related to the EPU will be accommodated in the surcharge during plant operations.

Therefore, the costs of decommissioning will not be substantively affected by the EPU.

5.9 Section 5 References

5-1. 10 CFR 51.51, Uranium Fuel Cycle Environmental Data – Table S-3

5-2. 10 CFR 51.52, Environmental Effects of Transportation of Fuel and Waste – Table S-4

5-3. HCGS to USNRC Letter LR-N00-0405, Request for License Amendment, Increased Licensed Power Level, LCR H00-05, December 1, 2000

5-4. NRC Letter, Subject: Hope Creek Generating Station – Environmental Assessment and Finding of No Significant Impact for Increase in Allowable Thermal Power Level (TAC No. MB0644), June 18, 2001

5-5. NUREG-1074, Final Environmental Statement Related to the Operation of Hope Creek Generating Station, Docket No. 50-354, December 1984

5-6. GE-NE-0000-0000-0152-01, Revision 1, Project Task Report T0800, Liquid and Solid Radwaste Management, April 2004

5-7. GE-NE-0000-0015-01114-R3, DRF 0000-0004-6923, Revision 3, Project Task Report T0802, Radioactive Source Term – Core Inventory, April 2004

5-8. HCGS Calculation No. H-1-ZZ-MDC-1955, Revision 0IR0, Radiological Impact Evaluation of EPU on Radwaste Management

5-9. GE Report No. 22A2703F, Revision 3, "Radiation Sources", (VTD PNO-A61-4100-0047, Sheet 1, Revision 2)

5-10. GE-NE-0000-0011-3853-R3, DRF 0000-0004-6923, Revision 3, Project Task Report T0807, Coolant Radiation Sources, April 2004

5-11. NUREG/CR-5009 (PNL-6258), Assessment of the Use of Extended Burnup Fuel in Light Water Power Reactors, February 1988

5-12. GE-NE-0000-0005-7177-01, Revision 1, Project Task Report T0801, Gaseous Waste Management, April 2004

5-13. ANSI/ANS-55.4-1993, Gaseous Radioactive Waste Processing Systems For Light Water Reactor Plants

5-14. HCGS Offsite Dose Calculation Manual, Revision 20

5-15. HCGS Calculation No. H-1-ZZ-MDC-1930, Revision 0IR1, EPU Impact on N-16 Radiation Exposure to Various Areas of Plant and Member of Public

5-16. HCGS Calculation No. H-1-ZZ-MDC-1956, Revision 0IR0, Radiological Impact Evaluation of EPU on Radiation Monitoring System

5-17. NUREG-0737, Clarification of TMI Action Plan Requirements

5-18. HCGS Annual Radioactive Effluent Release Reports (ARERRs):

a. 2000 HCGS RERR – 23

b. 2001 HCGS RERR – 24

c. 2002 HCGS RERR – 25

d. 2003 HCGS RERR – 26

e. 2004 HCGS RERR – 27 (Preliminary)

5-19. NUREG-1048, Safety Evaluation Report Related to the Operation of Hope Creek Generating Station, Docket No. 50-354, October 1984

5-20. NUREG-1437, Volume 1, Generic Environmental Impact Statement for License Renewal of Nuclear Plants

5-21. NUREG-75/038, Supplement I to WASH-1238, Environmental Survey of Transportation of Radioactive Material to and from Nuclear Power Plants, April 1975

5-22. NRC Safety Evaluation Related to Amendment No. 134 to Facility Operating License No. NPF-57, Re: Increase in Allowable Main Steam Isolation Valve (MSIV) Leakage Rate and Elimination of MSIV Sealing System (TAC No. MB1970), October 3, 2001

5-23. NRC Safety Evaluation Related to Amendment No. 146 to Facility Operating License No. NPF-57, Re: Containment Requirements During Fuel Handling and Removal of Charcoal Filters (TAC No. MB5548), April 15, 2003

5-24. HCGS Calculation No. H-1-ZZ-MDC-1929, Revision 0IR0, Fuel Handling Accident Radiological Consequences

5-25. NRC Regulatory Guide 1.183, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors, July 2000

5-26. HCGS Calculation No. H-1-ZZ-MDC-1880, Revision 1IR1, Post-LOCA EAB, LPZ, and CR Doses

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5-29. WASH-1238, Environmental Survey of Transportation of Radioactive Materials to and from Nuclear Power Plants, December 1972

5-30. HCGS Environmental Report – Operating License Stage, Volume 2

5-31. HCGS Engineering Evaluation No. H-1-ZZ-MEE-1791, Revision 0, Radiological Environmental Impact of EPU on Uranium Fuel Cycle and Spent Fuel & Radwaste Transportation

5-32. TLG Services, Inc. 2002. "Decommissioning Cost Analysis for the Hope Creek Generating Station. Document P07-1425-0022, Rev. 0."

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6.0 ALTERNATIVES TO THE PROPOSED ACTION

This section evaluates the environmental impacts of alternatives to the HCGS proposed EPU. The proposed EPU would result in an uprate from 3,339 MWt to a maximum of 3,952 MWt, resulting in a gross increase of about 200 MWe. The following discussion includes an assessment of the "no action" alternatives and other alternatives that would result in incremental changes in system generating capacity.

6.1 NO ACTION ALTERNATIVE

PSEG has defined the "no action" alternative as the condition in which the Station continues to operate under current power levels. Under this alternative, HCGS operation and associated impacts would not be different from those currently allowed through the various permits approved by federal, state and local regulatory agencies and PSEG would develop an alternate energy development strategy.

6.2 ALTERNATIVES THAT MEET INCREMENTAL CHANGES IN SYSTEM GENERATING CAPACITY

The Energy Information Administration (EIA, 2002) reports the primary sources of generation in New Jersey in 2002 were approximately the following: nuclear (50%), gas (31%), coal (16%), oil (2%), and other sources (2%). PSEG has concluded that gas- and possibly coal-fired facilities are the only reasonable alternatives to the EPU for incremental increases in generation comparable to the proposed EPU.

PSEG evaluated potential new gas- and coal-fired units for the existing HCGS site. Under this alternative, PSEG would construct a separate generating facility and minimize some environmental impacts by building on previously disturbed land, utilize existing facilities, transmission lines, roads and parking areas, office buildings, and cooling systems, to the extent practicable.

For comparability in analysis, PSEG selected gas- and coal-fired units of equal electric power and equal capacity factors. Therefore, to meet the electrical supply of the proposed EPU, PSEG selected alternative units of about 200 gross MWe. However, it is important to remember that these are hypothetical alternatives and PSEG does not have plans for such construction at HCGS.

6.2.1 Gas-Fired Generation Alternative

PSEG has chosen to evaluate the gas-fired generation alternative using combined-cycle turbines, because this technology has been employed at other sites and appears to be sufficiently economical and feasible for implementation at HCGS. Gas-fired combined cycle turbines are readily available in a standardized unit of about 200 MW and are more economical than customized units. Table 6-1 presents the basic gas-fired alternative characteristics. Employing this alternative would require, at a minimum a new dedicated, high pressure natural gas line that would extend for miles to the Station. In addition, a constant and reliable source of natural gas would have to be located, which may lead to further supply and reliability issues.

6.2.2 Coal-Fired Generation Alternative

Commonwealth Edison Company, in considering an extended power uprate for the Dresden Nuclear Power Station, evaluated a coal-fired alternative (Tetra Tech NUS Inc., 2000). PSEG has reviewed the analysis and believes it to be relevant to the proposed EPU for the HCGS. Thus, PSEG has used site- and New Jersey-specific information and has scaled from the Commonwealth Edison Company analysis, where appropriate, to provide this alternative.

Table 6.2 presents the coal-fired alternative characteristics employed in this evaluation. The emission control technology and percent control assumptions are based on alternatives that USEPA has identified as being available for minimizing emissions. Coal and some other emission control chemicals (e.g., lime/limestone) would probably be delivered via rail or barge that would require further modifications at HCGS.

Table 6-1

Gas-Fired Alternative Characteristics

Characteristic	Basis
Unit size = 200 MW[5] gross[6] : One 137 MW combustion turbine and a 63 MW heat recovery boiler	Chosen to be equivalent to proposed EPU
Unit size = 192 MW net	Assumed a 4% power usage at HCGS
Fuel type = natural gas	Assumed
Fuel heating value = 1,030 Btu/ft^3	2000 value for gas used in New Jersey (EIA, 2000)
Fuel sulfur content = 0.0034 lb/MMBtu	Used when sulfur content is not available (USEPA, 2000a)
NOx control = selective catalytic reduction (SCR)	Best available for minimizing NOx emissions (USEPA, 2000b)
NOx emission factor = 0.0128 lb/MMBtu	Typical for SCR-controlled gas-fired units (USEPA, 2000b)
CO emission factor = 0.0168 lb/MMBtu	Typical for SCR-controlled gas-fired units (USEPA, 2000b)
Heat rate = 8,200 Btu/Kwh	Typical for combined cycle gas-fired units (EIA, 2002)
Capacity factor = 0.75	Assumed same as coal for comparison

[5] MW = megawatt; Btu = British thermal unit; ft^3 = cubic foot; Kwh = kilowatt hour; MM = million; NOx = nitrogen oxides; CO = carbon monoxide
[6] The difference between gross and net size is the amount of electricity consumed at HCGS.

Table 6-2

Coal-Fired Alternative Characteristics

Characteristic	Basis
Unit size = 200 MW[7] gross[8]	Chosen to be equivalent to proposed EPU
Unit size = 192 MW net	Assumed a 4% power usage at HCGS
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxide emissions (USEPA, 1998)
Fuel type = bituminous, pulverized coal	Typical for coal used in New Jersey
Fuel heating value = 12,915 Btu/lb	2000 value for coal used in New Jersey (EIA, 2000)
Fuel ash content by weight = 8.8 percent	2000 value for coal used in New Jersey (EIA, 2000)
Fuel sulfur content by weight = 1.19 percent	2000 value for coal used in New Jersey (EIA, 2000)
Uncontrolled NOx emission = 9.7 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, pre-NSPS with low NOx burner (USEPA, 1998)
Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, pre-NSPS with low NOx burner (USEPA, 1998)
Heat rate = 10,200 Btu/Kwh	Typical for coal-fired, single cycle steam turbines (EIA, 2002)
Capacity factor = 0.75	Typical for small coal-fired units
NOx control = low NOx burners, overfire air and selective catalytic reduction (SCR, 95% reduction)	Best available technology for minimizing NOx emissions (USEPA, 1998, Table 1.1-2)
Particulate control = fabric filters (baghouse 99.9% removal efficiency)	Best available technology for minimizing particulate emissions (USEPA, 1998, Page 1.1-7)
Sox control = wet scrubber-lime/limestone (95% removal efficiency)	Best available technology for minimizing SOx emissions (USEPA, 1998, Table 1.1-1)

[7] MW = megawatt; Btu = British thermal unit; ft^3 = cubic foot; Kwh = kilowatt hour; lb = pound; NSPS = New Source Performance Standards; NOx = nitrogen oxides; CO = carbon monoxide; SOx = sulfur oxides

[8] The difference between gross and net size is the amount of electricity consumed at HCGS.

6.3 ENVIRONMENTAL IMPACTS OF ALTERNATIVES

This section evaluates the potential environmental impacts from the fossil fired alternatives described above.

6.3.1 Gas-Fired Generation Impacts

NRC (1996b) evaluated the environmental impacts from gas-fired generation alternatives in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants and focused on combined-cycle plants. Section 6.2.1 presents the assumptions for defining a combined-cycle gas-fired plant at HCGS.

Land use impacts at HCGS for gas-fired generation would be less than for coal-fired generation because of the following: construction on the existing site, a relatively small facility foot print, and no ash or lime sludge disposal. These attributes would potentially reduce impacts to ecological, cultural, and aesthetic resources when compared to the coal-fired generation alternative. A workforce of 10 to 20 individuals to operate the gas-fired facility would have minimal socioeconomic impacts. Gas-fired generation would result in minimal waste generation and produce minor, if any impacts.

The primary impacts with gas-fired generation appear to be associated with air emissions and potential impacts to ecological and cultural resources from gas pipeline construction.

PSEG estimates the gas-fired generation alternative would have the following annual air emissions:

- SOx, 13 tons per year
- NOx, 47 tons per year
- CO, 62 tons per year
- Total Suspended Particulates (TSP), 7 tons per year as PM_{10} (includes filterable and condensable)

Table 6-3 presents the equations used by PSEG to calculate these emissions, which are based on the plant characteristics provided in Table 6-1.

Air quality impacts of gas-fired generation are different from nuclear generation. A gas-fired plant would emit sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and particulate matter (PM), all of which are regulated pollutants as well as carbon dioxide (CO_2), a potential contributor to global warming. The gas-fired alternative would release similar types of emissions to the coal-fired generation but in lesser quantities.

NOx emissions are the primary focus of the control technology for gas-fired turbines. Emissions of NOx from the electric power industry in New Jersey increased by 4 percent from 1990 to 1999 (EIA, 2001). In 1998, the USEPA (2002b) promulgated the NOx State Implementation Plan (SIP) that required 22 states including New Jersey to substantially reduce their NOx emissions. The NOx SIP imposes a NOx budget to limit the NOx emissions from each state. NJDEP has allocated NOx credits among the existing electrical generators in the state and has set aside a small percentage of credits for new sources. New sources of NOx must obtain enough NOx credits to cover their annual emissions either from the set aside pool or by buying NOx credits from other sources.

Aspects of the Clean Air Act Amendments (CAAA) cap the sulfur dioxide emissions from power plants and provide allowances to each utility. To be in compliance with the CAAA, PSEG must have enough sulfur dioxide allowances to cover its annual emissions. PSEG would probably have to purchase additional allowances from the open market to operate a fossil fuel burning plant at the HCGS site.

The installation of a buried gas pipeline from an identified source to the HCGS site would likely be very costly (e.g., approximately $1 million per mile), time consuming from a permitting perspective, and have potential impacts to ecological and cultural resources, especially the wetlands in the region. PSEG could mitigate some impacts by employing best management practices during construction (e.g., minimizing soil loss, restoring vegetation immediately after the excavation is backfilled, choosing a pipeline route that minimizes interaction with the resources). Installation of the pipeline would probably not create a long-term reduction in the diversity of the plant and animal communities found along the pipeline corridor.

Table 6-3. Air Emissions for Gas-Fired Alternative.

Parameter	Calculation	Result
Annual gas consumption	$1\ \text{unit} \times \frac{137\ \text{MW}}{\text{unit}} \times \frac{8{,}200\ \text{Btu}}{\text{kw-hr}} \times \frac{1{,}000\text{Kw}}{\text{MW}} \times 0.75 \times \frac{\text{ft}^3}{1{,}018\ \text{Btu}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{days}}{\text{year}}$	7,250,233,791 ft^3 per year
Annual Btu input	$\frac{7{,}250{,}233{,}791\ \text{ft}^3}{\text{year}} \times \frac{1{,}018\ \text{Btu}}{\text{ft}^3} \times \frac{\text{MMBtu}}{10^6\text{Btu}}$	7,380,737 MMBtu per year
Sulfur oxides	$\frac{0.0034\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{7{,}380{,}737\ \text{MMBtu}}{\text{year}}$	13 tons per year
Nitrogen oxides	$\frac{0.0128\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{7{,}380{,}737\ \text{MMBtu}}{\text{year}}$	47 tons per year
Carbon monoxide	$\frac{0.0168\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{7{,}380{,}737\ \text{MMBtu}}{\text{year}}$	62 tons per year
Total Suspended Particulates	$\frac{0.0019\ \text{lb}^{a}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{7{,}380{,}737\ \text{MMBtu}}{\text{year}}$	7 tons per year

[a] Emission factor for filterable particulate matter (USEPA, 2000, Table 3.1-2a.)

Construction might require preservation of cultural resources. It is more likely that these activities would result in minimal impacts, if any. The greatest impact relative to HCGS would likely be the impacts to the wetlands during construction and maintenance of the pipeline.

6.3.2 Coal-Fired Generation Impacts

The coal-fired alternative defined in Section 6.2.2 would be located on the existing HCGS site on previously disturbed land, which would reduce construction impacts. The alternative assumes the use of the existing cooling water system with additional cooling tower cells that would operate within the existing NJPDES limits and thereby minimize aquatic impacts. Again for this alternative it was assumed that the heat rejection rate would be the same as for the EPU. Socioeconomic impacts are expected to be minimal and similar to those described for the gas-fired generation alternative. The primary impacts associated with coal-fired generation alternative appear to be those associated with air emissions and waste management

PSEG estimates the coal-fired generation alternative would have the following annual air emissions:

- SOx, 587 tons per year
- NOx, 126 tons per year
- CO, 130 tons per year
- Total Suspended Particulates (TSP), 18 tons per year
- PM_{10}, 4 tons per year

Table 6-4 presents the equations used by PSEG to calculate these emissions, which are based on the plant characteristics provided in Table 6-2.

Air quality impacts of coal-fired generation are also different from nuclear generation. A coal-fired plant would emit SOx, NOx, CO and particulate matter, all of which are regulated pollutants as well as carbon dioxide, a potential contributor to global warming. The coal-fired alternative would release similar types of emissions to the gas-fired generation but in greater quantities. The SOx would be emitted in quantities in excess of major threshold quantities. NOx and CO may also be emitted in excess of major threshold quantities.

This alternative may require offsets, the purchase of emission credits, or other control technologies beyond the combination of boiler technology and post-combustion pollutant removal assumed in this analysis. The emission of low levels of mercury and other toxic compounds from coal-fired generation may present other impacts to be addressed. As NRC (1996b) stated, the adverse human health effects from coal combustion have led to relatively recent Federal legislation to address public health issues, such as cancer and emphysema. The NRC also identified global warming, acid rain, ozone transport, and mercury deposition as significant air quality issues associated with coal-fired generation. Obviously, there are numerous, stringent state and federal air pollution control requirements applicable to the construction and operation of a coal-fired plant at the HCGS site with which PSEG would have to comply. These could include visibility impacts on the Brigantine National Wildlife Refuge that could preclude approval of a coal-fired plant at HCGS. This project would be subject to review under the Prevention of Significant Deterioration regulations which would require an extensive assessment of the environmental impacts. PSEG concludes that the coal-fired generation alternative would more likely have greater impacts on air quality than the other alternatives being considered.

Table 6-4. Air Emissions for Coal-Fired Alternative.

Parameter	Calculation	Result
Annual coal consumption	$1\ \text{unit} \times \frac{200\ \text{MW}}{\text{unit}} \times \frac{10{,}200\ \text{Btu}}{\text{kw-hr}} \times \frac{1{,}000\text{Kw}}{\text{MW}} \times 0.75 \times \frac{\text{lb}}{12{,}915\ \text{Btu}} \times \frac{\text{ton}}{2{,}000\text{lb}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{days}}{\text{year}}$	518,855 tons of coal per year
Sulfur oxides	$\frac{38^{a} \times 1.19\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times (1-\frac{95}{100}) \times \frac{518{,}855\ \text{tons}}{\text{year}}$	587 tons per year
Nitrogen oxides	$\frac{9.7\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times (1-\frac{95}{100}) \times \frac{518{,}855\ \text{tons}}{\text{year}}$	126 tons per year
Carbon monoxide	$\frac{0.5\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{518{,}855\ \text{tons}}{\text{year}}$	130 tons per year
Total Suspended Particulates	$\frac{10^{a} \times 7.1\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times (1-\frac{99.9}{100}) \times \frac{518{,}855\ \text{tons}}{\text{year}}$	18 tons per year
PM_{10}[b]	$\frac{2.3^{a} \times 7.1\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times (1-\frac{99.9}{100}) \times \frac{518{,}855\ \text{tons}}{\text{year}}$	4 tons per year

[a] Emission factors for pulverized coal dry bottom, tangentially fired, bituminous Pre-NSPS with low NOx burner (USEPA, 1998, Tables 1.1-3 and 1.1-4)
[b] Particulates having diameter less than 10 microns.

The NRC (1996b) also concluded that the operation of a coal-fired plant would produce substantial solid waste. The coal-fired generation alternative was estimated to consume 518,855 tons of coal per year having with an ash content of 8.8 percent (Tables 6-4 and 6-2). After combustion, most (>99%) of the ash, approximately 45,614 tons per year, would be collected along with approximately 32,005 tons per year of scrubber sludge (based on an annual lime usage of 10,853 tons). PSEG estimates that the disposal of this waste over the next 20 years would require approximately 21 acres of land for disposal based on a 30-foot high waste pile (Table 6-5).

PSEG believes that with proper siting, construction, operation, and monitoring that solid waste disposal is feasible for the HCGS site. There is potential space at the HCGS site for converting previously disturbed or unoccupied land (NRC, 1984 cites approximately 300 acres of unused land at the HCGS site) to waste disposal however there might be substantial engineering and public relation issues associated with siting a waste disposal facility at the HCGS site. NJDEP has strict standards for disposal facilities which might result in substantial costs or add to the complexity of the operation. The landfill would likely be above grade due to its close proximity to the Delaware River and groundwater table. PSEG believes these issues are greater than for the other alternatives and could have a local effect but are manageable.

Table 6-5. Estimate of Solid Waste Pile based on Coal-Fired Generation Alternative.

Parameter	Calculation							Result
SO_2 generated	1.19 tons S	x	518,855 tons	x	64.1 tons SO_2			12,343 tons SO_2 generated
	100 tons coal		year		32.066 tons S			
SO_2 removed	1.19 tons S	x	518,855 tons	x	64.1 tons SO_2	x	95	11,725 tons SO_2 removed
	100 tons coal		year		32.066 tons S		100	
Ash generated	8.8 tons ash	x	518,855 tons	x	99.9			45,614 tons ash per year
	100 tons coal		year		100			
Annual lime consumption	12,343 tons SO_2	x	56.1 tons CaO					10,853 tons CaO per year
	year		64.1 tons SO_2					
Annual calcium sulfate generation	11,725 tons SO_2	x	172 tons $CaSO_4*2H_2O$					31,462 tons $CaSO_4*2H_2O$/yr
	year		64.1 tons SO_2					
Annual scrubber waste generation	10,853 tons CaO	x	100-95		31,462 T $CaSO_4*2H_2O$			32,005 T scrubber waste/yr
	year		100					
Total volume of scrubber waste	32,005 tons	x	20 years	x	2,000 lb	x	ft^3	8,841,160 ft^3 scrubber waste
	year				ton		144.8 lb	
Total volume of ash generated	45,614 tons	x	20 years	x	2,000 lb	x	ft^3	18,245,600 ft^3 ash
	year				ton		100 lb	
Total volume of solid waste	8,841,160 ft^3		18,245,600 ft^3					27,086,760 ft^3 solid waste
Waste pile area (acres)	27,086,760 ft^3	x	acre					21 acres solid waste
	30 ft high		43,560 ft^2					

Calculation Assumptions:
100 perecnt combustion of coal; density of coal bottom ash is 100 lb/ft^3; density of calcium sulfate dihydrate is 144.8 lb/ft^3; plant life=20 years; and waste pile height =30 ft.

7.0 ENVIRONMENTAL COMPLIANCE PERMITS AND CONSULTATIONS

Table 7-1 lists the major environmental authorizations that PSEG has obtained for current HCGS operations. In this context PSEG uses the term "authorizations" to include permits, licenses, approvals, and other entitlements.

Attachment B includes a list of the relevant environmental permits for HCGS.

Table 7-1

Hope Creek Generating Station Major Environmental Authorizations for Current Operations

Agency[9]	Authority	Requirement	Number	Expires	Activity Covered
USNRC	Atomic Energy Act	Facility Operating License and Docket Number	NPF-57 and 50-354	12/20/26	Operation of the plant
NJDEP	Federal Clean Water Act	NJPDES Permit	NJ0025411	2/31/08	Water discharges to Delaware River
NJDEP	Water Supply Management Act	Water Allocation Permit	2216P	1/31/10	Groundwater withdrawal for industrial cooling and potable purposes
NJDEP	Federal Clean Air Act	Air Operating Permit	BOP030001	2/1/10	Air emissions
DRBC	Delaware River Basin Compact	DRBC Permit	D-73-193 CP (Revised)	Not Applicable	Construction and operation of the plant, stream quality objectives, surface water withdrawal, and temperature and heat dissipation area related to thermal discharge
DRBC	Delaware River Basin Compact	DRBC Permit	D-90-71	11/15/10	Groundwater withdrawal
USACOE	Federal Clean Water Act, Section 404 (33 U.S.C. 403)	USACOE Permit	OP-R-199501755-45	12/31/06	Waterfront development desilting & dredging
USEPA	Resource Conservation Recovery Act	Hazardous Waste Generator Permit	NJD07707 0811	Not Applicable	Hazardous waste management

[9] USNRC = United States Nuclear Regulatory Commission; NJDEP = New Jersey Department of Environmental Protection; DRBC = Delaware River Basin Commission; USACOE =United States Army Corps of Engineers; USEPA = United States Environmental Protection Agency.

8.0 SUMMARY COMPARISON

The extended power uprate will not result in significant impacts to the environment. It does not result in significant new environmental hazards or increase the risks of environmental hazards that were previously evaluated. The environmental impacts and adverse effects identified in the Summary and Conclusions Section of the FES for HCGS operation continue to encompass plant operation at extended power uprate conditions. The proposed changes do not, individually or cumulatively, affect the environment. There is no significant change in the types or amounts of plant effluents. Extended power uprate does not involve significant increases in individual or cumulative occupational radiation exposure.

The effect of the extended power uprate on the environment does not prevent continued compliance with any environmental permit or modified permit. With the exception of the hourly particulate emissions from the HCCT, none of the license conditions for environmental protection will be changed for extended power uprate. No water effluent limits will be exceeded and the present discharges which are below these limits will not be significantly changed. The extended power uprate does not involve a significant increase in the discharge of hazardous substances, contaminants, or pollutants and does not involve the use of any new hazardous substances, contaminants, or pollutants.

The extended power uprate does not involve any significant changes to air quality or water quality. It does not result in any changes to land use and has no effect on groundwater use. The amount of water withdrawn and consumed from the Delaware River remains within that previously evaluated by the NRC and the NJDEP. The increase in discharge temperature has an insignificant effect on Delaware River temperatures and will not result in any significant changes to aquatic biota. Extended power uprate will not involve new or different discharges of contaminants and does not involve changes to any bioaccumulation effects for aquatic organisms. The quality of drinking water is not affected.

Extended power uprate does not involve any changes to wildlife habitat and does not result in any significant impacts to aquatic or terrestrial biota. There are no deleterious effects on the diversity of biological systems or the sustainability of species due to extended power uprate. Extended power uprate does not involve additional changes to the stability or integrity of ecosystems. Extended power uprate does not affect the previous conclusions on impingement or entrainment. Extended power uprate does not affect HCGS compliance with Sections 316(a) or 316(b) of the Federal Water Pollution Control Act.

Extended power uprate does not significantly change any doses to the public from radiological effluents, and offsite doses will continue to be well within regulatory limits. The Safety Evaluation for HCGS concluded that the release of radioactive material in liquid and gaseous effluents from HCGS will meet the requirements of 10 CFR 50 for keeping such effluent levels to unrestricted areas as low as reasonably achievable and will result in doses that are a small percentage of the 10 CFR 20 limits. This conclusion was based on assumptions for effluent releases that bound releases expected for extended power uprate. Occupational dose will be maintained well within regulatory limits, and changes in radiation levels will not significantly increase the dose to the HCGS work force. Accident doses under extended power uprate conditions remain well within the applicable regulatory limits. Extended power uprate does not involve significant increases in the probability or consequences of previously evaluated environmental accidents.

The environmental effects of decommissioning were evaluated in the FES and it was determined that the primary contributor to environmental impact was the dose from transportation of waste to disposal facilities. As concluded in Section 5.0 above, the impact of EPU on transportation of fuel and radioactive waste is not significant. Extended power uprate does not affect the ability to maintain sufficient financial reserves for decommissioning.

This environmental evaluation has demonstrated that extended power uprate does not involve environmental impacts that differ significantly from those previously evaluated. The environmental impacts of HCGS operation with extended power uprate continue to be bounded by the FES or bounded by other appropriate and applicable regulatory criteria. Where environmental impacts differ from those previously evaluated, these impacts have been shown to be insignificant and well within regulatory environmental acceptance criteria.

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ATTACHMENT A

HOPE CREEK GENERATING STATION BIOLOGICAL TOXICITY TESTING DATA

BIOLOGICAL TOXICITY TESTING DATA

DATE OF TOXICITY TEST	TYPE OF TOXICITY TEST	RESULT OF TEST
09/01/98 **	Acute Toxicity Test	LC 50 >100%
01/15/99 **	Acute Toxicity Test	LC 50 >100%
04/24/99 **	Acute Toxicity Test	LC 50 >100%
06/15/99 **	Acute Toxicity Test	LC 50 >100%
09/01/98 **	Chronic Toxicity Test	IC 25 > 100%
01/15/99 **	Chronic Toxicity Test	IC 25 > 100%
04/24/99 **	Chronic Toxicity Test	IC 25 > 100%
06/15/99 **	Chronic Toxicity Test	IC 25 > 100%
06/26/01	Acute Toxicity Test	LC 50 >100%
06/26/01	Chronic Toxicity Test	IC 25 > 100%

** Whole Effluent Toxicity Characterization Study testing conducted in accordance with NJPDES Permit NJ0025411, Part IV-B/C, Sections 1.D and 1.E and reported to the NJDEP on October 5, 1999.

ATTACHMENT B

HOPE CREEK GENERATING STATION ENVIRONMENTAL PERMITS

HOPE CREEK GENERATING STATION
Environmental Permits

PERMIT/PURPOSE	NUMBER
Air Pollution Control Permits (Program Interest No. 65500)	
Title V Air Operating Permit	BOP 030001
Potable Water Supply	
Public Water Supply No.	1704306
Groundwater Diversion Permit - Production Wells	2216P
DRBC Ground Water Withdrawal	D-90-71
Treatment Works Approvals	
Cooling Tower TWA	Waiver
Liquid Radwaste Treatment System TWA	Waiver
Low Volume and Oily Waste System TWA	Waiver
Sewage Treatment Plant TWA	Waiver
Hazardous Waste Management Program	
Hazardous Waste Generator	NJD077070811
Medical Waste Generator	34571

PERMIT/PURPOSE	NUMBER
Relevant Environmental Permits	
CAFRA	74-014
Riparian License	74-46
Riparian License (Access Road)	68-12
Type "B" Wetlands Permit	W74-042
Waterfront Development (Dredging & Desilting)	OP-R-199501755-45
Waterfront Development (Maintenance Dredging)	1704-90-0001.8
DRBC Docket Decision (STP Allocation)	D-85-60CP
DRBC Docket Decision (STP)	D-87-70
DRBC HC Construction	D-73-193CP
Laboratory Certificate	17451
Air Navigation Determination	82-AEA-0822-OE
USNRC Facility Operating License	NPF-57
USNRC Facility Operating License (EPP)	50-354
Centralized Warehouse	91-5585-4
DPCC/DCR	170400041000
Surface Water Discharge Permit (NJPDES)	NJ0025411