North Anna 3 Combined License Application

Part 3: Applicants' Environmental Report - Combined License Stage

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Chapter 1 Introduction

This Applicants' Environmental Report-Combined License Stage is submitted pursuant to 10 CFR 51.50(c) to provide environmental information supporting the application of Virginia Electric and Power Company, doing business as Dominion Virginia Power (Dominion or DVP), and the Old Dominion Electric Cooperative (ODEC) for a combined construction permit and operating license for a third nuclear unit at the North Anna Power Station (NAPS).

The environmental impacts of constructing and operating new nuclear units at NAPS were previously assessed in North Anna Early Site Permit Application, Part 3, Environmental Report (ESP-ER) (Reference 1), and in NUREG-1811, Final Environmental Impact Statement for an Early Site Permit (ESP) at the North Anna Site (FEIS) (Reference 2). In accordance with 10 CFR 51.50(c)(1), this Applicants' Environmental Report - Combined License Stage incorporates by reference the assessment of environmental issues that were resolved in the ESP proceeding and provides, where necessary, the following supplemental information:

- Information demonstrating that the design of the facility falls within the ESP site characteristics and design parameters;
- Information resolving any significant environmental issue identified by the NRC that was not resolved in the early site permit proceeding;
- Any new and significant information for issues related to the impacts of construction and operation of the facility that were resolved in the early site permit proceeding;
- A description of the process used to identify new and significant information regarding the NRC's conclusions in the ESP environmental impact statement; and
- Demonstration that relevant environmental terms and conditions for the early site permit will be satisfied by the date of issuance of the combined license, or for requirements applicable to activities that may continue beyond COL issuance, would be appropriately included as terms and conditions of the combined license.

1.1 The Proposed Action

This section provides a description of the proposed action, the applicants, site location, and the selected design.

The proposed action is the issuance of a combined construction permit and operating license (COL) for a new nuclear unit (Unit 3) at the North Anna Power Station (NAPS). Unit 3 would be a 4500 megawatt thermal (MWt) ESBWR.

The purpose and need for the proposed action is to provide additional base load power for residential and industrial customers in the region served by Dominion and ODEC. Additional purposes of proposed Unit 3 are to maintain fuel diversity in this region, reduce dependence on imported power, leverage Dominion's and ODEC's existing nuclear facilities, and to promote the regional economy, while not contributing to CO_2 emissions.

1.1.1 The Applicant and the Owner

Dominion and ODEC are the applicants for the COL addressed in this environmental report. The NAPS site is owned by Dominion and ODEC as tenants in common. These companies also own all land outside the NAPS site boundary that forms Lake Anna, up to Elevation 255 msl. Dominion is the licensed operator of the existing units, with control of the existing site and facilities and the authority to act as ODEC's agent.

1.1.2 Site Location

The portion of the North Anna site on which Unit 3 will be located is the same as the ESP site described and evaluated in the ESP-ER and FEIS. The NAPS site is located on a peninsula on the southern shore of Lake Anna, approximately 5 miles upstream of the North Anna Dam. The NAPS site is located in Louisa County, Virginia, near the town of Mineral.

The portion of the NAPS site on which Unit 3 will be located is shown on ESP-ER Figure 1.1-1. Figures 1.1-1 and 1.1-2 show the location of Unit 3 buildings and equipment within the ESP proposed facility boundary (ESP plant parameter envelope) (see ESP-ER Figure 2.1-1) as well as the cooling tower area, switchyard expansion, spoils and overflow storage, temporary batch plant, construction laydown areas, and temporary construction parking.

1.1.3 Reactor Information

In the ESP-ER, the reactor technology to be used had not been selected. Since that time, Dominion has selected the ESBWR as the reactor technology to be constructed and operated at the ESP site. This ER addresses one unit (Unit 3) on the site. Details of the Unit 3 ESBWR design are provided in the FSAR.

1.1.4 Cooling System Information

As described in the ESP-ER, the cooling system for Unit 3 will be a closed-cycle, combination dry and wet cooling tower system, with make-up water supplied from Lake Anna. Make-up water will be withdrawn from the North Anna Reservoir through a new intake structure located on a cove on the south shore of the lake, originally planned for the intake of the never-constructed Units 3 and 4. This new structure will be adjacent to the existing units' intake structure. Cooling system discharges for the existing units and the Unit 3 wet cooling tower blowdown will be sent to the Waste Heat Treatment Facility (WHTF) via the existing discharge canal.

1.1.5 Transmission System Information

At the ESP stage, it was expected based on an initial evaluation that any two of the existing 500 kV transmission lines, together with the 230 kV transmission line, would have sufficient capacity to carry the total output of the existing units and the new units. Subsequently, a system study (load flow study) has been performed that models these lines with the new unit's power contribution. The results of the load flow study and import/export studies indicate that a new 500 kV transmission line and other system reinforcements will be required for grid reliability in association with the interconnection of new Unit 3. The new line will be installed on new transmission towers in the existing corridor between the North Anna Substation and the Ladysmith Switching Substation. Further information is provided in Section 3.7.

1.1.6 Construction Start Date

Subject to required regulatory approvals and a decision to build, the following are estimated dates related to construction and operation of Unit 3:

First Structural Concrete:	January 2011
Pre-operational Testing:	January 2013
Fuel Load:	July 2014
Commercial Operation:	March 2015

Section 1.1 References

1. North Anna Early Site Permit Application, Part 3 – Environmental Report, Dominion Nuclear North Anna, LLC, Revision 9, September 2006.

2. NUREG-1811, Environmental Impact Statement for an Early Site Permit (ESP) at the North Anna ESP Site, U. S. Nuclear Regulatory Commission, December 2006.

Figure 1.1-1 Site Utilization Plan

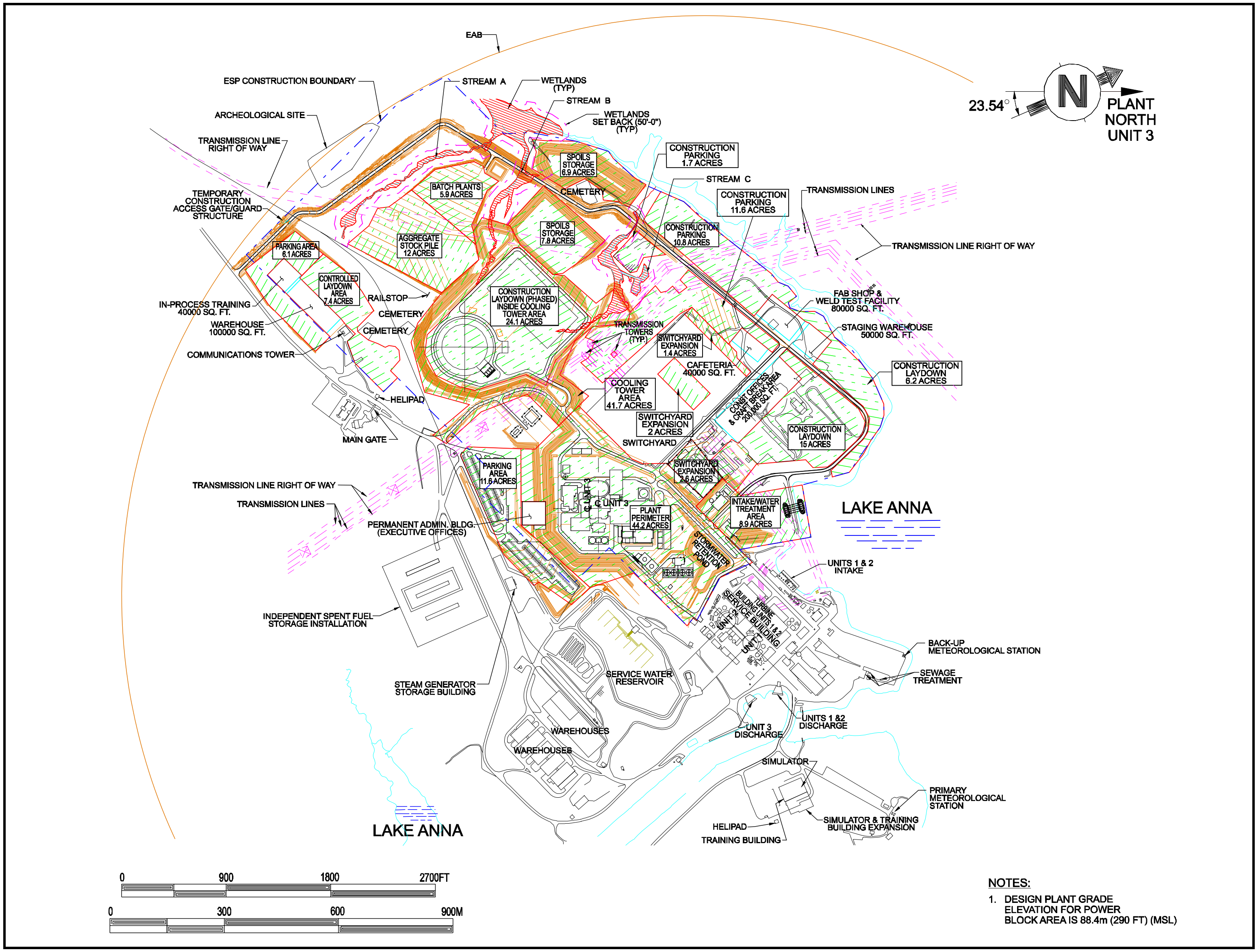
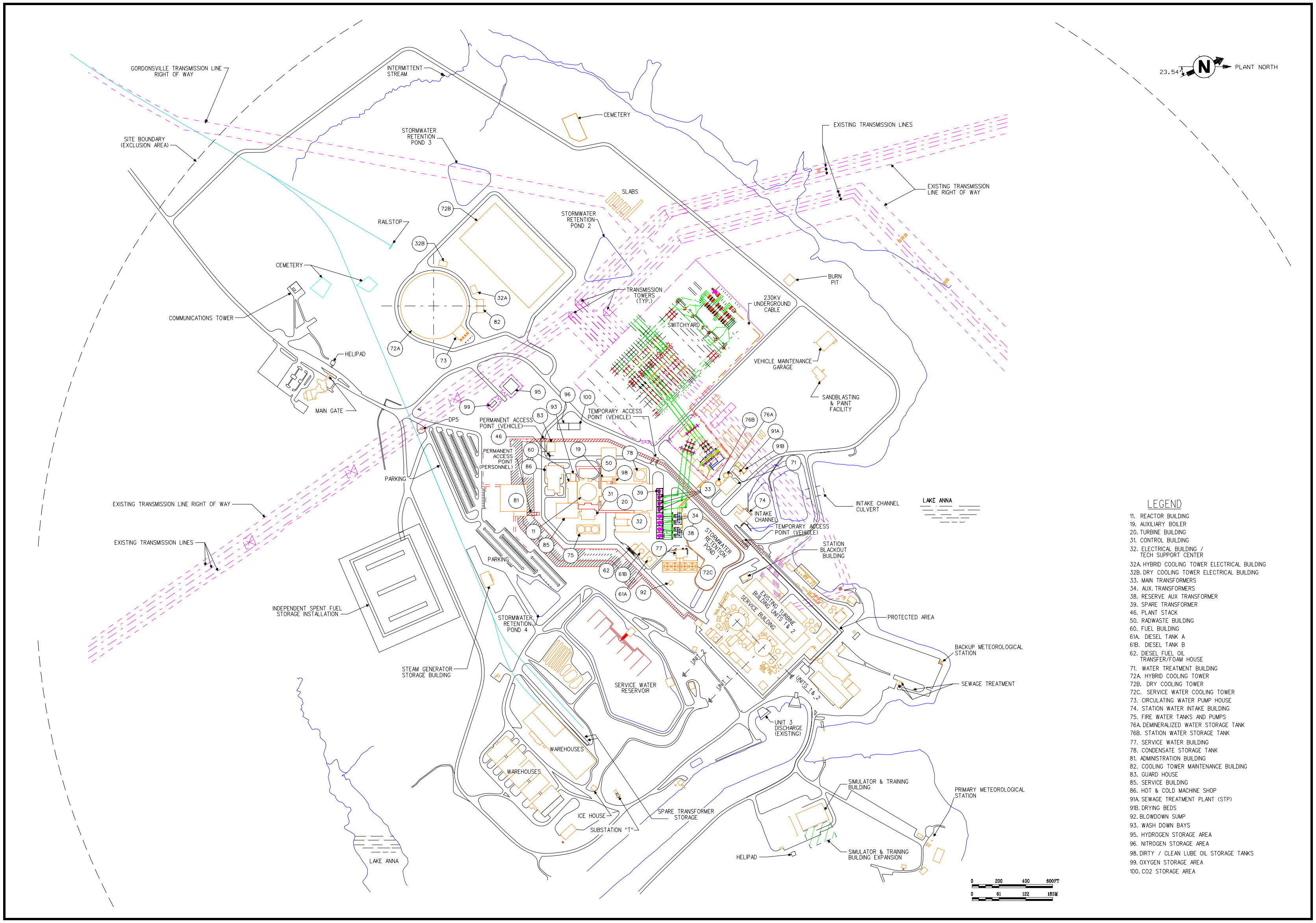


Figure 1.1-2 Site Plan With Building Legend



1.2 Status of Reviews, Approvals, and Consultations

Numerous reviews, approvals, and consultations will be required for the construction and operation of new Unit 3. Table 1.2-1 provides a list of the environmental-related authorizations, permits, and certifications required by federal, state, regional, and local agencies for activities related to the construction and operation of Unit 3 at the NAPS site.

Table 1.2-1 Federal, State and Local Authorizations

Agency	Authority	Requirement	License/ Permit No. (a)	Expiration Date (a)	Activity Covered
FAA	49 USC 1501	Construction Notice			Notice of erection of structures (if >200 feet) potentially impacting air navigation
Lake Anna Special Area Plan Committee		Conditional Land Use Approval	N/A	N/A	Local land use approval – Lake Overlay District
NRC	Atomic Energy Act (AEA), 10 CFR 51, 10 CFR 52.17	EIS	N/A	N/A	Environmental effects of construction and operation of a reactor
NRC	10 CFR 52, Subpart C	Combined License			Combined construction permit and operating license for a nuclear power facility
NRC	10 CFR 52, Subpart A	Early Site Permit	52-003		Approval of the site for one or more nuclear power facilities, and approval of limited construction as per 10 CFR 50.10(e)(1)
SCC	VA Code 56-265.2 and 56-46.1				Certificate of public convenience and necessity
USACE	Federal Water Pollution Control Act (FWPCA)	Section 404 Permit (individual, regional, general)			Disturbance or crossing wetland areas or navigable waters
USACE	Rivers and Harbors Act	Section 10 Permit			Impacts to navigable waters of the U.S. (would also include overhead transmission line crossings)

Table 1.2-1 Federal, State and Local Authorizations

Agency	Authority	Requirement	License/ Permit No. (a)	Expiration Date (a)	Activity Covered
USFWS	Endangered Species Act	Consultation regarding potential to adversely impact protected species	N/A	N/A	Concurrence with no adverse impact or consultation on appropriate mitigation measures
USFWS	Migratory Bird Treaty Act	Federal or State Permit			Adverse impact on protected species (e.g., eagles, ospreys) and/or their nests
VDEQ	9 VAC 5-20-160	Registration			Annual re-certification of air emission sources
VDEQ	Federal Clean Air Act Amendments (CAA) Title V 9 VAC 5-80-50	Title V Operating Permit			Operation of air emission sources
VDEQ	9 VAC 5-80-120	Minor Source - General Permit			Construction and operation of minor air emission sources
VDEQ	Federal Clean Water Act Amendments (FWPCA) 9 VAC 25-10	Virginia Pollutant Discharge Elimination System Permit (VPDES)			Limits on pollutants in liquid discharge to surface water and Section 316 compliance
VDCR Dept. of Conservation and Recreation	FWPCA 4 VAC 50-60-10	General Permit Registration Statement for storm water discharges from construction activities (DCR01) Form for the NOI is DCR 199-146			General permit to discharge storm water from site construction activities

Table 1.2-1 Federal, State and Local Authorizations

Agency	Authority	Requirement	License/ Permit No. (a)	Expiration Date (a)	Activity Covered
VDCR	FWPCA 4 VAC 50-60-10	General Permit Notice of Termination (NOT) for storm water discharges from construction activities (DCR 199-147)			Termination of coverage under the general permit for storm water discharge from construction site activities
VDEQ	9 VAC 25-210	Virginia Water Protection Permit (Individual or General)			Permit to dredge, fill, discharge pollutants into or adjacent to surface water. Joint application with USACE Section 404 permit
VDEQ	FWPCA	Section 401 Certification (VWP serves as the 401 certification)			Compliance with water quality standards
VDEQ	9 VAC 25-220	Virginia Water Protection Permit			Permit to withdraw water from Lake Anna (unless otherwise regulated by State Water Control Board)
VDEQ	Virginia Coastal Resources Management Program	Consistency determination (Coastal Zone Management Act)	N/A	N/A	Compliance with Virginia Coastal Program
VDHR	National Historic Preservation Act, 36 CFR 800	Cultural Resources Survey/Review	N/A	N/A	Confirm area of potential effects does not contain protected historic/cultural resources. If resources are present, avoidance is recommended per VDHR correspondence, November 7, 2007

Table 1.2-1 Federal, State and Local Authorizations

Agency	Authority	Requirement	License/ Permit No. (a)	Expiration Date (a)	Activity Covered
VMRC	9 VAC 25-210	VMRC Permit			Permit to fill submerged land; Joint application with USACE Section 404 permit

a. Licenses and permits will be applied for and received at the appropriate time.
N/A: Not applicable. No specific permit number or expiration date is associated with this consultation.

1.3 Report Contents

This report follows the same table of contents as the ESP-ER. Where a topic was previously addressed and resolved in the ESP proceeding, and no new and significant information has been identified, this report identifies the sections of the ESP-ER and FEIS that address the topic and states that no new and significant information has been identified. However, where new and significant information has been identified, the report provides the supplemental information required by 10 CFR 51.50(c)(1), as discussed in the following sections.

1.3.1 Information to Demonstrate That the Facility Design Falls Within the Site Characteristics and Design Parameters in the ESP

In accordance with the first row of FEIS Table J-1, Table 3.0-1 provides an evaluation of Unit 3 site characteristics against the ESP site characteristics identified in FEIS Table I-1.

In accordance with the second row of FEIS Table J-1, Table 3.0-2 provides an evaluation of Unit 3 design characteristics against the ESP design parameters identified in FEIS Table I-2.

See also FSAR Table 2.0-201 which includes an evaluation of ESBWR DCD site parameters, ESP site characteristics, and ESP design parameters.

1.3.2 Information to Resolve any Significant Environmental Issues that Were Not Resolved in the ESP Proceeding

Several issues were not resolved in the ESP proceeding. The issues applicable to Unit 3 and previously identified as unresolved in the FEIS are listed below along with the section of this report in which they are addressed:

- Need for Power (Chapter 8)
- Energy Alternatives (Section 9.2)
- Water Quality (Sections 3.6, 5.2)
- Alternatives to Mitigate Severe Accidents (Sections 7.2, 7.3)
- Chronic Health Impacts of Electromagnetic Fields (Section 5.6)
- Decommissioning impacts (Section 5.9)
- Relationship Between Short-Term Uses and Long-Term Productivity of the Human Environment (Section 10.3)
- Benefit-Cost Balance (Section 10.4)

1.3.3 New and Significant Information

In accordance with 10 CFR 51.50(c)(1)(iii), this ER provides new and significant information for various issues related to the impacts of construction and operation of the facility that were resolved in the ESP proceeding:

- New 500 kV Transmission Line (Sections 1.1.5, 2.2.2, 2.4.1, 3.7, 4.1.2, 4.3, 4.4, 5.1.2, 5.6)
- Revised Long-Term X/Q Values for Changes in Receptor Locations (Sections 2.7.6, 5.4)
- Offsite Road/Rail Transport of Large Components (Section 4.1.1)
- Change in Potentially Impacted Ephemeral Streams (Section 4.2.1.1)
- Revised Liquid Effluent Release Activities (Section 5.4)
- Separate Sanitary Waste Facility for Unit 3 (Section 5.5)
- Revised Accident Source Terms (Sections 2.7.5, 7.1)

In accordance with 10 CFR 51.50 (c)(1)(iv), a description of the process used to identify new and significant information regarding the NRC's conclusions in the FEIS is provided below.

1.3.3.1 **Definitions**

The following definitions apply to the new and significant process:

1. "Key inputs" means those assumptions and inputs, explicitly identified or implied, that were considered in the environmental review, either by the NRC Staff to support its findings and conclusions in the FEIS or in preparation of the ESP-ER.

   The FEIS is the primary document that was reviewed for key inputs used by the NRC Staff in its evaluations. These FEIS key inputs identify the main sources of information that were considered for whether or not there could be new information potentially affecting a finding or conclusion regarding an environmental impact. The representations and assumptions relied upon by the NRC Staff during its review of the ESP-ER and development of the FEIS are identified in each section of the FEIS and are also listed in FEIS Appendix J.

   In addition to the review of FEIS for key inputs, the ESP-ER was also reviewed to identify any relevant key inputs for which new information is available that may bear on the FEIS impact evaluations.

2. "New" in the phrase "new and significant information" is any information that was both: 1) not considered in preparing the ESP-ER or FEIS, and 2) not generally known or publicly available during the preparation of the FEIS. See 72 FR 49431.

3. For new information to be "significant," it must be material to the issue being considered, that is, it must have the potential to affect the finding or conclusions of the NRC Staff's evaluation of the issue. See 72 FR 49431.

The NRC has established three significance levels for environmental impacts: SMALL, MODERATE, and LARGE. In general, one of these three significance levels was assigned to each impact evaluated and resolved in the FEIS. New information was considered significant if it had the potential to change an NRC-assigned level of significance; that is, from SMALL to MODERATE or from MODERATE to LARGE for adverse impacts.

1.3.3.2 **Steps of the New and Significant Information Process**

The "new and significant information process" is a multi-step process used to identify new and significant information for inclusion in this ER per the requirements of 10 CFR 51.50(c)(1)(iii). The new and significant information process is documented in procedures and was implemented by qualified personnel including researchers, subject matter experts, licensing specialists, and engineering and environmental professionals.

Figure 1.3-1 is a flowchart that illustrates the steps of the new and significant information process. Process steps are described below.

Step 1: Identify issues that are resolved in the FEIS, and discussed in the ESP-ER, related to the topic being addressed.

Identify if the issue being reviewed was resolved in the FEIS. In general, an issue is resolved if an impact level of SMALL, MODERATE, or LARGE was assigned in the FEIS for the issue. In a few cases, the FEIS states conclusions in terms specific and appropriate to the subject area. (Issues that were identified as unresolved in the FEIS are identified in Section 1.3.2.)

Step 2: Document key inputs from the FEIS and ESP-ER.

For resolved issues, identify those FEIS sections and corresponding ESP-ER sections for the issue being addressed. Within these sections, identify the key inputs considered relevant to the resolved issue (used to make the FEIS determination). Document the identified key inputs.

Step 3a: Screen EIS key inputs.

Perform a screening of the FEIS key inputs to determine whether there is new information or whether there is a need to perform further research to determine if new information related to the key input exists. Give consideration to the potential for change of the input given the amount of time passage from FEIS completion to development of this ER. Document the results of the review by identifying whether or not new information exists for a given key input. If the existence of new information is not known, assume that new information may exist.

Screening reviews were performed by a review team consisting of subject matter experts, licensing specialists, engineering and environmental personnel, and other knowledgeable individuals.

Step 3b: Identify other and/or new key inputs.

Identify any other key inputs from the ESP-ER, subject matter expert's or review team's experience, or external documents, which were not otherwise identified in the Step 2 review for key inputs. Screen these key inputs in the same manner as described in Step 3a.

Step 4: Determine appropriate tasks to identify new information.

If it is not known whether new information exists for a key input, or the extent of the new information is not readily apparent, determine the appropriate actions to take to evaluate if new information exists for the key input.

Step 5: Perform actions identified in Step 4.

Perform the actions identified in Step 4, and document the resulting conclusion by identifying whether or not new information exists for a given key input. Describe the rationale used to arrive at this conclusion. Include references, as appropriate, to support the rationale used.

Step 6: Conduct significance evaluation.

If new information is found for any key input, evaluate the significance of the new information for the key input identified. Document the results of the significance evaluation, including whether or not the new information is determined to be significant. Refer to external documentation where appropriate.

Step 7: Address items identified as new and significant information in the appropriate section of the COLA ER.

For information identified as "new and significant" in Step 6, provide a description and evaluation of the information in the appropriate sections of this ER.

1.3.4 Environmental Terms and Conditions

In accordance with 10 CFR 51.50(c)(1)(v), Table 1.3-1 identifies relevant environmental terms and conditions listed in the draft ESP (Staff Exhibit 17 in Docket No. 52-008) and demonstrates that they will be satisfied by the date of issuance of the combined license or, for requirements applicable to activities that may continue beyond COL issuance, would be appropriately included as terms and conditions of the combined license. Table 1.3-1 also identifies those conditions that apply only to preconstruction activities if undertaken prior to COL issuance and are not prerequisites to COL issuance.

1.3.5 Commitments and Supplemental Information

In addition to the content requirements of 10 CFR 51.50(c)(1), the following information is provided in this ER to address commitments made in the ESP-ER or to provide supplemental information regarding items in the FEIS:

- Status of IFIM study (Table 1.3-1)
- Transmission system load flow study (Sections 3.7.2, 4.1.2)
- Visual impact study (Sections 3.1, 5.8)
- Description of switchyard upgrades (Section 3.7.1)
- Impacts of crud and activation products on spent fuel transportation accident risks (Section 3.8.2)
- Confirmatory evaluation of fogging, icing, and salt deposition (Sections 5.3, 5.8)
- Maximum annual occupational dose (Section 5.4)
- Confirmatory evaluation of cooling tower noise (Section 5.8)
- Description of Meteorological Monitoring Data Recording System (Section 6.4)
- Estimate of construction materials (Section 10.2)

Table 1.3-1 ESP (Draft Permit[a]) Environmental Terms and Conditions Applicable to Unit 3

ESP Environmental Term or Condition		Evaluation
3.D	The values of plant parameters considered in the environmental review of the application and set forth in Appendix D to this ESP are hereby incorporated into this ESP.	The ESP plant parameters are described and evaluated against Unit 3 design characteristics in Table 3.0-2.
3.F(1)	The holder of this ESP may perform the activities authorized by 10 C.F.R § 52.25 only insofar as such activities are described in the site redress plan. The holder of this ESP may perform activities not described in the site redress plan only with prior NRC approval. A request to perform such activities shall describe how such activities will be redressed, and, if the request is granted, the site redress plan shall be deemed to include this additional description of site redress.	This ESP condition applies only to pre-construction activities if undertaken prior to COL issuance and does not establish prerequisites to COL issuance. Activities after COL issuance will be authorized and governed by the COL.
3.F(2)	The holder of this ESP may change the site redress procedures set forth in the site redress plan set forth in Appendix E without obtaining Commission approval provided that the changes do not decrease the effectiveness of the plan.	This ESP condition is applicable to activities that may continue beyond COL issuance, and is therefore appropriate for inclusion as a condition of the combined license.
3.F(3)	The permit holder shall obtain the right to implement the site redress plan set forth in Appendix E before initiating any activities authorized by 10 CFR 52.25, “Extent of Activities Permitted.”	As the owners of NAPS, Dominion and ODEC possess the right to implement the site redress plan. See FSAR Section 2.1.2.1.
3.G	The permit holder shall notify the NRC Regional Administrators for Region II and the operator of North Anna Power Station of the permit holder’s plans to begin the site preparation and preliminary construction activities described in the site redress plan at least 120 days before commencement of such activities, and shall certify in that notification to the NRC that it has obtained all other permits, licenses, and certifications required for these activities;	This ESP condition applies only to preconstruction activities if undertaken prior to COL issuance and does not establish prerequisites to COL issuance. Activities after COL issuance will be authorized and governed by the COL.

Table 1.3-1 ESP (Draft Permit[a]) Environmental Terms and Conditions Applicable to Unit 3

ESP Environmental Term or Condition		Evaluation
3.H	The permit holder or an applicant referencing this ESP for a CP or COL application is prohibited from performing any site preparation or preliminary construction activities authorized by 10 CFR 52.25 unless such holder obtains and submits to the NRC the certification required pursuant to Section 401 of the Federal Water Pollution Control Act from the Commonwealth of Virginia, or obtains a determination by the Commonwealth that no certification is required before commencement of any such activities. A Virginia Water Protection Permit (which under Virginia's State Water Control Law at Va. Code §62.1-44.15:5(A) constitutes the certification required under FWPCA §401).	This ESP condition applies only to pre-construction activities if undertaken prior to COL issuance and does not establish prerequisites to COL issuance. Activities after COL issuance will be authorized and governed by the COL.
3.I (1)	Any activities performed pursuant to 10 CFR 52.25 are subject to the conditions for the protection of the environment set forth in the Environmental Protection Plan attached as Appendix F to this ESP.	This ESP condition applies only to preconstruction activities if undertaken prior to COL issuance and does not establish prerequisites to COL issuance. Activities after COL issuance will be controlled by the EPP proposed in this Application for the COL.

Table 1.3-1 ESP (Draft Permit[a]) Environmental Terms and Conditions Applicable to Unit 3

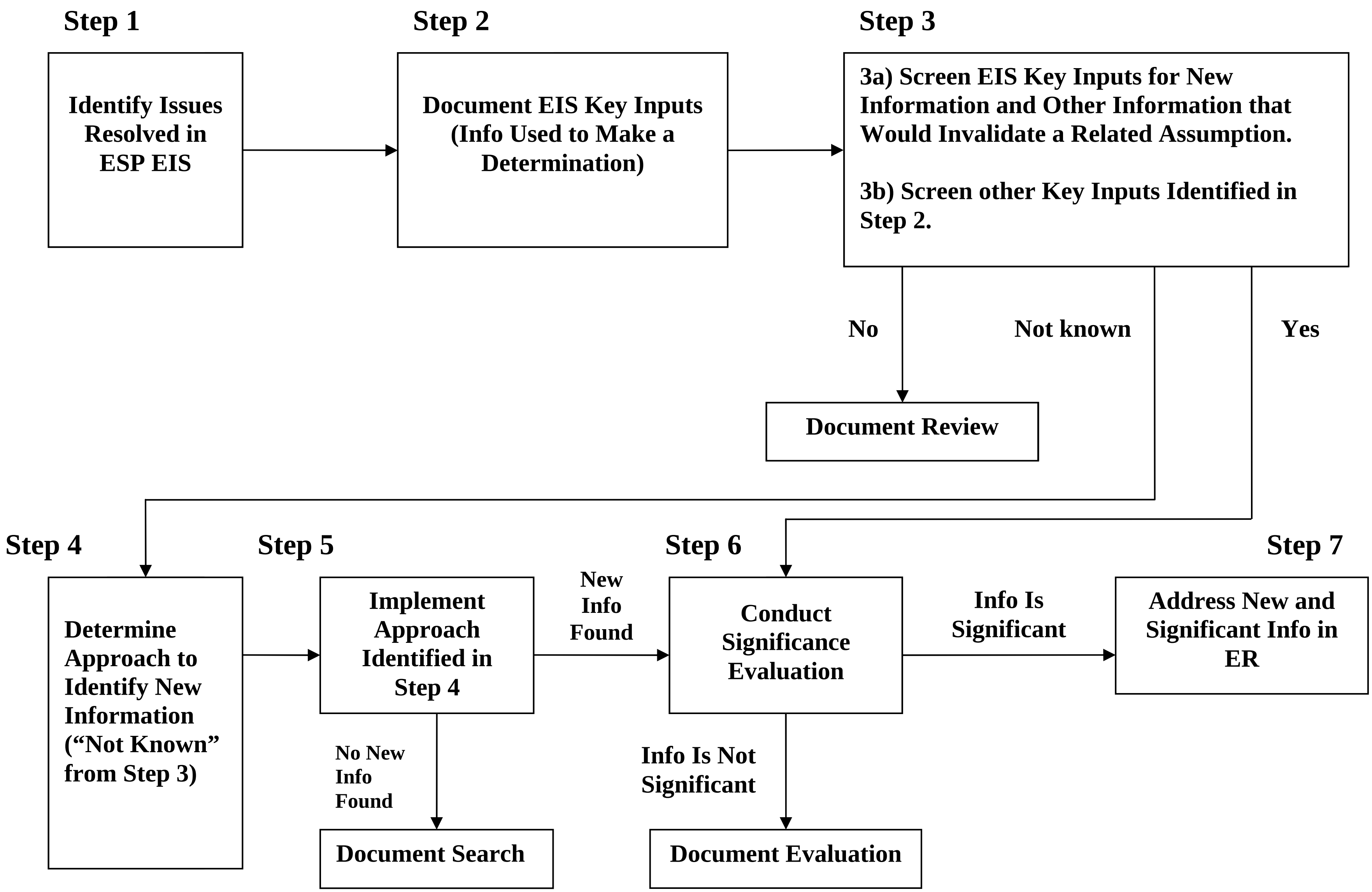
ESP Environmental Term or Condition		Evaluation
3.I (2)	Dominion shall conduct a comprehensive Instream Flow Incremental Methodology study (IFIM), designed and monitored in cooperation and consultation with the VDGIF and the VDEQ, to address potential impacts of the proposed Units 3 and 4 upon the fishes and other aquatic resources of Lake Anna and downstream waters. Dominion agrees to consult with VDGIF and VDEQ regarding analysis and interpretation of the results of that study, and to abide by surface water management, release, and instream flow conditions prescribed by VDGIF and VDEQ upon review of the completed IFIM study, and implemented through appropriate State or Federal permits or licenses.	Work on the IFIM study began in January 2006. The IFIM Study Plan has four major components and is focused on a single new unit: 1. IFIM Study Plan Design. The study plan design was conducted in collaboration with Virginia Resource Agencies. The study scope includes: a. designated North Anna River and Pamunkey River mileage and zones affected; b. species of concern and habitat parameters needed for life stages; c. a wide range of flows with parameters monitored and modeled; d. recreational impact; and e. Lake Anna water level impacts on shoreline and wetlands. 2. Field Data Collection. Field data collection began in Summer 2007 and is expected to continue through Spring 2008. 3. Analysis Methodology. The analysis methodology will be developed in collaboration with state agencies following data collection. The analysis will be performed from Spring through Summer 2008 following completion of data collection. 4. Interpretation of Analysis and Reporting. This will be performed in collaboration with state agencies following completion of the analysis. The expected completion date is September 2008. The results of the study will be factored into environmental permitting as appropriate.
3.I (3)	The CP or COL applicant will conduct an instream flow incremental methodology study pursuant to the Coastal Zone Management Act consistency determination.	See the description for Condition 3.I (2) above.

Table 1.3-1 ESP (Draft Permit[a]) Environmental Terms and Conditions Applicable to Unit 3

ESP Environmental Term or Condition		Evaluation
3.J	An applicant for a CP or COL referencing this ESP shall develop an Environmental Protection Plan (EPP) for construction and operation of the proposed reactor and include the EPP in the application. The portion of the EPP directed to operation shall include any environmental conditions derived in accordance with 10 C.F.R. § 50.36b.	The Environmental Protection Plan (EPP) is provided as Appendix 1A to this ER.

a. Staff Exhibit 17 in Docket No. 52-008

Figure 1.3-1 Flowchart of the New and Significant Information Process



1.4 Conformance with Division 4 Regulatory Guides

The supplemental analyses presented in this ER were prepared using the guidance provided in NUREG-1555, "Standard Review Plans for Environmental Reviews for Nuclear Power Plants." NUREG-1555 is the document that guides the NRC Staff's reviews of the information contained in Environmental Reports. The content guidelines outlined in NUREG-1555 are generally consistent with the guidance contained in Regulatory Guide 4.2.

None of the other Division 4 regulatory guides is applicable to the supplemental analyses presented in this ER.

1A Environmental Protection Plan

APPENDIX B

TO

FACILITY CONSTRUCTION PERMIT AND OPERATING LICENSE

NORTH ANNA UNIT 3

VIRGINIA ELECTRIC AND POWER COMPANY

ENVIRONMENTAL PROTECTION PLAN

(NONRADIOLOGICAL)

NOVEMBER 2007

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1. Objectives of the Environmental Protection Plan

The purpose of the Environmental Protection Plan (EPP) is to provide for protection of nonradiological environmental resources during construction and operation of Unit 3. The principal objectives of the EPP are as follows:

(a) To ensure that the facility is constructed and operated in an environmentally acceptable manner, as established by the ESP Final Environmental Impact Statement (FEIS) and COL FEIS Supplement (Reference 1) and (Reference 2)

(b) Coordinate NRC requirements and maintain consistency with other Federal, State, and local requirements for environmental protection

(c) Keep NRC informed of the environmental effects of facility construction and operation and of actions taken to control those effects

Environmental concerns identified in the FEIS and FEIS Supplement that relate to water quality matters or other matters regulated under the Federal Water Pollution Control Act will be governed by the licensee's Virginia Pollutant Discharge Elimination System (VPDES) permit.

2. Environmental Protection Issues

In the ESP FEIS, the staff considered the environmental impacts associated with the construction and operation of reactors at the North Anna ESP site. In the FEIS Supplement, the staff supplemented the ESP FEIS to consider issues that were not previously resolved or were affected by significant new information. The objective of this Environmental Protection Plan is to ensure that environmental impacts associated with construction and operation of Unit 3 and in accordance with the facility Combined Construction Permit and Operating License (COL) will not exceed in any significant respect the impacts assessed in the FEIS and FEIS Supplement.

3. Consistency Requirements

3.1 Construction Activities

The licensee shall take the mitigating actions identified in the following documents so as to avoid any unnecessary adverse environmental impacts from construction activities:

- Revision 9 of the ESP-ER (Reference 3)
- Chapter 4.0 of the FEIS (as summarized in FEIS Section 4.10)
- Revision 0 of the COL ER (Reference 4)
- Chapter 4.0 of the FEIS Supplement (to be summarized in FEIS Supplement Section 4.10)

These mitigating actions are identified in EPP Table 1. These actions include conducting activities in accordance with various environmental permit requirements.

The licensee shall maintain records of construction activities. These records shall include an assessment of whether the environmental impact of construction activities is consistent with that evaluated in the FEIS and FEIS Supplement.

3.2 Operations

The licensee shall take the mitigating actions identified in the following documents so as to avoid any unnecessary adverse environmental impacts from facility operation:

- Revision 9 of the ESP-ER
- Chapter 5.0 of the FEIS (as summarized in FEIS Section 5.11)
- Revision 0 of the COL ER
- Chapter 5.0 of the FEIS Supplement (to be summarized in FEIS Supplement Section 5.11)

These mitigating actions are identified in EPP Table 2. These actions include conducting activities in accordance with various environmental permit requirements.

3.3 Reporting Related to the VPDES Permit and State Certification

Violations of the VPDES Permit or the State certification (pursuant to Section 401 of the Clean Water Act) shall be reported to the NRC by submittal of copies of the reports required by the VPDES Permit or certification.

Changes and additions to the VPDES Permit or the State certification shall be reported to the NRC within 30 days following the date the change is approved. If a permit or certification, in part or in its entirety, is appealed and stayed, the NRC shall be notified within 30 days following the date the stay is granted.

The NRC shall be notified of changes to the effective VPDES Permit proposed by the licensee by providing NRC with a copy of the proposed change at the same time it is submitted to the permitting agency. The notification of a licensee-initiated change shall include a copy of the requested revision submitted to the permitting agency. The licensee shall provide the NRC a copy of the application for renewal of the VPDES permit at the same time the application is submitted to the permitting agency.

3.4 Changes

The licensee may make changes in construction activities, make changes in station design or operation, or perform tests or experiments affecting the environment provided such changes, tests, or experiments do not involve an unreviewed environmental question, and do not constitute a decrease in the effectiveness of this EPP to meet the objectives specified in Section 1. Changes in construction activities, changes in plant design or operation, or performance of tests or experiments which do not affect the environment are not subject to the requirements of this EPP. Activities governed by EPP Section 3.5 are not subject to the requirements of this section.

A proposed change, test, or experiment shall be deemed to involve an unreviewed environmental question if it concerns: a) a matter which may result in a significant increase in any adverse environmental impact previously evaluated in the Final Environmental Impact Statement (FEIS) and supplements as modified by staff's testimony to the Atomic Safety and Licensing Board, environmental impact appraisals, or in any decisions of the Atomic Safety and Licensing Board; or b) a significant change in effluents or power level; or c) a matter not previously reviewed and evaluated in the documents specified in a) of this section, which may have a significant adverse environmental impact.

Before engaging in additional construction or operational activities which may significantly affect the environment, the licensee shall prepare and record an environmental evaluation of such activity. Activities are excluded from this requirement if all measurable nonradiological environmental effects are confined to the onsite areas previously disturbed during site preparation and plant construction. When the evaluation indicates that such activity involves an unreviewed environmental question or constitutes a decrease in the effectiveness of this EPP to meet the objectives specified in Section 1, the licensee shall provide prior written notification to the NRC.

The licensee shall maintain records of changes in construction activities, changes in facility design or operation, and of tests and experiments carried out pursuant to this section. These records shall include a written evaluation which provides bases for the determination that the change, test, or experiment does not involve an unreviewed environmental question nor constitute a decrease in the effectiveness of this EPP to meet the objectives specified in Section 1. The licensee shall include as part of their Annual Environmental Operating Report (per EPP Section 5.4.1) brief descriptions, analyses, interpretations, and evaluations of such changes, tests, and experiments.

3.5 Changes Required for Compliance with Other Environmental Law

Changes in plant design or operation and performance of tests or experiments which are required to achieve compliance with other Federal, State, or local environmental statutes, regulations, permits, or orders are not subject to the requirements of EPP Section 3.4.

4. Environmental Conditions

4.1 Unusual or Important Environmental Events

The licensee shall evaluate and report to the NRC Operations Center within 24 hours in accordance with 10 CFR 50.72(b)(2)(vi) (followed by a written report in accordance with EPP Section 5.4) any occurrence of an unusual or important event that indicates or could result in significant environmental impact causally related to construction activities or plant operation under this license. The following are examples of unusual or important environmental events: excessive bird impaction events, onsite plant or animal disease outbreaks, mortality or unusual occurrence of any species protected by the Endangered Species Act of 1973, fish kills, unusual increase in nuisance organisms or conditions, and unanticipated or emergency discharge of waste water or chemical substances.

Routine monitoring programs are not required to implement this condition.

5. Administrative Procedures

5.1 Review and Audit

The licensee shall provide for review and audit of compliance with the EPP. The audits shall be conducted independently and shall not be conducted by the individual or groups responsible for performing the specific activity. A description of the organization structure used to achieve the independent review and audit function and results of the audit activities shall be maintained and made available for inspection.

5.2 Records Retention

The licensee shall make and retain records associated with this EPP in a manner convenient for review and inspection and shall make them available to the NRC on request.

The licensee shall retain records of construction and operation activities determined to potentially affect the continued protection of the environment until the date of termination of the license. Records of modifications to station structures, systems and components determined to potentially affect the continued protection of the environment shall be retained for the life of the plant. All other records, data and logs relating to this EPP shall be retained for five years or, where applicable, in accordance with the requirements of other agencies.

5.3 Changes in Environmental Protection Plan

Requests for changes in the EPP shall include an assessment of the environmental impact of the proposed change and a supporting justification. Implementation of such changes in the EPP shall not commence prior to NRC approval of the proposed changes in the form of a license amendment incorporating the appropriate revisions to the EPP.

5.4 Reporting Requirements

5.4.1 Routine Reports

An Annual Environmental Operating Report describing implementation of this EPP for the previous year shall be submitted to the NRC prior to May 1 of each year. The period for the first report shall begin with the date of issuance of the Combined License, and the initial report shall be submitted prior to May 1 of the year following issuance of the Combined License. At the discretion of the licensee, the Annual Environmental Operating Report for Unit 3 may be combined with the Annual Operating Report submitted for Units 1 & 2.

The report shall include summaries and analyses of the results of the environmental protection activities required by EPP for the report period, including a comparison with related preoperational studies, operational controls (as appropriate), and previous nonradiological environmental monitoring reports, and an assessment of the observed impacts of the plant operation on the environment. If unexpected harmful effects or evidence of trends toward irreversible damage to the environment are observed, the licensee shall provide a detailed analysis of the data and a proposed course of mitigating action.

The Annual Environmental Operating Report shall also include:

(a) A list of EPP noncompliances and the corrective actions taken to remedy them

(b) A list of changes in station design or operation, tests, and experiments made in accordance with EPP Section 3.4 which involved a potentially significant unreviewed environmental issue

(c) A list of nonroutine reports submitted in accordance with EPP Section 5.4.2

In the event that some results are not available by the report due date, the report shall be submitted noting and explaining the missing results. The missing results shall be submitted as soon as possible in a supplementary report.

5.4.2 Non-Routine Reports

A written report shall be submitted to the NRC within 60 days of occurrence of a nonroutine event that has a significant unanalyzed impact on the environment. The report shall: a) describe, analyze, and evaluate the event, including extent and magnitude of the impact, and plant operating characteristics; b) describe the probable cause of the event; c) indicate the action taken to correct the reported event; d) indicate the corrective action taken to preclude repetition of the event and to prevent similar occurrences involving similar components or systems; and e) indicate the agencies notified and their preliminary responses.

Events reportable under this section which also require reports to other Federal, State, or local agencies shall be reported in accordance with those reporting requirements in lieu of the requirements of this subsection. The NRC shall be provided with a copy of such report at the same time it is submitted to the other agency.

References

1. NUREG-1811, Environmental Impact Statement for an Early Site Permit (ESP) at the North Anna ESP Site, U. S. Nuclear Regulatory Commission, December 2006.
2. NUREG-LATER, Final Environmental Impact Statement Supplement.
3. North Anna Early Site Permit Application, Part 3 – Environmental Report, Dominion Nuclear North Anna, LLC, Revision 9, September 2006.
4. North Anna 3 Combined License Application, Part 3 – Environmental Report, Dominion Virginia Power, Revision 0, November 2007.

Table 1. Mitigating Actions for Construction Activities

1. Mitigating Actions Identified in ESP-ER Section 4.6

ESP-ER Section 4.1.1

- Conduct ground disturbing activities in accordance with regulatory and permit requirements.
- Use adequate erosion controls and stabilization measures to reduce impacts to the extent practicable.
- Limit tree and vegetation removal to the existing NAPS site, which is zoned "industrial.
- Reduce potential impacts to wetlands and intermittent streams through avoidance and compliance with applicable permitting requirements.
- Restrict soil stockpiling and re-use to the NAPS site.
- Restrict construction activities to the NAPS site.

ESP-ER Section 4.1.3

- Conduct sub-surface testing prior to initiating ground disturbing activities to identify buried historic or archeological resources.
- Take appropriate actions (e.g., stop work) following discovery of potential historic or archeological resources.
- Use existing Virginia Power procedures that require contacting the appropriate regulatory agencies following a discovery of potential historic or archeological resources.

ESP-ER Section 4.2.1

- Design and install appropriate barrier (e.g., turbidity curtain in the North Anna Reservoir near cofferdam work location) to prevent turbid water from migrating into the lake.
- Perform activities under applicable regulations and permit requirements with regard to seasonal restrictions for in-water work, installation of appropriate erosion control measures, drainage controls to convey stream flow, and construction storm water management.
- Use Best Management Practices (BMP) described in the Virginia Erosion and Sediment Control Handbook to control erosion and maintain the sediment load from the construction zone as low as practicable.
- Use wells unaffected by dewatering activities to maintain needed capacity for the NAPS site. Not all wells are expected to be affected by dewatering activities.

Table 1. Mitigating Actions for Construction Activities

ESP-ER Section 4.2.2 • Develop and implement a construction Storm Water Pollution Prevention Plan (SWPPP) and spill response plan during construction at the NAPS site. • Implement an Erosion and Sediment Control Plan that describes use of approved/recognized Best Management Practices (BMP). • Limit dewatering activities to only those necessary for construction. • Use offsite sources of potable water, if necessary, to temporarily supplement onsite water resources.
ESP-ER Section 4.3.2 • Develop and implement a construction Storm Water Pollution Prevention Plan (SWPPP) and spill response plan during construction in the transmission corridor. • Implement an Erosion and Sediment Control Plan that describes use of approved/recognized BMPs. • Design and install appropriate barrier (e.g., turbidity curtain in the North Anna Reservoir near cofferdam work location) to prevent turbid water from migrating into the lake. • Adhere to seasonal restrictions on in-water construction activities. Following temporary construction disturbance, intake channel cove will likely be re-colonized by benthic organisms and fish.
ESP-ER Section 4.4.1 • Train and appropriately protect NAPS site and temporary construction personnel (i.e., those most directly and frequently affected by construction noise, dust and gaseous emissions) to reduce the risk of potential harmful exposures from noise, dust, and gaseous emissions. • Provide onsite services for emergency first aid care and conduct regular health and safety monitoring for affected personnel on site. • Make public announcements and/or notifications prior to undertaking atypical or noisy construction activities. • Use normal dust control measures (e.g., watering, stabilizing disturbed areas, covering truck loads). • Manage concerns from adjacent residents, business owners, or landowners, on a case-by-case basis through a Dominion prepared concern resolution process. • Post signs at or near construction site entrances and exits to make the public aware of potentially high construction traffic areas. • Design and install appropriate barrier (e.g., turbidity curtain in the North Anna Reservoir near cofferdam work location) to restrict turbid water from migrating into the lake.

Table 1. Mitigating Actions for Construction Activities

ESP-ER Section 4.4.2

- Develop a construction traffic management plan prior to construction to address potential impacts on local roadways.
- Encourage the use of shared (e.g., carpooling) and multi-person transport (e.g., buses) of construction personnel to the ESP site.
- Coordinate schedules during work force shift changes to limit impacts on local roads.
- Schedule delivery of larger pieces of equipment or structures on off-peak traffic hours (e.g., at night) or through other transportation modes (e.g., rail).
- Consider/coordinate, if necessary, with local planning authorities the upgrading of local roads, intersections, and signals to handle increased traffic loads.

Table 1. Mitigating Actions for Construction Activities

2. Mitigating Actions Identified in FEIS Section 4.10
• Incorporation of environmental requirements into construction contracts (ESP-ER Section 4.6).
• Avoid watercourses and wetlands to the extent practical during any construction (ESP-ER Sections 4.1.1.6.2, and 4.3.1.2).
• Develop a dust control plan to mitigate the impacts of emissions from construction activities (ESP-ER Section 4.4.1.4).
• Develop a construction traffic management plan to include several traffic mitigating measures (ESP-ER Section 4.4.2.2.1).
• Mitigate potential impacts for materials delivery. Methods include: 1) avoiding routes that could adversely affect sensitive areas (e.g., housing, hospitals, schools, retirement communities, businesses) to the extent possible and 2) restricting delivery times activities to daylight hours (ESP-ER Section 4.4.1.1.3).
• Repair any damage to public roads, markings, or signs caused by construction activities to pre-existing condition or better (ESP-ER Section 4.4.1.1.3).
• Build and maintain new access road on the NAPS site to support construction activities (by Virginia Power personnel as needed) (ESP-ER Section 4.4.1.1.3).
• Maintain emissions from heavy construction equipment as low as reasonably practicable by scheduled equipment maintenance procedures (ESP-ER Section 4.3.1.2).
• To prevent contaminants from entering the aquatic system, implement a Spill Prevention Control and Countermeasure Plan (ESP-ER Section 4.3.2).
• Manage nuisances and concerns from adjacent residents, business owners, or landowners on a case-by-case basis through a Dominion prepared concern resolution process (ESP-ER Section 4.4.1).
• Coordinate with the VDHR regarding the potential presence of historic and cultural resources within planned disturbed areas and notify VDHR in the event of any unanticipated discovery (ESP-ER Section 4.1.3).

Table 1. Mitigating Actions for Construction Activities

3. Mitigating Actions Identified in COL-ER Section 4.6

- Upon completion of the transports, temporary structures will be removed, interferences will be reinstalled, and disturbed areas will be restored back to their original condition or better.
- The new transmission line will be located in an existing corridor (Sections 4.1.2, 4.2.1.1 and 4.3.1.1).
- Land clearing necessary to accommodate the new transmission tower foundations will be controlled by existing transmission line procedures, good construction practices, and established best management practices (4.3.1.1), as well as all applicable regulations.
- Clearing methods for small trees, bushes and vegetation will be performed to protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water will be hand-cleared and material approximately three inches in diameter and above will be removed from the buffer, leaving material less than three inches undisturbed (Sections 4.1.2 and 4.3.1.1).
- Once all the construction of transmission lines has been completed, Dominion will restore disturbed areas by means such as: discing, fertilizing, seeding, and installing erosion control devices (e.g., water bars and mulch); removal and proper disposal of debris left or caused by construction; and restoration of damaged property to its original condition and to the satisfaction of the property owner (Sections 4.1.2 and 4.3.1.1).
- Appropriate actions (e.g., stop work) will be taken following discovery of potential historic or archeological resources (Section 4.1.2).
- Potential impacts to streams and creeks will be mitigated by performing work related to stream crossings in accordance with state standards and specifications. In addition, streams and creeks will be crossed at right angles at one location on the corridor using culverts, temporary bridges, or large aggregate stone. Materials will be removed from the temporary crossing at the completion of the project (Section 4.2.1.1).

Table 1. Mitigating Actions for Construction Activities

- Soil disturbances will be avoided or reduced to the extent practicable within an approximately 100-foot buffer of streams and ditches with running water. Erosion and sedimentation control measures and buffer zone maintenance around water bodies will be implemented to reduce runoff and erosion. These measures will be left in place, until stabilization of the area is achieved. Work sites will be stabilized prior to moving to the next area (Sections 4.2.1.1 and 4.3.1.1).
- To the extent practicable, construction will avoid alterations to shorelines and wetland areas. Should wetlands be impacted, the U.S. Army Corps of Engineers (and other appropriate agencies) will be consulted, and permits and approvals will be obtained as necessary (Section 4.2.1.1).
- Dust suppression techniques will be utilized and equipment maintenance employed to reduce airborne emissions (Section 4.3.1.1).
- As a safety precaution, during installation of the transmission lines, access to the area will be temporarily restricted from recreational use (Section 4.4).

4. Mitigating Actions Identified in FEIS Supplement Section 4.10

LATER

Table 2. Mitigating Actions for Operation

1. Mitigating Actions Identified in ESP-ER Section 5.10

ESP-ER Section 5.1.1

- Water discharges from operation of the new unit will be governed by VPDES permit requirements.
- No new public roads needed for operation of the new units. Potential increases in traffic will be mitigated through effective traffic management.

ESP-ER Section 5.2.1

- Practices to minimize the hydrologic alterations may be implemented.
- During periods of extended drought, dry cooling towers will be put into service to dissipate a portion of waste heat from Unit 3 to minimize the make-up water requirements.

ESP-ER Section 5.2.2

- During periods of extended drought, dry cooling towers will be put into service to dissipate a portion of waste heat from Unit 3 to minimize the make-up water requirements.

ESP-ER Section 5.3.1.1

- Stabilizing the banks of the channel to the screen house and pump house will be considered.

ESP-ER Section 5.3.1.2

- The intake structure for Unit 3 will meet such requirements as the VDEQ may impose under Section 316(b) of the Clean Water Act and the implementing regulations, as applicable.
- A fish return system based on the latest technology available during detailed engineering will be considered for incorporation into the intake system.

ESP-ER Section 5.3.2.2

- Cooling water discharges to the North Anna Reservoir will be governed by VPDES water quality standards and permitted discharge limits.

ESP-ER Section 5.4.1

- Sources of radiation at the new units will be contained similar to the existing units.

Table 2. Mitigating Actions for Operation

ESP-ER Section 5.5.1

- Water availability issues regarding the North Anna River are addressed via regulated releases from the North Anna Dam.
- Comply with applicable VPDES water quality standards for any discharge from Dike 3.
- Prepare and implement a new operational Storm Water Pollution Prevention Plan to avoid and/or minimize releases of contaminated storm water.
- Use approved transporters and offsite landfills for disposal of solid waste. Continue existing units' program for reuse and recycling of nonradwastes.
- Operate any new minor air emission sources in accordance with applicable regulations and permits.
- Modify (if necessary) existing sanitary waste treatment systems to accommodate increased volume.

ESP-ER Section 5.5.2

- Limit need to manage and dispose of mixed waste through: 1) source reduction; 2) recycling options; 3) treatment.
- Develop a Waste Minimization Program, to address mixed waste inventory management; equipment maintenance; recycling and reuse; segregation; treatment (decay in storage); work planning; waste tracking; and awareness training.
- Implement a program to manage wastes stored onsite in compliance with applicable EPA and NRC regulatory requirements.
- Implement spill prevention and response plans and procedures to address hazards associated with managing mixed wastes. Include in plans and procedures measures for response personnel training and protective equipment.

ESP-ER Section 5.7

- Select mining techniques that minimize potential impacts.
- Consider use of new technology that requires less uranium hexafluoride.
- Consider use of centrifuge process over gaseous diffusion process, which can significantly reduce energy requirements and environmental impacts.
- Consider use of new technologies with less fuel loading to reduce energy, emissions and water usage. Projected impacts of TRISO fuel plant will be less than existing air, water, and solid waste regulations.
- Consider use of new gas-cooled reactor technologies that can result in generation of far less low-level wastes.

Table 2. Mitigating Actions for Operation

ESP-ER Section 5.8.1

- Comply with applicable VDEQ permit limits and regulations when installing and operating air emission sources.
- Perform noise study as part of final design for dry cooling towers.
- Perform visual impact study for new structures on site, including dry and wet cooling towers, as part of final design.

ESP-ER Section 5.8.2

- Perform noise study as part of final design for dry and wet cooling towers.
- Perform visual impact study for new structures on site, including dry and wet cooling towers, as part of final design.

ESP-ER Section 5.9

- The significance of the impacts is unknown because the decommissioning methods have not been chosen. No mitigation measures or controls are proposed at this time.

2. Mitigating Actions Identified in FEIS Section 5.11

- Current transmission line maintenance practices will continue if two new units were built at the ESP site (ESP-ER Section 5.6.1.1).
- A system study modeling the transmission lines with new units' contribution will be conducted (ESP-ER Section 5.1.2).
- Locations of rare or sensitive plant species within transmission line corridors will be identified so modified treatment practices can be used in these areas to avoid adverse impacts (ESP-ER Section 5.6.1.1).
- Demonstrate that the fogging and salt deposition analysis of the cooling system remains bounding (May 24, 2006, response to RAI).
- The intake structure for the proposed new units at the ESP site will meet Section 316(b) of the Clean Water Act and the implementing regulations, as applicable (ESP-ER Section 5.3.1.2).
- Vegetative shielding will block a clear view of the new units from most nearby residences (ESP-ER Section 5.8.1.5, ESP-ER Table 5.10-1).
- Noise levels will be controlled in accordance with applicable local county regulations (ESP-ER Section 5.3.1.2).
- Although the operation of the new units are not expected to require changes in land use (ESP-ER Section 5.1), any ground-disturbing activities necessary for operations will be conducted in coordination with the VDHR and professional archaeological practices consistent with the process established for construction activities (ESP-ER Section 4.1.3).

Table 2. Mitigating Actions for Operation

3. Mitigating Actions Identified in COLA ER Section 5.10

- Non radioactive effluents, including sanitary waste and blowdown from Unit 3 cooling towers, will be controlled by the limits established in VPDES permit (Sections 5.2.2 and 5.5.1).
- The new and separate Unit 3 sanitary waste treatment systems will be governed by applicable regulations and permits (Sections 5.2.2 and 5.5.1).
- Operation of a de-chlorination system to neutralize chlorine in the circulating water and plant service water cooling tower blowdown before discharge to the WHTF and eventually to the North Anna Reservoir (Section 5.2.2).

4. Mitigating Actions Identified in FEIS Supplement Section 5.11

LATER

Chapter 2 Environmental Description

2.1 Site Location

The information for this section is provided in ESP-ER Section 2.1 and in FEIS Section 2.1. Figure 1.1-1 shows the layout of Unit 3 within the ESP site.

No new and significant information has been identified for this section.

2.2 Land

The information for this section is provided in ESP-ER Section 2.2 and in FEIS Section 2.2. Supplemental information is provided below.

2.2.1 The Site and Vicinity

No new and significant information has been identified for this section.

2.2.2 Transmission Line Rights-of-Way and Offsite Areas

Based on an initial evaluation, the ESP-ER indicated that the existing transmission lines were expected to have sufficient capacity to carry the output of the new units at NAPS. However, a commitment was made to perform a load flow study to confirm that conclusion. In June 2007, PJM completed an impact study (Reference) to determine the required system reinforcements associated with a new unit at North Anna. Based on the results of this study, a new 15-mile long 500 kV line from the North Anna Substation to the Ladysmith Switching Substation will be installed on new transmission towers, within the existing transmission corridor. The location of this corridor is identified as "Line 575" on ESP-ER Figure 2.2-4, beginning at NAPS and heading east. Further information is provided in Section 3.7.

2.2.3 The Region

No new and significant information has been identified for this section.

Section 2.2 Reference

PJM Generator Interconnection Q65 North Anna 500kV (1594 MW) System Impact Study, PJM System Planning Division, June 2007.

2.3 Water

The information for this section is provided in ESP-ER Section 2.3 and in FEIS Section 2.6. Supplemental information is provided below.

2.3.1 Hydrology

No new and significant information has been identified for this section.

2.3.2 Water Use

No new and significant information has been identified for this section.

2.3.3 Water Quality

2.3.3.1 Surface Water

FEIS Section 5.3.3 identified the need to provide the chemical constituents of effluents in waste streams. This section provides information on surface water quality that is used (in conjunction with information in Section 3.3 concerning the chemical additives used in plant water systems) to determine the expected plant waste stream effluent discussed in Section 3.6.

Table 2.3-1 contains surface water quality data collected in the vicinity of the intake since submittal of the ESP-ER. The table provides the maximum value reported for each constituent. The parameters for which the samples were collected included the "126 Priority Pollutants" (Reference 1) as well as water temperature, suspended solids, total dissolved solids, hardness, turbidity, color, odor, conductivity, biological oxygen demand, chemical oxygen demand, phosphorus forms, nitrogen forms, alkalinity, chlorides, sulfate, sodium, potassium, calcium, magnesium, heavy metals, and pH. This surface water quality data is used in Section 3.6 in the discussion of the nonradioactive liquid wastes. Environmental impacts on surface water quality from station operation are discussed in Section 5.2.

2.3.3.2 Groundwater Aquifers

No new and significant information has been identified for this section.

Section 2.3 References

1. 40 CFR 423, Appendix A, EPA Steam Electric Generating Point Source Category, 126 Priority Pollutants.

2. 9 VAC 25-260 (et seq.) Virginia Water Quality Standards, State Water Control Board, effective August 14, 2007.

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2 & 3)*	Detection Limit (mg/L) *(Note 2)*	Notes
011	1,1,1-Trichloroethane	0.00	N/A	3.80E-03	4 & 5
015	1,1,2,2-Tetrachloroethane	0.00	1.10E-01	6.90E-03	4
014	1,1,2-Trichloroethane	0.00	4.20E-01	5.00E-03	4
013	1,1-Dichloroethane	0.00	N/A	4.70E-03	4 & 5
029	1,1-Dichloroethylene	0.00	17.00	2.80E-03	4
008	1,2,4-Trichlorobenzene	0.00	9.40E-01	7.90E-03	4
	1,2-Dichlorobenzene	0.00	17.00	4.00E-03	4
010	1,2-Dichloroethane	0.00	9.90E-01	2.80E-03	4
032	1,2-Dichloropropane	0.00	3.90E-01	6.00E-03	4
037	1,2-Diphenylhydrazine	0.00	5.40E-03	8.80E-03	4
030	1,2-Trans-dichloroethylene	0.00	140.00	1.60E-03	4
	1,3-Dichlorobenzene	0.00	2.60	3.10E-03	4
	1,4 Dichlorobenzene	0.00	2.60	4.4E-03	4
	2 Methyl-4,6, Dinitrophenol	0.00	7.70E-01	2.58E-04	4
129	2,3,7,8-TCDD	0.00	1.00E-09	1.00E-02	4
021	2,4,6-Trichlorophenol	0.00	6.50E-02	5.54E-04	4
031	2,4-Dichlorophenol	0.00	7.90E-01	4.24E-04	4
034	2,4-Dimethylphenol	0.00	2.30	3.19E-04	4
059	2,4-Dinitrophenol	0.00	14.00	3.54E-04	4
035	2,4-Dinitrotoluene	0.00	9.10E-02	5.70E-03	4
036	2,6-Dinitrotoluene	0.00	N/A	3.40E-03	4 & 5
019	2-Chloroethylvinyl Ether	0.00	N/A	1.20E-03	4 & 5
020	2-Chloronaphthalene	0.00	4.30	4.60E-03	4
024	2-Chlorophenol	0.00	4.00E-01	3.51E-04	4
057	2-Nitrophenol	0.00	N/A	4.75E-04	5
028	3,3'-Dichlrobenzidine	0.00	7.70E-04	1.65E-02	4
094	4,4-DDD	0.00	8.40E-06	2.1E-05	4
093	4,4-DDE	0.00	5.90E-06	1.7E-05	4

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2 & 3)*	Detection Limit (mg/L) *(Note 2)*	Notes
092	4,4-DDT	0.00	5.90E-06	1.7E-05	4
041	4-Bromophenyl-phenylether	3.00E-03	N/A	3.00E-03	5
040	4-Chlorophenyl-phenylether	0.00	N/A	4.20E-03	4 & 5
058	4-Nitrophenol	0.00	N/A	6.12E-04	4 & 5
001	Acenapthene	0.00	2.70	3.00E-03	4
077	Acenapthylene	0.00	N/A	3.50E-03	4 & 5
002	Acrolein	0.00	7.80E-01	1.0E-02	4
003	Acrylonitrile	0.00	6.60E-03	1.50E-03	4
089	Aldrin	0.00	1.40E-06	1.6E-05	4
102	Alpha BHC	0.00	1.30E-04	7.0E-06	4
095	Alpha-Endosulfan	0.00	2.40E-01	1.4E-05	4
	Ammonia as N	3.00E-02	1.20	1.0E-02	
078	Anthracene	0.00	110.00	1.90E-03	4
114	Antimony	0.00	4.30	1.00E-03	4
115	Arsenic	0.00	1.50E-01	3.00E-03	4
116	Asbestos (MF/L)	0.00	N/A	1.80E-01	4 & 5
	Barium	2.00E-02	NAWQC	3.0E-03	6
004	Benzene	0.00	7.10E-01	4.40E-03	4
005	Benzidine	0.00	5.40E-06	6.30E-02	4
072	Benzo (a) Anthracene	0.00	4.90E-04	7.80E-03	4
073	Benzo (a) pyrene	0.00	4.90E-04	2.50E-03	4
074	Benzo (b) Fluoranthene	0.00	4.90E-04	4.80E-03	4
079	Benzo (g h i) perylene	0.00	N/A	4.10E-03	4 & 5
075	Benzo (k) Fluoranthene	0.00	4.90E-04	2.50E-03	4
117	Beryllium	0.00	N/A	2.00E-04	4 & 5
103	Beta BHC	0.00	4.60E-04	1.3E-05	4
096	Beta-Endosulfan	0.00	2.40E-01	1.7E-05	4
043	Bis (-2-Chloroethoxy) Methane	0.00	N/A	5.30E-03	4 & 5

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2 & 3)*	Detection Limit (mg/L) *(Note 2)*	Notes
018	Bis (-2-chloroethyl) Ether	0.00	1.40E-02	5.70E-03	4
	Bis (2-Chloroisopropyl) Ether	0.00	170.00	5.70E-03	4
066	Bis (2-ethylhexyl) Phthalate	0.00	N/A	2.50E-03	4 & 5
	BOD	5.36	N/A	2.00	5
	Bromide	0.00	N/A	2.01E-01	4 & 5
047	Bromoform	0.00	3.60	4.70E-03	4
067	Butylbenzylphthalate	0.00	5.20	2.50E-03	4
118	Cadmium	0.00	3.80E-04	3.00E-04	4
	Calcium	3.44	N/A	9.0E-02	5
006	Carbon tetrachloride	0.00	4.40E-02	2.80E-03	4
091	Chlordane	0.00	2.00E-05	1.4E-05	4
	Chloride	4.68	230.00	5.0E-02	
007	Chlorobenzene	0.00	21.00	6.00E-03	4
051	Chlorodibromomethane	0.00	3.40E-01	3.10E-03	4
016	Chloroethane	0.00	N/A	1.10E-03	4 & 5
023	Chloroform	0.00	29.00	1.60E-03	4
	Chlorpyrifos	0.00	4.10E-05	1.38E-05	4
119	Chromium	0.00	N/A	1.00E-03	4, 5 & 7
	Chromium +6	0.00	1.10E-02	1.00E-02	4
076	Chrysene	0.00	4.90E-04	2.50E-03	4
	Cis-1,3-Dichloropropylene	0.00	1.70	5.0E-03	4
	COD	13.69	N/A	5.0	5
	Color	20.00	N/A	N/A	5
	Conductivity (µmhos)	64.00	N/A	N/A	5
120	Copper	3.00E-03	2.70E-03	1.0E-03	
121	Cyanide as CN	0.00	220.00	1.00E-02	4
105	Delta BHC	0.00	N/A	1.5E-05	4 & 5
	Demeton	0.00	1.00E-04	5.206E-04	4

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2 & 3)*	Detection Limit (mg/L) *(Note 2)*	Notes
083	Dibenzo (a h) anthracene	0.00	4.90E-04	2.50E-03	4
048	Dichlorobromomethane	0.00	4.60E-01	2.20E-03	4
090	Dieldrin	0.00	1.40E-06	1.00E-05	4
070	Diethylphthalate	0.00	120.00	7.40E-03	4
071	Dimethyl Phthalate	0.00	2900.00	7.50E-03	4
	Di-n-Butylphthalate	0.00	12.00	6.40E-03	4
069	Di-n-octyl Phthalate	0.00	N/A	2.50E-03	4 & 5
	Dioxin	Not reported	1.20E-12	1.0E-05	
097	Endosulfan sulfate	0.00	2.40E-01	9.0E-6	4
098	Endrin	0.00	8.10E-04	2.0E-05	4
099	Endrin aldehyde	0.00	8.10E-04	1.9E-05	4
038	Ethylbenzene	0.00	29.00	7.20E-03	4
039	Fluoranthene	0.00	3.70E-01	2.20E-03	4
080	Fluorene	0.00	14.00	2.20E-03	4
104	Gamma BHC (Lindane)	0.00	6.30E-04	1.1E-05	4
	Gross Alpha (pCi/L)	0.00	15.00	<1.62	4
	Gross Beta (pCi/L)	2.09	4 mrem/yr	N/A	
	Guthion	0.00	1.00E-05	3.577E-04	4
	Hardness (ppm as $CaCO_3$)	23.94	N/A	3.0	5
100	Heptachlor	0.00	2.10E-06	1.6E-05	4
101	Heptachlor epoxide	0.00	1.10E-06	1.2E-05	4
009	Hexachlorobenzene	0.00	7.70E-06	3.10E-03	4
052	Hexachlorobutadiene	0.00	5.00E-01	1.80E-03	4
053	Hexachlorocyclopentadiene	0.00	17.00	1.00E-02	4
012	Hexachloroethane	0.00	8.90E-02	2.40E-03	4
	Hydrogen Sulfide	0.00	2.00E-03	5.00E-02	4
083	Indeno (1 2 3-CR) pyrene	0.00	4.90E-04	3.70E-03	4

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2 & 3)*	Detection Limit (mg/L) *(Note 2)*	Notes
054	Isophorone	0.00	26.00	5.10E-03	4
122	Lead	0.00	2.30E-03	1.00E-03	4
	Magnesium	2.33	N/A	1.0E-02	5
	Malathion	0.00	1.00E-04	1.227E-04	4
	M-Alkalinity (ppm as $CaCO_3$)	18.96	N/A	N/A	5
123	Mercury	1.01E-06	5.10E-05	2.0E-04	
	Methoxychlor	0.00	3.00E-05	1.7E-05	4
046	Methyl Bromide	0.00	4.00	1.40E-03	4
045	Methyl Chloride	0.00	N/A	1.10E-03	4 & 5
044	Methylene Chloride	0.00	16.00	2.80E-03	4
	Molybdenum	1.1E-02	N/A	1.0E-03	5
055	Naphthalene	0.00	N/A	3.80E-03	4 & 5
124	Nickel	0.00	4.60	5.00E-03	4
	Nitrate as N	1.70E-01	NAWQC	1.0E-02	6
	Nitrite as N	0.00	N/A	1.00E-02	4 & 5
056	Nitrobenzene	0.00	1.90	4.20E-03	4
061	N-Nitrosodimethylamine	0.00	8.10E-02	6.20E-03	4
063	N-nitroso-Di-n-propylamine	0.00	1.40E-02	3.60E-03	4
062	N-nitrosodiphenylamine	0.00	1.60E-01	2.70E-03	4
	Odor	0.00	N/A	N/A	5
	Parathion	0.00	6.50E-05	1.21E-04	4
112	PCB 1016	0.00	1.40E-05	5.00E-02	4
108	PCB 1221	0.00	1.40E-05	3.00E-02	4
109	PCB 1232	0.00	1.40E-05	5.00E-02	4
106	PCB 1242	0.00	1.40E-05	5.00E-02	4
110	PCB 1248	0.00	1.40E-05	5.00E-02	4
107	PCB 1254	0.00	1.40E-05	3.60E-02	4
111	PCB 1260	0.00	1.40E-05	5.00E-02	4

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2 & 3)*	Detection Limit (mg/L) *(Note 2)*	Notes
064	Pentachlorophenol	0.00	8.20E-02	6.85E-04	4
	pH (standard units)	7.30	N/A	N/A	5
081	Phenanthrene	0.00	N/A	5.40E-03	4 & 5
065	Phenol	0.00	4600.00	4.8E-04	4
	Phosphate as P	Not reported	N/A	1.0E-02	5
	Phosphorous as P	3.00E-02	N/A	1.0E-02	5
	Potassium	2.86	N/A	1.0E-02	5
084	Pyrene	0.00	11.00	3.80E-03	4
125	Selenium	0.00	11.00	3.00E-03	4
126	Silver	0.00	3.20E-04	1.00E-04	4
	Sodium	4.00	N/A	1.0E-01	5
	Strontium (pCi/L)	0.00	8.00	N/A	
	Sulfate	7.05	NAWQC	6.0E-02	6
	Sulfide	0.00	N/A	1.00E-02	4 & 5
	TDS	60.00	NAWQC	10.0	6
	Temperature (°C)	18.40	N/A	N/A	5
085	Tetrachloroethylene	0.00	8.90E-02	4.10E-03	4
127	Thallium	0.00	6.30E-03	2.00E-04	4
	Tin	0.00	N/A	5.00E-03	4 & 5
086	Toluene	0.00	200.00	6.00E-03	4
	Total Kjeldahl Nitrogen, as N	3.5E-01	N/A	1.0E-02	5
	Total PCBs	4.70E-08	1.70E-06	N/A	
	Total Residual Chlorine	0.00	1.10E-02	1.00E-01	4
113	Toxaphene	0.00	7.50E-06	5.7E-05	4
	Trans-1,2 Dichloroethylene	0.00	140.00	1.6E-03	4
	Trans-1,3-Dichloropropene	Not reported	1.70	9.0E-04	

Table 2.3-1 Lake Anna Water Quality Data

Priority Pollutant Number *(Note 1)*	Constituent Name	Reported Level (mg/L) *(Note 2)*	Water Quality Criteria (mg/L) *(Notes 2 & 3)*	Detection Limit (mg/L) *(Note 2)*	Notes
	Tributyltin	6.30E-05	6.30E-05	3.0E-05	
087	Trichloroethylene	0.00	8.10E-01	1.90E-03	4
	Tritium (pCi/L)	7,460.00	20,000.00	N/A	
	TSS	4.8	N/A	1.0	5
	Turbidity (NTU)	3.40	N/A	N/A	5
088	Vinyl Chloride	0.00	6.10E-02	1.80E-03	4
128	Zinc	1.30E-02	69.00	1.0E-02	

Notes to Table 2.3-1:

1. The Priority Pollutant Numbers are in accordance with 40 CFR 423, Appendix A, EPA Steam Electric Generating Point Source Category (Reference 1).
2. Each constituent's Reported Level, Water Quality Criteria, and Detection Limit are specified in milligrams of constituent as ion per liter of water, unless specified otherwise.
3. The Water Quality Criteria listed are the most restrictive numeric criteria contained in Virginia's Water Quality Standards Regulation (9 VAC 25-260 et seq) (Reference 2).
4. Many of the constituents were reported below the detection limit. These constituents are listed with a "Reported Level" of "0.00".
5. A Water Quality Criteria specified as "N/A" indicates that Virginia does not have numeric water quality criteria for that constituent.
6. A Water Quality Criteria specified as "NAWQC" means that the only existing Virginia numeric criterion for that parameter is for the protection of Public Water Supplies. Lake Anna is not a designated Public Water Supply.
7. The Water Quality Criterion presented is for Trivalent Chromium, which was not directly measured.

2.4 Ecology

The information for this section is provided in ESP-ER Section 2.4 and in FEIS Sections 2.2, 2.4, and 2.7. Supplemental information is provided below.

2.4.1 Terrestrial Ecology

As described in Section 3.7, the PJM System Impact Study (Reference 1) determined that an additional 500 kV transmission line from the North Anna Substation to the Ladysmith Switching Substation is required for grid stability associated with the interconnection of Unit 3. The new line will be installed on new transmission towers along the existing corridor between the North Anna Substation and the Ladysmith Switching Substation (NAPS-to-Ladysmith corridor). Information concerning terrestrial ecology in the NAPS transmission corridors is provided in ESP-ER Sections 2.2 and 2.4. Supplemental information regarding wetlands and water bodies in the NAPS-to-Ladysmith transmission corridor is provided in Section 2.4.1.8.

2.4.1.1 Terrain

No new and significant information has been identified for this section.

2.4.1.2 Wildlife Species

No new and significant information has been identified for this section.

2.4.1.3 Common Bird Species

No new and significant information has been identified for this section.

2.4.1.4 Wading Birds and Waterfowl

No new and significant information has been identified for this section.

2.4.1.5 Critical Habitat

No new and significant information has been identified for this section

2.4.1.6 Endangered Species

No new and significant information has been identified for this section.

2.4.1.7 Rare Plant Species

No new and significant information has been identified for this section.

2.4.1.8 Wetlands

The new 500 kV transmission line will be installed on new towers in the existing NAPS-to-Ladysmith corridor. This corridor is identified as "Line 575" on ESP-ER Figure 2.2-4 (beginning at NAPS and heading east) and is 84 m (275 ft) wide and approximately 15 miles long.

The NAPS-to-Ladysmith corridor crosses the following water bodies and wetlands, identified on the UGSS Ladysmith (VA) Quadrangle (Reference 2):

- Lake Anna
- Five tributaries to Lake Anna
- Nine tributaries to Northeast Creek, which is a tributary of the North Anna River below the Lake Anna dam
- Five tributaries to the South River
- One tributary to the Motto River

The two largest areas of wetlands in the corridor are along Northeast Creek, approximately 3 miles north of the dam, and along a tributary of the South River, approximately 3 miles west of the Ladysmith Switching Substation.

2.4.1.9 **Important Species**

No new and significant information has been identified for this section.

2.4.1.10 **Proposed Site**

No new and significant information has been identified for this section.

2.4.2 **Aquatic Ecology**

No new and significant information has been identified for this section.

Section 2.4 References

1. PJM Generator Interconnection Q65 North Anna 500kV (1594 MW) System Impact Study, PJM System Planning Division, June 2007.

2. USGS Ladysmith (VA) Quadrangle (UTM 18 274527E 4214449N).

2.5 Socioeconomics

The information for this section is provided in ESP-ER Section 2.5 and in FEIS Sections 2.8 and 2.9.

No new and significant information has been identified for socioeconomics.

2.6 Geology

The information for this section is provided in ESP-ER Section 2.6 and in FEIS Section 2.4.

No new and significant information has been identified for this section.

2.7 Meteorology and Air Quality

The information for this section is provided in ESP-ER Section 2.7 and in FEIS Section 2.3 Supplemental information concerning atmospheric dispersion coefficients as provided in Sections 2.7.5 and 2.7.6.

2.7.1 General Climate

No new and significant information has been identified for this section.

2.7.2 Regional Air Quality

No new and significant information has been identified for this section.

2.7.3 Severe Weather

No new and significant information has been identified for this section.

2.7.4 Local Meteorology

No new and significant information has been identified for this section.

2.7.5 Short-Term Diffusion Estimates

For the short-term atmospheric dispersion coefficients (used in the evaluation of doses due to design basis accidents, in Section 7.1), the ESP values listed in FEIS Table 5-14 are used for this ER.

2.7.6 Long-Term (Routine) Diffusion Estimates

As a part of the preparation of this ER, the annual Radiological Environmental Monitoring Program was reviewed to determine if the distances to any of the nearest sensitive receptors, modeled for the ESP-ER have changed. The results of that review, as documented in Table 2.7-1, show the closest receptor to be the residence at the NW direction at a distance of 1.20 km (3930 feet). For the purposes of the atmospheric dispersion analysis and the subsequent dose evaluations, it was conservatively assumed that each sensitive receptor (meat animal, vegetable garden, residence) is at the location of the closest receptor. Therefore, one of each type of receptor was assumed to be at 1.20 km (3930 feet) in each compass direction. The maximum annual average χ/Q value calculated for the nearest residence, vegetable garden, and meat animal, all assumed at 0.74 miles to the ESE of the facility boundary shown in FSAR Figure 2.0-205, is 4.20 E-6 sec/m^3. In the evaluation performed for this ER, the distance to the EAB was found to be 1.0 mile in the direction where the maximum χ/Q is calculated. However, for conservatism, the greater χ/Q value from the ESP-ER, which is based on a distance of 0.88 miles, is retained for use in this ER. The maximum annual χ/Q (no decay) at the EAB is 3.70 E-6 sec/m^3, at a distance of 1.42 km (0.88 mile) to the ESE of the facility boundary. The results are summarized in Table 2.7-2 and Table 2.7-3. These tables present the maximum calculated χ/Qs and D/Qs at sensitive receptors and at various distances from the site.

Annual average χ/Q and D/Q estimates generated by the XOQDOQ model for the sensitive receptors and at distances between 0.25 mile to 50 miles, as well as for various segment boundaries, are also presented. Table 2.7-4 presents χ/Q and D/Q estimates at the specific points of interest. Table 2.7-5 lists χ/Q estimates at downwind distances between 0.25 and 50 miles and along various segments. Table 2.7-6 contains χ/Q estimates that include radioactive decay with a half-life of 2.26 days for short-lived noble gases. Table 2.7-7 contains χ/Q estimates that include radioactive decay with a half-life of 8 days for all iodines released to the atmosphere. Finally, Table 2.7-8 contains estimates of long-term average D/Q at downwind distances between 0.25 and 50 miles.

The methodology used to determine the long-term dispersion and deposition coefficients (used in the evaluation of doses due to normal operating releases) remains the same as that described in ESP-ER Section 2.7.6. ESP-ER Tables 2.7-13 through 2.7-20 have been replaced in this ER by Tables 2.7-1 through 2.7-8.

No other new and significant information has been identified for this section.

Table 2.7-1 Source to Sensitive Receptor Distances

Type	Direction	Distance from Unit 1 (Feet)	Distance from Unit 1 (Miles/km)	Distance From Facility Boundary (Feet)[1]	Distance from Facility Boundary (Miles/km)[1]
			Vegetation		
Veg	S	No Receptor Listed			
Veg	SSW	7392	1.4 / 2.25	5293	1.00 / 1.61
Veg	SW	20592	3.9 / 6.28	17943	3.40 / 5.47
Veg	WSW	14256	2.7 / 4.35	11576	2.19 / 3.53
Veg	W	10560	2.0 / 3.22	7945	1.50 / 2.42
Veg	WNW	8976	1.7 / 2.74	6951	1.32 / 2.12
Veg	NW	No Receptor Listed			
Veg	NNW	5808	1.1 / 1.77	4924	0.93 / 1.50
Veg	N	5808	1.1 / 1.77	5432	1.03 / 1.66
Veg	NNE	17952	3.4 / 5.47	18109	3.43 / 5.52
Veg	NE	4752	0.9 / 1.45	5174	0.98 / 1.58
Veg	ENE	11088	2.1 / 3.38	11601	2.20 / 3.54
Veg	E	6864	1.3 / 2.09	7233	1.37 / 2.20
Veg	ESE	8976	1.7 / 2.74	9188	1.74 / 2.80
Veg	SE	5280	1.0 / 1.61	4824	0.91 / 1.47
Veg	SSE	6336	1.2 / 1.93	5184	0.98 / 1.58
			Meat Animal		
Meat	S	14784	2.8 / 4.51	13361	2.53 / 4.07
Meat	SSW	10032	1.9 / 3.06	7877	1.49 / 2.40
Meat	SW	No Receptor Listed			
Meat	WSW	8448	1.6 / 2.57	5769	1.09 / 1.76
Meat	W	No Receptor Listed			
Meat	WNW	20592	3.9 / 6.28	18454	3.50 / 5.62
Meat	NW	No Receptor Listed			
Meat	NNW	No Receptor Listed			
Meat	N	No Receptor Listed			

Table 2.7-1 Source to Sensitive Receptor Distances

Type	Direction	Distance from Unit 1 (Feet)	Distance from Unit 1 (Miles/km)	Distance From Facility Boundary (Feet)[1]	Distance from Facility Boundary (Miles/km)[1]
Meat	NNE	7920	1.5 / 2.41	8095	1.53 / 2.47
Meat	NE	7920	1.5 / 2.41	8351	1.58 / 2.55
Meat	ENE	13200	2.5 / 4.02	13713	2.60 / 4.18
Meat	E	18480	3.5 / 5.63	18861	3.57 / 5.75
Meat	ESE	No Receptor Listed			
Meat	SE	7920	1.5 / 2.41	7905	1.50 / 2.41
Meat	SSE	14784	2.8 / 4.51	14174	2.68 / 4.32
Resident					
Res	S	No Receptor Listed			
Res	SSW	7392	1.4 / 2.25	5293	1.00 / 1.61
Res	SW	8976	1.7 / 2.74	6345	1.20 / 1.93
Res	WSW	8448	1.6 / 2.57	5769	1.09 / 1.76
Res	W	7920	1.5 / 2.41	5317	1.01 / 1.62
Res	WNW	No Receptor Listed			
Res	NW	5808	1.1 / 1.77	**3930**	**0.74** / **1.20**
Res	NNW	5280	1.0 / 1.61	4440	0.84 / 1.35
Res	N	5280	1.0 / 1.61	4876	0.92 / 1.49
Res	NNE	4752	0.9 / 1.45	4948	0.94 / 1.51
Res	NE	4752	0.9 / 1.45	5175	0.98 / 1.58
Res	ENE	11088	2.1 / 3.38	11601	2.20 / 3.54
Res	E	6864	1.3 / 2.09	7233	1.37 / 2.20
Res	ESE	7392	1.4 / 2.25	7379	1.40 / 2.25
Res	SE	5280	1.0 / 1.61	4824	0.91 / 1.47
Res	SSE	5808	1.1 / 1.77	4693	8.89 / 1.43

Note 1: Distances are from the plant facility boundary. See FSAR Figure 2.0-205.

Note 2: No milk cows or goats within a 5-mile radius of NAPS.

Table 2.7-2 XOQDOQ Predicted Maximum χ/Q and D/Q Values at Specific Points of Interest

Type of Location	Direction from Site	Distance (miles)	χ/Q (No Decay)	χ/Q (2.260 Day Decay)	χ/Q (8.000 Day Decay)	D/Q
Residence	ESE	0.74	4.20E-06	4.10E-06	3.70E-06	9.00E-09
EAB	ESE	0.88	3.7E-06	3.7E-06	3.3E-06	1.2E-08[a]
Meat Animal	ESE	0.74	4.20E-06	4.10E-06	3.70E-06	9.00E-09
Veg. Garden	ESE	0.74	4.20E-06	4.10E-06	3.70E-06	9.00E-09

Notes:
χ/Q – sec/m^3
D/Q – 1/m^2

a. Direction = south

Table 2.7-3 XOQDOQ Predicted Maximum Annual Average χ/Q Values

No Decay Undepleted

	Distance In Miles From Site										
ESE	0.25	0.5	0.75	1	1.5	2	2.5	3	3.5	4	4.5
X/Q (s/m^3)	2.566E-05	7.927E-06	4.114E-06	2.670E-06	1.524E-06	1.038E-06	7.709E-07	6.052E-07	4.936E-07	4.140E-07	3.546E-07
	Distance In Miles From Site										
ESE	5	7.5	10	15	20	25	30	35	40	45	50
X/Q (s/m^3)	3.089E-07	1.823E-07	1.258E-07	7.493E-08	5.206E-08	3.932E-08	3.130E-08	2.583E-08	2.188E-08	1.891E-08	1.660E-08
	Segment Boundaries In Miles From Site										
ESE	0.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50	
X/Q (s/m^3)	4.319E-06	1.563E-06	7.757E-07	4.952E-07	3.553E-07	1.853E-07	7.606E-08	3.951E-08	2.588E-08	1.893E-08	

2.260 Day Decay Undepleted

	Distance In Miles From Site										
ESE	0.25	0.5	0.75	1	1.5	2	2.5	3	3.5	4	4.5
X/Q (s/m^3)	2.562E-05	7.901E-06	4.094E-06	2.653E-06	1.509E-06	1.024E-06	7.584E-07	5.935E-07	4.825E-07	4.033E-07	3.443E-07
	Distance In Miles From Site										
ESE	5	7.5	10	15	20	25	30	35	40	45	50
X/Q (s/m^3)	2.989E-07	1.735E-07	1.178E-07	6.789E-08	4.566E-08	3.339E-08	2.573E-08	2.057E-08	1.688E-08	1.413E-08	1.202E-08
	Segment Boundaries In Miles From Site										
ESE	0.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50	
X/Q (s/m^3)	4.300E-06	1.548E-06	7.634E-07	4.840E-07	3.450E-07	1.766E-07	6.909E-08	3.360E-08	2.064E-08	1.416E-08	

Table 2.7-3 XOQDOQ Predicted Maximum Annual Average χ/Q Values

8.000 Day Decay Depleted					**Distance In Miles From Site**						
ESE	0.25	0.5	0.75	1	1.5	2	2.5	3	3.5	4	4.5
X/Q (s/m^3)	2.428E-05	7.232E-06	3.661E-06	2.333E-06	1.291E-06	8.561E-07	6.216E-07	4.781E-07	3.827E-07	3.154E-07	2.659E-07
					Distance In Miles From Site						
ESE	5	7.5	10	15	20	25	30	35	40	45	50
X/Q (s/m^3)	2.281E-07	1.267E-07	8.293E-08	4.530E-08	2.928E-08	2.076E-08	1.560E-08	1.221E-08	9.839E-09	8.111E-09	6.808E-09
					Segment Boundaries In Miles From Site						
ESE	0.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50	
X/Q (s/m^3)	3.864E-06	1.329E-06	6.267E-07	3.843E-07	2.666E-07	1.298E-07	4.654E-08	2.097E-08	1.227E-08	8.140E-09	
Relative Deposition					**Distance In Miles From Site**						
NNE	0.25	0.5	0.75	1	1.5	2	2.5	3	3.5	4	4.5
D/Q (1/m^2)	6.257E-08	2.116E-08	1.086E-08	6.671E-09	3.326E-09	2.017E-09	1.364E-09	9.882E-10	7.514E-10	5.920E-10	4.793E-10
					Distance In Miles From Site						
NNE	5	7.5	10	15	20	25	30	35	40	45	50
D/Q (1/m^2)	3.964E-10	1.943E-10	1.219E-10	6.161E-11	3.729E-11	2.500E-11	1.792E-11	1.345E-11	1.046E-11	8.355E-12	6.820E-12
					Segment Boundaries In Miles From Site						
NNE	0.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50	
D/Q (1/m^2)	1.129E-08	3.487E-09	1.388E-09	7.583E-10	4.820E-10	2.070E-10	6.420E-11	2.544E-11	1.359E-11	8.410E-12	

Table 2.7-4 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Specific Points of Interest

Ground Level Release – No Purge Releases

Release ID	Type of Location	Direction From Site	Distance miles	Distance meters	χ/Q no decay, undepleted (sec/m^3)	χ/Q 2.260 day decay, undepleted (sec/m^3)	χ/Q 8.000 day decay, depleted (sec/m^3)	D/Q (per m^2)
A	Residences	S	0.74	1198.	1.6E-06	1.6E-06	1.4E-06	8.5E-09
A	Residences	SSW	0.74	1198.	1.3E-06	1.3E-06	1.1E-06	5.6E-09
A	Residences	SW	0.74	1198.	1.1E-06	1.1E-06	1.0E-06	4.6E-09
A	Residences	WSW	0.74	1198.	1.1E-06	1.1E-06	9.4E-07	4.0E-09
A	Residences	W	0.74	1198.	1.3E-06	1.3E-06	1.1E-06	4.7E-09
A	Residences	WNW	0.74	1198.	1.1E-06	1.1E-06	9.9E-07	4.4E-09
A	Residences	NW	0.74	1198.	1.1E-06	1.1E-06	1.0E-06	3.9E-09
A	Residences	NNW	0.74	1198.	9.7E-07	9.6E-07	8.6E-07	2.9E-09
A	Residences	N	0.74	1198.	2.5E-06	2.5E-06	2.2E-06	7.6E-09
A	Residences	NNE	0.74	1198.	3.1E-06	3.1E-06	2.8E-06	1.1E-08
A	Residences	NE	0.74	1198.	2.6E-06	2.5E-06	2.3E-06	8.9E-09
A	Residences	ENE	0.74	1198.	1.5E-06	1.5E-06	1.4E-06	4.8E-09
A	Residences	E	0.74	1198.	2.9E-06	2.9E-06	2.6E-06	6.7E-09
A	Residences	ESE	0.74	1198.	4.2E-06	4.1E-06	3.7E-06	9.0E-09
A	Residences	SE	0.74	1198.	2.9E-06	2.9E-06	2.6E-06	8.0E-09
A	Residences	SSE	0.74	1198.	1.7E-06	1.7E-06	1.5E-06	7.2E-09
A	Exclusion Area B	S	0.70	1134.	1.8E-06	1.8E-06	1.6E-06	9.3E-09
A	Exclusion Area B	SSW	0.61	987.	1.7E-06	1.7E-06	1.5E-06	7.7E-09

Table 2.7-4 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Specific Points of Interest

Ground Level Release – No Purge Releases

Release ID	Type of Location	Direction From Site	Distance miles	Distance meters	χ/Q no decay, undepleted (sec/m^3)	χ/Q 2.260 day decay, undepleted (sec/m^3)	χ/Q 8.000 day decay, depleted (sec/m^3)	D/Q (per m^2)
A	Exclusion Area B	SW	0.54	877.	1.8E-06	1.8E-06	1.7E-06	7.7E-09
A	Exclusion Area B	WSW	0.55	881.	1.7E-06	1.7E-06	1.5E-06	6.7E-09
A	Exclusion Area B	W	0.55	888.	2.0E-06	2.0E-06	1.8E-06	7.8E-09
A	Exclusion Area B	WNW	0.64	1034.	1.4E-06	1.4E-06	1.2E-06	5.6E-09
A	Exclusion Area B	NW	0.74	1194.	1.1E-06	1.1E-06	1.0E-06	4.0E-09
A	Exclusion Area B	NNW	0.84	1346.	8.2E-07	8.1E-07	7.2E-07	2.4E-09
A	Exclusion Area B	N	0.92	1477.	1.8E-06	1.8E-06	1.6E-06	5.3E-09
A	Exclusion Area B	NNE	0.97	1558.	2.1E-06	2.1E-06	1.9E-06	7.0E-09
A	Exclusion Area B	NE	0.92	1481.	1.9E-06	1.9E-06	1.6E-06	6.2E-09
A	Exclusion Area B	ENE	0.94	1514.	1.1E-06	1.1E-06	9.7E-07	3.2E-09
A	Exclusion Area B	E	1.06	1708.	1.7E-06	1.7E-06	1.5E-06	3.7E-09
A	Exclusion Area B	ESE	1.00	1617.	2.7E-06	2.6E-06	2.3E-06	5.4E-09
A	Exclusion Area B	SE	0.87	1403.	2.3E-06	2.3E-06	2.0E-06	6.2E-09
A	Exclusion Area B	SSE	0.79	1274.	1.5E-06	1.5E-06	1.3E-06	6.5E-09
A	MEAT ANIMAL	S	0.74	1198.	1.6E-06	1.6E-06	1.4E-06	8.5E-09
A	MEAT ANIMAL	SSW	0.74	1198.	1.3E-06	1.3E-06	1.1E-06	5.6E-09
A	MEAT ANIMAL	SW	0.74	1198.	1.1E-06	1.1E-06	1.0E-06	4.6E-09
A	MEAT ANIMAL	WSW	0.74	1198.	1.1E-06	1.1E-06	9.4E-07	4.0E-09

Table 2.7-4 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Specific Points of Interest

Ground Level Release – No Purge Releases

Release ID	Type of Location	Direction From Site	Distance miles	Distance meters	χ/Q no decay, undepleted (sec/m^3)	χ/Q 2.260 day decay, undepleted (sec/m^3)	χ/Q 8.000 day decay, depleted (sec/m^3)	D/Q (per m^2)
A	MEAT ANIMAL	W	00.74	1198.	1.3E-06	1.3E-06	1.1E-06	4.7E-09
A	MEAT ANIMAL	WNW	0.74	1198.	1.1E-06	1.1E-06	9.9E-07	4.4E-09
A	MEAT ANIMAL	NW	0.74	1198.	1.1E-06	1.1E-06	1.0E-06	3.9E-09
A	MEAT ANIMAL	NNW	0.74	1198.	9.7E-07	9.6E-07	8.6E-07	2.9E-09
A	MEAT ANIMAL	N	0.74	1198.	2.5E-06	2.5E-06	2.2E-06	7.6E-09
A	MEAT ANIMAL	NNE	0.74	1198.	3.1E-06	3.1E-06	2.8E-06	1.1E-08
A	MEAT ANIMAL	NE	0.74	1198.	2.6E-06	2.5E-06	2.3E-06	8.9E-09
A	MEAT ANIMAL	ENE	0.74	1198.	1.5E-06	1.5E-06	1.4E-06	4.8E-09
A	MEAT ANIMAL	E	0.74	1198.	2.9E-06	2.9E-06	2.6E-06	6.7E-09
A	MEAT ANIMAL	ESE	0.74	1198.	4.2E-06	4.1E-06	3.7E-06	9.0E-09
A	MEAT ANIMAL	SE	0.74	1198.	2.9E-06	2.9E-06	2.6E-06	8.0E-09
A	MEAT ANIMAL	SSE	0.74	1198.	1.7E-06	1.7E-06	1.5E-06	7.2E-09
A	VEG. GARDEN	S	0.74	1198.	1.6E-06	1.6E-06	1.4E-06	8.5E-09
A	VEG. GARDEN	SSW	0.74	1198.	1.3E-06	1.3E-06	1.1E-06	5.6E-09
A	VEG. GARDEN	SW	0.74	1198.	1.1E-06	1.1E-06	1.0E-06	4.6E-09
A	VEG. GARDEN	WSW	0.74	1198.	1.1E-06	1.1E-06	9.4E-07	4.0E-09
A	VEG. GARDEN	W	0.74	1198.	1.3E-06	1.3E-06	1.1E-06	4.7E-09
A	VEG. GARDEN	WNW	0.74	1198.	1.1E-06	1.1E-06	9.9E-07	4.4E-09

Table 2.7-4 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Specific Points of Interest

Ground Level Release – No Purge Releases

Release ID	Type of Location	Direction From Site	Distance miles	Distance meters	χ/Q no decay, undepleted (sec/m^3)	χ/Q 2.260 day decay, undepleted (sec/m^3)	χ/Q 8.000 day decay, depleted (sec/m^3)	D/Q (per m^2)
A	VEG. GARDEN	NW	0.74	1198.	1.1E-06	1.1E-06	1.0E-06	3.9E-09
A	VEG. GARDEN	NNW	0.74	1198.	9.7E-07	9.6E-07	8.6E-07	2.9E-09
A	VEG. GARDEN	N	0.74	1198.	2.5E-06	2.5E-06	2.2E-06	7.6E-09
A	VEG. GARDEN	NNE	0.74	1198.	3.1E-06	3.1E-06	2.8E-06	1.1E-08
A	VEG. GARDEN	NE	0.74	1198.	2.6E-06	2.5E-06	2.3E-06	8.9E-09
A	VEG. GARDEN	ENE	0.74	1198.	1.5E-06	1.5E-06	1.4E-06	4.8E-09
A	VEG. GARDEN	E	0.74	1198.	2.9E-06	2.9E-06	2.6E-06	6.7E-09
A	VEG. GARDEN	ESE	0.74	1198.	4.2E-06	4.1E-06	3.7E-06	9.0E-09
A	VEG. GARDEN	SE	0.74	1198.	2.9E-06	2.9E-06	2.6E-06	8.0E-09
A	VEG. GARDEN	SSE	0.74	1198.	1.7E-06	1.7E-06	1.5E-06	7.2E-09

Table 2.7-5 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles No Decay, Undepleted

Ground Level Release - No Purge Releases

	Distance in Miles from the Site										
Sector	**0.250**	**0.500**	**0.750**	**1.000**	**1.500**	**2.000**	**2.500**	**3.000**	**3.500**	**4.000**	**4.500**
S	8.349E-06	2.976E-06	1.595E-06	1.023E-06	5.508E-07	3.558E-07	2.538E-07	1.928E-07	1.529E-07	1.252E-07	1.050E-07
SSW	6.537E-06	2.338E-06	1.261E-06	8.122E-07	4.388E-07	2.841E-07	2.030E-07	1.544E-07	1.226E-07	1.005E-07	8.434E-08
SW	5.863E-06	2.085E-06	1.125E-06	7.259E-07	3.931E-07	2.550E-07	1.825E-07	1.390E-07	1.105E-07	9.067E-08	7.617E-08
WSW	5.511E-06	1.940E-06	1.044E-06	6.739E-07	3.656E-07	2.375E-07	1.702E-07	1.298E-07	1.033E-07	8.482E-08	7.132E-08
W	6.877E-06	2.365E-06	1.265E-06	8.167E-07	4.457E-07	2.913E-07	2.098E-07	1.606E-07	1.282E-07	1.056E-07	8.904E-08
WNW	6.006E-06	2.046E-06	1.097E-06	7.084E-07	3.860E-07	2.519E-07	1.812E-07	1.387E-07	1.107E-07	9.113E-08	7.682E-08
NW	6.009E-06	2.064E-06	1.122E-06	7.288E-07	4.001E-07	2.624E-07	1.895E-07	1.454E-07	1.163E-07	9.597E-08	8.104E-08
NNW	5.110E-06	1.747E-06	9.583E-07	6.266E-07	3.458E-07	2.274E-07	1.645E-07	1.264E-07	1.013E-07	8.362E-08	7.067E-08
N	1.299E-05	4.468E-06	2.462E-06	1.613E-06	8.890E-07	5.834E-07	4.214E-07	3.234E-07	2.588E-07	2.136E-07	1.803E-07
NNE	1.657E-05	5.654E-06	3.098E-06	2.029E-06	1.119E-06	7.350E-07	5.312E-07	4.079E-07	3.265E-07	2.695E-07	2.276E-07
NE	1.352E-05	4.622E-06	2.530E-06	1.656E-06	9.142E-07	6.013E-07	4.350E-07	3.343E-07	2.679E-07	2.212E-07	1.870E-07
ENE	8.502E-06	2.817E-06	1.532E-06	1.007E-06	5.622E-07	3.730E-07	2.717E-07	2.100E-07	1.690E-07	1.401E-07	1.188E-07
E	1.668E-05	5.305E-06	2.852E-06	1.885E-06	1.069E-06	7.183E-07	5.283E-07	4.114E-07	3.333E-07	2.779E-07	2.368E-07
ESE	2.566E-05	7.927E-06	4.114E-06	2.670E-06	1.524E-06	1.038E-06	7.709E-07	6.052E-07	4.936E-07	4.140E-07	3.546E-07
SE	1.818E-05	5.672E-06	2.914E-06	1.868E-06	1.056E-06	7.154E-07	5.298E-07	4.149E-07	3.378E-07	2.828E-07	2.420E-07
SSE	9.287E-06	3.113E-06	1.640E-06	1.051E-06	5.752E-07	3.782E-07	2.737E-07	2.104E-07	1.687E-07	1.394E-07	1.179E-07

Table 2.7-5 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles No Decay, Undepleted

Ground Level Release - No Purge Releases

	Distance in Miles from the Site										
Sector	**5.000**	**7.500**	**10.000**	**15.000**	**20.000**	**25.000**	**30.000**	**35.000**	**40.000**	**45.000**	**50.000**
S	8.977E-08	4.929E-08	3.232E-08	1.794E-08	1.188E-08	8.646E-09	6.678E-09	5.373E-09	4.453E-09	3.776E-09	3.259E-09
SSW	7.215E-08	3.970E-08	2.608E-08	1.450E-08	9.599E-09	6.984E-09	5.393E-09	4.338E-09	3.595E-09	3.047E-09	2.629E-09
SW	6.521E-08	3.601E-08	2.372E-08	1.324E-08	8.788E-09	6.409E-09	4.959E-09	3.995E-09	3.315E-09	2.813E-09	2.430E-09
WSW	6.111E-08	3.386E-08	2.236E-08	1.253E-08	8.344E-09	6.101E-09	4.730E-09	3.818E-09	3.174E-09	2.697E-09	2.333E-09
W	7.648E-08	4.280E-08	2.847E-08	1.613E-08	1.083E-08	7.971E-09	6.213E-09	5.038E-09	4.205E-09	3.587E-09	3.113E-09
WNW	6.599E-08	3.696E-08	2.460E-08	1.396E-08	9.406E-09	6.937E-09	5.417E-09	4.399E-09	3.676E-09	3.139E-09	2.727E-09
NW	6.970E-08	3.920E-08	2.616E-08	1.488E-08	1.002E-08	7.391E-09	5.770E-09	4.684E-09	3.913E-09	3.340E-09	2.900E-09
NNW	6.083E-08	3.431E-08	2.294E-08	1.307E-08	8.809E-09	6.497E-09	5.072E-09	4.118E-09	3.439E-09	2.935E-09	2.548E-09
N	1.551E-07	8.723E-08	5.819E-08	3.307E-08	2.223E-08	1.637E-08	1.276E-08	1.034E-08	8.630E-09	7.358E-09	6.382E-09
NNE	1.958E-07	1.103E-07	7.363E-08	4.190E-08	2.821E-08	2.079E-08	1.622E-08	1.316E-08	1.099E-08	9.374E-09	8.135E-09
NE	1.609E-07	9.075E-08	6.066E-08	3.457E-08	2.329E-08	1.718E-08	1.341E-08	1.089E-08	9.095E-09	7.763E-09	6.739E-09
ENE	1.026E-07	5.856E-08	3.948E-08	2.277E-08	1.547E-08	1.148E-08	9.008E-09	7.345E-09	6.158E-09	5.273E-09	4.592E-09
E	2.053E-07	1.190E-07	8.114E-08	4.750E-08	3.260E-08	2.439E-08	1.926E-08	1.579E-08	1.330E-08	1.144E-08	9.993E-09
ESE	3.089E-07	1.823E-07	1.258E-07	7.493E-08	5.206E-08	3.932E-08	3.130E-08	2.583E-08	2.188E-08	1.891E-08	1.660E-08
SE	2.106E-07	1.239E-07	8.534E-08	5.075E-08	3.524E-08	2.661E-08	2.118E-08	1.748E-08	1.481E-08	1.280E-08	1.124E-08
SSE	1.016E-07	5.751E-08	3.860E-08	2.216E-08	1.504E-08	1.116E-08	8.765E-09	7.150E-09	5.999E-09	5.141E-09	4.480E-09

Table 2.7-5 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles No Decay, Undepleted

Ground Level Release - No Purge Releases

	Segment Boundaries in Miles from the Site									
Direction From Site	**0.5-1**	**1-2**	**2-3**	**3-4**	**4-5**	**5-10**	**10-20**	**20-30**	**30-40**	**40-50**
S	1.648E-06	5.691E-07	2.566E-07	1.538E-07	1.054E-07	5.074E-08	1.844E-08	8.721E-09	5.395E-09	3.785E-09
SSW	1.301E-06	4.530E-07	2.052E-07	1.233E-07	8.461E-08	4.086E-08	1.489E-08	7.045E-09	4.357E-09	3.055E-09
SW	1.161E-06	4.057E-07	1.845E-07	1.111E-07	7.641E-08	3.704E-08	1.359E-08	6.463E-09	4.011E-09	2.820E-09
WSW	1.079E-06	3.772E-07	1.720E-07	1.038E-07	7.154E-08	3.480E-08	1.285E-08	6.151E-09	3.833E-09	2.704E-09
W	1.310E-06	4.595E-07	2.118E-07	1.289E-07	8.930E-08	4.392E-08	1.652E-08	8.030E-09	5.056E-09	3.594E-09
WNW	1.135E-06	3.980E-07	1.830E-07	1.112E-07	7.705E-08	3.792E-08	1.430E-08	6.988E-09	4.415E-09	3.146E-09
NW	1.157E-06	4.120E-07	1.913E-07	1.169E-07	8.126E-08	4.018E-08	1.523E-08	7.444E-09	4.700E-09	3.347E-09
NNW	9.862E-07	3.556E-07	1.660E-07	1.017E-07	7.086E-08	3.515E-08	1.337E-08	6.544E-09	4.132E-09	2.941E-09
N	2.530E-06	9.140E-07	4.254E-07	2.601E-07	1.808E-07	8.941E-08	3.383E-08	1.649E-08	1.038E-08	7.373E-09
NNE	3.191E-06	1.151E-06	5.362E-07	3.280E-07	2.283E-07	1.130E-07	4.287E-08	2.094E-08	1.321E-08	9.393E-09
NE	2.606E-06	9.399E-07	4.391E-07	2.691E-07	1.875E-07	9.297E-08	3.536E-08	1.730E-08	1.093E-08	7.778E-09
ENE	1.584E-06	5.770E-07	2.740E-07	1.697E-07	1.191E-07	5.987E-08	2.324E-08	1.155E-08	7.368E-09	5.283E-09
E	2.967E-06	1.094E-06	5.322E-07	3.345E-07	2.373E-07	1.214E-07	4.835E-08	2.453E-08	1.583E-08	1.145E-08
ESE	4.319E-06	1.563E-06	7.757E-07	4.952E-07	3.553E-07	1.853E-07	7.606E-08	3.951E-08	2.588E-08	1.893E-08
SE	3.062E-06	1.085E-06	5.334E-07	3.389E-07	2.425E-07	1.260E-07	5.154E-08	2.674E-08	1.752E-08	1.282E-08
SSE	1.705E-06	5.933E-07	2.763E-07	1.695E-07	1.182E-07	5.889E-08	2.265E-08	1.124E-08	7.173E-09	5.150E-09

Table 2.7-6 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles 2.260 Day Decay, Undepleted

Ground Level Release - No Purge Releases

	Distance in Miles from the Site										
Sector	**0.250**	**0.500**	**0.750**	**1.000**	**1.500**	**2.000**	**2.500**	**3.000**	**3.500**	**4.000**	**4.500**
S	8.340E-06	2.969E-06	1.590E-06	1.019E-06	5.474E-07	3.529E-07	2.512E-07	1.904E-07	1.507E-07	1.231E-07	1.030E-07
SSW	6.530E-06	2.333E-06	1.257E-06	8.086E-07	4.359E-07	2.816E-07	2.007E-07	1.523E-07	1.207E-07	9.866E-08	8.262E-08
SW	5.856E-06	2.080E-06	1.121E-06	7.224E-07	3.903E-07	2.526E-07	1.804E-07	1.370E-07	1.087E-07	8.892E-08	7.452E-08
WSW	5.504E-06	1.936E-06	1.041E-06	6.705E-07	3.628E-07	2.351E-07	1.681E-07	1.278E-07	1.015E-07	8.308E-08	6.967E-08
W	6.868E-06	2.359E-06	1.260E-06	8.125E-07	4.423E-07	2.883E-07	2.070E-07	1.581E-07	1.259E-07	1.034E-07	8.693E-08
WNW	5.998E-06	2.041E-06	1.093E-06	7.049E-07	3.831E-07	2.494E-07	1.789E-07	1.366E-07	1.087E-07	8.928E-08	7.507E-08
NW	6.001E-06	2.059E-06	1.117E-06	7.252E-07	3.971E-07	2.598E-07	1.871E-07	1.432E-07	1.143E-07	9.404E-08	7.920E-08
NNW	5.103E-06	1.742E-06	9.543E-07	6.231E-07	3.429E-07	2.248E-07	1.622E-07	1.243E-07	9.926E-08	8.173E-08	6.888E-08
N	1.297E-05	4.455E-06	2.452E-06	1.604E-06	8.816E-07	5.770E-07	4.156E-07	3.181E-07	2.538E-07	2.088E-07	1.759E-07
NNE	1.655E-05	5.639E-06	3.086E-06	2.019E-06	1.110E-06	7.273E-07	5.242E-07	4.014E-07	3.205E-07	2.638E-07	2.222E-07
NE	1.350E-05	4.610E-06	2.520E-06	1.647E-06	9.071E-07	5.950E-07	4.294E-07	3.291E-07	2.630E-07	2.166E-07	1.826E-07
ENE	8.490E-06	2.809E-06	1.525E-06	1.001E-06	5.574E-07	3.687E-07	2.678E-07	2.063E-07	1.656E-07	1.369E-07	1.158E-07
E	1.665E-05	5.288E-06	2.839E-06	1.874E-06	1.059E-06	7.094E-07	5.201E-07	4.038E-07	3.261E-07	2.710E-07	2.302E-07
ESE	2.562E-05	7.901E-06	4.094E-06	2.653E-06	1.509E-06	1.024E-06	7.584E-07	5.935E-07	4.825E-07	4.033E-07	3.443E-07
SE	1.815E-05	5.654E-06	2.900E-06	1.857E-06	1.046E-06	7.064E-07	5.213E-07	4.070E-07	3.302E-07	2.756E-07	2.350E-07
SSE	9.275E-06	3.105E-06	1.634E-06	1.045E-06	5.708E-07	3.743E-07	2.701E-07	2.071E-07	1.656E-07	1.364E-07	1.151E-07

Table 2.7-6 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles 2.260 Day Decay, Undepleted

Ground Level Release - No Purge Releases

	Distance in Miles from the Site										
Sector	**5.000**	**7.500**	**10.000**	**15.000**	**20.000**	**25.000**	**30.000**	**35.000**	**40.000**	**45.000**	**50.000**
S	8.787E-08	4.771E-08	3.094E-08	1.680E-08	1.087E-08	7.736E-09	5.842E-09	4.596E-09	3.725E-09	3.089E-09	2.607E-09
SSW	7.050E-08	3.834E-08	2.489E-08	1.351E-08	8.731E-09	6.203E-09	4.677E-09	3.673E-09	2.972E-09	2.460E-09	2.074E-09
SW	6.364E-08	3.471E-08	2.257E-08	1.228E-08	7.951E-09	5.654E-09	4.265E-09	3.351E-09	2.712E-09	2.244E-09	1.891E-09
WSW	5.954E-08	3.256E-08	2.121E-08	1.157E-08	7.502E-09	5.340E-09	4.031E-09	3.168E-09	2.564E-09	2.123E-09	1.788E-09
W	7.446E-08	4.111E-08	2.697E-08	1.486E-08	9.706E-09	6.949E-09	5.269E-09	4.157E-09	3.376E-09	2.802E-09	2.367E-09
WNW	6.431E-08	3.555E-08	2.335E-08	1.291E-08	8.466E-09	6.082E-09	4.626E-09	3.660E-09	2.980E-09	2.479E-09	2.099E-09
NW	6.795E-08	3.772E-08	2.484E-08	1.377E-08	9.036E-09	6.493E-09	4.940E-09	3.908E-09	3.182E-09	2.648E-09	2.242E-09
NNW	5.912E-08	3.287E-08	2.166E-08	1.200E-08	7.858E-09	5.634E-09	4.276E-09	3.375E-09	2.741E-09	2.276E-09	1.922E-09
N	1.508E-07	8.364E-08	5.502E-08	3.040E-08	1.988E-08	1.424E-08	1.080E-08	8.516E-09	6.914E-09	5.737E-09	4.844E-09
NNE	1.907E-07	1.059E-07	6.976E-08	3.863E-08	2.532E-08	1.816E-08	1.380E-08	1.090E-08	8.864E-09	7.367E-09	6.228E-09
NE	1.567E-07	8.721E-08	5.752E-08	3.192E-08	2.094E-08	1.504E-08	1.144E-08	9.046E-09	7.361E-09	6.123E-09	5.181E-09
ENE	9.965E-08	5.604E-08	3.722E-08	2.084E-08	1.375E-08	9.910E-09	7.553E-09	5.983E-09	4.873E-09	4.055E-09	3.432E-09
E	1.990E-07	1.136E-07	7.620E-08	4.324E-08	2.877E-08	2.087E-08	1.598E-08	1.271E-08	1.038E-08	8.662E-09	7.346E-09
ESE	2.989E-07	1.735E-07	1.178E-07	6.789E-08	4.566E-08	3.339E-08	2.573E-08	2.057E-08	1.688E-08	1.413E-08	1.202E-08
SE	2.038E-07	1.179E-07	7.991E-08	4.598E-08	3.091E-08	2.259E-08	1.741E-08	1.391E-08	1.142E-08	9.560E-09	8.134E-09
SSE	9.884E-08	5.519E-08	3.652E-08	2.038E-08	1.344E-08	9.697E-09	7.400E-09	5.869E-09	4.787E-09	3.989E-09	3.381E-09

Table 2.7-6 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles 2.260 Day Decay, Undepleted

Ground Level Release - No Purge Releases

	Segment Boundaries in Miles from the Site									
Direction From Site	**0.5-1**	**1-2**	**2-3**	**3-4**	**4-5**	**5-10**	**10-20**	**20-30**	**30-40**	**40-50**
S	1.643E-06	5.658E-07	2.540E-07	1.515E-07	1.034E-07	4.918E-08	1.731E-08	7.815E-09	4.620E-09	3.099E-09
SSW	1.297E-06	4.501E-07	2.029E-07	1.213E-07	8.288E-08	3.951E-08	1.391E-08	6.267E-09	3.693E-09	2.469E-09
SW	1.157E-06	4.029E-07	1.823E-07	1.092E-07	7.476E-08	3.574E-08	1.264E-08	5.711E-09	3.368E-09	2.252E-09
WSW	1.075E-06	3.744E-07	1.699E-07	1.020E-07	6.989E-08	3.351E-08	1.190E-08	5.393E-09	3.185E-09	2.130E-09
W	1.305E-06	4.561E-07	2.091E-07	1.265E-07	8.719E-08	4.224E-08	1.526E-08	7.012E-09	4.177E-09	2.811E-09
WNW	1.131E-06	3.952E-07	1.808E-07	1.093E-07	7.530E-08	3.652E-08	1.325E-08	6.135E-09	3.677E-09	2.487E-09
NW	1.152E-06	4.090E-07	1.889E-07	1.148E-07	7.943E-08	3.871E-08	1.413E-08	6.550E-09	3.926E-09	2.656E-09
NNW	9.822E-07	3.527E-07	1.637E-07	9.973E-08	6.907E-08	3.372E-08	1.231E-08	5.684E-09	3.391E-09	2.283E-09
N	2.520E-06	9.067E-07	4.196E-07	2.551E-07	1.764E-07	8.585E-08	3.120E-08	1.437E-08	8.557E-09	5.755E-09
NNE	3.179E-06	1.142E-06	5.292E-07	3.220E-07	2.228E-07	1.087E-07	3.963E-08	1.832E-08	1.095E-08	7.389E-09
NE	2.597E-06	9.328E-07	4.335E-07	2.642E-07	1.831E-07	8.946E-08	3.273E-08	1.517E-08	9.088E-09	6.141E-09
ENE	1.578E-06	5.722E-07	2.701E-07	1.663E-07	1.160E-07	5.737E-08	2.133E-08	9.991E-09	6.009E-09	4.067E-09
E	2.954E-06	1.085E-06	5.241E-07	3.273E-07	2.307E-07	1.159E-07	4.413E-08	2.102E-08	1.276E-08	8.685E-09
ESE	4.300E-06	1.548E-06	7.634E-07	4.840E-07	3.450E-07	1.766E-07	6.909E-08	3.360E-08	2.064E-08	1.416E-08
SE	3.048E-06	1.075E-06	5.249E-07	3.313E-07	2.355E-07	1.201E-07	4.682E-08	2.274E-08	1.396E-08	9.582E-09
SSE	1.699E-06	5.889E-07	2.727E-07	1.663E-07	1.154E-07	5.659E-08	2.088E-08	9.777E-09	5.894E-09	4.001E-09

Table 2.7-7 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles 8.000 Day Decay, Depleted

Ground Level Release - No Purge Releases

	Distance in Miles from the Site										
Sector	**0.250**	**0.500**	**0.750**	**1.000**	**1.500**	**2.000**	**2.500**	**3.000**	**3.500**	**4.000**	**4.500**
S	7.899E-06	2.716E-06	1.420E-06	8.947E-07	4.669E-07	2.939E-07	2.050E-07	1.526E-07	1.188E-07	9.566E-08	7.897E-08
SSW	6.185E-06	2.134E-06	1.122E-06	7.101E-07	3.720E-07	2.347E-07	1.639E-07	1.222E-07	9.526E-08	7.674E-08	6.340E-08
SW	5.547E-06	1.902E-06	1.002E-06	6.345E-07	3.332E-07	2.106E-07	1.474E-07	1.100E-07	8.583E-08	6.922E-08	5.723E-08
WSW	5.214E-06	1.771E-06	9.297E-07	5.891E-07	3.098E-07	1.961E-07	1.374E-07	1.027E-07	8.020E-08	6.473E-08	5.357E-08
W	6.506E-06	2.158E-06	1.126E-06	7.138E-07	3.777E-07	2.405E-07	1.693E-07	1.270E-07	9.954E-08	8.058E-08	6.686E-08
WNW	5.682E-06	1.867E-06	9.770E-07	6.193E-07	3.271E-07	2.080E-07	1.463E-07	1.097E-07	8.593E-08	6.955E-08	5.770E-08
NW	5.685E-06	1.884E-06	9.984E-07	6.371E-07	3.391E-07	2.167E-07	1.529E-07	1.150E-07	9.032E-08	7.325E-08	6.088E-08
NNW	4.835E-06	1.594E-06	8.530E-07	5.476E-07	2.930E-07	1.877E-07	1.327E-07	9.991E-08	7.856E-08	6.378E-08	5.304E-08
N	1.229E-05	4.077E-06	2.192E-06	1.410E-06	7.532E-07	4.816E-07	3.400E-07	2.557E-07	2.009E-07	1.629E-07	1.354E-07
NNE	1.568E-05	5.159E-06	2.758E-06	1.774E-06	9.485E-07	6.068E-07	4.287E-07	3.225E-07	2.534E-07	2.056E-07	1.709E-07
NE	1.279E-05	4.218E-06	2.252E-06	1.447E-06	7.747E-07	4.964E-07	3.511E-07	2.644E-07	2.079E-07	1.688E-07	1.404E-07
ENE	8.043E-06	2.570E-06	1.363E-06	8.802E-07	4.763E-07	3.079E-07	2.192E-07	1.660E-07	1.311E-07	1.068E-07	8.918E-08
E	1.578E-05	4.840E-06	2.539E-06	1.647E-06	9.054E-07	5.927E-07	4.260E-07	3.251E-07	2.584E-07	2.118E-07	1.776E-07
ESE	2.428E-05	7.232E-06	3.661E-06	2.333E-06	1.291E-06	8.561E-07	6.216E-07	4.781E-07	3.827E-07	3.154E-07	2.659E-07
SE	1.720E-05	5.175E-06	2.593E-06	1.633E-06	8.942E-07	5.903E-07	4.272E-07	3.278E-07	2.619E-07	2.155E-07	1.814E-07
SSE	8.786E-06	2.841E-06	1.460E-06	9.185E-07	4.874E-07	3.122E-07	2.209E-07	1.664E-07	1.309E-07	1.064E-07	8.852E-08

Table 2.7-7 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles 8.000 Day Decay, Depleted

Ground Level Release - No Purge Releases

	Distance in Miles from the Site										
Sector	**5.000**	**7.500**	**10.000**	**15.000**	**20.000**	**25.000**	**30.000**	**35.000**	**40.000**	**45.000**	**50.000**
S	6.651E-08	3.443E-08	2.145E-08	1.095E-08	6.764E-09	4.634E-09	3.389E-09	2.593E-09	2.050E-09	1.663E-09	1.376E-09
SSW	5.343E-08	2.771E-08	1.729E-08	8.835E-09	5.456E-09	3.735E-09	2.730E-09	2.087E-09	1.650E-09	1.337E-09	1.106E-09
SW	4.828E-08	2.512E-08	1.571E-08	8.057E-09	4.988E-09	3.421E-09	2.504E-09	1.917E-09	1.517E-09	1.230E-09	1.018E-09
WSW	4.522E-08	2.361E-08	1.480E-08	7.614E-09	4.727E-09	3.249E-09	2.383E-09	1.827E-09	1.447E-09	1.175E-09	9.732E-10
W	5.658E-08	2.983E-08	1.883E-08	9.796E-09	6.130E-09	4.240E-09	3.125E-09	2.406E-09	1.913E-09	1.559E-09	1.295E-09
WNW	4.883E-08	2.577E-08	1.629E-08	8.491E-09	5.330E-09	3.696E-09	2.730E-09	2.106E-09	1.677E-09	1.369E-09	1.139E-09
NW	5.158E-08	2.733E-08	1.732E-08	9.051E-09	5.682E-09	3.940E-09	2.910E-09	2.244E-09	1.787E-09	1.458E-09	1.212E-09
NNW	4.498E-08	2.389E-08	1.516E-08	7.933E-09	4.979E-09	3.451E-09	2.547E-09	1.963E-09	1.562E-09	1.274E-09	1.058E-09
N	1.147E-07	6.077E-08	3.848E-08	2.008E-08	1.258E-08	8.703E-09	6.415E-09	4.939E-09	3.926E-09	3.198E-09	2.655E-09
NNE	1.449E-07	7.685E-08	4.871E-08	2.546E-08	1.597E-08	1.107E-08	8.167E-09	6.294E-09	5.008E-09	4.082E-09	3.393E-09
NE	1.191E-07	6.325E-08	4.014E-08	2.101E-08	1.320E-08	9.151E-09	6.758E-09	5.211E-09	4.149E-09	3.384E-09	2.813E-09
ENE	7.585E-08	4.077E-08	2.608E-08	1.381E-08	8.733E-09	6.090E-09	4.516E-09	3.495E-09	2.791E-09	2.282E-09	1.901E-09
E	1.517E-07	8.281E-08	5.355E-08	2.876E-08	1.837E-08	1.291E-08	9.628E-09	7.488E-09	6.004E-09	4.927E-09	4.118E-09
ESE	2.281E-07	1.267E-07	8.293E-08	4.530E-08	2.928E-08	2.076E-08	1.560E-08	1.221E-08	9.839E-09	8.111E-09	6.808E-09
SE	1.555E-07	8.612E-08	5.627E-08	3.068E-08	1.982E-08	1.405E-08	1.056E-08	8.261E-09	6.659E-09	5.490E-09	4.608E-09
SSE	7.512E-08	4.007E-08	2.552E-08	1.345E-08	8.506E-09	5.932E-09	4.402E-09	3.409E-09	2.724E-09	2.229E-09	1.859E-09

Table 2.7-7 Long-Term Average χ/Q (sec/m^3) for Routine Releases at Distances Between 0.25 to 50 Miles 8.000 Day Decay, Depleted

Ground Level Release - No Purge Releases

	Segment Boundaries in Miles from the Site									
Direction From Site	**0.5-1**	**1-2**	**2-3**	**3-4**	**4-5**	**5-10**	**10-20**	**20-30**	**30-40**	**40-50**
S	1.474E-06	4.851E-07	2.078E-07	1.197E-07	7.930E-08	3.579E-08	1.142E-08	4.704E-09	2.613E-09	1.671E-09
SSW	1.164E-06	3.861E-07	1.661E-07	9.590E-08	6.366E-08	2.879E-08	9.212E-09	3.792E-09	2.104E-09	1.344E-09
SW	1.039E-06	3.457E-07	1.493E-07	8.640E-08	5.747E-08	2.608E-08	8.394E-09	3.472E-09	1.932E-09	1.237E-09
WSW	9.652E-07	3.213E-07	1.392E-07	8.073E-08	5.378E-08	2.449E-08	7.927E-09	3.297E-09	1.841E-09	1.181E-09
W	1.172E-06	3.914E-07	1.714E-07	1.002E-07	6.712E-08	3.089E-08	1.018E-08	4.298E-09	2.424E-09	1.566E-09
WNW	1.016E-06	3.391E-07	1.481E-07	8.647E-08	5.793E-08	2.668E-08	8.818E-09	3.746E-09	2.121E-09	1.375E-09
NW	1.035E-06	3.509E-07	1.548E-07	9.087E-08	6.110E-08	2.827E-08	9.391E-09	3.993E-09	2.260E-09	1.465E-09
NNW	8.820E-07	3.028E-07	1.342E-07	7.903E-08	5.324E-08	2.470E-08	8.226E-09	3.497E-09	1.977E-09	1.279E-09
N	2.263E-06	7.783E-07	3.440E-07	2.021E-07	1.359E-07	6.285E-08	2.083E-08	8.820E-09	4.975E-09	3.213E-09
NNE	2.854E-06	9.800E-07	4.337E-07	2.550E-07	1.716E-07	7.946E-08	2.641E-08	1.122E-08	6.339E-09	4.101E-09
NE	2.331E-06	8.004E-07	3.552E-07	2.092E-07	1.409E-07	6.538E-08	2.179E-08	9.272E-09	5.248E-09	3.399E-09
ENE	1.417E-06	4.912E-07	2.215E-07	1.318E-07	8.948E-08	4.204E-08	1.428E-08	6.165E-09	3.519E-09	2.292E-09
E	2.654E-06	9.313E-07	4.301E-07	2.597E-07	1.781E-07	8.511E-08	2.965E-08	1.305E-08	7.534E-09	4.946E-09
ESE	3.864E-06	1.329E-06	6.267E-07	3.843E-07	2.666E-07	1.298E-07	4.654E-08	2.097E-08	1.227E-08	8.140E-09
SE	2.740E-06	9.232E-07	4.309E-07	2.631E-07	1.819E-07	8.828E-08	3.154E-08	1.419E-08	8.307E-09	5.510E-09
SSE	1.526E-06	5.054E-07	2.235E-07	1.317E-07	8.884E-08	4.140E-08	1.394E-08	6.007E-09	3.432E-09	2.239E-09

Table 2.7-8 Long-Term Average D/Q ($1/m^2$) for Routine Releases at Distances Between 0.25 to 50 Miles

Ground Level Release - No Purge Releases
Relative Deposition Per Unit Area ($1/m^2$) At Fixed Points By Downwind Sectors
Distances In Miles

Direction From Site	0.25	0.50	0.75	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50
S	4.819E-08	1.630E-08	8.367E-09	5.138E-09	2.561E-09	1.553E-09	1.050E-09	7.611E-10	5.787E-10	4.559E-10	3.691E-10
SSW	3.194E-08	1.080E-08	5.546E-09	3.405E-09	1.698E-09	1.030E-09	6.961E-10	5.045E-10	3.836E-10	3.022E-10	2.446E-10
SW	2.633E-08	8.902E-09	4.571E-09	2.807E-09	1.399E-09	8.486E-10	5.738E-10	4.158E-10	3.161E-10	2.491E-10	2.016E-10
WSW	2.286E-08	7.732E-09	3.970E-09	2.438E-09	1.215E-09	7.371E-10	4.983E-10	3.611E-10	2.746E-10	2.163E-10	1.751E-10
W	2.691E-08	9.101E-09	4.673E-09	2.869E-09	1.430E-09	8.676E-10	5.866E-10	4.251E-10	3.232E-10	2.546E-10	2.061E-10
WNW	2.495E-08	8.438E-09	4.333E-09	2.660E-09	1.326E-09	8.044E-10	5.439E-10	3.941E-10	2.997E-10	2.361E-10	1.911E-10
NW	2.242E-08	7.583E-09	3.893E-09	2.391E-09	1.192E-09	7.229E-10	4.887E-10	3.542E-10	2.693E-10	2.122E-10	1.718E-10
NNW	1.628E-08	5.504E-09	2.826E-09	1.735E-09	8.652E-10	5.247E-10	3.548E-10	2.571E-10	1.955E-10	1.540E-10	1.247E-10
N	4.309E-08	1.457E-08	7.481E-09	4.594E-09	2.290E-09	1.389E-09	9.391E-10	6.805E-10	5.175E-10	4.077E-10	3.300E-10
NNE	6.257E-08	2.116E-08	1.086E-08	6.671E-09	3.326E-09	2.017E-09	1.364E-09	9.882E-10	7.514E-10	5.920E-10	4.793E-10
NE	5.046E-08	1.706E-08	8.761E-09	5.379E-09	2.682E-09	1.627E-09	1.100E-09	7.969E-10	6.059E-10	4.774E-10	3.865E-10
ENE	2.720E-08	9.199E-09	4.723E-09	2.900E-09	1.446E-09	8.769E-10	5.929E-10	4.296E-10	3.267E-10	2.574E-10	2.084E-10
E	3.824E-08	1.293E-08	6.640E-09	4.077E-09	2.033E-09	1.233E-09	8.335E-10	6.040E-10	4.593E-10	3.618E-10	2.929E-10
ESE	5.097E-08	1.724E-08	8.849E-09	5.434E-09	2.709E-09	1.643E-09	1.111E-09	8.050E-10	6.121E-10	4.822E-10	3.904E-10
SE	4.574E-08	1.547E-08	7.942E-09	4.877E-09	2.431E-09	1.475E-09	9.970E-10	7.225E-10	5.493E-10	4.328E-10	3.504E-10
SSE	4.085E-08	1.381E-08	7.092E-09	4.355E-09	2.171E-09	1.317E-09	8.902E-10	6.451E-10	4.905E-10	3.865E-10	3.129E-10

Table 2.7-8 Long-Term Average D/Q (1/m^2) for Routine Releases at Distances Between 0.25 to 50 Miles

Ground Level Release - No Purge Releases
Relative Deposition Per Unit Area (1/m^2) At Fixed Points By Downwind Sectors
Distances In Miles

DIRECTION FROM SITE	5.00	7.50	10.00	15.00	20.00	25.00	30.00	35.00	40.00	45.00	50.00
S	3.053E-10	1.496E-10	9.388E-11	4.745E-11	2.872E-11	1.926E-11	1.380E-11	1.036E-11	8.056E-12	6.435E-12	5.252E-12
SSW	2.024E-10	9.917E-11	6.222E-11	3.145E-11	1.904E-11	1.276E-11	9.145E-12	6.867E-12	5.339E-12	4.265E-12	3.481E-12
SW	1.668E-10	8.174E-11	5.129E-11	2.592E-11	1.569E-11	1.052E-11	7.538E-12	5.660E-12	4.401E-12	3.515E-12	2.869E-12
WSW	1.449E-10	7.099E-11	4.454E-11	2.251E-11	1.363E-11	9.136E-12	6.547E-12	4.916E-12	3.822E-12	3.053E-12	2.492E-12
W	1.705E-10	8.356E-11	5.243E-11	2.650E-11	1.604E-11	1.075E-11	7.706E-12	5.786E-12	4.499E-12	3.594E-12	2.933E-12
WNW	1.581E-10	7.748E-11	4.861E-11	2.457E-11	1.487E-11	9.971E-12	7.145E-12	5.365E-12	4.171E-12	3.332E-12	2.720E-12
NW	1.421E-10	6.962E-11	4.369E-11	2.208E-11	1.336E-11	8.961E-12	6.421E-12	4.821E-12	3.749E-12	2.994E-12	2.444E-12
NNW	1.031E-10	5.054E-11	3.171E-11	1.603E-11	9.701E-12	6.504E-12	4.661E-12	3.500E-12	2.721E-12	2.174E-12	1.774E-12
N	2.730E-10	1.338E-10	8.394E-11	4.243E-11	2.568E-11	1.722E-11	1.234E-11	9.264E-12	7.203E-12	5.754E-12	4.697E-12
NNE	3.964E-10	1.943E-10	1.219E-10	6.161E-11	3.729E-11	2.500E-11	1.792E-11	1.345E-11	1.046E-11	8.355E-12	6.820E-12
NE	3.197E-10	1.567E-10	9.830E-11	4.968E-11	3.007E-11	2.016E-11	1.445E-11	1.085E-11	8.435E-12	6.738E-12	5.500E-12
ENE	1.724E-10	8.446E-11	5.300E-11	2.679E-11	1.621E-11	1.087E-11	7.789E-12	5.849E-12	4.548E-12	3.633E-12	2.965E-12
E	2.423E-10	1.187E-10	7.451E-11	3.766E-11	2.279E-11	1.528E-11	1.095E-11	8.223E-12	6.393E-12	5.107E-12	4.168E-12
ESE	3.229E-10	1.583E-10	9.929E-11	5.019E-11	3.038E-11	2.037E-11	1.459E-11	1.096E-11	8.520E-12	6.806E-12	5.555E-12
SE	2.898E-10	1.420E-10	8.912E-11	4.504E-11	2.726E-11	1.828E-11	1.310E-11	9.835E-12	7.647E-12	6.108E-12	4.986E-12
SSE	2.588E-10	1.268E-10	7.957E-11	4.022E-11	2.434E-11	1.632E-11	1.170E-11	8.782E-12	6.828E-12	5.454E-12	4.452E-12

Table 2.7-8 Long-Term Average D/Q ($1/m^2$) for Routine Releases at Distances Between 0.25 to 50 Miles

Ground Level Release - No Purge Release
Relative Deposition Per Unit Area ($1/m^2$) By Downwind Sectors
Segment Boundaries In Miles

Direction From Site	0.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	8.694E-09	2.686E-09	1.069E-09	5.841E-10	3.712E-10	1.594E-10	4.944E-11	1.960E-11	1.046E-11	6.477E-12
SSW	5.762E-09	1.780E-09	7.084E-10	3.871E-10	2.460E-10	1.057E-10	3.277E-11	1.299E-11	6.936E-12	4.293E-12
SW	4.749E-09	1.467E-09	5.839E-10	3.191E-10	2.028E-10	8.710E-11	2.701E-11	1.071E-11	5.717E-12	3.538E-12
WSW	4.125E-09	1.274E-09	5.071E-10	2.771E-10	1.761E-10	7.565E-11	2.346E-11	9.298E-12	4.965E-12	3.073E-12
W	4.855E-09	1.500E-09	5.969E-10	3.262E-10	2.073E-10	8.905E-11	2.761E-11	1.094E-11	5.844E-12	3.617E-12
WNW	4.502E-09	1.391E-09	5.534E-10	3.024E-10	1.922E-10	8.256E-11	2.560E-11	1.015E-11	5.419E-12	3.354E-12
NW	4.045E-09	1.250E-09	4.973E-10	2.718E-10	1.727E-10	7.420E-11	2.301E-11	9.119E-12	4.870E-12	3.014E-12
NNW	2.937E-09	9.072E-10	3.610E-10	1.973E-10	1.254E-10	5.386E-11	1.670E-11	6.619E-12	3.535E-12	2.188E-12
N	7.773E-09	2.402E-09	9.557E-10	5.222E-10	3.319E-10	1.426E-10	4.421E-11	1.752E-11	9.357E-12	5.792E-12
NNE	1.129E-08	3.487E-09	1.388E-09	7.583E-10	4.820E-10	2.070E-10	6.420E-11	2.544E-11	1.359E-11	8.410E-12
NE	9.103E-09	2.812E-09	1.119E-09	6.115E-10	3.887E-10	1.669E-10	5.177E-11	2.052E-11	1.096E-11	6.782E-12
ENE	4.908E-09	1.516E-09	6.033E-10	3.297E-10	2.095E-10	9.001E-11	2.791E-11	1.106E-11	5.907E-12	3.656E-12
E	6.899E-09	2.132E-09	8.482E-10	4.635E-10	2.946E-10	1.265E-10	3.924E-11	1.555E-11	8.305E-12	5.140E-12
ESE	9.195E-09	2.841E-09	1.130E-09	6.177E-10	3.926E-10	1.686E-10	5.230E-11	2.073E-11	1.107E-11	6.851E-12
SE	8.252E-09	2.550E-09	1.015E-09	5.544E-10	3.524E-10	1.514E-10	4.693E-11	1.860E-11	9.934E-12	6.149E-12
SSE	7.369E-09	2.277E-09	9.059E-10	4.950E-10	3.146E-10	1.351E-10	4.191E-11	1.661E-11	8.870E-12	5.490E-12

2.8 Related Federal Project Activities

The information for this section is provided in ESP-ER Section 2.8 and in FEIS Section 2.11.

No new and significant information has been identified for this section. Dominion has identified no past, present, or reasonably foreseeable Federal or non-Federal action that would result in new and significant cumulative impacts.

Chapter 3 Plant Description

Per 10 CFR 51.50(c)(1)(i), an application at the Combined License Stage, referencing an early site permit, must contain "information to demonstrate that the design of the facility falls within the site characteristics and design parameters specified in the early site permit."

ESP-ER Table 3.1-9 identifies the bounding site characteristics and design parameter values for assessing the environmental impacts of constructing and operating nuclear power plants at the North Anna ESP site. These site characteristic and design parameter values were used by the NRC in its independent evaluation of impacts and, in some cases, the NRC substituted values based on its own analysis. FEIS Table I-1 presents the ESP site characteristic values used by the NRC. FEIS Table I-2 presents the ESP design parameter values used by the NRC.

In accordance with 10 CFR 51.50(c)(1)(i) and FEIS Table J-1 (Rows 1 and 2), Table 3.0-1 and Table 3.0-2 provide an evaluation of the design of the Unit 3 ESBWR facility to determine if it falls within the ESP site characteristic and design parameter values specified in the FEIS:

- Table 3.0-1 evaluates site characteristics. For each site characteristic listed in FEIS Table I-1, Table 3.0-1 identifies the ESP site characteristic value, the corresponding Unit 3 value, and provides an evaluation of whether the Unit 3 site characteristic value falls within the FEIS site characteristic value. Evaluations are included to provide clarification or additional information where needed, or to provide reference to other sections where further evaluation is provided. The environmental impacts documented in the FEIS, based on the site characteristic values in FEIS Table I-1, are considered bounding, and therefore resolved, when the ESP site characteristic value bounds the Unit 3 site characteristic value.
- Table 3.0-2 evaluates design parameters. For each design parameter listed in FEIS Table I-2, Table 3.0-2 identifies the ESP design parameter value, the corresponding Unit 3 design characteristic value, and provides an evaluation of whether the Unit 3 design characteristic value falls within the FEIS design parameter value. Evaluations are included to provide clarification or additional information where needed, or to provide reference to other sections where further evaluation is provided. The environmental impacts documented in the FEIS, based on the design parameter values in FEIS Table I-2, are considered bounding, and therefore resolved, when the ESP design parameter value bounds the Unit 3 design characteristic value.

10 CFR 51.50(c)(1) also requires that this ER address environmental issues that were not resolved in the ESP proceeding, or that are affected by new and significant information. This chapter provides additional plant description to the extent necessary to support these supplemental analyses.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Atmospheric Dispersion (χ/Q) (Design Basis Accident)		Time-dependent values as listed in FEIS Table 5-14		
Exclusion Area Boundary (EAB)	3.34×10^{-5} sec/m^3	0 to 2 hr interval	3.34×10^{-5} sec/m^3	The Unit 3 site characteristic value for the 0–2 hr short term (accident release) atmospheric dispersion factor, χ/Q, at the EAB is taken from ESP-ER Table 3.1-9 and FEIS Table 5-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. Note that although the EAB location yielding the highest atmospheric dispersion factors was determined by GIS measurement to be 1609 m (1.0 mi) ESE, the ESP-ER and FEIS distance of 1416 m (0.88 mi) ESE is conservative and was used. See Section 7.1 for the analysis of radiological consequences of accident airborne releases.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Atmospheric Dispersion (χ/Q) (Design Basis Accident) (continued)				
Low Population Zone (LPZ)	2.17×10^{-6} sec/m^3	0 to 8 hr interval	2.17×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 0–8 hr short term (accident release) atmospheric dispersion factor, χ/Q, at the LPZ is taken from FEIS Table 5-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. See Section 7.1 for the analysis of radiological consequences of accident airborne releases.
	1.5×10^{-6} sec/m^3	8 to 24 hr interval	1.5×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 8-24 hr short term (accident release) atmospheric dispersion factor, χ/Q, at the LPZ is taken from FEIS Table 5-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. See Section 7.1 for the analysis of radiological consequences of accident airborne releases.
	1.2×10^{-6} sec/m^3	1 to 4 day interval	1.2×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 1-4 day short term (accident release) atmospheric dispersion factor, χ/Q, at the LPZ is taken from FEIS Table 5-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. See Section 7.1 for the analysis of radiological consequences of accident airborne releases.
	9.0×10^{-7} sec/m^3	4 to 30 day interval	9.0×10^{-7} sec/m^3	The Unit 3 site characteristic value for the 4-30 day short term (accident release) atmospheric dispersion factor, χ/Q, at the LPZ is taken from FEIS Table 5-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. See Section 7.1 for the analysis of radiological consequences of accident airborne releases.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Gaseous Effluents Dispersion, Deposition (Annual Average)				
Atmospheric Dispersion (χ/Q)	χ/Q values presented in ESP-ER Table 2.7-14	The atmospheric dispersion coefficients used to estimate dose consequences of normal airborne releases.		
Residence	2.4×10^{-6} sec/m^3	No decay	4.2×10^{-6} sec/m^3	The Unit 3 site characteristic value for the no-decay long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest residence is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1a].
	2.4×10^{-6} sec/m^3	2.26-day decay	4.1×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 2.26-day decay long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest residence is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1b].
	2.1×10^{-6} sec/m^3	8-day decay	3.7×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 8-day decay long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest residence is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1c].

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Gaseous Effluents Dispersion, Deposition (Annual Average) (continued)				
EAB	3.7×10^{-6} sec/m^3	No decay	3.7×10^{-6} sec/m^3	The Unit 3 site characteristic value for the no-decay long term (annual average) atmospheric dispersion factor, χ/Q, for the EAB is taken from ESP-ER Table 2.7-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. As noted previously in this table, the ESP-ER and FEIS distance of 1,416 meters (0.88 mile) ESE is conservative and used. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
	3.7×10^{-6} sec/m^3	2.26-day decay	3.7×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 2.26-decay long term (annual average) atmospheric dispersion factor, χ/Q, for the EAB is taken from ESP-ER Table 2.7-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. As noted previously in this table, the ESP-ER and FEIS distance of 1,416 meters (0.88 mile) ESE is conservative and used. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
	3.3×10^{-6} sec/m^3	8-day decay	3.3×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 8-day decay long term (annual average) atmospheric dispersion factor, χ/Q, for the EAB is taken from ESP-ER Table 2.7-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. As noted previously in this table, the ESP-ER and FEIS distance of 1,416 meters (0.88 mile) ESE is conservative and used. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Gaseous Effluents Dispersion, Deposition (Annual Average) (continued)				
Meat animal	1.4×10^{-6} sec/m^3	No decay	4.2×10^{-6} sec/m^3	The Unit 3 site characteristic value for the no-decay long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest meat animal is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1h].
	1.4×10^{-6} sec/m^3	2.26-day decay	4.1×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 2.26-day decay long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest meat animal is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1i].
	1.2×10^{-6} sec/m^3	8-day decay	3.7×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 8-day decay long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest meat animal is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1j].

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Gaseous Effluents Dispersion, Deposition (Annual Average) (continued)				
Vegetable garden	2.0×10^{-6} sec/m^3	No decay	4.2×10^{-6} sec/m^3	The Unit 3 site characteristic value for the no-decay long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest vegetable garden is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1l].
	2.0×10^{-6} sec/m^3	2.26-day decay	4.1×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 2.26-day decay long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest vegetable garden is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1m].
	1.8×10^{-6} sec/m^3	8-day decay	3.7×10^{-6} sec/m^3	The Unit 3 site characteristic value for the 8-day decay long-term (annual average) atmospheric dispersion factor, χ/Q, for the nearest vegetable garden is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1n].
Ground Deposition (D/Q)	D/Q values presented in ESP-ER Table 2.7-14	The ground deposition coefficients used to estimate dose consequences of normal airborne releases		

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	ESP Site Characteristics (From FEIS Table I-1): Description and References	Unit 3 Site Characteristic Value	Evaluation
Gaseous Effluents Dispersion, Deposition (Annual Average) (continued)				
Residence	7.2×10^{-9} /m^2		9.0×10^{-9} /m^2	The Unit 3 site characteristic value for the long-term (annual average) ground deposition factor, D/Q, for the nearest residence is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1d].
EAB	1.2×10^{-8} /m^2		1.2×10^{-8} /m^2	The Unit 3 site characteristic value for the long-term (annual average) ground deposition factor, D/Q, for the EAB is taken from ESP-ER Table 2.7-14. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1. As noted previously in this table, the ESP-ER and FEIS distance of 1,416 meters (0.88 mile) ESE is conservative and used. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.
Meat animal	3.1×10^{-9} /m^2		9.0×10^{-9} /m^2	The Unit 3 site characteristic value for the long-term (annual average) ground deposition factor, D/Q, for the nearest meat animal is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1k].
Vegetable garden	6.0×10^{-9} /m^2		9.0×10^{-9} /m^2	The Unit 3 site characteristic value for the long-term (annual average) ground deposition factor, D/Q, for the nearest vegetable garden is provided in Table 2.7-2. The Unit 3 site characteristic value does not fall within (is not equal to or less than) the ESP value identified in FEIS Table I-1. See Section 5.4 for the analysis of radiological consequences of routine airborne releases. See also FSAR Section 1.8 and FSAR Table 2.0-201 for NAPS ESP [VAR 2.0-1o].

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	ESP Site Characteristics (From FEIS Table I-1): Description and References	Unit 3 Site Characteristic Value	Evaluation
Dose Consequences				
Normal	10 CFR 20; 10 CFR 50, Appendix I, Dose Objectives; and 40 CFR 190 dose limits	Radiological dose consequences due to gaseous and liquid releases from normal operation of the plant	10 CFR 20; 10 CFR 50, Appendix I, Dose Objectives; and 40 CFR 190 dose limits	
Liquid effluent	1.6 mrem/yr	Total body (Value for two units, see ESP-ER Table 5.4-11)	0.094 mrem/yr	The Unit 3 site characteristic value is the total body dose to the Maximally Exposed Individual (MEI) from Unit 3 liquid effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Tables 12.2-20bR and 12.2-202.
	1.4 mrem/yr	Thyroid (Value for two units, see ESP-ER Table 5.4-11)	0.18 mrem/yr	The Unit 3 site characteristic value is the thyroid dose to the MEI from Unit 3 liquid effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See FSAR Table 12.2-20bR.
	5.0 mrem/yr	Other organ/bone (Value for two units, see ESP-ER Table 5.4-11)	1.3 mrem/yr	The Unit 3 site characteristic value is the other organ/bone dose to the MEI from Unit 3 liquid effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Tables 12.2-20bR and 12.2-202.

Table 3.0-1 Evaluation of ESP Site Characteristics

	ESP Site Characteristics (From FEIS Table I-1)			
Item	**ESP Value**	**Description and References**	**Unit 3 Site Characteristic Value**	**Evaluation**
Dose Consequences (continued)				
Gaseous effluent	4.8 mrem/yr	Total body (Value for two units, see ESP-ER Table 5.4-11)	1.6 mrem/yr	The Unit 3 site characteristic value is the highest total body dose to the MEI from Unit 3 gaseous effluents as shown in Tables 5.4-4, 5.4-5 and 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Tables 12.2-18bR and 12.2-201.
	25 mrem/yr	Thyroid (Value for two units, see ESP-ER Table 5.4-11)	15 mrem/yr	The Unit 3 site characteristic value is the highest thyroid dose to the MEI from Unit 3 gaseous effluents as shown in Tables 5.4-4 and 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units and is well below the 40 CFR 190 limit. See also FSAR Section 1.8 and FSAR Table 12.2-18bR for NAPS ESP [VAR 12.2-1].
	6.5 mrem/yr	Other organ/bone (Value for two units, see ESP-ER Table 5.4-11)	4.6 mrem/yr	The Unit 3 site characteristic value is the highest other organ/bone dose to the MEI from Unit 3 gaseous effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Table 2.0-203.
	6.2 mrem/yr	Skin (Value for one unit, see ESP-ER Table 5.4-10)	4.0 mrem/yr	The Unit 3 site characteristic value is the highest skin dose to the MEI from Unit 3 gaseous effluents as shown in Tables 5.4-4 and 5.4-5. It represents the summation of plume, ground, and inhalation doses. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1. See also FSAR Table 2.0-201.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Dose Consequences (continued)				
Total	6.4 mrem/yr	Total body (Value for two units, see ESP-ER Table 5.4-11)	1.7 mrem/yr	The Unit 3 site characteristic value is the total total-body dose to the MEI from Unit 3 liquid and gaseous effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Table 12.2-203.
	27 mrem/yr	Thyroid (Value for two units, see ESP-ER Table 5.4-11)	15 mrem/yr	The Unit 3 site characteristic value is the total thyroid dose to the MEI from Unit 3 liquid and gaseous effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Table 12.2-203.
	11 mrem/yr	Other organ/bone (Value for two units, see ESP-ER Table 5.4-11)	5.8 mrem/yr	The Unit 3 site characteristic value is the total other organ/bone dose to the MEI from Unit 3 liquid and gaseous effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Table 12.2-203.
	6.2 mrem/yr	Skin (Value for one unit, see ESP-ER Table 5.4-10)	4.0 mrem/yr	This Unit 3 site characteristic value is the total skin dose to the MEI from Unit 3 liquid and gaseous effluents as shown in Table 5.4-5. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1. See also FSAR Table 12.2-201.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	ESP Site Characteristics (From FEIS Table I-1): Description and References	Unit 3 Site Characteristic Value	Evaluation
Dose Consequences (continued)				
Post-Accident	10 CFR 50.34(a)(1) and 10 CFR 100 dose limits	Radiological dose consequences due to gaseous releases from postulated plant accidents Design basis accidents (DBA) as listed in FEIS Tables 5-15, 5-16, and 5-17 Severe accidents as listed in FEIS Tables 5-18, 5-19, and 5-20	10 CFR 50.34(a)(1) and 10 CFR 100 dose limits	The Unit 3 site characteristic criteria are taken from ESP-ER Table 3.1-9. The Unit 3 site characteristic criteria for Unit 3 falls within (are equal to) the ESP criteria specified in FEIS Table I-1. FEIS Tables 5-15 and 5-18 (ABWR) and FEIS Tables 5-16 and 5-19 (AP1000) apply to a non-ESBWR plant and hence are not applicable to Unit 3. ESP-ER Table 2.7-2 and FEIS Table 5-17 identify Design Basis Accident (DBA) dose consequences for the ESBWR at the EAB and LPZ. Table 7.1-2 provides DBA dose consequences for Unit 3. All Unit 3 DBA doses are lower than and bounded by the ESP DBA dose values for the ESBWR except for LOCA, which remains a small fraction of the regulatory limit. In addition, a new DBA, RWCU/SDC System Line Failure (pre-incident Iodine Spike), was added to the evaluation, which was not considered in the ESP-ER. Environmental risk values for the ESBWR are identified in FEIS Table 5-20. There is no change in the severe accident population doses and associated costs listed in ESP-ER Tables 7.2-1 and 7.2-2.
Minimum Distance to Site Boundary	2854.9 ft	Minimum lateral distance from the ESP PPE boundaries to the EAB	2854.9 ft	The Unit 3 site characteristic value is taken from ESP-ER Table 3.1-9. See also ESP-ER Figure 2.1-1. The Unit 3 site characteristic value falls within (is equal to) the ESP value identified in FEIS Table I-1.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	ESP Site Characteristics (From FEIS Table I-1): Description and References	Unit 3 Site Characteristic Value	Evaluation
Liquid Radwaste System				
Normal Dose Consequences	10 CFR 20; 10 CFR 50, Appendix I, Dose Objectives; and 40 CFR 190 dose limits		10 CFR 20; 10 CFR 50, Appendix I, Dose Objectives; and 40 CFR 190 dose limits	
	1.6 mrem/yr	Total body (Value for two units, see ESP-ER Table 5.4-11)	0.094 mrem/yr	The Unit 3 site characteristic value is the total body dose to the MEI from Unit 3 liquid effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Tables 12.2-20bR and 12.2-202.
	1.4 mrem/yr	Thyroid (Value for two units, see ESP-ER Table 5.4-11)	0.18 mrem/yr	The Unit 3 site characteristic value is the thyroid dose to the MEI from Unit 3 liquid effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Table 12.2-20bR.
	5.0 mrem/yr	Other organ/bone (Value for two units, see ESP-ER Table 5.4-11)	1.3 mrem/yr	The Unit 3 site characteristic value is the other organ/bone dose to the MEI from Unit 3 liquid effluents as shown in Table 5.4-6. The Unit 3 site characteristic value falls within (is less than) the ESP value identified in FEIS Table I-1 for two units. See also FSAR Tables 12.2-20bR and 12.2-202.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	ESP Site Characteristics (From FEIS Table I-1): Description and References	Unit 3 Site Characteristic Value	Evaluation
Population Density				
Population density at the time of initial site approval and within about 5 years thereafter	Population density meets the guidance of RS-002, Section 2.1.3 for RG 4.7, Regulatory Position C.4	At the time of initial site approval and within about 5 years hereafter, the population densities, including weighted transient population, averaged over any radial distance out to 20 miles (cumulative population at a distance divided by the circular area at that distance), would not exceed 500 persons per square mile.	Population density meets the guidance of RS-002, Section 2.1.3 for RG 4.7, Regulatory Position C.4	Based on ESP-ER Table 3.1-9, the Unit 3 site characteristic criterion is, that at the time of initial site approval and within about 5 years hereafter, the population densities, including weighted transient population, averaged over any radial distance out to 20 miles (cumulative population at a distance divided by the circular area at that distance), would not exceed 500 persons per square mile. The Unit 3 site characteristic criterion falls within (is the same as) the ESP criterion specified in FEIS Table I-1. Time dependent population densities are provided in ESP-ER Section 2.5.1 which refers to ESP-ER Figure 2.5-13. That figure shows the projected population density at 5 years meets the requirement.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	ESP Site Characteristics (From FEIS Table I-1): Description and References	Unit 3 Site Characteristic Value	Evaluation
Population Density (continued)				
Population density at the time of initial operation	Population density meets the guidance of RS-002, Section 2.1.3	The population densities, including weighted transient population, averaged over any radial distance out to 30 miles (cumulative population at a distance divided by the area at that distance), would not exceed 500 persons per square mile at the time of initial operation.	Population density meets the guidance of RS-002, Section 2.1.3	Based on ESP-ER Table 3.1-9, the Unit 3 site characteristic criterion is that the population densities, including weighted transient population, averaged over any radial distance out to 30 miles (cumulative population at a distance divided by the area at that distance), would not exceed 500 persons per square mile at the time of initial operation. The Unit 3 site characteristic criterion falls within (is the same as) the ESP criterion identified in FEIS Table I-1. Time dependent population densities are provided in ESP-ER Section 2.5.1 which refers to ESP-ER Figure 2.5-13. That figure shows the projected population density at the time of initial operation meets the requirement.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1): ESP Value	ESP Site Characteristics (From FEIS Table I-1): Description and References	Unit 3 Site Characteristic Value	Evaluation
Population Density (continued)				
Population density over the lifetime of the new units until 2065	Population density meets the guidance of RS-002, Section 2.1.3	The population densities, including weighted transient population, averaged over any radial distance out to 30 miles (cumulative population at a distance divided by the area at that distance), would not exceed 1000 persons per square mile over the lifetime of new units.	Population density meets the guidance of RS-002, Section 2.1.3	Based on ESP-ER Table 3.1-9, the Unit 3 site characteristic criterion is that the population densities, including weighted transient population, averaged over any radial distance out to 30 miles (cumulative population at a distance divided by the area at that distance), would not exceed 1000 persons per square mile over the lifetime of Unit 3. The Unit 3 site characteristic criterion falls within (is the same as) the ESP criterion identified in FEIS Table I-1. Time dependent population densities are provided in ESP-ER Section 2.5.1 which refers to ESP-ER Figure 2.5-13. That figure shows the projected population density over the lifetime of Unit 3 meets the requirement.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Population Density (continued)				
Population Center Distance	10 CFR 100.21(b) Meets requirement	The distance from the ESP PPE to the nearest boundary of a densely populated center containing more than about 25,000 residents is not less than one and one-third times the distance from the ESP PPE to the outer boundary of the LPZ.	10 CFR 100.21(b) Meets requirement	The Unit 3 site characteristic value is that the nearest population center to Unit 3 with more than 25,000 residents is the City of Charlottesville which is 36 miles away as described in ESP-ER Section 2.5.1.2 and ESP-ER Table 3.1-9. The Unit 3 site characteristic value falls within (meets) the ESP criterion identified in FEIS Table I-1. (Note that the ESP site characteristic value for minimum population center distance is 8 miles as provided in FSAR Table 2.0-201).
EAB	10 CFR 100.21(a) Meets requirement	The exclusion area boundary is the perimeter of a 5000-ft-circle from the center of the originally-planned NAPS Unit 3 containment.	10 CFR 100.21(a) Meets requirement	The Unit 3 site characteristic value is a 5,000-ft-radius circle from the center of the originally-planned NAPS Unit 3 containment as described in ESP-ER Table 3.1-9. The Unit 3 site characteristic value falls within (meets) the ESP criterion and is equal to the ESP value of a 5,000 ft-circle identified in FEIS Table I-1.

Table 3.0-1 Evaluation of ESP Site Characteristics

Item	ESP Site Characteristics (From FEIS Table I-1) ESP Value	Description and References	Unit 3 Site Characteristic Value	Evaluation
Population Density (continued)				
LPZ	10 CFR 100.21(a) Meets requirement	The LPZ is a 6-mile-radius circle centered at the NAPS Unit 1 containment building.	10 CFR 100.21(a) Meets requirement	The Unit 3 site characteristic value is a 6-mile-radius circle centered at the center of the Unit 1 containment building as described in ESP-ER Table 3.1-9. The Unit 3 site characteristic value falls within (meets) the ESP criterion and is equal to the ESP value of a 6-mile-radius circle identified in FEIS Table I-1.

Except where specifically noted, the values provided from FEIS Table I-1 are for one unit.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Structure Height	≤234 ft	The height from finished grade to the top of the tallest power block structure, excluding cooling towers	190 ft	The tallest power block structure is the Turbine Building (see DCD Figure 1.2-20) at 57.9 m (190 ft) above finished grade. The height of 57.9 m (190 ft) is based on the highest structural elevation of 60 m (196.85 ft) and a finished ground level grade of 4.5 m (14.76 ft), yielding a height of 55.5 m (182.09 ft), not including the parapet. The parapet of 1 m (3.28 ft) height is added to this for a total height above finished grade of 56.5 m (185.38 ft). This is rounded to 190 ft as the Unit 3 design characteristic value. The Unit 3 design characteristic value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2.
Structure Foundation Embedment	≤140 ft	The depth from finished grade to the bottom of the basemat for the most deeply embedded power block structure	65.6 Feet Nominal	The Unit 3 design characteristic value is 65.6 ft which is the depth of embedment from finished grade (El. 289.5 ft) to the bottom of the deepest power block structure basemat as shown in FSAR Table 2.5-213. The Unit 3 design characteristic value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2.
Normal Plant Heat Sink				
Condenser / Heat Exchanger Duty	$\leq 1.03 \times 10^{10}$ Btu/hr	Waste heat rejected from the main condenser and the auxiliary heat exchangers during normal plant operation at full station load	$\leq 1.03 \times 10^{10}$ Btu/hr	The Unit 3 design characteristic value is 1.03×10^{10} Btu/hr maximum waste heat rejected from the main condenser and auxiliary heat exchangers. The main condenser heat rate of 1.0×10^{10} Btu/hr and the plant service water system heat rate of 3×10^{8} Btu/hr (based on one of two redundant trains operating) are shown in the appropriate FSAR tables. The Unit 3 design characteristic value falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.
Maximum Inlet Temperature Condenser / Heat Exchanger	100°F	Maximum intake temperature at condenser and heat exchanger inlet	100°F	The Unit 3 design characteristic value is a maximum inlet water temperature of 100°F for the condenser as identified in FSAR Table 10.4-3R. The Unit 3 design characteristic value falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Unit 3 Closed-Cycle, Dry and Wet Tower				
Height	≤180 ft	The height above finished grade of the cooling towers	180 ft	The Unit 3 design characteristic value is the hybrid cooling tower height of 55 m (180 ft) above finished grade as identified in FSAR Table 10.4-3R. The Unit 3 design characteristic value falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.
Make-Up Flow Rate	15,384 gpm, maximum (MWC mode) 22,268 gpm, maximum (EC mode)	The expected rate of removal of water from Lake Anna to replace water losses from the closed-cycle cooling water system	15,376 gpm (MWC mode) 22,260 gpm (EC mode)	The Unit 3 design characteristic values for the hybrid cooling tower makeup rate are the expected rates of water withdrawal from Lake Anna to replace water lost from the operation of the tower. These losses are from evaporation, blowdown, and drift. The hybrid cooling tower has two modes of operation, Maximum Water Conservation (MWC) and Energy Conservation (EC). The Unit 3 design characteristic values for the MWC and EC modes of operation falls within (are less than) the ESP design parameter values identified in FEIS Table I-2.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Unit 3 Closed-Cycle, Dry and Wet Tower (continued)				
Evaporation Rate	8707 gpm, 365-day rolling average[a]	Maximum rates at which water is lost by evaporation resulting from operation of the plant cooling towers.	8707 gpm, average (96% plant capacity factor with wet tower cooling)	The ESP design parameter value of 8,707 gpm presented in FEIS Table I-2 was used by the NRC Staff to characterize the average evaporation rate over a 365 day period and does not include a 96% capacity factor. See the description in the 5th paragraph of FEIS Section 5.3.2. The Unit 3 design characteristic value of 8,707 gpm is taken from ESP-ER Table 3.1-9 which is the expected long-term cooling tower evaporation rate using a 96% capacity factor. FEIS Section 5.3.2 concludes that this consumptive water use estimate is not unreasonable if the representations described in the ESP-ER are fulfilled. The FEIS concludes that, during normal water years, water use impacts based on the ESP-ER value, including impacts on downstream users, would be SMALL, and mitigation is not warranted. During severe droughts, the FEIS concludes that the impact to the water level could be temporarily MODERATE. Thus, the Unit 3 design characteristic value of 8,707 gpm falls within (is the same as) the design parameter value for long-term cooling tower evaporation rate using a 96% capacity factor that was evaluated in FEIS Section 5.3.2.
	None[b]		11,532 gpm (MWC)	The Unit 3 design characteristic value of 11,532 gpm is taken from ESP-ER Table 3.1-9 for the MWC mode. The Unit 3 design characteristic value for the MWC mode of operation falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.
	16,695 gpm, maximum (EC mode)		16,695 gpm (EC)	The Unit 3 design characteristic value of 16,695 gpm is taken from ESP-ER Table 3.1-9 for the EC mode. The Unit 3 design characteristic value for the mode of operation falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Unit 3 Closed-Cycle, Dry and Wet Tower (continued)				
Drift Rate	8 gpm, maximum (MWC mode) 8 gpm, maximum (EC mode)	Expected rates at which water is lost by drift resulting from operation of the plant cooling towers based on 0.001% of cooling water flow	8 gpm (MWC) 8 gpm (EC)	The Unit 3 design characteristic values of 8 gpm for the MWC and EC modes are taken from ESP-ER Table 3.1-9. The Unit 3 hybrid cooling tower drift rate is the expected rate at which water is lost through drift from operation of the tower. The Unit 3 design characteristic values for the MWC and EC modes of operation falls within (are equal to) the ESP design parameter values identified in FEIS Table I-2.
Blowdown Flow Rate	3844 gpm, maximum (MWC mode) 5565 gpm, maximum (EC mode)	Flow rate of the blowdown stream from the closed-cycle cooling water system to the WHTF	3837 gpm (MWC) 5558 gpm (EC)	The Unit 3 design characteristic value for the hybrid cooling tower blowdown rate is the expected rate at which water is lost through blowdown flow from the cooling tower system to the WHTF. The Unit 3 design characteristic values for the MWC and EC modes of operation falls within (are less than) the ESP design parameter values identified in FEIS Table I-2.
Blowdown Temperature	100°F, maximum	The maximum expected temperature of the cooling tower blowdown stream to the WHTF	100°F, maximum	The Unit 3 design characteristic value of 100°F is taken from ESP-ER Table 3.1-9. The maximum Unit 3 cooling tower blowdown temperature is the same as the maximum condenser inlet water temperature. The Unit 3 design characteristic value falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.
Blowdown Constituents and Concentrations		The maximum expected concentrations for anticipated constituents in the cooling water system blowdown to the WHTF		

Table 3.0-2 Evaluation of ESP Design Parameters

	ESP Design Parameters [From FEIS Table I-2]		Unit 3 Design Characteristic Value	
Item	**ESP Value**	**Description and References**		**Evaluation**
Unit 3 Closed-Cycle, Dry and Wet Tower (continued)				
Free Available Chlorine	<0.3 ppm		Less than detectable (<0.1 ppm)	The Unit 3 design characteristic value for maximum free chlorine concentration (based on 9 cycles of concentration) in the Unit 3 cooling tower blowdown flow from the Blowdown Sump to the WHTF is "less than detectable," (<0.1 ppm). The Unit 3 design characteristic value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2.
Copper	<1 ppm		≤0.03 ppm	The Unit 3 design characteristic value for maximum Unit 3 copper concentration (based on 9 cycles of concentration) in the Unit 3 cooling tower blowdown flow from the Blowdown Sump to the WHTF is 0.03 ppm. The Unit 3 design characteristic value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2.
Iron	<1 ppm		≤2.4 ppm	The Unit 3 design characteristic value for maximum expected iron concentration (based on 9 cycles of concentration) in the Unit 3 cooling tower blowdown flow from the Blowdown Sump to the WHTF is 2.4 ppm. The Unit 3 design characteristic value does not falls within (is not equal to or less than) the ESP design parameter value identified in FEIS Table I-2. Although the Unit 3 value exceeds the ESP design parameter, iron is not a priority pollutant in 40 CFR 423, Appendix A, and the Virginia Department of Environmental Quality has no water quality standard for it. Upon dilution in the WHTF, the iron concentration falls within the ESP design parameter. See also Section 3.6.
Sulfate	<300 ppm		≤65 ppm	The Unit 3 design characteristic value for maximum sulfate concentration (based on 9 cycles of concentration) in the Unit 3 cooling tower blowdown flow from the Blowdown Sump to the WHTF is 65 ppm. The Unit 3 design characteristic value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Unit 3 Closed-Cycle, Dry and Wet Tower (continued)				
Total Dissolved Solids	<3000 ppm		$\leq$550 ppm	The Unit 3 design characteristic value for maximum concentration (based on 9 cycles of concentration) of total dissolved solids (TDS) contained in the Unit 3 cooling tower blowdown flow from the Blowdown Sump to the WHTF is 550 ppm. The Unit 3 design characteristic value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2.
Heat Rejection Rate	$\leq$1.03 E 10 Btu/hr	The expected maximum heat rejection rate to the atmosphere during normal operation at full station load.	$\leq 1.03 \times 10^{10}$ Btu/hr	The Unit 3 design characteristic value is 1.03×10^{10} Btu/hr maximum waste heat rejected from the main condenser and auxiliary heat exchangers. The main condenser heat rate of 1.0×10^{10} Btu/hr and the plant service water system heat rate of 3×10^{8} Btu/hr (based on one of two redundant trains operating) are shown in the appropriate FSAR tables. The Unit 3 design characteristic value falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.
Noise	<65 dBA EAB	Maximum expected sound level at the EAB from operation of the cooling towers	<65 dBA EAB	The Unit 3 site characteristic value is less than 65 dBA based on the confirmatory analysis described in Section 5.8. This analysis demonstrates that the maximum expected sound level of operation of the Unit 3 Circulating Water and Plant Service Water system cooling towers is less than 65 dBA. The Unit 3 design characteristic value falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.
Unit 4 Dry Cooling Towers				
Evaporation Rate	None or negligible (on the order of 1 gpm, average)	The expected rate at which water is lost by evaporation from the cooling water system	Not applicable	This design parameter is not applicable because Unit 4 is not included in this ER.
Height	$\leq$180 ft	The vertical height above finished grade of the cooling towers	Not applicable	This design parameter is not applicable because Unit 4 is not included in this ER.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Unit 4 Dry Cooling Towers (continued)				
Makeup Flow Rate	None or negligible (on the order of 1 gpm, average)	The expected rate of removal of water from Lake Anna to replace evaporative water losses from the cooling water system	Not applicable	This design parameter is not applicable because Unit 4 is not included in this ER.
Noise	<60 dBA at EAB	Maximum expected sound level at the EAB from operation of the cooling towers	Not applicable	This design parameter is not applicable because Unit 4 is not included in this ER.
Heat Rejection Rate	$\leq 1.03 \times 10^{10}$ Btu/hr	Waste heat rejected to the atmosphere from the cooling water system, during normal plant operation at full station load	Not applicable	This design parameter is not applicable because Unit 4 is not included in this ER.
Ultimate Heat Sink (UHS) **Mechanical Draft Cooling Towers**				
Blowdown Constituents and Concentrations		The maximum expected concentrations for anticipated constituents in the UHS blowdown to the WHTF		
Free Available Chlorine	<0.3 ppm		Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Copper	<1 ppm		Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.

Table 3.0-2 Evaluation of ESP Design Parameters

ESP Design Parameters [From FEIS Table I-2]			Unit 3 Design Characteristic Value	Evaluation
Item	ESP Value	Description and References		
Ultimate Heat Sink (UHS) (continued)				
Mechanical Draft Cooling Towers (continued)				
Iron	<1 ppm		Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Sulfate	<300 ppm		Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Total Dissolved Solids	<3000 ppm		Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Blowdown Flow Rate	144 gpm expected, 850 gpm maximum	The normal expected and maximum flow rate of the blowdown stream from the UHS system to the WHTF	Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Evaporation Rate	411 gpm normal, 850 gpm shutdown	The expected (and maximum) rate at which water is lost by evaporation from the UHS System	Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Height	≤60 ft	The vertical height above finished grade of mechanical draft cooling towers associated with the UHS system	Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.

Table 3.0-2 Evaluation of ESP Design Parameters

ESP Design Parameters [From FEIS Table I-2]			Unit 3 Design Characteristic Value	Evaluation
Item	ESP Value	Description and References		
Ultimate Heat Sink (UHS) (continued)				
Mechanical Draft Cooling Towers (continued)				
Maximum Consumption of Raw Water	850 gpm, nominal	The expected maximum short-term consumptive use of water from Lake Anna by the UHS system (evaporation and drift losses)	Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Monthly Average Consumption of Raw Water	411 gpm	The expected normal operating consumption of water from Lake Anna by the UHS system (evaporation and drift losses)	Not Applicable	This design parameter is not applicable because the UHS for the passive Unit 3 ESBWR design does not use mechanical draft cooling towers.
Release Point				
Elevation	Ground Level	The elevation above finished grade of the release point for routine operational and accident sequence releases	Ground level	This Unit 3 design characteristic value is a ground level release point elevation for radiological consequences for routine and accident releases. The Unit 3 design characteristic value falls within (is the same as) the ESP design parameter value identified in FEIS Table I-2.
Source Term				
Gaseous (Normal)	Maximum values presented in FEIS Table H-5 and ESP-ER Table 5.4-7	The annual activity, by isotope, contained in routine plant airborne effluent streams	Values presented in Table 5.4-3	This Unit 3 design characteristic source term values for normal gaseous releases are provided in Table 5.4-3. All Unit 3 design characteristic values fall within (are less than) the ESP design parameter values identified in ESP-ER Table 5.4-7 which is referenced in FEIS Table I-2. See Section 5.4 for the analysis of radiological consequences of routine airborne releases.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Source Term (continued)				
Atmospheric (Design Basis Accidents)	Ci as indicated in			
	ESP-ER Table 7.1-3	AP1000 Main Steam Line Break, Pre-existing Iodine Spike	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	ESP-ER Table 7.1-5	AP1000 Main Steam Line Break, Accident-Initiated Iodine Spike	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	ESP-ER Table 7.1-6a	ABWR Cleanup Water Line Break	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	ESP-ER Table 7.1-6c	ESBWR Feedwater System Pipe Break	MBq values presented in DCD Table 15.4-15	The Unit 3 design characteristic source term values for a FSPB are provided in DCD Table 15.4-15. The Unit 3 design characteristic values fall within (are less than) the ESP design parameter values identified in ESP-ER Table 7.1-6c which is referenced in FEIS Table I-2. See Section 7.1 for the analysis of radiological consequences of accidental releases.
	ESP-ER Table 7.1-7	AP1000 Locked Rotor Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	ESP-ER Table 7.1-9	AP1000 Rod Ejection Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	ESP-ER Table 7.1-12	ABWR Failure of Small Lines Carrying Primary Coolant Outside Containment	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.

Table 3.0-2 Evaluation of ESP Design Parameters

ESP Design Parameters [From FEIS Table I-2]				
Item	**ESP Value**	**Description and References**	**Unit 3 Design Characteristic Value**	**Evaluation**
Source Term (continued)				
Atmospheric (Design Basis Accidents)	ESP-ER Table 7.1-16	AP1000 Steam Generator Tube Rupture, Accident Initiated Iodine Spike	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	ESP-ER Table 7.1-18	ABWR Main Steam Line Break	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	ESP-ER Table 7.1-20a	ESBWR Main Steam Line Break	MBq values presented in DCD Table 15.4-12	The Unit 3 design characteristic source term values for an MSLB are provided in DCD Table 15.4-12. The Unit 3 design characteristic values do not fall within (are not equal to or less than) the ESP design parameter values identified in ESP-ER Table 7.1-20a which is referenced in FEIS Table I-2. Although the source terms listed in ESP-ER Table 7.1-20a have decreased, additional radionuclides have been identified. A comparison of each ESP and Unit 3 source term value is provided in Table 3.0-4 of this ER. See Section 7.1 for the analysis of radiological consequences of accidental releases. As described in Section 7.1, the resultant MSLB doses remain below those presented in ESP-ER Table 7.1-20b and 7.1-20c.
	ESP-ER Table 7.1-11	AP1000 Loss-of-Coolant Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	ESP-ER Table 7.1-11	ABWR Loss-of-Coolant Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Source Term (continued)				
	ESP-ER Table 7.1-24a	ESBWR Loss-of Coolant Accident	MBq values presented in DCD Table 15.4-7	The Unit 3 design characteristic source term values for a LOCA are provided in DCD Table 15.4-7. The Unit 3 design characteristic values do not fall within (are not equal to or less than) the ESP design parameter values identified in ESP-ER Table 7.1-24a which is referenced in FEIS Table I-2. Some source term activities have increased and additional radionuclides have been identified. A comparison of each ESP and Unit 3 source term value is provided in Table 3.0-5. See Section 7.1 for the analysis of radiological consequences of accidental releases. As described in Section 7.1, the resultant LOCA doses, though marginally higher than those shown in ESP-ER Table 7.1-24b, remain well below 10 CFR 50.34(a)(1) and SRP limits.
	ESP-ER Table 7.1-25	AP1000 Fuel Handling Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	ESP-ER Table 7.1-25	ABWR Fuel Handling Accident	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
	ESP-ER Table 7.1-29	ESBWR Fuel Handling Accident	MBq values presented in DCD Table 15.4-3a	The Unit 3 design characteristic source term values for an FHA are provided in DCD Table 15.4-3a. The Unit 3 design characteristic values fall within (are less than) the ESP design parameter values identified in ESP-ER Table 7.1-29 which is referenced in FEIS Table I-2. See Section 7.1 for the analysis of radiological consequences of accidental releases.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Source Term (continued)				
	ESP-ER Table 7.1-31	ESBWR Cleanup Water Line Break	MBq values presented in DCD Table 15.4-22	The Unit 3 design characteristic source term values for CWLB are provided in DCD Table 15.4-22. The Unit 3 design characteristic values do not fall within (are not equal to or less than) the ESP design parameter values identified in ESP-ER Table 7.1-31 which is referenced in FEIS Table I-2. Some source term activities have increased and additional radionuclides have been identified. A comparison of each ESP and Unit 3 source term value is provided in Table 3.0-6. See Section 7.1 for the analysis of radiological consequences of accidental releases. As described in Section 7.1, some Unit 3 CWLB doses are marginally higher than those shown in ESP-ER Table 7.1-32; however, they remain well below regulatory limits.
	ESP-ER Table 7.1-13a	ESBWR Failure of Small Lines Carrying Primary Coolant Outside Containment	MBq values presented in DCD Table 15.4-18	The Unit 3 design characteristic source term values for an FSLCPCOC are provided in DCD Table 15.4-18. The Unit 3 design characteristic values do not fall within (are not equal to or less than) the ESP design parameter values identified in ESP-ER Table 7.1-13a which is referenced in FEIS Table I-2. Some source term activities have increased and additional radionuclides have been identified. A comparison of each ESP and Unit 3 source term value is provided in Table 3.0-3. See Section 7.1 for the analysis of radiological consequences of accidental releases. As described in Section 7.1, the resultant FSLCPCOC doses remain below those presented in ESP-ER Table 7.1-13b.
	ESP-ER Table 7.1-14	AP1000 Steam Generator Tube Rupture, Pre-Existing Iodine Spike	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Source Term (continued)				
Tritium	3500 Ci/yr (maximum values)	The annual activity of tritium contained in routine plant airborne effluent streams	76 Ci/yr	The Unit 3 design characteristic annual activity of tritium contained in routine plant airborne effluent streams is 76 Ci/yr and is shown in Table 5.4-3. The Unit 3 design characteristic value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2.
Liquid Radwaste System				
Release Point Dilution Factor	1000 (minimum)	The ratio of liquid potentially radioactive effluent streams to liquid nonradioactive effluent streams from plant systems to the WHTF through the discharge canal used for NAPS Units 1 and 2	1000	The Unit 3 dilution factor is shown in FSAR Table 12.2-20aR, which indicates a minimum dilution factor requirement of 10 as the basis for liquid effluent dose calculations. Unit 3 effluent streams (both radiological and nonradiological) are directed to the Cooling Tower Blowdown Sump where they are mixed and their constituents diluted prior to gravity drain to the Discharge Canal and WHTF. At the Discharge Canal and WHTF, the Unit 3 effluents are further mixed and diluted with the much larger quantity of water there. This dilution process is further described in Section 5.2. The resulting design characteristic dilution factor for Unit 3 effluents is therefore greater than 1000. The Unit 3 design characteristic value falls within (is equal to or greater than) the ESP design parameter value identified in FEIS Table I-2.
Liquid	Values presented in FEIS Table H-2 and ESP-ER Table 5.4-6 (maximum values)	The annual activity, by isotope, contained in routine plant liquid effluent streams	Values presented in Table 5.4-1	The Unit 3 design characteristic source term values for normal liquid effluent releases are provided in Table 5.4-1. The Unit 3 design characteristic values do not fall within (are not equal to or less than) the ESP design parameter values identified in ESP-ER Table 5.4-6 which is referenced in FEIS Table I-2. Some source term activities have increased, and others are no longer present. A comparison of each ESP and Unit 3 source term value is provided in Table 3.0-7. The sum of the activity releases falls within the sum of activities in ESP-ER Table 5.4-6. Additionally, as described in Section 5.4, the resultant liquid effluent doses remain below those shown in ESP-ER Table 5.4-8.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Liquid Radwaste System (continued)				
Tritium	≤850 Ci/yr	The annual activity of tritium contained in routine plant liquid effluent streams	14 Ci/yr	The Unit 3 design characteristic annual activity of tritium contained in routine plant liquid effluent streams is 14 Ci/yr as shown in Table 5.4-1. The Unit 3 design characteristic value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2.
Solid Radwaste System				
Activity	≤2700 Ci/yr	The annual activity contained in solid radioactive wastes generated during routine plant operations	1718 Ci/yr	The Unit 3 design characteristic annual activity contained in solid radioactive wastes generated during routine plant operations is 1718 Ci/yr. The Unit 3 design characteristic value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2.
Volume	≤9041 cu ft/yr (Per Unit)	The expected volume of solid radioactive wastes generated during routine plant operations	16,764 cu ft/yr	This Unit 3 design characteristic expected volume of solid radioactive waste generated during routine plant operations is 16,764 cu ft/yr per DCD Table 11.4-2. The volume for Unit 3 does not fall within the single unit value identified in the FEIS. However, the volume for Unit 3 does fall within the overall site value evaluated in the FEIS for two units. Furthermore, the number of waste shipments based on the DCD volume remains well below the one truck shipment per day condition given in 10 CFR 51.52(c), Table S-4.
Plant Characteristics				
Acreage	Approximately 128.5 acres [Both units]	Approximate area on the NAPS site that would be affected on a long-term basis as a result of additional permanent facilities	Approximately 120 acres as shown in Figure 1.1-1	The Unit 3 design characteristic value of approximately 120 acres is the area on the NAPS site that will be affected on a long term basis by the construction of permanent Unit 3 facilities. These areas are shown in Figure 1.1-1. The Unit 3 design characteristic value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2 for two units.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Plant Characteristics (continued)				
Megawatts Thermal	≤4500 MWt	The thermal power generated by one unit	4500 MWt (Rated)	This Unit 3 design characteristic value of 4500 MWt is the rated reactor thermal power, as described in Section 1.1. The Unit 3 design characteristic value falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.
Plant Population – Operation	Approximately 720 permanent employees (both units)	Anticipated number of new employees that would be required for operation of the new units	500 permanent employees	The Unit 3 value of 500 is the anticipated number of new employees required for operation of Unit 3. The Unit 3 value falls within the total (two-unit) value identified in the FEIS. The Unit 3 value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2 for two units.
Plant Population – Refueling / Major Maintenance	Approximately 700 to 1000 temporary workers during planned outages	Anticipated number of additional workers onsite during planned outages of the new units	1000 temporary workers	The Unit 3 value of 1,000 is the anticipated number of additional workers needed on site during Unit 3 planned outages. The Unit 3 value falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.
Plant Population – Construction	5000 people maximum (simultaneous construction)	Peak workforce of 5000 for construction of both new units	2,500-3,500 people	The Unit 3 value of 2,500-3,500 is the expected peak number of construction workers that are required for the construction of Unit 3. The Unit 3 value falls within (is less than) the ESP design parameter value identified in FEIS Table I-2 for two units.
Maximum Fuel Enrichment for Light-Water-Cooled Reactors	5%	Concentration of U-235 in fuel	5%	The Unit 3 design characteristic value is 5% maximum concentration of U-235 in the Unit 3 fuel. The Unit 3 design characteristic value falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.

Table 3.0-2 Evaluation of ESP Design Parameters

Item	ESP Design Parameters [From FEIS Table I-2] ESP Value	Description and References	Unit 3 Design Characteristic Value	Evaluation
Plant Characteristics (continued)				
Maximum Fuel Burn-up for Light-Water-Cooled Reactors	62,000 MWd/MTU	The value derived by calculating the reactor thermal power multiplied by the time of irradiation divided by fuel mass (expressed as megawatt-days per metric ton of irradiated fuel)	62,000 MWd/MTU	The Unit 3 design characteristic value is 62,000 MWd/MTU maximum fuel burn-up for Unit 3. The Unit 3 design characteristic value falls within (is equal to) the ESP design parameter value identified in FEIS Table I-2.
Maximum Fuel Enrichment for Gas-Cooled Reactors	19.8%	Concentration of U-235 in fuel	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.
Maximum Fuel Burn-up for Gas-Cooled Reactors	133,000 MWd/MTU	The value derived by calculating the reactor thermal power multiplied by the time of irradiation divided by fuel mass (expressed as megawatt-days per metric ton of irradiated fuel)	Not Applicable	This design parameter is not applicable because it is related to a non-ESBWR plant.

a. The staff used a 100 percent capacity factor based on a 365-day rolling average evaporative water use vs. the applicant's 96 percent capacity factor based on long term annual average evaporative water use.

b. FEIS Table I-2 presents no value for the MWC mode evaporation rate. However, it states on page 5-11: "The definition of the PPE instantaneous maximum evaporation rate parameters for the MWC and EC modes was unchanged." This indicates that NRC accepted the 11,532 gpm maximum as the bounding value for MWC mode evaporation rate. In addition, the value of 11,532 gpm was shown in NUREG-1811, Supp 1, (SDEIS).

Unless noted otherwise, the ESP design parameter for one unit is one half of the two-unit value shown, when it is noted that the ESP value is for two units.

Table 3.0-3 Comparison of Unit 3 and ESP-ER Activity Releases for Failure of Small Lines Carrying Primary Coolant Outside Containment Accident

	ESP-ER Activity Release (Ci)			Unit 3 Activity Release (Ci)				Unit 3 Activity Release (MBq)			
Isotope	**0–2 hr**	**2–8 hr**	**Total**	**0–2 hr**	**2–8 hr**	**8-12 hr**	**Total**	**0–2 hr**	**2–8 hr**	**8-12 hr**	**Total**
Co-58	NP	NP	NP	2.22E-04	1.08E-03	2.97E-04	1.59E-03	8.20E+00	3.98E+01	1.10E+01	5.90E+01
Co-60	NP	NP	NP	4.32E-04	2.16E-03	6.49E-04	3.24E-03	1.60E+01	8.00E+01	2.40E+01	1.20E+02
Rb-86	NP	NP	NP	9.46E-02	4.46E-01	1.35E-01	6.76E-01	3.50E+03	1.65E+04	5.00E+03	2.50E+04
Sr-89	NP	NP	NP	2.22E-04	1.08E-03	2.97E-04	1.59E-03	8.20E+00	3.98E+01	1.10E+01	5.90E+01
Sr-90	NP	NP	NP	1.51E-05	7.41E-05	1.89E-05	1.08E-04	5.60E-01	2.74E+00	7.00E-01	4.00E+00
Sr-91	NP	NP	NP	8.38E-03	4.03E-02	1.08E-02	5.95E-02	3.10E+02	1.49E+03	4.00E+02	2.20E+03
Sr-92	NP	NP	NP	2.03E-02	9.86E-02	2.43E-02	1.43E-01	7.50E+02	3.65E+03	9.00E+02	5.30E+03
Y-90	NP	NP	NP	1.51E-05	7.41E-05	1.89E-05	1.08E-04	5.60E-01	2.74E+00	7.00E-01	4.00E+00
Y-91	NP	NP	NP	8.92E-05	4.24E-04	1.08E-04	6.22E-04	3.30E+00	1.57E+01	4.00E+00	2.30E+01
Y-92	NP	NP	NP	1.24E-02	6.05E-02	1.62E-02	8.92E-02	4.60E+02	2.24E+03	6.00E+02	3.30E+03
Y-93	NP	NP	NP	8.38E-03	4.03E-02	1.08E-02	5.95E-02	3.10E+02	1.49E+03	4.00E+02	2.20E+03
Zr-95	NP	NP	NP	1.78E-05	8.76E-05	2.16E-05	1.27E-04	6.60E-01	3.24E+00	8.00E-01	4.70E+00
Nb-95	NP	NP	NP	1.78E-05	8.76E-05	2.16E-05	1.27E-04	6.60E-01	3.24E+00	8.00E-01	4.70E+00
Mo-99	NP	NP	NP	4.32E-03	2.16E-02	6.49E-03	3.24E-02	1.60E+02	8.00E+02	2.40E+02	1.20E+03
Tc-99m	NP	NP	NP	4.32E-03	2.16E-02	6.49E-03	3.24E-02	1.60E+02	8.00E+02	2.40E+02	1.20E+03
Ru-103	NP	NP	NP	4.32E-05	2.16E-04	6.49E-05	3.24E-04	1.60E+00	8.00E+00	2.40E+00	1.20E+01
Ru-106	NP	NP	NP	6.49E-06	3.14E-05	8.11E-06	4.59E-05	2.40E-01	1.16E+00	3.00E-01	1.70E+00
Te-129m	NP	NP	NP	8.92E-05	4.24E-04	1.08E-04	6.22E-04	3.30E+00	1.57E+01	4.00E+00	2.30E+01
Te-131m	NP	NP	NP	2.16E-04	1.05E-03	2.70E-04	1.54E-03	8.00E+00	3.90E+01	1.00E+01	5.70E+01

Table 3.0-3 Comparison of Unit 3 and ESP-ER Activity Releases for Failure of Small Lines Carrying Primary Coolant Outside Containment Accident

	ESP-ER Activity Release (Ci)			Unit 3 Activity Release (Ci)				Unit 3 Activity Release (MBq)			
Isotope	**0–2 hr**	**2–8 hr**	**Total**	**0–2 hr**	**2–8 hr**	**8-12 hr**	**Total**	**0–2 hr**	**2–8 hr**	**8-12 hr**	**Total**
Te-132	NP	NP	NP	2.22E-05	1.08E-04	2.97E-05	1.59E-04	8.20E-01	3.98E+00	1.10E+00	5.90E+00
I-131	6.13E+00	1.05E+01	1.66E+01	7.84E-01	3.81E+00	1.08E+00	5.68E+00	2.90E+04	1.41E+05	4.00E+04	2.10E+05
I-132	8.03E+00	7.35E+00	1.54E+01	7.57E+00	3.57E+01	1.08E+01	5.41E+01	2.80E+05	1.32E+06	4.00E+05	2.00E+06
I-133	1.51E+01	2.35E+01	3.86E+01	5.41E+00	2.70E+01	5.41E+00	3.78E+01	2.00E+05	1.00E+06	2.00E+05	1.40E+06
I-134	8.78E+00	4.60E+00	1.34E+01	1.38E+01	6.73E+01	1.62E+01	9.73E+01	5.10E+05	2.49E+06	6.00E+05	3.60E+06
I-135	1.39E+01	1.85E+01	3.24E+01	7.57E+00	3.84E+01	8.11E+00	5.41E+01	2.80E+05	1.42E+06	3.00E+05	2.00E+06
Cs-134	NP	NP	NP	5.95E-05	2.92E-04	8.11E-05	4.32E-04	2.20E+00	1.08E+01	3.00E+00	1.60E+01
Cs-136	NP	NP	NP	4.05E-05	1.92E-04	3.78E-05	2.70E-04	1.50E+00	7.10E+00	1.40E+00	1.00E+01
Cs-137	NP	NP	NP	1.57E-04	7.62E-04	2.16E-04	1.14E-03	5.80E+00	2.82E+01	8.00E+00	4.20E+01
Ba-140	NP	NP	NP	8.92E-04	4.24E-03	1.08E-03	6.22E-03	3.30E+01	1.57E+02	4.00E+01	2.30E+02
La-140	NP	NP	NP	8.92E-04	4.24E-03	1.08E-03	6.22E-03	3.30E+01	1.57E+02	4.00E+01	2.30E+02
Ce-141	NP	NP	NP	6.49E-05	3.14E-04	8.11E-05	4.59E-04	2.40E+00	1.16E+01	3.00E+00	1.70E+01
Ce-144	NP	NP	NP	6.49E-06	3.14E-05	8.11E-06	4.59E-05	2.40E-01	1.16E+00	3.00E-01	1.70E+00
Np-239	NP	NP	NP	1.78E-02	8.76E-02	2.16E-02	1.27E-01	6.60E+02	3.24E+03	8.00E+02	4.70E+03
Total	5.19E+01	6.45E+01	1.16E+02	3.53E+01	1.73E+02	4.19E+01	2.50E+02	1.31E+06	6.40E+06	1.55E+06	9.26E+06

Notes:

NP – Not present in the ESP-ER

ESBWR accident release activities from ESP-ER Table 7.1-13a

Unit 3-specific accident release activities in the unit of curie (Ci) from DCD Table 15.4-18

Unit 3-specific accident release activities in the unit of mega-becquerel (MBq) from DCD Table 15.4-18

Table 3.0-4 Comparison of Unit 3 and ESP-ER Activity Releases for Main Steam Line Break Accident

	ESP-ER Activity Release (Ci)		Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
Isotope	**Pre-Existing**	**Equilibrium Activity**	**Equilibrium Activity**	**Iodine Spike Activity**	**Equilibrium Activity**	**Iodine Spike Activity**
Co-58	NP	NP	3.78E-02	3.78E-02	1.40E+03	1.40E+03
Co-60	NP	NP	7.30E-02	7.30E-02	2.70E+03	2.70E+03
Kr-85	6.75E-05	6.75E-05	4.59E-05	4.59E-05	1.70E+00	1.70E+00
Kr-85m	1.72E-02	1.72E-02	1.19E-02	1.19E-02	4.40E+02	4.40E+02
Kr-87	5.74E-02	5.74E-02	3.78E-02	3.78E-02	1.40E+03	1.40E+03
Kr-88	5.74E-02	5.74E-02	3.78E-02	3.78E-02	1.40E+03	1.40E+03
Rb-86	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sr-89	NP	NP	3.78E-02	3.78E-02	1.40E+03	1.40E+03
Sr-90	NP	NP	2.54E-03	2.54E-03	9.40E+01	9.40E+01
Sr-91	NP	NP	1.41E+00	1.41E+00	5.20E+04	5.20E+04
Sr-92	NP	NP	3.24E+00	3.24E+00	1.20E+05	1.20E+05
Y-90	NP	NP	2.54E-03	2.54E-03	9.40E+01	9.40E+01
Y-91	NP	NP	1.49E-02	1.49E-02	5.50E+02	5.50E+02
Y-92	NP	NP	2.05E+00	2.05E+00	7.60E+04	7.60E+04
Y-93	NP	NP	1.41E+00	1.41E+00	5.20E+04	5.20E+04
Zr-95	NP	NP	2.97E-03	2.97E-03	1.10E+02	1.10E+02
Zr-97	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Nb-95	NP	NP	2.97E-03	2.97E-03	1.10E+02	1.10E+02

Table 3.0-4 Comparison of Unit 3 and ESP-ER Activity Releases for Main Steam Line Break Accident

Isotope	ESP-ER Activity Release (Ci)		Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
	Pre-Existing	Equilibrium Activity	Equilibrium Activity	Iodine Spike Activity	Equilibrium Activity	Iodine Spike Activity
Mo-99	NP	NP	7.30E-01	7.30E-01	2.70E+04	2.70E+04
Tc-99m	NP	NP	7.30E-01	7.30E-01	2.70E+04	2.70E+04
Ru-103	NP	NP	7.30E-03	7.30E-03	2.70E+02	2.70E+02
Ru-105	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ru-106	NP	NP	1.08E-03	1.08E-03	4.00E+01	4.00E+01
Rh-105	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sb-127	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sb-129	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Te-127	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Te-127m	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Te-129	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Te-129m	NP	NP	1.49E-02	1.49E-02	5.50E+02	5.50E+02
Te-131m	NP	NP	3.51E-02	3.51E-02	1.30E+03	1.30E+03
Te-132	NP	NP	3.78E-03	3.78E-03	1.40E+02	1.40E+02
I-131	1.96E+02	9.79E+00	6.49E+00	1.32E+02	2.40E+05	4.90E+06
I-132	1.86E+03	9.45E+01	6.22E+01	1.24E+03	2.30E+06	4.60E+07
I-133	1.35E+03	6.75E+01	4.59E+01	9.19E+02	1.70E+06	3.40E+07
I-134	3.38E+03	1.72E+02	1.14E+02	2.30E+03	4.20E+06	8.50E+07

Table 3.0-4 Comparison of Unit 3 and ESP-ER Activity Releases for Main Steam Line Break Accident

Isotope	ESP-ER Activity Release (Ci)		Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
	Pre-Existing	Equilibrium Activity	Equilibrium Activity	Iodine Spike Activity	Equilibrium Activity	Iodine Spike Activity
I-135	1.92E+03	9.45E+01	6.49E+01	1.27E+03	2.40E+06	4.70E+07
Xe-133	2.46E-02	2.46E-02	1.59E-02	1.59E-02	5.90E+02	5.90E+02
Xe-135	6.75E-02	6.75E-02	4.32E-02	4.32E-02	1.60E+03	1.60E+03
Cs-134	NP	NP	1.00E-02	1.00E-02	3.70E+02	3.70E+02
Cs-136	NP	NP	6.49E-03	6.49E-03	2.40E+02	2.40E+02
Cs-137	NP	NP	2.62E-02	2.62E-02	9.70E+02	9.70E+02
Ba-139	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ba-140	NP	NP	1.49E-01	1.49E-01	5.50E+03	5.50E+03
La-140	NP	NP	1.49E-01	1.49E-01	5.50E+03	5.50E+03
La-141	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
La-142	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ce-141	NP	NP	1.08E-02	1.08E-02	4.00E+02	4.00E+02
Ce-143	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ce-144	NP	NP	1.08E-03	1.08E-03	4.00E+01	4.00E+01
Pr-143	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Nd-147	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Np-239	NP	NP	2.97E+00	2.97E+00	1.10E+05	1.10E+05
Pu-238	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Table 3.0-4 Comparison of Unit 3 and ESP-ER Activity Releases for Main Steam Line Break Accident

Isotope	ESP-ER Activity Release (Ci)		Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
	Pre-Existing	Equilibrium Activity	Equilibrium Activity	Iodine Spike Activity	Equilibrium Activity	Iodine Spike Activity
Pu-239	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pu-240	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pu-241	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Am-241	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cm-242	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cm-244	NP	NP	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total	8.70E+03	4.39E+02	3.06E+02	5.88E+03	1.13E+07	2.17E+08

NOTES:

NP – Not present in the ESP-ER

ESBWR accident release activities from ESP-ER Table 7.1-20a

Unit 3-specific accident release activities in the unit of curie (Ci) from DCD Table 15.4-12

Unit 3-specific accident release activities in the unit of mega-becquerel (MBq) from DCD Table 15.4-12

Table 3.0-5 Comparison of Unit 3 and ESP-ER Activity Releases for Loss-of-Coolant Accident

	ESP-ER Activity Release (Ci)						Unit 3 Activity Release (Ci)						Unit 3 Activity Release (MBq)					
Isotope	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total
Co-58	2.28E-03	2.22E-02	3.89E-02	4.18E-02	2.61E-02	1.31E-01	2.70E-03	1.89E-02	4.32E-02	1.30E-01	4.81E-01	6.76E-01	1.00E+02	7.00E+02	1.60E+03	4.80E+03	1.78E+04	2.50E+04
Co-60	2.19E-03	2.16E-02	3.76E-02	4.10E-02	2.89E-02	1.31E-01	2.68E-03	1.84E-02	4.38E-02	1.27E-01	5.38E-01	7.30E-01	9.90E+01	6.81E+02	1.62E+03	4.70E+03	1.99E+04	2.70E+04
Kr-85	6.59E+00	3.23E+02	2.72E+03	2.08E+04	5.31E+04	7.70E+04	9.46E+00	2.61E+02	2.22E+03	2.72E+04	4.57E+05	4.86E+05	3.50E+05	9.65E+06	8.20E+07	1.01E+09	1.69E+10	1.80E+10
Kr-85m	1.14E+02	3.01E+03	5.21E+03	8.50E+02	0.00E+00	9.19E+03	1.54E+02	2.33E+03	3.73E+03	8.11E+02	0.00E+00	7.03E+03	5.70E+06	8.63E+07	1.38E+08	3.00E+07	0.00E+00	2.60E+08
Kr-87	1.17E+02	8.60E+02	1.08E+02	0.00E+00	0.00E+00	1.09E+03	1.43E+02	6.14E+02	8.11E+01	0.00E+00	0.00E+00	8.38E+02	5.30E+06	2.27E+07	3.00E+06	0.00E+00	0.00E+00	3.10E+07
Kr-88	2.68E+02	5.12E+03	4.30E+03	1.63E+02	0.00E+00	9.85E+03	3.51E+02	3.97E+03	2.97E+03	0.00E+00	0.00E+00	7.30E+03	1.30E+07	1.47E+08	1.10E+08	0.00E+00	0.00E+00	2.70E+08
Rb-86	1.38E-01	1.00E+00	1.72E+00	1.79E+00	8.25E-01	5.48E+00	1.38E-01	7.81E-01	1.78E+00	4.86E+00	1.22E+01	1.97E+01	5.10E+03	2.89E+04	6.60E+04	1.80E+05	4.50E+05	7.30E+05
Sr-89	3.53E+00	3.46E+01	6.01E+01	6.43E+01	3.88E+01	2.01E+02	4.32E+00	2.81E+01	7.03E+01	1.95E+02	7.30E+02	1.03E+03	1.60E+05	1.04E+06	2.60E+06	7.20E+06	2.70E+07	3.80E+07
Sr-90	3.48E-01	3.42E+00	5.98E+00	6.51E+00	4.63E+00	2.09E+01	4.32E-01	2.81E+00	7.03E+00	1.95E+01	8.65E+01	1.16E+02	1.60E+04	1.04E+05	2.60E+05	7.20E+05	3.20E+06	4.30E+06
Sr-91	3.95E+00	3.06E+01	2.63E+01	5.00E+00	0.00E+00	6.58E+01	4.86E+00	2.49E+01	2.70E+01	1.08E+01	0.00E+00	6.76E+01	1.80E+05	9.20E+05	1.00E+06	4.00E+05	0.00E+00	2.50E+06
Sr-92	3.18E+00	1.45E+01	2.88E+00	1.25E-01	0.00E+00	2.06E+01	3.78E+00	1.11E+01	2.70E+00	0.00E+00	0.00E+00	1.76E+01	1.40E+05	4.10E+05	1.00E+05	0.00E+00	0.00E+00	6.50E+05
Y-90	6.34E-03	1.70E-01	9.06E-01	2.51E+00	4.25E+00	7.84E+00	5.68E-03	1.38E-01	1.05E+00	8.81E+00	7.92E+01	8.92E+01	2.10E+02	5.09E+03	3.87E+04	3.26E+05	2.93E+06	3.30E+06
Y-91	4.59E-02	4.70E-01	8.96E-01	1.03E+00	6.38E-01	3.08E+00	5.68E-02	4.03E-01	1.03E+00	3.11E+00	1.16E+01	1.62E+01	2.10E+03	1.49E+04	3.80E+04	1.15E+05	4.30E+05	6.00E+05
Y-92	4.89E-01	1.01E+01	8.31E+00	3.75E-01	0.00E+00	1.93E+01	2.49E-01	7.05E+00	7.84E+00	5.41E-01	0.00E+00	1.57E+01	9.20E+03	2.61E+05	2.90E+05	2.00E+04	0.00E+00	5.80E+05
Y-93	4.94E-02	3.87E-01	3.45E-01	7.25E-02	0.00E+00	8.54E-01	5.95E-02	3.19E-01	3.78E-01	1.35E-01	0.00E+00	8.92E-01	2.20E+03	1.18E+04	1.40E+04	5.00E+03	0.00E+00	3.30E+04
Zr-95	6.39E-02	6.26E-01	1.09E+00	1.18E+00	7.25E-01	3.68E+00	7.84E-02	5.43E-01	1.24E+00	3.54E+00	1.35E+01	1.89E+01	2.90E+03	2.01E+04	4.60E+04	1.31E+05	5.00E+05	7.00E+05
Zr-97	6.16E-02	5.28E-01	6.10E-01	2.25E-01	0.00E+00	1.43E+00	7.57E-02	4.38E-01	6.76E-01	5.14E-01	0.00E+00	1.70E+00	2.80E+03	1.62E+04	2.50E+04	1.90E+04	0.00E+00	6.30E+04
Nb-95	6.43E-02	6.30E-01	1.11E+00	1.20E+00	8.25E-01	3.83E+00	7.84E-02	5.43E-01	1.24E+00	3.81E+00	1.54E+01	2.11E+01	2.90E+03	2.01E+04	4.60E+04	1.41E+05	5.70E+05	7.80E+05
Mo-99	8.30E-01	7.86E+00	1.23E+01	9.88E+00	1.00E+00	3.19E+01	1.00E+00	6.57E+00	1.41E+01	2.70E+01	1.62E+01	6.49E+01	3.70E+04	2.43E+05	5.20E+05	1.00E+06	6.00E+05	2.40E+06
Tc-99m	7.46E-01	7.24E+00	1.19E+01	1.01E+01	8.75E-01	3.09E+01	8.11E-01	5.95E+00	1.35E+01	2.84E+01	1.35E+01	6.22E+01	3.00E+04	2.20E+05	5.00E+05	1.05E+06	5.00E+05	2.30E+06
Ru-103	6.66E-01	6.52E+00	1.13E+01	1.21E+01	6.88E+00	3.75E+01	8.11E-01	5.68E+00	1.27E+01	3.76E+01	1.27E+02	1.84E+02	3.00E+04	2.10E+05	4.70E+05	1.39E+06	4.70E+06	6.80E+06
Ru-105	3.48E-01	2.09E+00	8.88E-01	3.75E-02	0.00E+00	3.36E+00	4.05E-01	1.68E+00	8.92E-01	0.00E+00	0.00E+00	2.97E+00	1.50E+04	6.20E+04	3.30E+04	0.00E+00	0.00E+00	1.10E+05
Ru-106	2.33E-01	2.28E+00	3.99E+00	4.34E+00	3.04E+00	1.39E+01	2.97E-01	1.92E+00	4.54E+00	1.35E+01	5.54E+01	7.57E+01	1.10E+04	7.10E+04	1.68E+05	5.00E+05	2.05E+06	2.80E+06
Rh-105	4.05E-01	3.88E+00	5.85E+00	3.74E+00	1.25E-01	1.40E+01	4.86E-01	3.30E+00	6.49E+00	9.73E+00	1.89E+00	2.19E+01	1.80E+04	1.22E+05	2.40E+05	3.60E+05	7.00E+04	8.10E+05
Sb-127	9.09E-01	8.69E+00	1.40E+01	1.23E+01	1.75E+00	3.76E+01	1.11E+00	7.27E+00	1.59E+01	3.51E+01	2.70E+01	8.65E+01	4.10E+04	2.69E+05	5.90E+05	1.30E+06	1.00E+06	3.20E+06
Sb-129	2.18E+00	1.30E+01	5.25E+00	1.25E-01	0.00E+00	2.05E+01	2.57E+00	1.04E+01	5.14E+00	2.70E-01	0.00E+00	1.84E+01	9.50E+04	3.85E+05	1.90E+05	1.00E+04	0.00E+00	6.80E+05
Te-127	9.29E-01	8.96E+00	1.49E+01	1.39E+01	3.13E+00	4.18E+01	1.05E+00	7.32E+00	1.70E+01	3.95E+01	5.41E+01	1.19E+02	3.90E+04	2.71E+05	6.30E+05	1.46E+06	2.00E+06	4.40E+06
Te-127m	1.22E-01	1.20E+00	2.09E+00	2.29E+00	1.54E+00	7.24E+00	1.49E-01	1.01E+00	2.35E+00	7.03E+00	3.00E+01	4.05E+01	5.50E+03	3.75E+04	8.70E+04	2.60E+05	1.11E+06	1.50E+06
Te-129	2.41E+00	1.62E+01	1.15E+01	6.75E+00	3.50E+00	4.04E+01	1.84E+00	1.19E+01	1.22E+01	2.00E+01	6.22E+01	1.08E+02	6.80E+04	4.42E+05	4.50E+05	7.40E+05	2.30E+06	4.00E+06

Table 3.0-5 Comparison of Unit 3 and ESP-ER Activity Releases for Loss-of-Coolant Accident

	ESP-ER Activity Release (Ci)						Unit 3 Activity Release (Ci)						Unit 3 Activity Release (MBq)					
Isotope	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total	0–2 hr	2–8 hr	8–24 hr	24–96 hr	96–720 hr	Total
Te-129m	4.09E-01	4.02E+00	6.98E+00	7.35E+00	4.13E+00	2.29E+01	4.86E-01	3.30E+00	8.11E+00	2.32E+01	7.57E+01	1.11E+02	1.80E+04	1.22E+05	3.00E+05	8.60E+05	2.80E+06	4.10E+06
Te-131m	1.22E+00	1.11E+01	1.53E+01	8.75E+00	2.50E-01	3.66E+01	1.49E+00	9.32E+00	1.62E+01	2.16E+01	5.41E+00	5.41E+01	5.50E+04	3.45E+05	6.00E+05	8.00E+05	2.00E+05	2.00E+06
Te-132	1.24E+01	1.19E+02	1.88E+02	1.59E+02	1.88E+01	4.96E+02	1.51E+01	1.01E+02	2.08E+02	4.59E+02	2.97E+02	1.08E+03	5.60E+05	3.74E+06	7.70E+06	1.70E+07	1.10E+07	4.00E+07
I-131	6.66E+01	5.13E+02	9.33E+02	1.44E+03	7.00E+02	3.65E+03	7.30E+01	4.41E+02	1.00E+03	3.08E+03	7.84E+03	1.24E+04	2.70E+06	1.63E+07	3.70E+07	1.14E+08	2.90E+08	4.60E+08
I-132	7.88E+01	3.44E+02	2.45E+02	1.89E+02	2.25E+01	8.79E+02	7.57E+01	2.76E+02	2.70E+02	5.41E+02	3.24E+02	1.49E+03	2.80E+06	1.02E+07	1.00E+07	2.00E+07	1.20E+07	5.50E+07
I-133	1.31E+02	9.10E+02	1.22E+03	7.63E+02	1.25E+01	3.04E+03	1.43E+02	7.49E+02	1.30E+03	1.32E+03	2.70E+02	3.78E+03	5.30E+06	2.77E+07	4.80E+07	4.90E+07	1.00E+07	1.40E+08
I-134	4.96E+01	5.10E+01	3.75E-01	0.00E+00	0.00E+00	1.01E+02	4.59E+01	3.24E+01	0.00E+00	0.00E+00	0.00E+00	7.84E+01	1.70E+06	1.20E+06	0.00E+00	0.00E+00	0.00E+00	2.90E+06
I-135	1.11E+02	6.07E+02	4.16E+02	5.38E+01	0.00E+00	1.19E+03	1.19E+02	5.03E+02	4.05E+02	8.11E+01	0.00E+00	1.11E+03	4.40E+06	1.86E+07	1.50E+07	3.00E+06	0.00E+00	4.10E+07
Xe-133	1.08E+03	5.19E+04	4.08E+05	2.51E+06	1.20E+06	4.18E+06	1.51E+03	4.17E+04	3.35E+05	3.14E+06	1.22E+07	1.57E+07	5.60E+07	1.54E+09	1.24E+10	1.16E+11	4.50E+11	5.80E+11
Xe-135	3.68E+02	1.40E+04	5.13E+04	3.80E+04	0.00E+00	1.04E+05	4.59E+02	1.06E+04	3.76E+04	3.51E+04	0.00E+00	8.38E+04	1.70E+07	3.93E+08	1.39E+09	1.30E+09	0.00E+00	3.10E+09
Cs-134	1.16E+01	8.50E+01	1.48E+02	1.63E+02	1.14E+02	5.21E+02	1.16E+01	6.68E+01	1.54E+02	4.43E+02	1.76E+03	2.43E+03	4.30E+05	2.47E+06	5.70E+06	1.64E+07	6.50E+07	9.00E+07
Cs-136	4.03E+00	2.92E+01	5.00E+01	5.05E+01	2.00E+01	1.54E+02	4.05E+00	2.27E+01	5.16E+01	1.35E+02	3.00E+02	5.14E+02	1.50E+05	8.40E+05	1.91E+06	5.00E+06	1.11E+07	1.90E+07
Cs-137	7.54E+00	5.52E+01	9.60E+01	1.05E+02	7.50E+01	3.39E+02	7.57E+00	4.38E+01	1.00E+02	2.81E+02	1.16E+03	1.59E+03	2.80E+05	1.62E+06	3.70E+06	1.04E+07	4.30E+07	5.90E+07
Ba-139	2.96E+00	7.50E+00	3.00E-01	0.00E+00	0.00E+00	1.08E+01	3.24E+00	5.14E+00	2.70E-01	0.00E+00	0.00E+00	8.65E+00	1.20E+05	1.90E+05	1.00E+04	0.00E+00	0.00E+00	3.20E+05
Ba-140	6.26E+00	6.10E+01	1.04E+02	1.06E+02	4.00E+01	3.18E+02	7.57E+00	5.19E+01	1.19E+02	3.08E+02	7.30E+02	1.22E+03	2.80E+05	1.92E+06	4.40E+06	1.14E+07	2.70E+07	4.50E+07
La-140	1.40E-01	4.41E+00	2.37E+01	5.83E+01	4.35E+01	1.30E+02	1.16E-01	3.67E+00	2.59E+01	2.00E+02	7.70E+02	1.00E+03	4.30E+03	1.36E+05	9.60E+05	7.40E+06	2.85E+07	3.70E+07
La-141	4.50E-02	2.56E-01	9.13E-02	2.50E-03	0.00E+00	3.95E-01	5.41E-02	2.03E-01	9.46E-02	0.00E+00	0.00E+00	3.51E-01	2.00E+03	7.50E+03	3.50E+03	0.00E+00	0.00E+00	1.30E+04
La-142	2.84E-02	8.09E-02	4.50E-03	0.00E+00	0.00E+00	1.14E-01	3.24E-02	5.68E-02	2.70E-03	0.00E+00	0.00E+00	9.19E-02	1.20E+03	2.10E+03	1.00E+02	0.00E+00	0.00E+00	3.40E+03
Ce-141	1.49E-01	1.46E+00	2.54E+00	2.69E+00	1.46E+00	8.30E+00	1.81E-01	1.25E+00	2.89E+00	8.38E+00	2.78E+01	4.05E+01	6.70E+03	4.63E+04	1.07E+05	3.10E+05	1.03E+06	1.50E+06
Ce-143	1.35E-01	1.23E+00	1.75E+00	1.05E+00	2.50E-02	4.19E+00	1.65E-01	1.05E+00	2.03E+00	2.70E+00	2.70E-01	6.22E+00	6.10E+03	3.89E+04	7.50E+04	1.00E+05	1.00E+04	2.30E+05
Ce-144	1.21E-01	1.19E+00	2.08E+00	2.26E+00	1.55E+00	7.20E+00	1.49E-01	1.01E+00	2.35E+00	7.03E+00	3.00E+01	4.05E+01	5.50E+03	3.75E+04	8.70E+04	2.60E+05	1.11E+06	1.50E+06
Pr-143	5.46E-02	5.40E-01	9.68E-01	1.06E+00	4.63E-01	3.09E+00	6.76E-02	4.46E-01	1.11E+00	3.24E+00	8.38E+00	1.32E+01	2.50E+03	1.65E+04	4.10E+04	1.20E+05	3.10E+05	4.90E+05
Nd-147	2.38E-02	2.31E-01	3.94E-01	3.95E-01	1.39E-01	1.18E+00	2.97E-02	1.95E-01	4.51E-01	1.19E+00	2.46E+00	4.32E+00	1.10E+03	7.20E+03	1.67E+04	4.40E+04	9.10E+04	1.60E+05
Np-239	1.69E+00	1.59E+01	2.44E+01	1.88E+01	1.38E+00	6.21E+01	2.05E+00	1.34E+01	2.78E+01	5.14E+01	2.16E+01	1.16E+02	7.60E+04	4.94E+05	1.03E+06	1.90E+06	8.00E+05	4.30E+06
Pu-238	2.98E-04	2.93E-03	5.11E-03	5.54E-03	4.00E-03	1.79E-02	3.51E-04	2.62E-03	5.68E-03	1.73E-02	7.41E-02	1.00E-01	1.30E+01	9.70E+01	2.10E+02	6.40E+02	2.74E+03	3.70E+03
Pu-239	3.59E-05	3.53E-04	6.19E-04	6.80E-04	4.75E-04	2.16E-03	4.32E-05	3.08E-04	7.03E-04	2.19E-03	8.92E-03	1.22E-02	1.60E+00	1.14E+01	2.60E+01	8.10E+01	3.30E+02	4.50E+02
Pu-240	4.65E-05	4.56E-04	7.98E-04	8.75E-04	6.13E-04	2.79E-03	5.68E-05	3.76E-04	9.19E-04	2.70E-03	1.16E-02	1.57E-02	2.10E+00	1.39E+01	3.40E+01	1.00E+02	4.30E+02	5.80E+02
Pu-241	1.35E-02	1.33E-01	2.31E-01	2.53E-01	1.78E-01	8.08E-01	1.65E-02	1.13E-01	2.76E-01	7.84E-01	3.41E+00	4.59E+00	6.10E+02	4.19E+03	1.02E+04	2.90E+04	1.26E+05	1.70E+05
Am-241	6.08E-06	5.97E-05	1.06E-04	1.15E-04	9.25E-05	3.79E-04	7.57E-06	5.19E-05	1.19E-04	3.62E-04	1.73E-03	2.27E-03	2.80E-01	1.92E+00	4.40E+00	1.34E+01	6.40E+01	8.40E+01

Table 3.0-5 Comparison of Unit 3 and ESP-ER Activity Releases for Loss-of-Coolant Accident

	ESP-ER Activity Release (Ci)						Unit 3 Activity Release (Ci)						Unit 3 Activity Release (MBq)					
Isotope	**0–2 hr**	**2–8 hr**	**8–24 hr**	**24–96 hr**	**96–720 hr**	**Total**	**0–2 hr**	**2–8 hr**	**8–24 hr**	**24–96 hr**	**96–720 hr**	**Total**	**0–2 hr**	**2–8 hr**	**8–24 hr**	**24–96 hr**	**96–720 hr**	**Total**
Cm-242	1.43E-03	1.40E-02	2.44E-02	2.65E-02	1.76E-02	8.39E-02	1.73E-03	1.18E-02	2.70E-02	8.38E-02	3.35E-01	4.59E-01	6.40E+01	4.36E+02	1.00E+03	3.10E+03	1.24E+04	1.70E+04
Cm-244	6.91E-05	6.77E-04	1.19E-03	1.29E-03	9.13E-04	4.14E-03	8.38E-05	5.65E-04	1.38E-03	3.92E-03	1.73E-02	2.32E-02	3.10E+00	2.09E+01	5.10E+01	1.45E+02	6.40E+02	8.60E+02
Total	2.46E+03	7.82E+04	4.76E+05	2.58E+06	1.25E+06	4.39E+06	3.17E+03	6.20E+04	3.86E+05	3.21E+06	1.26E+07	1.63E+07	1.17E+08	2.29E+09	1.43E+10	1.19E+11	4.67E+11	6.03E+11

NOTES:

ESBWR accident release activities from ESP-ER Table 7.1-24a

Unit 3-specific accident release activities in the unit of curie (Ci) from DCD Table 15.4-7

Unit 3-specific accident release activities in the unit of mega-becquerel (MBq) from DCD Table 15.4-7

Table 3.0-6 Activity Releases for ESBWR Cleanup Water Line Break

	ESP-ER Activity Release (Ci)	Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
Isotope	0–2 hr	Coincident Spike	Pre-incident Spike	Coincident Spike	Pre-incident Spike
I-131	3.48E+01	3.95E+00	7.89E+01	1.46E+05	2.92E+06
I-132	7.05E+01	3.73E+01	7.49E+02	1.38E+06	2.77E+07
I-133	9.28E+01	2.73E+01	5.46E+02	1.01E+06	2.02E+07
I-134	1.22E+02	6.86E+01	1.38E+03	2.54E+06	5.09E+07
I-135	9.59E+01	3.84E+01	7.68E+02	1.42E+06	2.84E+07
Cs-134	NP	4.54E-02	9.11E-01	1.68E+03	3.37E+04
Cs-136	NP	3.03E-02	6.05E-01	1.12E+03	2.24E+04
Cs-137	NP	1.21E-01	2.42E+00	4.49E+03	8.97E+04
Co-58	NP	2.27E-02	2.27E-02	8.40E+02	8.40E+02
Co-60	NP	4.41E-02	4.41E-02	1.63E+03	1.63E+03
Sr-89	NP	1.72E-01	3.43E+00	6.36E+03	1.27E+05
Sr-90	NP	1.21E-02	2.42E-01	4.49E+02	8.97E+03
Y-90	NP	1.21E-02	2.42E-01	4.49E+02	8.97E+03
Sr-91	NP	6.46E+00	1.29E+02	2.39E+05	4.79E+06
Sr-92	NP	1.52E+01	3.03E+02	5.61E+05	1.12E+07
Y-91	NP	6.68E-02	1.34E+00	2.47E+03	4.94E+04
Y-92	NP	9.41E+00	1.88E+02	3.48E+05	6.95E+06
Y-93	NP	6.46E+00	1.29E+02	2.39E+05	4.79E+06
Zr-95	NP	1.31E-02	2.63E-01	4.86E+02	9.72E+03

Table 3.0-6 Activity Releases for ESBWR Cleanup Water Line Break

	ESP-ER Activity Release (Ci)	Unit 3 Activity Release (Ci)		Unit 3 Activity Release (MBq)	
Isotope	**0–2 hr**	**Coincident Spike**	**Pre-incident Spike**	**Coincident Spike**	**Pre-incident Spike**
Nb-95	NP	1.31E-02	2.63E-01	4.86E+02	9.72E+03
Mo-99	NP	3.32E+00	6.68E+01	1.23E+05	2.47E+06
Tc-99m	NP	3.32E+00	6.68E+01	1.23E+05	2.47E+06
Ru-103	NP	3.32E-02	6.68E-01	1.23E+03	2.47E+04
Ru-106	NP	5.05E-03	1.01E-01	1.87E+02	3.74E+03
Te-129m	NP	6.68E-02	1.34E+00	2.47E+03	4.94E+04
Te-131m	NP	1.62E-01	3.24E+00	5.98E+03	1.20E+05
Te-132	NP	1.62E-02	3.24E-01	5.98E+02	1.20E+04
Ba-140	NP	6.68E-01	1.34E+01	2.47E+04	4.94E+05
La-140	NP	6.68E-01	1.34E+01	2.47E+04	4.94E+05
Ce141	NP	5.05E-02	1.01E+00	1.87E+03	3.74E+04
Ce-144	NP	5.05E-03	1.01E-01	1.87E+02	3.74E+03
Np-239	NP	1.31E+01	2.63E+02	4.86E+05	9.72E+06
Total	4.16E+02	2.35E+02	4.71E+03	8.70E+06	1.74E+08

NOTES:

NP – Not present in the ESP-ER

ESBWR accident release activities from ESP-ER Table 7.1-31

Unit 3-specific accident release activities in the unit of curie (Ci) from DCD Table 15.4-22

Unit 3-specific accident release activities in the unit of mega-becquerel (MBq) from DCD Table 15.4-22

Table 3.0-7 Comparison of Unit 3 and ESP-ER Liquid Effluent Release Activities

Isotope	ESP-ER Composite Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (MBq/yr)
H-3	8.5E+02	1.4E+01	5.18E+05
C-14	4.4E-04	NP	NP
Na-24	3.5E-03	5.1E-03	1.89E+02
P-32	6.6E-04	4.2E-04	1.55E+01
Cr-51	2.1E-02	1.3E-02	4.81E+02
Mn-54	2.8E-03	1.6E-04	5.92E+00
Mn-56	4.2E-03	1.3E-03	4.81E+01
Fe-55	6.4E-03	2.3E-03	8.51E+01
Fe-59	2.0E-04	7.0E-05	2.59E+00
Co-56	5.7E-03	NP	NP
Co-57	7.9E-05	NP	NP
Co-58	3.4E-03	4.4E-04	1.63E+01
Co-60	1.0E-02	9.0E-04	3.33E+01
Ni-63	1.5E-04	NP	NP
Cu-64	8.2E-03	1.3E-02	4.81E+02
Zn-65	7.5E-04	4.5E-04	1.67E+01
Zn-69m	6.0E-04	9.2E-04	3.40E+01
Br-83	7.5E-05	9.0E-05	3.33E+00
Br-84	2.0E-05	NP	NP

Table 3.0-7 Comparison of Unit 3 and ESP-ER Liquid Effluent Release Activities

Isotope	ESP-ER Composite Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (MBq/yr)
Rb-88	2.7E-04	NP	NP
Rb-89	4.8E-05	NP	NP
Sr-89	3.6E-04	2.2E-04	8.14E+00
Sr-90	3.8E-05	2.0E-05	7.40E-01
Sr-91	9.8E-04	1.2E-03	4.44E+01
Sr-92	8.8E-04	2.9E-04	1.07E+01
Y-90	3.4E-06	NP	NP
Y-91m	1.0E-05	NP	NP
Y-91	2.4E-04	1.4E-04	5.18E+00
Y-92	6.6E-04	1.1E-03	4.07E+01
Y-93	9.8E-04	1.2E-03	4.44E+01
Zr-95	1.0E-03	2.0E-05	7.40E-01
Nb-95	1.9E-03	2.0E-05	7.40E-01
Mo-99	3.9E-03	3.0E-03	1.11E+02
Tc-99m	5.1E-03	5.5E-03	2.04E+02
Ru-103	4.9E-03	4.0E-05	1.48E+00
Ru-105	1.0E-04	1.7E-04	6.29E+00
Ru-106	7.4E-02	NP	NP
Rh-103	4.9E-03	NP	NP

Table 3.0-7 Comparison of Unit 3 and ESP-ER Liquid Effluent Release Activities

Isotope	ESP-ER Composite Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (MBq/yr)
Rh-106	7.4E-02	NP	NP
Ag-110	1.1E-03	NP	NP
Ag-110	1.4E-04	NP	NP
Sb-124	6.8E-04	NP	NP
Te-129	1.4E-04	9.0E-05	3.33E+00
Te-129	1.5E-04	NP	NP
Te-131	1.0E-04	1.0E-04	3.70E+00
Te-131	3.0E-05	NP	NP
Te-132	2.4E-04	2.0E-05	7.40E-01
I-131	1.4E-02	4.2E-03	1.55E+02
I-132	2.8E-03	8.2E-04	3.03E+01
I-133	2.4E-02	2.1E-02	7.77E+02
I-134	1.9E-03	4.0E-05	1.48E+00
I-135	8.2E-03	5.4E-03	2.00E+02
Cs-134	9.9E-03	6.8E-04	2.52E+01
Cs-136	1.2E-03	4.1E-4	1.52E+01
Cs-137	1.3E-02	1.8E-03	6.66E+01
Cs-138	2.1E-04	NP	NP
Ba-137	1.2E-02	NP	NP

Table 3.0-7 Comparison of Unit 3 and ESP-ER Liquid Effluent Release Activities

Isotope	ESP-ER Composite Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (Ci/yr)	North Anna Unit 3 Release Activity (MBq/yr)
Ba-139	2.5E-05	4.0E-05	1.48E+00
Ba-140	5.5E-03	8.2E-04	3.03E+01
La-140	7.4E-03	NP	NP
La-142	2.5E-05	3.0E-05	1.11E+00
Ce-141	1.3E-04	7.0E-05	2.59E+00
Ce-143	1.9E-04	3.0E-05	1.11E+00
Ce-144	3.2E-03	NP	NP
Pr-143	1.4E-04	9.0E-05	3.33E+00
Pr-144	3.2E-03	NP	NP
W-187	2.1E-04	2.4E-04	8.88E+00
Np-239	1.4E-02	1.1E-02	4.07E+02
Total	3.7E-01	9.8E-02	3.62E+03
Total w/	8.5E+02	1.4E+01	5.22E+05

NOTES:

NP – Not present; Note: Isotopes with liquid effluent release activity greater than their previous ESP-ER activity are represented in bold face

ESBWR accident release activities from ESP-ER Table 5.4-6

Unit 3-specific normal operation liquid effluent release activities in the unit of curie (Ci) from DCD Table 12.2-19b

Unit 3-specific normal operation liquid effluent release activities in the unit of mega-becquerel (MBq) from DCD Table 12.2-19b

3.1 External Appearance and Plant Layout

Information regarding external appearance and plant layout is provided in ESP-ER Section 3.1. Supplemental information is provided below.

The design selected for Unit 3 is an ESBWR. A general description of the ESBWR design is provided in FSAR Section 1.1 and FSAR Section 1.2, and the site layout is provided in Figure 1.1-1 and Figure 1.1-2. Table 3.0-2 lists the ESP design parameters that were identified in FEIS Table I-2 and compares them to the corresponding Unit 3 design characteristics.

In accordance with the commitment in ESP-ER Section 5.8.1.5, a visual impact evaluation has been conducted to assess the aesthetic impact of the external appearance of Unit 3. Section 5.8 describes the results of this evaluation and provides artist renderings of the site with Unit 3.

3.2 Reactor Power Conversion System

The Unit 3 reactor power conversion system consists of an ESBWR, a turbine-generator set, and its auxiliaries. As shown in Table 3.0-2, design characteristics of the Unit 3 reactor power conversion system fall within the ESP design parameters identified in FEIS Table I-2. For further information on the reactor power conversion system, refer to FSAR Chapter 4, Chapter 5, Chapter 6, and Chapter 10.

3.3 Plant Water Use

Information for this section is provided in ESP-ER Section 3.3 and FEIS Section 3.2.1. Although ESP-ER Section 3.3 described several water treatment systems for the operation of new units, specific chemicals to be used in water treatment were not known. FEIS Section 5.3.3 identified the need to provide the chemical constituents of effluents in waste streams, other than those in cooling tower blowdown. To provide the information requested in FEIS Section 5.3.3, water treatment systems and associated chemical additives for Unit 3 are described in the following subsections.

3.3.1 Water Consumption

The current water consumption associated with proposed Unit 3 is unchanged from that reported in the ESP-ER for a single unit. ESP-ER Table 3.3-1 provides discharge rates for various systems, including the sanitary waste system. Water release points and quantities are described in Section 3.6 and in ESP-ER Section 3.3.1, respectively. The ESP-ER indicated that the existing sanitary waste system would be modified to accommodate the sanitary waste requirements of the new units. However, it has now been determined that a separate sanitary waste system will be provided for new Unit 3. A description of the Unit 3 sanitary waste system is provided in Section 3.6.2.

3.3.2 Water Treatment

Several water treatment systems will be used in Unit 3 operations. The water treatment systems and associated chemical additives are described in the following sections.

3.3.2.1 Raw Water

Make-up water necessary for the Unit 3 cooling towers will be treated for biofouling, scaling, and suspended matter, with acceptable biocides, anti-scalants, and dispersants, respectively.

Each chemical treatment feed system consists of a tank and/or totes, metering pumps and the necessary associated strainers, pulsation dampeners, piping, valves, instrumentation and controls. Chemical injection points are identified in Table 3.3-1, and the treatment chemicals and their quantities are described below.

The primary biocide to be used for circulating water and plant service water is commercially available 12 percent sodium hypochlorite, which will be injected directly into the cooling tower basins and will be equivalent to 120g Cl_2 per liter. A chlorination dosage of 2 ppm chlorine for approximately 30 minutes, three times a day, will maintain a residual of 0.5 ppm Cl_2. This dose is based on the respective system water flow rates.

The anti-scalant to be used is Nalco's 3D TRASAR® 3DT177 (or equivalent) at a continuous dose rate of 12 ppm neat (i.e., undiluted). The dose is based on the cooling tower blowdown flow rate.

The dispersant to be used is Nalco's 3D TRASAR® 3DT104 (or equivalent) at a continuous dose rate of 60 ppm neat. The dose is based on the cooling tower blowdown flow rate.

Sodium hypochlorite injection for plant water intake chlorination will be injected at the intake structure and is based on a continuous dose of 0.5 ppm Cl_2. The dose is based on plant cooling tower make-up flow, station water flow, and firewater flow, with the dosage adjusted seasonally as required.

Sodium bisulfate will be used for circulating water and plant service water dechlorination. It will be injected at a dose based on neutralizing residual combined chlorine of 0.5 ppm as Cl_2 to 0 ppm as Cl_2. The dose rate will be approximately 120 percent of the stoichiometric rate required to neutralize the residual chlorine in the circulating water and plant service water cooling tower blowdown. This is sufficient to dechlorinate both circulating water and plant service water cooling tower blowdown flows.

Sodium bromide (44.7 weight percent) will be used as a secondary biocide. It will be injected at a 6:1 to 10:1 hypochlorite to bromide ratio. Sodium bromide injection will occur simultaneously with sodium hypochlorite injection (approximately 30 minutes, three times a day) as needed.

Provisions are also included to inject, as an option, a non-oxidizing biocide (Nalco's H-130 or equivalent). The proposed dose rate is 15 to 25 ppm neat, based on circulating and plant service water system volume. The injection will be in a 20-to-40-minute period as needed from once per week to once per month.

Raw water from the North Anna Reservoir will be treated by filtration in the station water system and used to provide make-up for demineralized water, fire protection, and miscellaneous station water users. Prior to filtration, the station water system will be treated with hydrogen peroxide, alum as a coagulant and sodium bicarbonate for final pH adjustment.

3.3.2.2 **Make-up Water**

Make-up water from the North Anna Reservoir for systems other than circulating water and service water will be treated by a process that includes filtration in the station water system followed by processing through activated carbon filters, reverse osmosis (RO), and mixed bed demineralizers, which will result in highly purified water for use in various plant systems. In addition to the processing described above, the demineralized water system will be treated with an anti-scalant just prior to the RO membranes and with sodium hydroxide between the first and second stages of the RO membranes to extend membrane life. Once purified, the make-up water will be directed to various plant systems and services such as condensate, the auxiliary boiler, and cooling water systems.

3.3.2.3 **Condensate System**

Treated condensate water serves as the source of feedwater. Condensate-grade water also serves as the heat transfer media for residual heat removal from primary systems and for the chilled water subsystem. For the existing units, component cooling water is treated by the chemical addition of chromates for corrosion inhibition and pH control. For Unit 3, the component cooling water and chilled water systems will be provided with a chemical feed tank for corrosion inhibitor addition. A specific corrosion inhibitor has not been selected at this time. Water for the chilled water subsystem may need additional treatment depending on the piping materials used.

3.3.2.4 **Domestic Water System**

The domestic water system will provide a safe, state-permitted potable water supply. The Unit 3 domestic water system will be supplied from groundwater wells using hydro-pneumatic tanks and compressors, for pressure maintenance, and a distribution system. Water treatment will be provided through filtration and disinfection, as needed.

Table 3.3-1 Unit 3 Chemical Injection Points

Service	Injection Point
Circulating water sodium hypochlorite feed	Circulating water cooling tower basin
Circulating water anti-scalant feed	Circulating water cooling tower basin or circulating water pump intake bay
Circulating water dispersant feed	Circulating water cooling tower basin or circulating water pump intake bay
Circulating water sodium bromide feed	Circulating water cooling tower basin
Circulating water non-oxidizing biocide feed (optional)	Circulating water cooling tower basin
Plant service water sodium hypochlorite feed	Plant service water cooling tower basin
Plant service water anti-scalant feed	Plant service water cooling tower basin or plant service water pump intake bay
Plant service water dispersant feed	Plant service water cooling tower basin or plant service water pump intake bay
Plant service water sodium bromide feed	Plant service water cooling tower basin
Plant service water non-oxidizing biocide feed (optional)	Plant service water cooling tower basin
Plant intake sodium hypochlorite feed	Plant intake bay
Firewater sodium hypochlorite injection	Plant intake, secondary firewater pump discharge
Cooling tower blowdown sodium bisulfate feed	Cooling tower blowdown sump
Anti-scalant injection	Upstream of RO membrane
Sodium hydroxide	Between 1st and 2nd stage RO membranes
Hydrogen peroxide, alum (coagulant) & sodium bicarbonate (pH adjustment)	Upstream of station water filters

3.4 Cooling System

The Unit 3 cooling system is a closed-cycle, hybrid cooling system, as described in ESP-ER Section 3.4. Table 3.0-2 compares ESP design parameters against the corresponding design characteristics of the Unit 3 cooling system.

3.5 Radioactive Waste Management System

Information regarding the radioactive waste management system is provided in ESP-ER Section 3.5 and FEIS Section 3.2.3. Supplemental information is provided below.

Descriptions of the liquid, gaseous, and solid radioactive waste management systems are provided in FSAR Section 11.2, Section 11.3, and Section 11.4, respectively.

Liquid effluent release activities are provided in Table 5.4-1. Liquid pathway doses are evaluated in Section 5.4.2.1.

Gaseous effluent release activities are provided in Table 5.4-3. Gaseous pathway doses are evaluated in Section 5.4.2.2.

The total predicted yearly activity and yearly generated volume of solid radwaste are provided in Table 3.0-2.

3.6 Nonradioactive Waste Systems

Information for this section is provided in ESP-ER Section 3.6 and FEIS Section 3.2.4. At the time of the ESP-ER, the sanitary waste system for Units 1 and 2 was being evaluated for modification to accommodate Unit 3 sanitary waste requirements. It was subsequently determined that a separate sanitary waste system will be designed for Unit 3. A discussion of this separate sanitary waste system is provided in Section 3.6.2.

FEIS Section 5.3.3 states that the applicant would need to provide information regarding chemical effluents at the time of the COL application.

3.6.1 Effluents Containing Chemicals or Biocides

Proper treatment of lake water will be required for use in various plant systems such as: circulating water, service water, station water and demineralized water. Waste effluents from these systems would include circulating water and service water system blowdown, station and demineralized water system filter backwashes, demineralized water reverse osmosis reject and nonradioactive drains throughout the station. Unit 3 effluent streams will be directed to the cooling tower blowdown sump. Effluent from the sump will be routed to the head of the existing discharge canal where it will mix with circulating water from Units 1 and 2, prior to discharge to the WHTF.

Unit 3 effluent streams will contain some low-level chemicals and/or biocides used for water treatment. Section 3.3 identifies systems that use such chemicals, a description of those chemicals and their injection points. None of the chemicals and/or biocides used for water treatment in Unit 3 will contain any of the "126 priority pollutants" listed in 40 CFR 423, Appendix A (Reference 1). Furthermore, their interaction within the plant systems would not create any by-products that would contain any of these pollutants. However, the effluent streams from Unit 3 will include some of the "126 priority pollutants" due to the fact that they are already present in the lake water. Table 2.3-1 provides a list of the constituents that have been measured in lake water. This table also includes the Reported Level of the constituent concentration in the lake, the Virginia Surface Water Quality Criteria (VSWQC) and the Detection Level of various constituents. In addition to the "126 priority pollutants," this table also includes other constituents and characteristics listed on NPDES Form 2C for which sampling is currently performed.

An analysis was performed using Lake Anna water chemistry data to estimate the constituent levels of the projected effluent streams from Unit 3 and to predict if the new effluents would comply with the existing VPDES permit for Units 1 and 2 (Reference 2). As stated above, these effluent streams will contain all of the constituents already present in the lake water. In all of the effluent streams except two, the concentrations of various constituents are the same as in the lake. The analysis used the maximum value for each constituent for conservatism. The two effluent streams which project higher constituent concentrations are the service water and circulating water cooling tower blowdown. Constituent concentrations will increase in these two effluent streams due to evaporation losses from these cooling systems. Consequently the potential impact of these effluent streams was estimated by increasing measured lake water concentrations, by factors of four and nine (as separate cases), to account for evaporative loss. The combined cooling tower blowdown sump discharge was then evaluated to account for the dilution provided by three different circulating water flow conditions for Units 1 and 2 operation (i.e., all eight circulating water pumps running, two pumps running, or only one pump running).

The results of the analysis demonstrate that for all of the case-condition combinations stated above, the constituent concentrations present at the end of the discharge canal will be less than or equal to the existing Virginia Surface Water Quality Criteria for all but two constituents: copper and tributyltin (TBT).

Both of these constituents, on at least one occasion during the sampling period, have been measured in Lake Anna at concentrations equal to or greater than the current Virginia Surface Water Quality Criteria. The table below shows the maximum and average reported lake water concentrations in comparison to the surface water quality criteria. The table also shows that, based on the maximum concentration and the minimum dilution, the projected concentrations are only approximately 6 to 7 percent above that in the lake. Finally, the table shows that if the average readings were used in place of the maximums, the projected concentrations would be below the surface water quality criteria.

Table 3.6-1 Copper and Tributyltin Concentrations vs. Water Quality Criteria

Constituent Name (See Note 1)	Virginia Surface Water Quality Criteria (VSWQC)	Reported Level in Lake (Max. Reading)	Projected Concentration in WHTF (Max. Reading) (See Note 2)	Reported Level in Lake (Avg.)	Projected Concentration in WHTF (Avg. Reading) (See Note 2)
Copper	0.0027	0.0030	0.0032	0.0024	0.0026
Tributyltin	0.000063	0.000063	0.000067	0.000020	0.000022

Notes:
1. All values are in mg/L (ppm).
2. Based on 9 cycles of concentration with one Unit 1/2 Circulating Water Pump operating considering the reported levels in the lake.

The presence of elevated levels of copper is explained by past mining operations that heavily impacted Contrary Creek, which flows into Lake Anna above the North Anna Power Station (see ESP-ER Section 5.3.2.2.2.b). TBT was used in paint for marine application, as a biocide that prevented the buildup of algae on boat hulls. Although TBT has been restricted for use in this application and the use of marine paints containing TBT is now regulated under the Organotin Antifouling Paint Control Act of 1988, residual amounts of TBT still remain in water bodies such as Lake Anna. The presence of both of these constituents is unrelated to the operation of Units 1 and 2, and Unit 3 would not contribute further. Additionally the increase in concentrations of these constituents in the discharge to the WHTF attributable to the operation of Unit 3 would be essentially immeasurable using current VDEQ-approved analytical methods.

Nominal amounts of non-priority pollutants may be generated from corrosion and wear of plant piping and equipment, some of which could appear in effluent streams. These include three constituents described in the ESP-ER, i.e., oil and grease, total suspended solids and iron. As indicated in Table 2.3-1, these constituents do not have Virginia Surface Water Quality Criteria. For iron, the only existing numeric criterion is for the protection of public water supplies, and Lake Anna is not a designated public water supply. Although these constituents have no VSWQC, they were included in the waste stream analysis. The results indicate that once mixed with the minimum discharge from Units 1 and 2, oil & grease and iron concentrations are much less than 1 mg/L (ppm) and total suspended solids is approximately 5 mg/L (ppm).

Dominion analyzes station discharge for these constituents and characteristics as required by the VPDES permit for Units 1 and 2. Similar sampling and analyses will be performed in accordance with the VPDES permit for Unit 3. See Section 3.3 for chemicals that would be used in the systems requiring pre-treatment along with the proposed injection points for those chemicals.

The potable water system will be supplied from onsite wells. Currently, water from onsite wells is not treated; however, it can be treated if sampling indicates treatment is necessary.

3.6.2 Sanitary System Effluents

A sanitary waste system would be maintained onsite during the construction and operation of Unit 3, with effluents in compliance with acceptable industry design standards, the Clean Water Act (CWA), the state regulatory authority through the VPDES permit and 9 VAC 25-790, Sewage Collection & Treatment Regulations, Commonwealth of Virginia, State Water Control Board. (Reference 3)

The waste treatment system would be permanent, with no wastes handled or processed through a municipal system. Until the permanent sanitary waste treatment facility is functional either during construction or for operation of Unit 3 or as needed during peak construction or outage support activities, additional sewage treatment capacity and approved supplemental means of handling sanitary wastes would be employed. Typically, this supplemental means would be portable sanitary facilities. These facilities could include a centralized restroom and hand-wash trailer(s) in addition to single restroom units located throughout the site as necessary. The wastes collected in these temporary facilities would be pumped out and disposed of by a licensed sanitary waste disposal contractor.

The sanitary waste discharge system for Unit 3 would be designed to collect and transfer sanitary water/waste from the potable water and sanitary waste system to the sewage treatment plant. The sewage treatment plant would be a standard industry design, consisting of two 50 percent-capacity extended aeration type packaged units designed to process the sanitary water/waste to meet local and state regulations for effluent quality in accordance with the VPDES permit. Treated water at a maximum rate of approximately 105 gpm would be routed to the cooling tower blowdown sump which, in turn, would drain to the WHTF just south of the Units 1 and 2 circulating water discharge structure. The sludge generated by the treatment facility would be transported to a licensed sanitary waste landfill for disposal.

The sludge would be regularly monitored for radioactivity. In the event that sewage sludge becomes radioactively contaminated, the contents of the sludge tank would be pumped to a drying bed. The sludge would be allowed to dry completely. Once dry, Radiation Protection personnel would survey the bed and collect all contaminated sludge. The sludge would be packaged in an appropriately sized DOT approved shipping container for disposal at a licensed burial facility. Alternatively, the packaged sludge may be shipped to a third party vendor for further processing (e.g., volume reduction by incineration), re-packaging and final disposal.

Approved technology for processing wastes would include laboratory testing of effluents to ensure proper treatment. Monitoring would be implemented to ensure compliance with regulatory limits.

Section 3.6 References

1. 40 CFR 423, Appendix A, EPA Steam Electric Power Generating Point Source Category, 126 Priority Pollutants.

2. VPDES Permit No. VA0052451, Authorization to Discharge Under the Virginia Pollutant Discharge Elimination System and the Virginia State Water Control Act, Commonwealth of Virginia, Department of Environmental Quality, effective October 25, 2007.

3. 9 VAC 25-790, Sewage Collection & Treatment Regulations, Commonwealth of Virginia, State Water Control Board, effective February 12, 2004.

3.7 Power Transmission System

ESP-ER Section 3.7 described the anticipated switchyard interfaces and transmission system for new units at NAPS and, based on initial evaluation, stated that existing transmission lines were expected to have sufficient capacity to carry the output of the existing and new units. ESP-ER Section 3.7 stated that detailed system load studies could not be performed until an in-service date for the new units is established.

A system load flow study has now been performed for Unit 3, which determined that a new transmission line and other system reinforcements would be required for grid reliability in association with the interconnection of Unit 3. The sections below provide a description of the final configuration of switchyard interfaces and transmission system connections that would be made for Unit 3.

3.7.1 Switchyard Interfaces

Unit 3 would be connected to the existing 500 kV switchyard by an overhead conductor circuit. The existing switchyard would be extended to the north for construction of additional 230 kV bays. The interface of the extension with the transmission system is through the existing switchyard.

PJM Generator Interconnection Q65 North Anna 500 kV (1594 MW) System Impact Study, also referred to as the "PJM System Impact Study" (Reference 1), describes the system reinforcements associated with the interconnection of new Unit 3:

- Replacement of existing 500 kV circuit breakers and associated high voltage equipment with ones with higher current and/or short circuit rating.
- Adding a 500 kV breaker in one of the half bays to support the new North Anna-to-Ladysmith transmission line.
- Adding a 230 kV bay parallel to the existing 230 kV bay on the North side to support the reserve auxiliary transformer's feed to Unit 3.

On the east side of the existing 500 kV Substation, workshops and other auxiliary buildings would be relocated in order to add a new 500/230 kV intermediate switchyard. This 500/230 kV intermediate switchyard would be provided to step down the normal preferred power source from 500 kV to 230 kV to support the requirements for the unit auxiliary transformers and to provide a 500 kV connection to the generator step-up transformer (GSU). Four 500/230kV single-phase transformers, two 500kV circuit breakers, disconnect switches, and other required equipment would be added to the 500/230kV switchyard. One 500 kV circuit breaker would connect to the Unit 3 GSU via overhead conductors. The other 500 kV circuit breaker would connect the 500/230 kV intermediate transformers to the unit auxiliary transformers via an underground cable with overhead bus-to-cable terminations at both ends.

New control and relay protection equipment would be installed in a new or expanded control house. Some existing service systems, such as grounding, raceway, lighting, AC/DC station service, and switchyard lightning protection would be expanded or modified.

3.7.2 Transmission System

The PJM System Impact Study determined that an additional 500 kV transmission line from the North Anna Substation to the Ladysmith Switching Substation is required for grid stability associated with the interconnection of Unit 3. The new transmission line would be installed in the NAPS-to-Ladysmith corridor, on new transmission towers located in proximity to the existing towers. This corridor is identified as "Line 575" on ESP-ER Figure 2.2-4 (beginning at NAPS and heading east) and is 84 m (275 ft) wide and approximately 15 miles long.

Transmission tower separation, line installation, and clearances to ground will be consistent with the National Electrical Safety Code (NESC) and transmission line standards. Basic tower structural design parameters, including the number of conductors and other considerations such as height, materials, color, and finish will be consistent with transmission line design standards. Marking for aircraft visibility will be consistent with the existing adjacent tower. The towers will be approximately 10 feet taller than the existing transmission towers. No expansion of the corridor is required. Electrical design parameters, including the electric-field-induced current from transmission lines will not exceed allowable NESC code requirements (Reference 2). In addition, considerations for visibility for aircraft are the same as for the existing, adjacent towers.

Conductors and other line parameters will meet the PJM and transmission line design criteria. The tower grounding system will be verified for safety and adequacy.

The noise levels resulting from new transmission line operations will be consistent with the existing transmission system. Actual decibel noise levels will be minimized by proper sizing of conductors and the use of corona-free hardware. Examples of the measurement of audible noise from overhead transmission lines are given in IEEE Standard 656-1992 (Reference 3).

Section 3.7 References

1. PJM Generator Interconnection Q65 North Anna 500 kV (1594 MW) System Impact Study, PJM System Planning Division, June 2007.
2. National Electrical Safety Code (NESC 2007 - Section 21, Rule 232.C.1.c).
3. IEEE Standard 656-1992, "IEEE Standard for the Measurement of Audible Noise from Overhead Transmission Lines."

3.8 Transportation of Radioactive Materials

The information for this section is provided in ESP-ER Section 3.8 and associated impacts are resolved as SMALL in FEIS Section 6.2.

3.8.1 Transportation of Unirradiated Fuel

No new and significant information has been identified for this section.

3.8.2 Transportation of Spent Fuel

The following commitment was identified in FEIS Section 6.2.2.2 and is addressed below:

> Consequently, the impacts of crud and activation products on spent fuel transportation accident risks will need to be examined at the CP or COL stage.

The highest surface radioactivity of Co-60 in spent fuel crud available for spallation during transportation accidents for the proposed Unit 3 ESBWR is expected to be 579 µCi/cm^2. NUREG/CR-6672 (Reference) indicates that the total surface area for a BWR fuel rod is approximately 1600 cm^2. The number of fuel rods for an ESBWR assembly is expected to be about 100. As a result, the total surface area of an ESBWR spent fuel assembly would be 160,000 cm^2. The weight of UO_2 for each ESBWR assembly is estimated to be 0.163 MTU (163 kg U). Thus, the unit-specific inventory of Co-60 in ESBWR spent fuel crud available for spallation during transportation accidents is estimated to be 568 Ci/MTU.

The unit-specific inventory of Co-60 in spent fuel crud used for the FEIS analysis was 2730 Ci/MTU (associated with the ABWR), which also represented the entire inventory of activation products in spent fuel. As such, the available unit-specific inventory of Co-60 in ESBWR spent fuel crud is about a factor of 5 lower than that used in the evaluation for the FEIS.

The FEIS states that activation products will need to be examined at the CP or COL stage. Because FEIS Table 6-8 contains data on activation products for the ESBWR, no additional information is required.

Based on the above discussion, the conclusion presented in the FEIS that the impact is SMALL remains valid.

3.8.3 Transportation of Radioactive Waste

No new and significant information has been identified for this section.

Section 3.8 References

NUREG/CR-6672, Reexamination of Spent Fuel Shipment Risk Estimates, March 2000, U.S. Nuclear Regulatory Commission, Washington, D.C.

Chapter 4 Environmental Impacts of Construction

4.1 Land-Use Impacts

The information for this section is provided in ESP-ER Section 4.1 and associated impacts are resolved as SMALL in FEIS Sections 4.1 and 4.6. Supplemental information is provided in Sections 4.1.1 and 4.1.2 below.

4.1.1 The Site and Vicinity

In ESP-ER Section 4.1.1.4, it was concluded that all construction activities for new units, including ground-disturbing activities, would occur within the NAPS site boundary. It has now been determined that offsite modifications would be required for Unit 3 to support the transport of the reactor pressure vessel and other large components to the site.

It is expected that the reactor pressure vessel and other large components (e.g., the main generator, large plant modules) would be transported by barge up the Mattaponi River to an offload location near the town of West Point or the town of Walkerton. From West Point or Walkerton, the oversized equipment would be transported to the site either entirely over-the-road or by a combination of over-the-road and rail.

Road improvements (e.g., repairs, widening, and filling-in low areas) would be required for over-the-road transport. Lowering sections of road for clearance under bridges and installation of temporary road bridges may also be needed. Removal of overhead and/or lateral interferences (wires, signs, etc.) would also be required for both transport methods.

Transport operations for the large components, including the road/rail modifications described above, would be coordinated with State and local officials to minimize land use and other impacts. Upon completion of the transports, temporary structures would be removed, interferences would be re-installed, and disturbed areas would be restored back to their original condition or better. Permanent changes are anticipated to be limited in scope and would be coordinated with State and local officials.

For these reasons, land use and other impacts associated with transport of large components to the North Anna site will be SMALL.

4.1.2 Transmission Line Rights-of-Way and Offsite Areas

As described in Section 3.7, the PJM System Impact Study (Reference) determined that an additional 500 kV transmission line from the North Anna Substation to the Ladysmith Switching Substation is required for grid stability associated with the interconnection of Unit 3. The new line would be installed on new transmission towers in the existing NAPS-to-Ladysmith corridor. This corridor is identified as "Line 575" on ESP-ER Figure 2.2-4 (beginning at NAPS and heading east) and is 84 m (275 ft) wide and approximately 15 miles long.

Land use impacts from constructing the new transmission line would be limited to the existing corridor and access roads and would be minimal. The potential impacts within the corridor and access roads could include:

- Removal of natural landscape (small trees, bushes, vegetation)
- Soil disturbance and erosion
- Siltation of streams
- Tree and brush piles
- Damage to culverts, driveways, and roadways
- Disturbance of archaeological artifacts

Clearing methods for trees, bushes and vegetation would be performed to protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately three inches in diameter and above would be removed from the buffer, leaving material less than three inches undisturbed. Appropriate actions (e.g., stop work) would be taken following discovery of potential historic or archeological resources.

Once the construction of the transmission line has been completed, the transmission corridor and access roads would be restored by means such as:

- Rehabilitation of land including discing, fertilizing, seeding, and installing erosion control devices (e.g., water bars and mulch)
- Removal and proper disposal of debris left or caused by construction
- Restoration of damaged property to its original condition and to the satisfaction of the property owner

Thus, the construction of a new transmission line would result in no additional land use, and land use impacts will be SMALL.

4.1.3 **Historic Properties and Cultural Resources**

No new and significant information has been identified for this section.

Section 4.1 Reference

PJM Generator Interconnection Q65 North Anna 500 kV (1594 MW) System Impact Study, PJM System Planning Division, June 2007.

4.2 Water-Related Impacts

The information for this section is provided in ESP-ER Section 4.2 and associated impacts are resolved as SMALL in FEIS Section 4.3. Supplemental information is provided in Section 4.2.1.1 below.

4.2.1 Hydrologic Alterations

4.2.1.1 Surface Water

The ESP-ER describes two small ephemeral streams that discharge in the vicinity of the cooling tower area and indicates that these streams would be impacted by construction activities. These streams are designated Stream A and Stream B on ESP-ER Figure 4.2-1. A third ephemeral stream (designated as Stream C) has been identified in the cooling tower area. All three streams are shown on ESP-ER Figure 2.4-5, ESP-ER Figure 2.4-6, and Figure 1.1-1. It has now been determined that Unit 3 construction activities would alter only Streams B and C and that Stream A would not be altered, as it is outside of the construction area. The drainage area of Stream A and Stream C are not substantially different, and the discharge point of both streams is Lake Anna. Once construction is complete, the area would continue to drain to the wetlands, through stream beds, to Lake Anna. Thus, while the particular streams identified as being altered by construction have changed, the impact remains SMALL because the area of concern is not substantially different than what was evaluated in the ESP-ER.

The ESP-ER indicated that no new transmission lines or alterations to existing rights-of-way were expected; however, the PJM System Impact Study (Reference) concludes that an additional transmission line would be required as a system reinforcement associated with the interconnection of Unit 3. The new transmission line would be installed in the NAPS-to-Ladysmith corridor on new transmission towers located in proximity to the existing towers. Construction activities for the new transmission line would be performed in accordance with existing corridor procedures.

Section 2.4 identifies wetlands crossed by the Ladysmith corridor. To the extent practical, the construction of new transmission towers would avoid alterations to wetlands and shorelines. In accordance with existing corridor procedures, impacts from construction of overhead transmission lines adjacent to streams would be minimized through various practices, including:

- Hand-clearing of trees and brush located within approximately 100 feet of a stream or ditch with running water
- Removing material approximately three inches in diameter and above from the buffer and leaving material less than three inches undisturbed
- Limiting the disturbance of soil within an approximate 100-foot buffer zone around streams and ditches

- Crossing creeks and streams at right angles in one location on the corridor using culverts, temporary bridges, or large aggregate stone
- Performing work related to stream crossings in accordance with state standards and specifications
- Removing materials from temporary stream crossings at the completion of the project
- Removing logs, trimmings, or brush from ditches, creeks, and drains

In addition impacts from construction of structure foundations and structure erections would be mitigated through various practices, including:

- Evaluation of the site with respect to earth disturbance and erosion potential
- Stabilization of the work site prior to moving to the next location
- Restoration of areas damaged during foundation construction and structural erection activities to approximate original grade and installation of erosion and sedimentation control measures
- Maintaining temporary erosion and sedimentation controls until permanent stabilization is achieved.

Should wetlands be impacted, the U.S. Army Corps of Engineers and other appropriate agencies would be consulted and permits and approvals obtained as necessary.

For these reasons, no significant hydrologic alterations are anticipated from the installation of the new transmission line and water-related impacts will remain SMALL.

4.2.1.2 **Groundwater**

No new and significant information has been identified for this section.

4.2.2 Water-Use Impacts

No new and significant information has been identified for this section.

4.2.3 Future Growth and Development Impacts

No new and significant information has been identified for this section.

Section 4.2 Reference

PJM Generator Interconnection Q65 North Anna 500kV (1594 MW) System Impact Study, PJM System Planning Division, June 2007.

4.3 Ecological Impacts

The information for this section is provided in ESP-ER Section 4.3 and associated impacts are resolved as SMALL in FEIS Section 4.4. Supplemental information is provided in Sections 4.3.1.1 and 4.3.2.

As discussed in Section 3.7, a new 500 kV transmission line required for Unit 3 would be installed along the existing NAPS-to-Ladysmith corridor. The following sections provide supplemental information regarding the impacts of this construction on terrestrial and aquatic ecological resources.

4.3.1 Terrestrial Ecosystems

4.3.1.1 Transmission Corridors

The new transmission line would be installed on new transmission towers in the existing NAPS-to-Ladysmith corridor. Because the transmission corridor has been maintained at a full 275-foot width, widening to accommodate the additional line would not be required. The NAPS-to-Ladysmith corridor passes through land that is typical of north-central Virginia, such as pastures, row crops, forests and shrub bogs. No areas designated as critical habitat for endangered species by the U.S. Fish and Wildlife Service or VDEQ exist along or adjacent to the transmission line corridor. Additionally, the corridor does not cross any state or federal parks, wildlife refuges, or wildlife management areas. Existing access roads would be used to bring the tower components and heavy equipment to the new tower locations, and some clearing of the access roads is anticipated.

Land clearing necessary to accommodate the tower foundations would be controlled by existing transmission line procedures, good construction practices, and established best management practices, as well as applicable regulatory requirements. Clearing methods for trees, bushes and vegetation would be performed to protect natural resources and control erosion of the landscape and siltation of streams. Areas disturbed during tower construction would be restored to the original grade, and temporary erosion and sedimentation controls would remain in place until permanent stabilization by means such as re-vegetation is achieved.

Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately three inches in diameter and above would be removed from the buffer, leaving material less than three inches undisturbed. Soil disturbances would be avoided or reduced to the extent practicable within an approximately 100-foot buffer of streams and ditches with running water. Erosion and sedimentation control measures and buffer zone maintenance around water bodies would be implemented to reduce runoff and erosion. These measures would be left in place, until stabilization of the area is achieved. Work sites would be stabilized prior to moving to the next area.

Potential impacts to streams and creeks would be mitigated by performing work related to stream crossings in accordance with state standards and specifications. In addition, streams and creeks would be crossed at right angles at one location on the corridor using culverts, temporary bridges, or large aggregate stone. Materials would be removed from the temporary crossing at the completion of the project.

Once all the construction of transmission lines has been completed, Dominion would restore disturbed areas by means such as: 1) rehabilitating land by discing, fertilizing, seeding, and installing erosion control devices (e.g., water bars and mulch); 2) properly removing and disposing debris left or caused by construction; and 3) restoring damaged property to its original condition and to the satisfaction of the property owner.

Dust suppression techniques and routine equipment maintenance would be employed to reduce airborne emissions.

The construction activity and associated noise would temporarily disperse nearby wildlife, and a small amount of habitat associated with the tower foundations would be impacted. Although small amphibians and mammals may be displaced, no critical habitats or known protected species would be impacted. Once construction is completed and the corridor is re-vegetated, displaced animals would return to the area.

Thus, impacts from the installation of the transmission line and new transmission towers on terrestrial ecology will be SMALL.

4.3.1.2 ESP Site

No new and significant information has been identified for this section.

4.3.2 Aquatic Ecosystems

No new transmission towers would be constructed in Lake Anna (or other water bodies) and, as discussed in Section 4.3.1.1, a buffer zone would be maintained around water bodies, where feasible. Construction within wetlands would be avoided to the extent practical. Should wetlands be impacted, the U.S. Army Corps of Engineers and other appropriate agencies would be consulted and permits and approvals obtained as necessary.

Thus, impacts from construction of the new transmission line and associated transmission towers on aquatic ecosystems will be SMALL.

4.4 Socioeconomic Impacts

The information for this section is provided in ESP-ER Section 4.4 and associated impacts are resolved in FEIS Sections 4.2, 4.5, 4.7, and 4.8. These FEIS sections resolved that adverse impacts range from SMALL to MODERATE and beneficial impacts range from SMALL to MODERATE. Supplemental information is provided below.

As discussed in Section 3.7, the new 500 kV transmission line required in connection with Unit 3 would be installed in the existing NAPS-to-Ladysmith corridor. As discussed in Section 2.4, a portion of this new transmission line would cross Lake Anna, as well as other waterways and wetlands. As a precaution, during installation of the new transmission line across Lake Anna and the other waterways, access to the subject areas would be temporarily restricted from recreational use. Although this would limit the areas that are accessible to the public for recreational use, the limitation would be temporary in nature, and full use would be restored once the installation has been completed. The impacts of construction of the transmission line on the recreational use of Lake Anna and the other waterways will be SMALL, and further mitigation is not warranted.

4.5 Radiation Exposure to Construction Workers

The information for this section is provided in ESP-ER Section 4.5 and associated impacts are resolved as SMALL in FEIS Section 4.9.

No new and significant information has been identified for this section.

4.6 Measures and Controls to Limit Adverse Impacts During Construction

Measures and controls to limit adverse impacts during construction were addressed in ESP-ER Section 4.6 and in FEIS Section 4.10. These measures and controls have been incorporated into the Environmental Protection Plan (EPP) in Appendix 1A, along with the following new mitigation measures and controls:

- Upon completion of the transports, temporary structures would be removed, interferences would be reinstalled, and disturbed areas would be restored back to their original condition or better. (Section 4.1.1).
- The new transmission line would be located in an existing corridor and constructed under practices and procedures applicable to the existing transmission lines. (Sections 4.1.2, 4.2.1.1 and 4.3.1.1).
- Land clearing necessary to accommodate the new transmission tower foundations would be controlled by existing transmission line procedures, good construction practices, and established best management practices (Section 4.3.1.1), as well as all applicable regulations.
- Clearing methods for small trees, bushes, and vegetation would be performed to protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately three inches in diameter and above would be removed from the buffer, leaving material less than three inches undisturbed (Sections 4.1.2, 4.2.1.1, and 4.3.1.1)
- Once all the construction of transmission lines has been completed, Dominion would restore disturbed areas by means such as: 1) rehabilitating land by discing, fertilizing, seeding, and installing erosion control devices (e.g. water bars and mulch); 2) properly removing and disposing debris left or caused by construction; and 3) restoring damaged property to its original condition and to the satisfaction of the property owner (Sections 4.1.2 and 4.3.1.1).
- Appropriate actions (e.g., stop work) would be taken following discovery of potential historic or archeological resources (Section 4.1.3).

- Potential impacts to streams and creeks would be mitigated by performing work related to stream crossings in accordance with state standards and specifications. In addition, streams and creeks would be crossed at right angles at one location on the corridor using culverts, temporary bridges, or large aggregate stone. Materials would be removed from the temporary crossing at the completion of the project (Section 4.2.1.1).
- Soil disturbances would be avoided or reduced to the extent practicable within an approximately 100-foot buffer of streams and ditches with running water. Erosion and sedimentation control measures and buffer zone maintenance around water bodies would be implemented to reduce runoff and erosion. These measures would be left in place, until stabilization of the area is achieved. Work sites would be stabilized prior to moving to the next area (Sections 4.2.1.1 and 4.3.1.1).
- To the extent practicable, construction would avoid alterations to shorelines and wetland areas. Should wetlands be impacted, the U.S. Army Corps of Engineers (and other appropriate agencies) would be consulted, and permits and approvals would be obtained as necessary. (Section 4.2.1.1)
- Dust suppression techniques would be utilized and equipment maintenance employed to reduce airborne emissions (Section 4.3.1.1).
- As a safety precaution, during installation of the transmission lines, access to the area would be temporarily restricted from recreational use (Section 4.4).

Chapter 5 Environmental Impacts of Station Operation

5.1 Land-Use Impacts (Operations)

The information for this section is provided in ESP-ER Section 5.1 and associated impacts are resolved as SMALL in FEIS Section 5.1. Supplemental information is provided in Section 5.1.2 below.

5.1.1 The Site and Vicinity

No new and significant information has been identified for this section.

5.1.2 Transmission Corridors and Offsite Areas

As discussed in Section 3.7, the new 500 kV transmission line required in connection with Unit 3 will be installed along the existing NAPS-to-Ladysmith corridor. As discussed in Section 5.6, the impacts of maintenance practices, visual impacts, shock, noise, or electro-magnetic fields would not change. Existing corridor access routes would be used. Therefore, no changes in or new restrictions to land use would result, and offsite land-use impacts will remain SMALL. No new mitigation measures or controls are warranted.

5.1.3 Historic Properties

No new and significant information has been identified for this section.

5.2 Water-Related Impacts

The information for this section is provided in ESP-ER Section 5.2 and associated impacts, with the exception of water quality impacts, are resolved in FEIS Sections 5.3 and 7.3 as SMALL during normal water years and temporarily MODERATE during severe droughts. Supplemental information regarding water quality impacts is provided in Section 5.2.2 below.

5.2.1 Hydrologic Alterations and Plant Water Supply

No new and significant information has been identified for this section.

5.2.2 Water-Use Impacts

Section 3.3 describes water treatment and Section 3.6 describes nonradioactive effluents, including sanitary waste and cooling tower blowdown. Section 3.6 identifies the expected constituents that would be contained in the effluents discharged to the WHTF (from Units 1 and 2, as well as Unit 3) and compares them to Virginia Surface Water Quality Criteria (Reference), as applicable.

The effluent from Unit 3 would include circulating water and service water system blowdown (which have been concentrated due to evaporation from the systems) and other system backwashes, rejects and drains (which have the same concentrations as the lake water). Concentrations of various constituents in the Unit 3 effluent would be diluted with a much larger volume of water in the WHTF. Operation of a dechlorination system would neutralize chlorine in the circulating water and plant service water cooling tower blowdown before discharge to the WHTF and eventually to the North Anna Reservoir.

As described in Section 3.6, the results of the effluent analysis demonstrate that for all postulated case/condition combinations, the constituent concentrations that are discharged to the lake would remain within the existing VPDES permit water quality criteria with the exception of two constituents: copper and tributyltin.

Both of these constituents are already present in the lake water at concentrations equal to or greater than the current VPDES water quality criteria. The presence of both of these constituents is unrelated to the operation of the existing Units 1 and 2, and Unit 3 would not contribute to the amounts already existing in the lake. Additionally the increase in concentrations of these constituents in the discharge to the WHTF attributable to the operation of Unit 3 would be essentially immeasurable using current VDEQ-approved analytical methods.

Dominion analyzes station discharge for these constituents and characteristics as required by the VPDES permit for Units 1 and 2. Similar sampling and analyses would be performed in accordance with the VPDES permit for Unit 3.

Section 5.2 Reference

9 VAC 25-260 (et seq.) Virginia Water Quality Standards, State Water Control Board, effective August 14, 2007.

5.3 Cooling System Impacts

The information for this section is provided in ESP-ER Section 5.3, and associated cooling system impacts are resolved as SMALL in FEIS Sections 5.4 and 5.8.

For the ESP-ER, an analysis was performed for the wet cooling towers to describe the plume impacts including: fogging, icing, salt deposition and visible plumes from traditional (e.g., non plume abated) wet cooling towers. The results of that analysis are documented in ESP-ER Section 5.3. In ESP-ER Section 5.3.3.1, a commitment was made to conduct a confirmatory evaluation of the fogging, icing, and salt deposition to show that the values in the ESP-ER remain bounding, when specific cooling tower and plant designs had been selected. To satisfy this commitment, a confirmatory analysis of the plume impacts associated with the closed-cycle, combination dry and wet towers has been performed, using manufacturer's data representative of the Unit 3 cooling tower design. The methodology used is the same as that used in the ESP-ER analysis. The confirmatory analysis concluded that the plume impacts reported in the ESP-ER, associated with the main cooling towers, remain bounding.

No new and significant information has been identified for this section.

5.4 Radiological Impacts of Normal Operation

The information for this section is provided in the ESP-ER Section 5.4, and associated impacts are resolved as SMALL in FEIS Section 5.9. However, ESP-ER Section 5.4 includes a commitment to verify the maximum occupational dose at the time of selection of the reactor design. The commitment is addressed in Section 5.4.2.

5.4.1 **Exposure Pathways**

No new and significant information has been identified for this section.

5.4.2 **Radiation Doses to Members of the Public**

In the ESP-ER, the maximum annual occupational dose to the workers from normal operation of proposed Unit 3 was estimated to be 150 person-rem. Using ESBWR-specific data, the annual occupational dose has been recalculated to be 60.4 person-rem. The ESP-ER value for occupational dose bounds the dose calculated for the ESBWR, and thus the impact due to occupation worker dose remains SMALL and no new mitigation measures or controls are warranted.

5.4.2.1 **Liquid Pathway Doses**

ESP-ER Table 5.4-6 presented the composite release activities of liquid effluents for a single new unit. These composite activities were obtained by taking the maximum activity for each isotope from multiple reactor designs. ESBWR-specific liquid effluent release activities are presented in Table 5.4-1 and compared to the ESP-ER composite release activities. Activities in bold print indicate isotopes for which the estimated ESBWR release activity is greater than the corresponding ESP-ER composite release activity. "NP" denotes isotopes which are not present in ESBWR liquid effluents.

There are small increases in liquid effluent release activities for twelve radioisotopes associated with normal operation of Unit 3 as compared to the composite release activities presented in the ESP-ER. However, the total liquid effluent release activity of Unit 3 is at least an order of magnitude lower than the total ESP-ER composite release activity.

ESP-ER Table 5.4-10 provided the total body and organ doses to the maximally exposed individual (MEI) resulting from liquid and gaseous effluent releases of a single new unit. These calculated doses were determined to be within the design objectives of 10 CFR 50, Appendix I. Using design-specific release activities of liquid effluents from Unit 3, the total annual doses to the MEI from liquid effluents are calculated and presented in Table 5.4-2. The total annual doses from liquid effluents were calculated using the same methodologies and parameters (with the exception of release activity) as those used in ESP-ER annual MEI dose calculations.

As shown in Table 5.4-2, the annual doses to the MEI from different liquid effluent pathways are consistently lower than those calculated and presented in the ESP-ER. Therefore, the dose impacts to the MEI remain SMALL, and no new mitigation measures or controls are warranted.

5.4.2.2 **Gaseous Pathway Doses**

ESP-ER Table 5.4-7 presented the composite release activities of gaseous effluents for a single new unit. These composite activities were obtained by taking the maximum activity for each isotope from multiple reactor designs. ESBWR-specific gaseous effluent release activities are presented in Table 5.4-3 and are compared to ESP-ER composite release activities. All Unit 3 ESBWR-specific release activities are lower than the corresponding ESP-ER composite release activities. "NP" denotes isotopes which are not present in ESBWR liquid effluents.

The total annual doses to the MEI from gaseous effluents have been re-calculated using the ESBWR-specific gaseous release activities and the same methodologies and parameters as those used in ESP-ER calculations, with the exception of MEI locations. As discussed in Section 2.7, the MEI locations for the vegetable garden, residential, and meat cow receptors have changed. A single, bounding location (0.74 mile ESE from the facility boundary), has been selected for these receptors. However, since the three receptors are not physically at the same location, the doses for the three receptors are not summed. The nearest site boundary MEI location (0.88 mile ESE of the site) is the same as was used in the ESP-ER. The results of the total annual dose calculations are provided in Table 5.4-4. The values in bold print indicate the Unit 3 gaseous pathway doses to the MEI that are larger than the corresponding ESP-ER doses.

As shown in Table 5.4-4, several pathways show slight increases in total body and thyroid doses to the MEI, resulting from the change in MEI locations. Table 5.4-5 shows that the annual total body and skin doses to the MEI are lower than those calculated and presented in the ESP-ER. Although the annual thyroid dose to the MEI from iodine and particulates in gaseous effluents calculated using Unit 3-specific release activities is slightly higher than that presented in the ESP-ER, it remains within the 10 CFR 50, Appendix I limit. Therefore, the impact of gaseous pathway doses remains SMALL, and no mitigation measures or controls are warranted.

5.4.2.3 Direct Radiation from Station Operation

As indicated in ESP-ER Section 5.4.1.3, the offsite dose due to direct radiation from the new and existing units will be negligible. However, another source of direct radiation is the NAPS ISFSI, which is located south of the proposed Unit 3 site. The distance from the ISFSI to the site boundary is 2500 ft. The annual direct radiation contribution at the site boundary from the ISFSI is about 1.7 mrem/yr. The distance from the ISFSI to the nearest residence is 2860 ft. Since this is farther away than the site boundary, the direct radiation dose to the MEI at the nearest residence would be less than 1.7 mrem/yr.

5.4.3 Impacts to Members of the Public

ESP-ER Table 5.4-11 demonstrated that the total site liquid and gaseous effluent doses resulting from the normal operation of the two existing North Anna units and two proposed new units would be well within the regulatory limits of 40 CFR 190. ESP-ER Table 5.4-12 presented the collective doses attributable to two new units for the population within 50 miles of the proposed ESP site. Accounting for changes in the liquid and gaseous effluent release activities, identified in Table 5.4-1 and Table 5.4-3, the total annual doses to the MEI and the total population doses resulting from the proposed Unit 3 liquid and gaseous effluents are calculated and presented in Table 5.4-6 and Table 5.4-7, respectively. These total annual doses to the MEI and to the population were calculated using the same methodologies and parameters (with the exception of the release activities) as those used in ESP-ER.

As shown in Table 5.4-6 and Table 5.4-7, the annual total site dose to the MEI and the population within 50 miles resulting from Unit 3 liquid and gaseous effluents are lower than those calculated and presented in ESP-ER. Therefore, the liquid and gaseous effluent doses to the MEI and the population provided in the ESP-ER are bounding, the impact to members of the public remains SMALL, and no mitigation measures or controls are warranted.

5.4.4 Impacts to Biota Other Than Members of the Public

ESP-ER Table 5.4-16 presented the maximum calculated doses to biota from liquid and gaseous effluents. In FEIS Section 5.9.5.3, the NRC staff concluded that, based on Dominion calculations, the impacts to the biota would be SMALL, and mitigation is not warranted. The maximum doses to biota resulting from proposed Unit 3 liquid and gaseous effluents have been calculated using the same methodologies in the ESP-ER, accounting for the changes in liquid and gaseous effluent release activities. These doses are provided in Table 5.4-8.

As shown in Table 5.4-8, the annual doses to the biota from liquid and gaseous effluent releases are lower than those calculated and presented in ESP-ER. Therefore, the liquid and gaseous effluent biota doses in the ESP-ER are still bounding, and impact from doses on biota other than members of the public remains SMALL, and no mitigation measures and controls are warranted.

5.4.5 Conclusion

As discussed previously, the impacts of radiological exposure to the MEI, the population, occupational workers, and biota resulting from normal operation of Unit 3 will be SMALL, and mitigation measures and controls are not warranted.

Table 5.4-1 Release Activities (Ci/yr) in Liquid Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
H-3	8.5E+02	1.4E+01
C-14	4.4E-04	NP
Na-24	3.5E-03	**5.1E-03**
P-32	6.6E-04	4.2E-04
Cr-51	2.1E-02	1.3E-02
Mn-54	2.8E-03	1.6E-04
Mn-56	4.2E-03	1.3E-03
Fe-55	6.4E-03	2.3E-03
Fe-59	2.0E-04	7.0E-05
Co-56	5.7E-03	NP
Co-57	7.9E-05	NP
Co-58	3.4E-03	4.4E-04
Co-60	1.0E-02	9.0E-04
Ni-63	1.5E-04	NP
Cu-64	8.2E-03	**1.3E-02**
Zn-65	7.5E-04	4.5E-04
Zn-69m	6.0E-04	**9.2E-04**
Br-83	7.5E-05	**9.0E-05**
Br-84	2.0E-05	NP
Rb-88	2.7E-04	NP
Rb-89	4.8E-05	NP
Sr-89	3.6E-04	2.2E-04
Sr-90	3.8E-05	2.0E-05
Sr-91	9.8E-04	**1.2E-03**
Sr-92	8.8E-04	2.9E-04
Y-90	3.4E-06	NP
Y-91m	1.0E-05	NP
Y-91	2.4E-04	1.4E-04
Y-92	6.6E-04	**1.1E-03**

Table 5.4-1 Release Activities (Ci/yr) in Liquid Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
Y-93	9.8E-04	**1.2E-03**
Zr-95	1.0E-03	2.0E-05
Nb-95	1.9E-03	2.0E-05
Mo-99	3.9E-03	3.0E-03
Tc-99m	5.1E-03	**5.5E-03**
Ru-103	4.9E-03	4.0E-05
Ru-105	1.0E-04	**1.7E-04**
Ru-106	7.4E-02	NP
Rh-103m	4.9E-03	NP
Rh-106	7.4E-02	NP
Ag-110m	1.1E-03	NP
Ag-110	1.4E-04	NP
Sb-124	6.8E-04	NP
Te-129m	1.4E-04	9.0E-05
Te-129	1.5E-04	NP
Te-131m	1.0E-04	1.0E-04
Te-131	3.0E-05	NP
Te-132	2.4E-04	2.0E-05
I-131	1.4E-02	4.2E-03
I-132	2.8E-03	8.2E-04
I-133	2.4E-02	2.1E-02
I-134	1.9E-03	4.0E-05
I-135	8.2E-03	5.4E-03
Cs-134	9.9E-03	6.8E-04
Cs-136	1.2E-03	4.1E-4
Cs-137	1.3E-02	1.8E-03
Cs-138	2.1E-04	NP
Ba-137m	1.2E-02	NP
Ba-139	2.5E-05	**4.0E-05**

Table 5.4-1 Release Activities (Ci/yr) in Liquid Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
Ba-140	5.5E-03	8.2E-04
La-140	7.4E-03	NP
La-142	2.5E-05	**3.0E-05**
Ce-141	1.3E-04	7.0E-05
Ce-143	1.9E-04	3.0E-05
Ce-144	3.2E-03	NP
Pr-143	1.4E-04	9.0E-05
Pr-144	3.2E-03	NP
W-187	2.1E-04	**2.4E-04**
Np-239	1.4E-02	1.1E-02
Total w/o H-3	3.7E-01	9.8E-02
Total w/ H-3	8.5E+02	1.4E+01

Note 1: Activities in bold print indicate isotopes for which the estimated ESBWR release activity is greater than the corresponding ESP-ER composite release activity.
Note 2: "NP" denotes isotopes which are "not present" in ESBWR liquid effluents.

Table 5.4-2 Comparison of Annual Doses to MEI from Unit 3 Liquid Effluent at Lake Anna

	ESP Dose (mrem/yr)			Unit 3 Dose (mrem/yr)		
Pathway	**Total Body**	**Thyroid**	**Bone**	**Total Body**	**Thyroid**	**Bone**
Fish	5.1E-01	N/A	2.3E+00	7.8E-02	N/A	1.2E+00
Invertebrate	6.6E-02	N/A	1.5E-01	8.3E-03	N/A	6.5E-02
Drinking	2.0E-01	6.5E-01	2.7E-02	4.1E-03	1.8E-01	5.6E-03
Shoreline	3.0E-02	3.0E-02	3.0E-02	3.0E-03	3.0E-03	3.0E-03
Swimming	3.2E-04	3.2E-04	3.2E-04	1.2E-04	1.2E-04	1.2E-04
Boating	4.0E-04	4.0E-04	4.0E-04	1.5E-04	1.5E-04	1.5E-04
Total	8.1E-01	6.8E-01	2.5E+00	9.4E-02	1.8E-01	1.3E+00
Age group receiving maximum dose	Adult	Infant	Child	Adult	Infant	Child

Note 1: Bone of the child is the organ receiving the maximum dose.

Note 2: There are no infant doses for the vegetable and meat pathways because infants do not consume these foods. "NA" denotes "not applicable."

Table 5.4-3 Release Activities (Ci/yr) in Gaseous Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
H-3	3.5E+03	7.6E+01
C-14	1.2E+01	9.6E+00
Na-24	4.4E-03	1.5E-05
P-32	1.0E-03	3.6E-06
Ar-41	3.0E+02	7.7E-03
Cr-51	3.8E-02	2.1E-03
Mn-54	5.9E-03	4.0E-03
Mn-56	3.8E-03	2.9E-05
Fe-55	7.1E-03	1.3E-04
Fe-59	8.9E-04	5.2E-04
Co-57	8.2E-06	NP
Co-58	2.3E-02	1.0E-03
Co-60	1.4E-02	8.6E-03
Ni-63	7.1E-06	1.3E-07
Cu-64	1.1E-02	1.9E-05
Zn-65	1.2E-02	7.6E-03
Kr-83m	1.3E-03	1.0E-03
Kr-85m	3.6E+01	1.8E+01
Kr-85	4.1E+03	1.2E+02
Kr-87	4.9E+01	3.9E+01
Kr-88	7.4E+01	5.9E+01
Kr-89	4.7E+02	3.8E+02
Kr-90	4.2E-04	3.4E-04
Rb-89	4.7E-05	5.4E-07
Sr-89	6.2E-03	4.0E-03
Sr-90	1.2E-03	2.1E-05
Sr-91	1.1E-03	1.8E-05
Sr-92	8.6E-04	1.3E-05

Table 5.4-3 Release Activities (Ci/yr) in Gaseous Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
Y-90	5.0E-05	8.8E-07
Y-91	2.6E-04	4.7E-06
Y-92	6.8E-04	9.9E-06
Y-93	1.2E-03	2.0E-05
Zr-95	1.7E-03	1.2E-03
Nb-95	9.2E-03	6.6E-03
Mo-99	6.5E-02	4.5E-02
Tc-99m	3.3E-04	6.0E-06
Ru-103	3.8E-03	2.8E-03
Ru-106	7.8E-05	3.6E-07
Rh-103m	1.2E-04	2.2E-06
Rh-106	2.1E-05	3.6E-07
Ag-110m	2.2E-06	1.6E-06
Sb-124	2.0E-04	1.5E-04
Sb-125	6.1E-05	NP
Te-129m	2.4E-04	4.4E-06
Te-131m	8.3E-05	1.5E-06
Te-132	2.1E-05	3.8E-07
I-131	5.1E-01	4.1E-01
I-132	2.4E+00	1.6E+00
I-133	1.9E+00	1.3E+00
I-134	4.1E+00	2.9E+00
I-135	2.6E+00	1.7E+00
Xe-131m	1.8E+03	3.0E+00
Xe-133m	8.7E+01	2.3E-03
Xe-133	4.6E+03	8.4E+02
Xe-135m	7.7E+02	6.1E+02
Xe-135	8.2E+02	6.6E+02

Table 5.4-3 Release Activities (Ci/yr) in Gaseous Effluent

Isotope	ESP-ER Composite Release Activity (Ci/yr)	Unit 3 Release Activity
Xe-137	9.8E+02	7.8E+02
Xe-138	7.8E+02	6.3E+02
Xe-139	5.3E-04	4.2E-04
Cs-134	6.8E-03	4.8E-03
Cs-136	6.5E-04	4.0E-04
Cs-137	1.0E-02	7.3E-03
Cs-138	1.9E-04	2.3E-06
Ba-140	3.0E-02	2.1E-02
La-140	2.0E-03	3.5E-05
Ce-141	1.0E-02	7.2E-03
Ce-144	2.1E-05	3.6E-07
Pr-144	2.1E-05	3.6E-07
W-187	2.1E-04	3.5E-06
Np-239	1.3E-02	2.2E-04
Total w/o H-3	1.5E+04	4.2E+03
Total w/ H-3	1.8E+04	4.2E+03

Note: "NP" denotes isotopes which are "not present."

Table 5.4-4 Gaseous Pathway Doses (mrem/yr) to the MEI

		ESP-ER			Unit 3		
Location	**Pathway**	**Total Body**	**Thyroid**	**Skin**	**Total Body**	**Thyroid**	**Skin**
Nearest Site Boundary (0.88 mi ESE for ESP-ER; same location for this ER)	Plume	2.1E+00	N/A	6.2E+00	1.6E+00	**1.6E+00**	4.0E+00
	Inhalation						
	Adult	3.0E-01	1.6E+00	N/A	9.6E-03	9.7E-01	N/A
	Teen	3.1E-01	2.0E+00	N/A	1.0E-02	1.2E+00	N/A
	Child	2.7E-01	2.3E+00	N/A	9.8E-03	1.5E+00	N/A
	Infant	1.6E-01	2.0E+00	N/A	6.0E-03	1.4E+00	N/A
Nearest Garden (0.94 mi NE for ESP-ER; 0.74 mi ESE for this ER)	Vegetable						
	Adult	4.4E-01	4.9E+00	N/A	2.6E-01	**5.6E+00**	N/A
	Teen	5.7E-01	6.6E+00	N/A	4.1E-01	**7.6E+00**	N/A
	Child	1.1E-00	1.3E+01	N/A	9.4E-01	**1.5E+01**	N/A
Nearest Residence (0.96 mi NNE for ESP-ER; 0.74 mi ESE for this ER)	Plume	1.4E+00	N/A	4.0E+00	2.8E-01	**2.8E-01**	5.6E-01
	Inhalation						
	Adult	2.0E-01	1.0E+00	N/A	1.0E-02	1.0E+00	N/A
	Teen	2.0E-01	1.3E+00	N/A	1.1E-02	1.3E+00	N/A
	Child	1.8E-01	1.5E+00	N/A	1.0E-02	**1.6E+00**	N/A
	Infant	1.0E-01	1.3E+00	N/A	6.4E-03	**1.5E+00**	N/A
Nearest Meat Cow (1.37 mi SE for ESP-ER; 0.74 mi ESE for this ER)	Meat						
	Adult	6.7E-02	1.5E-01	N/A	**9.1E-02**	**2.8E-01**	N/A
	Teen	4.9E-02	1.1E-01	N/A	**7.6E-02**	**2.1E-01**	N/A
	Child	7.9E-02	1.7E-01	N/A	**1.4E-01**	**3.5E-01**	N/A

Notes:

1. There are no infant doses for the vegetable and meat pathways because infants do not consume these foods.

2. "N/A" denotes "not applicable."

Table 5.4-5 Comparison of Annual Doses to the MEI from Gaseous Effluents

Type of Dose	ESP-ER 1 New Unit (MEI Location)	Unit 3 (MEI Location)	10 CFR 50 Appendix I Limit
Gamma Air (mrad/yr)	3.2 (Site Boundary)	2.1 (Site Boundary)	10
Beta Air (mrad/yr)	4.8 (Site Boundary)	2.4 (Site Boundary)	20
Total Body (mrem/yr)	2.4 (Site Boundary)	1.6 (Site Boundary)	5
Skin (mrem/yr)	6.2 (Site Boundary)	4.0 (Site Boundary)	15
Iodine and Particulates – Thyroid (mrem/yr)	12 (Garden)	**14** (Garden)	15

Table 5.4-6 Comparison of Site Doses (mrem/yr) to the MEI

	ESP	North Anna Unit 3 (ESBWR)					
Type of Dose	Site Total (1)	Liquid	Gaseous	Total	Existing Units (2)	Site Total (3)	40 CFR 190 Limit
Total Body (mrem/yr)	6.8	0.094	1.6	1.7	2.1	3.7	25
Thyroid (mrem/yr)	27	0.18	15	15	2.2	17	75
Bone (mrem/yr)	12	1.3	4.6	5.8	2.2	8.1	25

Notes:

1. The ESP site total doses are for two new units, and do not include a dose contribution from the ISFSI.
2. The doses from existing units include ISFSI contribution.
3. This site total dose includes the Unit 3 total dose and the dose from the existing units

Table 5.4-7 Collective Total Body (Population) Doses (person-rem/yr) Within 50 Miles

	ESP-ER 1 New Unit	Unit 3
Liquid	8.6E+00	1.0E+00
Noble Gases (Gaseous)	3.5E+00	1.4E+00
Iodines and Particulates (Gaseous)	1.4E+00	9.0E-01
H-3 and C-14 (Gaseous)	1.4E+01	3.7E+00
Total	2.8E+01	7.0E+00
Natural Background	9.2E+05	9.2E+05

Table 5.4-8 Comparison of Annual Doses (mrad/yr) to Biota from Liquid and Gaseous Effluent

Biota Effluents	ESP-ER		Unit 3	
	Liquid	**Gaseous**	**Liquid**	**Gaseous**
Fish	9.7E+00	N/A	3.3E+00	N/A
Invertebrates	4.6E+01	N/A	1.2E+01	N/A
Algae	5.4E+01	N/A	1.7E+01	N/A
Muskrat	4.3E+01	3.4E+01	2.1E+01	1.7E+01
Raccoon	4.9E+00	3.4E+01	6.2E-01	1.7E+01
Heron	5.4E+01	3.4E+01	9.9E+00	1.7E+01
Duck	4.3E+01	3.4E+01	2.1E+01	1.7E+01

5.5 Environmental Impact of Waste

The information for this section is provided in ESP-ER Section 5.5. Supplemental information is provided in Section 5.5.1 below.

5.5.1 Nonradioactive-Waste-System Impacts

No new and significant information has been identified for this section, with the exception of the sanitary waste system, as discussed below.

The ESP-ER described that sewage from new units would be combined with the sanitary sewage from Units 1 & 2 for treatment. As discussed in Section 3.6, it has since been determined that sanitary sewage from Unit 3 would be treated in a new dedicated sanitary sewage waste treatment system. This new system would be similar to sanitary sewage treatment plants typically used for industrial applications. These sanitary waste plants have proven performance and substantial operational history.

Sanitary wastes from this new system would be managed on site and disposed of off site in compliance with applicable laws, regulations, and permit conditions imposed by federal, Virginia, and local agencies.

Impacts associated with treatment of sanitary waste from operation of Unit 3 will be SMALL and no mitigation is warranted.

5.5.2 Mixed Waste Impacts

No new and significant information has been identified for this section.

5.5.3 Conclusions

Impacts associated with treatment of sanitary waste from operation of Unit 3 will be SMALL and no mitigation is warranted.

5.6 Transmission System Impacts

The information for this section is provided in ESP-ER Section 5.6 and associated impacts, other than the effects of electro-magnetic fields (EMFs) are resolved as SMALL in FEIS Sections 5.1.2 and 5.4.1.5. Supplemental information is provided below to address the impacts of the new transmission line for Unit 3 and the unresolved FEIS issue on EMF exposure from transmission system operations.

5.6.1 Terrestrial Ecosystems

Maintenance practices for the existing NAPS transmission corridors are described in ESP-ER Sections 5.6.1.1 and 5.6.1.2. The new transmission line would be installed in the existing NAPS-to-Ladysmith corridor and would not result in changes to these practices. Therefore, impacts on terrestrial ecosystems from operation of the new transmission line will be SMALL. No mitigation measures or controls are warranted.

5.6.2 Aquatic Ecosystems

Maintenance practices for the existing NAPS transmission corridors are described in ESP-ER Sections 5.6.2.1 and 5.6.2.2. The effect of these procedures is described in ESP-ER Section 5.6.2. The new transmission line would not result in changes to these practices. Therefore, impacts on aquatic ecosystems from operation of the new transmission line will be SMALL. No mitigation measures or controls are warranted.

5.6.3 Impacts to Members of the Public

This section discusses the potential impacts on members of the public from electrical shock, EMF exposure, noise, and aesthetics associated with transmission system operations.

5.6.3.1 Electrical Shock

The new transmission line would be designed to ensure that steady-state short-circuit discharge currents from both the existing lines and additional line are no greater than 5 milliamperes, for the limiting case, per the NESC. Thus, potential electrical shock impacts to members of the public from the transmission lines would be SMALL.

5.6.3.2 Electromagnetic Field Exposure

FEIS Sections 5.8.5 and 7.7 state that the NRC staff does not consider potential impact of chronic effects of electromagnetic fields as significant. However, because available evidence was inconclusive, this issue was not resolved. As discussed below, the evidence remains inconclusive but continues to suggest that the impact is insignificant.

In 1996, after 17 years of research that examined more than 500 studies, the National Research Council released the results of a study that stated, "the conclusion of the committee is that the current body of evidence does not show that exposure to these fields presents a human-health hazard." Furthermore the report added there is no conclusive evidence that EMF plays a role in the development of cancer, or reproductive or other abnormalities in humans. (Reference 1)

As part of The World Health Organization (WHO) International EMF Project, in 1997 a working group of 45 scientists from around the world surveyed the evidence for adverse EMF health effects. Regarding health effects other than cancer, the WHO scientists reported that the epidemiological studies "do not provide sufficient evidence to support an association between extremely-low-frequency magnetic-field exposure and adult cancers, pregnancy outcome, or neurobehavioural disorders." (Reference 2)

The American Physical Society (APS) represents thousands of U.S. physicists. In response to the National Institute of Environmental Health Sciences (NIEHS) Working Group's conclusion that EMF is a possible human carcinogen, the APS executive board voted in 1998 to reaffirm its 1995 opinion that there is “no consistent, significant link between cancer and power line fields.”

A 1999 NIEHS report (Reference 3) contains the following conclusion:

> The NIEHS concludes that ELF-EMF (extremely low frequency-electromagnetic field) exposure cannot be recognized as entirely safe because of weak scientific evidence that exposure may pose a leukemia hazard. In our opinion, this finding is insufficient to warrant aggressive regulatory concern. However, because virtually everyone in the United States uses electricity and therefore is routinely exposed to ELF-EMF, passive regulatory action is warranted such as a continued emphasis on educating both the public and the regulated community on means aimed at reducing exposures. The NIEHS does not believe that other cancers or non-cancer health outcomes provide sufficient evidence of a risk to currently warrant concern.

Although studies continue to be conducted and additional information is published regarding the effects of exposure to EMF (References 4 and 5), there continues to be no conclusive evidence of a link between EMF and the development of cancer, or reproductive or other abnormalities in humans. Thus, impacts to members of the public attributable to EMF exposure from transmission system operations will be SMALL. No mitigation measures or controls are warranted.

5.6.3.3 **Noise**

The noise levels resulting from transmission system operations would be in accordance with the state and local code requirements. Actual decibel noise levels would be minimized by proper sizing of conductors and the use of corona-free hardware. Thus, the impacts to the public attributable to noise from the transmission system operations will be SMALL, and no mitigation measures or controls are warranted.

5.6.3.4 **Visual Impacts**

As stated in Section 3.7, the transmission towers for the new 500 kV line would be approximately 10 feet taller than the existing towers and thus would not have a significantly greater visual impact. Further, the visual impacts of the new line would be mitigated by techniques such as selecting material colors that would blend into the surroundings, aligning the new towers with the existing towers, and maintaining a screen of natural vegetation in the corridor on each side of major highways and rivers. Based on the design and vegetation control practices, the visual impacts to members of the public from the NAPS transmission lines will be SMALL.

5.6.3.5 **Conclusions**

Potential impacts from electric shock, EMF exposure, noise, or visual impacts from transmission system operations will be SMALL, and no mitigation measures or controls are warranted.

Section 5.6 References

1. Possible Health Effects of Exposure to Residential Electric and Magnetic Fields, National Research Council, October 1996.

2. "EMF, Electric and Magnetic Fields Associated with the Use of Electric Power, Questions and Answers," National Institute of Environmental Health Sciences/National Institutes of Health, dated June 2002. (www.niehs.nih.gov/health/topics/agents/emf/docs/emf2002.pdf)

3. Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields, NIEHS report to U.S. Congress, June 1999.

4. "NIEHS Report on Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields," National Institute of Environmental Health Sciences/National Institutes of Health, dated May 1999. (www.niehs.nih.gov/health/topics/agents/emf/docs/emf2002.pdf)

5. Electromagnetic Fields and Public Health - Electromagnetic Hypersensitivity - Fact Sheet No. 296, World Health Organization - December 2005. (www.who.int/mediacentre/factsheets/fs296/en/print.html)

5.7 Uranium Fuel Cycle Impacts

The information for this section is provided in ESP-ER Section 5.7, and associated impacts for light-water reactors are resolved as SMALL in FEIS Section 6.1.

No new and significant information has been identified for this section.

5.8 Socioeconomic Impacts

The information for this section is provided in ESP-ER Section 5.8 and associated impacts are resolved in FEIS Sections 5.4, 5.5, and 5.7. These FEIS sections resolved that adverse impacts range from SMALL to MODERATE and beneficial impacts range from SMALL to LARGE. Supplemental information is provided below.

In ESP-ER Section 5.8, commitments were made to perform a confirmatory noise evaluation and a visual impact study.

Cooling Tower Noise Study

For the ESP-ER, a noise study was performed for the main cooling tower and the service water cooling tower, and the results are documented in ESP-ER Section 5.8. To satisfy the commitment made in the ESP-ER, a confirmatory analysis of the noise level associated with the cooling towers has been performed, using the location of the towers, the topography of the area surrounding the towers, and manufacturer's data typical of the towers selected for Unit 3. The methodology used is the same as that used in the ESP-ER analysis. The confirmatory analysis concluded that the noise level reported in the ESP-ER, associated with the cooling towers, remains bounding.

Visual Impact Study

The visual impact study has been performed. Figure 5.8-1, 5.8-2, and 5.8-3 provide artist renderings of Unit 3, including the main building group (reactor building, turbine building, fuel building, etc.) and the cooling towers, as they would appear upon their completion. These renderings have been superimposed on photographs taken of existing Unit 1 and 2 facilities from various locations.

Figure 5.8-1 and 5.8-2 depict the approach to the main gate along the plant access road, in views progressively closer to the gate. The principal Unit 3 structures encountered along this approach are the hybrid and dry cooling towers, which emerge in profile off the road to the north. The low profile of the towers results in their view being mostly obscured behind a line of trees adjacent to the access road.

Figure 5.8-3 depicts the facility looking southwest from the Unit 1 and 2 intake area. From this perspective, the Unit 3 facilities are seen to blend in with the existing Units 1 and 2 buildings. The Unit 3 profile is of a similar shape and size as that of Units 1 and 2. The overall shape and configuration of the Unit 3 setting, which consists of a main building group with several adjacent smaller buildings, is similar to that of the existing units.

These figures portray the completed facility. During construction of Unit 3, there would be additional temporary visual impacts. Equipment and material storage areas, parking areas, and elevated cranes and other construction equipment would be visible at least in part as construction progresses. However, these impacts would be temporary and would not be unexpected by members of the public during construction of new Unit 3.

In summary, the visual impact to the public from Unit 3 will be similar to the visual impact from the existing units, and thus the aesthetic impact will continue to be SMALL. No mitigation measures or controls are warranted.

Figure 5.8-1 Looking Northeast Along the Plant Access Road

Figure 5.8-2 Looking Northward from Final Approach after Main Gate. Unit 3 Is Shown in the Distance.

Figure 5.8-3 Looking Southwest from Unit 1 and 2 Intake Area

5.9 Decommissioning

FEIS Sections 6.3 and 7.9 identified that impacts from decommissioning were not addressed at the ESP-ER stage and would be required to be addressed at the COL stage. The following information is provided to address the impacts from decommissioning.

5.9.1 Financial Assurance

Information on decommissioning funding, including the funding amount required by 10 CFR 50.75(c), method of funding, and certification, is provided in the Decommissioning Funding Assurance Report provided in COLA Part 1.

5.9.2 Environmental Impacts

According to NUREG-1555, Section 5.9 (Reference 1, p. 5.9-7), studies of social and environmental effects of decommissioning large commercial power generating units have not identified any significant impacts beyond those considered in the Final Generic Environmental Impact Statement (GEIS) on decommissioning (Reference 2). The GEIS evaluates the environmental impact of the following three decommissioning methods:

- DECON - The equipment, structures, and portions of the facility and site that contain radioactive contaminants are removed or decontaminated to a level that permits termination of the license shortly after cessation of operations.
- SAFSTOR - The facility is placed in a safe stable condition and maintained in that state until it is subsequently decontaminated and dismantled to levels that permit license termination. During SAFSTOR, a facility is left intact, but the fuel has been removed from the reactor vessel and radioactive liquids have been drained from systems and components and then processed. Radioactive decay occurs during the SAFSTOR period, thus reducing the quantity of contaminated and radioactive material that must be disposed of during the decontamination and dismantlement.
- ENTOMB - This alternative involves encasing radioactive structures, systems, and components in a structurally long-lived substance, such as concrete. The entombed structure is appropriately maintained, and continued surveillance is carried out until the radioactivity decays to a level that permits termination of the license.

NRC regulations do not require a COL applicant to select one of these decommissioning alternatives or to prepare definite plans for decommissioning at the time of the COL (Reference 1, p. 5.9-6). Pursuant to 10 CFR 50.82, planned decommissioning activities would be described after a decision has been made by the licensee to cease operations. Further, the choice of decommissioning methods, the identification of disposal sites for waste, and other pertinent information required to develop definitive plans would be determined by the conditions at the time.

Therefore, at this stage, a general assessment of decommissioning environmental impacts is provided.

Decommissioning of a nuclear facility that has reached the end of its useful life is in essence an environmental remediation and therefore has an overall positive environmental impact (Reference 1, p. 5.9-7). The main adverse environmental impact, regardless of the specific decommissioning option selected, is the commitment of relatively small amounts of land for waste burial in exchange for the potential re-use of the land where the facility is located (Reference 2).

NUREG-0586 (Reference 2) indicates that the NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts presented in this report include: 1) occupational and population doses; 2) impacts of waste management; 3) impacts to air and water quality; and 4) ecological, economic, and socioeconomic impacts. NRC also indicated (Reference 3, p. 4-15) that the environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations. As such, Dominion adopts by reference the NRC conclusions regarding environmental impacts of decommissioning presented in NUREG-0586.

In addition, a DOE study (Reference 4, p. 17) indicated that projected physical plant inventories associated with the ESBWR design would generally be less than those for currently operating power reactors. This is due to the advances in technology and the use of passive support systems that have significantly simplified and reduced inventories of electrical cabling, piping, pumps, motors, instrumentation and controls wiring, building size and concrete volume typically used in contemporary power plants. This ultimately reduces the overall quantity of contaminated and non-contaminated waste required for disposal, along with transportation to and from disposal sites. Additionally, the ESBWR is designed to reduce accumulation of radioactivity in plant components (DCD Section 12.1.2.2.3). Unlike existing BWRs, the ESBWR has only one significant source of radiation in the containment post operation—the reactor core (DCD Section 12.2.1.1). It also includes a number of design features as described in DCD Section 12.1.2.1 to maintain low occupational doses during decommissioning. Further, the new facility is situated on the existing NAPS site and is contained within the original site boundaries, not requiring encroachment onto additional property that is not already designated for use in power production. Therefore, the estimated environmental impacts of decommissioning presented in NUREG-0586 are reasonably expected to bound the impacts of decommissioning an ESBWR at North Anna.

Regardless of the option chosen in the future, decommissioning must be completed within 60 years of permanent cessation of plant operations per 10 CFR 50.82(a)(3). Unit 3 would be operated until the approved combined license expires and then decommissioning activities would be initiated in accordance with NRC requirements. In accordance with 10 CFR 50.82, these decommissioning activities would include the following submissions:

1. Written certification to the NRC within 30 days of the decision to permanently cease operations per 10 CFR 50.4(b)(8);

2. Written certification to the NRC once the fuel has been permanently removed from the reactor vessel per 10 CFR 50.4(b)(9);

3. A post-shutdown decommissioning activities report (PSDAR) to the NRC within two years after permanent cessation of operations per 10 CFR 50.82(a)(4), detailing planned decommissioning activities, schedule for the accomplishment of significant milestones, estimated decommissioning costs, and documentation showing that the environmental impacts associated with the site-specific decommissioning activities are bounded by appropriate previously issued environmental impact statements and;

4. A license termination plan at least two years before termination of the license date, per 10 CFR 50.82(a)(9), which includes: site characterization, identification of remaining dismantlement activities, plans for site remediation, detailed plans for the final radiation survey, a description of the end use of the site (if restricted), an updated site-specific estimate of remaining decommissioning costs and a supplement to the environmental report describing any new information or significant environmental change associated with the proposed termination activities.

During decommissioning of Unit 3 facilities, radiological doses would be controlled with appropriate work procedures, shielding, and other control measures similar to those used during plant operations. Experience with decommissioned power plants has shown that the occupational exposures during the decommissioning period are comparable to those associated with refueling and plant maintenance of an operational unit (Reference 2). Each decommissioning alternative has radiological impacts resulting from the transport of materials to disposal sites. The expected impact from this transportation activity would not be significantly different from that associated with normal operations (Reference 1, Section 5.9).

Based on the factors described above, it can be reasonably concluded that the environmental impacts resulting from decommissioning proposed Unit 3, after it ceases operations, are bounded by those presented in NUREG-0586. Pursuant to 10 CFR 50.82(a)(4), a further analysis would be provided at the time of decommissioning, when the activities and schedule are known, to demonstrate that the previously estimated impacts are still bounding.

Section 5.9 References

1. NUREG-1555, Environmental Standard Review Plan, U.S. Nuclear Regulatory Commission, October 1999.

2. NUREG-0586, Supplement 1, Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities, U.S. Nuclear Regulatory Commission, November 2002.

3. NUREG-0586, Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities, U.S. Nuclear Regulatory Commission, August 1988.

4. Study of Construction Technologies and Schedules, O&M Staffing and Cost, Decommissioning Costs and Funding Requirements for Advanced Reactor Designs, Volume 1, U.S. Department of Energy, May 27, 2004.

5.10 Measures and Controls to Limit Adverse Impacts During Operation

Measures and controls to limit adverse impacts during operation were addressed in ESP-ER Section 5.10 and in FEIS Section 5.11. These measures and controls have been incorporated into the Environmental Protection Plan (EPP) in Appendix 1A, along with the following new mitigation measures and controls.

- Nonradioactive effluents, including sanitary waste and blowdown from the Unit 3 cooling towers, would be controlled by the limits established in VPDES permit (Sections 5.2.2 and 5.5.1).
- The new and separate Unit 3 sanitary waste treatment systems would be governed by applicable regulations and permits (Section 5.5.1).
- Operation of a dechlorination system would neutralize chlorine in the circulating water and plant service water cooling tower blowdown before discharge to the WHTF and eventually to the North Anna Reservoir (Section 5.2.2).

Chapter 6 Environmental Measurements and Monitoring Programs

6.1 Thermal Monitoring

The information for this section is provided in ESP-ER Section 6.1 and resolved in FEIS Section 2.6.3.3.

No new and significant information has been identified for this section.

6.2 Radiological Monitoring

The information for this section is provided in ESP-ER Section 6.2 and resolved in FEIS Section 5.9.6.

No new and significant information has been identified for this section.

6.3 Hydrological Monitoring

The information for this section is provided in ESP-ER Section 6.3 and resolved in FEIS Section 2.6.1.3.

No new and significant information has been identified for this section.

6.4 Meteorological Monitoring

The information for this section is provided in ESP-ER Section 6.4 and resolved in FEIS Section 2.3.1.6. Dominion will use the existing Unit 1 and 2 data recording systems for Unit 3. These systems will be linked to the Unit 3 control room for meteorological monitoring.

No new and significant information has been identified for this section.

6.5 Ecological Monitoring

The information for this section is provided in ESP-ER Section 6.5 and resolved in FEIS Section 2.7.

No new and significant information has been identified for this section.

6.6 Chemical Monitoring

The information for this section is provided in ESP-ER Section 6.6 and resolved in FEIS Section 2.6.3.4.

No new and significant information has been identified for this section.

6.7 Summary of Monitoring Programs

The information for this section is provided in ESP-ER Section 6.7. No new and significant information has been identified for this section.

Chapter 7 Environmental Impacts of Postulated Accidents Involving Radioactive Materials

7.1 Design Basis Accidents

The information for this section is provided in ESP-ER Section 7.1 and associated impacts are resolved as SMALL in FEIS Section 5.10, for light-water reactors. Supplemental information, regarding Unit 3 specific source terms and doses, is provided in the following sections.

7.1.1 Selection of Accidents

No new and significant information has been identified for this section. The same ESBWR accidents are considered as in ESP-ER Section 7.1. These encompass all of the Design Basis Accidents (DBAs) evaluated for radiological consequences in DCD Chapter 15.

7.1.2 Evaluation Methodology

No new and significant information has been identified for this section.

7.1.3 Source Terms

The activity releases and doses for Unit 3 are based on a power level of 4590 MWt, which represents a core thermal power of 4500 MWt multiplied by an uncertainty factor of 1.02. Unit 3 DBA source terms have been updated and are presented as isotopic activity releases to the environment in the unit of megabecquerel (MBq) in DCD Section 15.4, Tables 15.4-3a, 15.4-7, 15.4-12, 15.4-15, 15.4-18, and 15.4-22. These tables reflect updated activity releases from those presented in the ESP-ER. The DCD updated activity releases do not include the 25 percent margin of uncertainty previously assumed in the ESP-ER analysis.

7.1.4 Radiological Consequences

In the ESP-ER, design basis accident doses for the ESBWR were calculated based on activity releases, χ/Q values, breathing rates, and dose conversion factors. In this ER, Unit 3-specific doses are calculated based on the DCD doses for the ESBWR. For each of the design basis accidents, the Unit 3-specific dose is calculated by multiplying the ESBWR dose (provided in DCD Section 15.4) by the ratio of the Unit 3 site-specific χ/Q value to the DCD χ/Q value (provided in DCD Section 15.4). The Unit 3 site-specific χ/Q values are the time-dependent χ/Q values from FEIS Table I-1. The resulting χ/Q ratios are shown in Table 7.1-1.

Because the Unit 3 site-specific χ/Q values are bounded by the DCD χ/Q values, the Unit 3-specific doses are within those calculated in DCD Section 15.4. The DBA doses summarized in Table 7.1-2 are based on individual accident doses presented in Table 7.1-3 through Table 7.1-10. These tables replace those showing ESBWR doses in the ESP-ER. For each accident, the EAB dose shown is for the two-hour period that yields the maximum dose, in accordance with RG 1.183 (Reference 1).

The Unit 3-specific doses summarized in Table 7.1-2 are lower than and thus remain bounded by the surrogate ESBWR DBA doses calculated for the ESP-ER for all accidents except for LOCA (Table 7.1-7, ESP-ER Table 7.1-24b) and Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System Line Failure (Pre-Incident Iodine Spike) (Table 7.1-10), which was not considered in the ESP-ER. However, the Unit 3-specific doses for these two accidents remain a small fraction of the regulatory limit. All doses are within the acceptance criteria of RG 1.183 and NUREG-0800 (Reference 2). Thus, the potential environmental impacts of DBAs will remain SMALL.

Section 7.1 References

1. Regulatory Guide 1.183, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors, U. S. Nuclear Regulatory Commission, July 2000.

2. NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, U. S. Nuclear Regulatory Commission, March 2007.

Table 7.1-1 DCD and Unit 3 Site-Specific χ/Qs, and Unit 3/DCD χ/Q Ratios

Accident	Location		χ/Q (sec/m^3) DCD	χ/Q (sec/m^3) Unit 3	Ratio (Unit 3/DCD)
FHA, RWCU (Coincident Iodine Spike & Pre-Incident Iodine Spike)	EAB		2.00E-03	3.34E-05	1.67E-02
	LPZ		1.90E-04	2.17E-06	1.14E-02
MSLB (Pre-Existing Iodine Spike & Equilibrium Iodine Activity)	EAB		2.00E-03	3.34E-05	1.67E-02
	LPZ		2.00E-03	2.17E-06	1.09E-03
LOCA, SBOC	EAB		2.00E-03	3.34E-05	1.67E-02
	LPZ	0–8 hr	1.90E-04	2.17E-06	1.14E-02
		8–24 hr	1.40E-04	1.50E-06	1.07E-02
		24–96 hr	7.50E-05	1.20E-06	1.60E-02
		96–720 hr	3.00E-05	9.00E-07	3.00E-02
FW Line Break	EAB		1.00E-03	3.34E-05	3.34E-02
	LPZ		1.00E-03	2.17E-06	2.17E-03

Table 7.1-2 Summary of Design Basis Accident Doses

SRP Section	Accident	Unit 3 TEDE (Rem) EAB	LPZ	Limit
15.2.8	Feedwater Line Break	5.7E-06	3.7E-07	2.5
15.3.3	Locked Rotor Accident	Not applicable to the ESBWR		
15.3.4	Reactor Coolant Pump Shaft Break	Not applicable to the ESBWR		
15.4.9	BWR Control Rod Drop Accident	Evaluation of radiological consequences not required		
15.6.2	Failure of Small Line Carrying			
	Primary Coolant Outside Containment	2.5E-03	5.6E-04	2.5
15.6.4	Main Steam Line Break Accident			
	Pre-Existing Iodine Spike	2.1E-01	1.4E-02	25
	Equilibrium Iodine Activity	1.2E-02	7.6E-04	2.5
15.6.5	Loss-of-Coolant Accident	2.2E-01	3.5E-01	25
15.7.4	Fuel Handling Accident	6.9E-02	4.5E-03	6.3
	RWCU/SDC System Line Failure			
	Coincident Iodine Spike	8.2E-03	5.4E-04	2.5
	Pre-Incident Iodine Spike	1.6E-01	1.1E-02	25
15.7.5	Spent Fuel Cask Drop Accident	Evaluation of radiological consequences not required		

Table 7.1-3 Doses for ESBWR Feedwater Line Break

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	1.70E-04	3.34E-02	5.68E-06
LPZ	1.70E-04	2.17E-03	3.69E-07
Limit			2.5

Table 7.1-4 Doses for ESBWR Failure of Small Line Carrying Primary Coolant Outside Containment

	DCD TEDE (Rem)		χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)	
Time	EAB	LPZ		EAB	LPZ
	1.50E-01		1.67E-02	2.51E-03	
0–8 hr		4.00E-02	1.14E-02		4.57E-04
8–24 hr		1.00E-02	1.07E-02		1.07E-04
24–96 hr		0.00E+00			0.00E+00
96–720 hr		0.00E+00			0.00E+00
Total	1.50E-01	5.00E-02		2.51E-03	5.64E-04
Limit				2.5	2.5

Table 7.1-5 Doses for ESBWR Main Steam Line Break, Pre-Existing Iodine Spike

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	1.26E+01	1.67E-02	2.10E-01
LPZ	1.26E+01	1.09E-03	1.37E-02
Limit			25

Table 7.1-6 Doses for ESBWR Main Steam Line Break, Equilibrium Iodine Activity

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3 /DCD)	Unit 3 TEDE (Rem)
EAB	7.00E-01	1.67E-02	1.17E-02
LPZ	7.00E-01	1.09E-03	7.60E-04
Limit			2.5

Table 7.1-7 Doses for ESBWR Loss-of-Coolant Accident

	DCD TEDE (Rem)		χ/Q Ratio	Unit 3 TEDE (Rem)	
Time	EAB	LPZ	(Unit 3/DCD)	EAB	LPZ
	1.30E+01		1.67E-02	2.17E-01	
0–8 hr		3.20E+00	1.14E-02		3.65E-02
8–24 hr		2.70E+00	1.07E-02		2.89E-02
24–96 hr		5.20E+00	1.60E-02		8.32E-02
96–720 hr		6.60E+00	3.00E-02		1.98E-01
Total	1.30E+01	1.77E+01		2.17E-01	3.47E-01
Limit				25	25

Table 7.1-8 Doses for ESBWR Fuel Handling Accident

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	4.13E+00	1.67E-02	6.90E-02
LPZ	3.90E-01	1.14E-02	4.45E-03
Limit			6.3

Table 7.1-9 Doses for ESBWR RWCU/SDC System Line Failure, Coincident Iodine Spike

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	4.90E-01	1.67E-02	8.18E-03
LPZ	4.70E-02	1.14E-02	5.37E-04
Limit			2.5

Table 7.1-10 Doses for ESBWR RWCU/SDC System Line Failure, Pre-Incident Iodine Spike

	DCD TEDE (Rem)	χ/Q Ratio (Unit 3/DCD)	Unit 3 TEDE (Rem)
EAB	9.80E+00	1.67E-02	1.64E-01
LPZ	9.30E-01	1.14E-02	1.06E-02
Limit			25

7.2 Severe Accidents

The information for this section is provided in ESP-ER Section 7.2 and associated impacts are resolved as SMALL in FEIS Section 5.10.2 for light water reactors.

No new and significant information has been identified for this section.

7.3 Severe Accident Mitigation Alternatives

This section addresses severe accident mitigation alternatives (SAMAs), based on GE's evaluation of severe accident mitigation design alternatives (SAMDAs) for the ESBWR (NEDO-33306, Reference), which is incorporated herein by reference, and North Anna site and regional data. This section demonstrates that the severe accident mitigation design alternatives screened out by GE are also screened out when North Anna site-specific characteristics are considered.

In the GE analysis, potential design improvements are identified, in a systematic method, and evaluated on a cost-benefit basis. The evaluation determined that there are no practical and cost-beneficial design enhancements that should be considered. Therefore, appropriate mitigating measures are already incorporated into the plant design.

This section determines that the conclusions in the GE analysis remain valid for Unit 3. The analysis in this section indicates that there are no cost-beneficial design alternatives that would need to be implemented for North Anna Unit 3 to further mitigate severe accident risk.

7.3.1 The SAMA Analysis Process

Measures that could mitigate the consequences of a severe accident are known as SAMAs. The evaluation process for identifying potential SAMAs includes four steps:

1. Define the base case – The base case is the dose-risk and cost-risk of severe accident before implementation of any SAMAs. A plant's probabilistic risk assessment is a primary source of data in calculating the base case. The base case risks are converted to a monetary value to use for screening SAMAs.

2. Identify and screen potential SAMAs – Potential SAMAs can be identified from the plant's probabilistic risk assessment and the results of other plants' SAMA analyses. This list of potential SAMAs is assigned a conservatively low implementation cost based on historical costs, similar design changes and/or engineering judgment, then compared to the base case screening value. SAMAs with higher implementation cost than the base case are not evaluated further.

3. Determine the cost and net value of each SAMA – Each SAMA remaining after Step 2, has a detailed engineering cost evaluation developed using current plant engineering processes. If the SAMA continues to pass the screening value Step 4 is performed.

4. Determine the benefit associated with each screened SAMA – Each SAMA that passes the screening in Step 3, is evaluated using the probabilistic risk assessment model to determine the reduction in risk associated with implementation of the proposed SAMA. The reduction in risk benefit is then monetized and compared to the detailed cost estimate. Those SAMAs with reasonable cost-benefit ratios are considered for implementation.

The SAMA analysis for Unit 3 focuses on demonstrating that the North Anna site is bounded by the GE DCD analysis and determining what magnitude of plant-specific design or procedural modifications would be cost-effective. The base case benefit value is calculated by assuming the current dose risk of the unit could be reduced to zero and assigning a defined dollar value for this change in risk. Any design or procedural change cost that exceeded the benefit value would not be considered cost-effective. The dose-risk and cost-risk results (provided in ESP-ER Section 7.2 analyses) are monetized in accordance with methods established in NUREG/BR-0184, Regulatory Analysis Technical Evaluation Handbook, 1997. NUREG/BR-0184 presents methods for determination of the value of decreases in risk, using four types of attributes: public health, occupational health, offsite property, and onsite property. Any SAMAs in which the conservatively low implementation cost exceeds the base case monetization are screened out. If the analysis produces a value that is below that expected for implementation of any reasonable SAMA, no matter how inexpensive, then the remaining steps of the SAMA analysis are not necessary.

7.3.2 The GE ESBWR SAMDA Analysis

NEDO-33306 compiles a list of potential SAMDAs based on the prior North Anna license extension analysis and other plant designs. Some SAMDAs were then screened out based on their inapplicability to the ESBWR or the fact that they were already included in the ESBWR design. Rough implementation costs that far exceeded any reasonable benefit were also excluded. None of the SAMDAs passed the screening process.

GE compared the implementation costs for each SAMDA to the maximum severe accident risk reduction value possible and found that none of the SAMDAs would be cost-effective.

7.3.3 Unit 3 ESBWR SAMA Analysis

Unit 3 specific design features (e.g., cooling towers, lake location, proximity to Units 1 and 2, weather, seismology) were all considered for potential impact on the generic GE ESBWR SAMDA analysis, and none were determined to potentially impact the GE ESBWR SAMA analysis. The GE ESBWR PRA specifically considered Unit 3 site characteristics, which could impact the risk of severe accidents. The GE ESBWR PRA included North Anna site-specific Level 3 PRA analyses (i.e., MACCS runs using North Anna specific meteorology and site characteristics).

A review was performed of the compilation of SAMAs in NEDO-33306 to identify procedural and administrative measures that were not considered design alternatives. Most of these items related to PWRs and have no relevance to the ESBWR. Those administrative and procedural measures applicable to the ESBWR will be considered for implementation when procedures are developed prior to fuel load, as long as their cost does not exceed the $4,833 maximum value associated with averting all risk of severe accidents.

Accordingly, no cost-beneficial SAMDAs have been identified. Further, pursuant to 10 CFR 51.30(d), the NRC will, as part of its design certification rulemaking, prepare an environmental assessment evaluating the costs and benefits of SAMDAs for the ESBWR. Pursuant to 10 CFR 51.50(c)(2) and 51.75(c)(2), this environmental assessment may be incorporated by reference into the ER and EIS upon completion.

Section 7.3 References

NEDO-33306, GE Nuclear Energy, "ESBWR Severe Accident Mitigation Design Alternatives," Revision 1, August 2007.

7.4 Transportation Accidents

The information for this section is provided in ESP-ER Section 3.8, and the associated impacts, with the exception of crud and activation products on spent fuel transportation accidents, are resolved as SMALL for light-water reactors in FEIS Section 6.2.

The evaluation of the impact of crud and activation products on spent fuel transportation accidents is provided in Section 3.8.

Chapter 8 Need for Power

This chapter demonstrates the need for the power to be generated by the proposed facility and related benefits. This demonstration is supported by an analysis, which is organized into five sections:

- A discussion of benefits in Section 8.0.1,
- A power system description in Section 8.1,
- An analysis of demand for capacity and energy in Section 8.2,
- An analysis of supply resources in Section 8.3, and
- An assessment of need in Section 8.4.

8.0.1 Benefits

This section describes the benefits associated with construction and operation of the proposed NAPS Unit 3. Non-monetary benefits of constructing and operating the proposed Unit 3 include benefits related to: net electrical generating benefits; fuel diversity, dampened price volatility, and enhanced reliability; emissions avoidance; waste reduction; and reduction in dependence on imported power. Monetary benefits of constructing and operating Unit 3 include benefits related to tax revenues and to the local and state economy.

8.0.1.1 Net Electrical Generating Benefits

As demonstrated in Section 8.4, the Dominion Zone,[1] the region of interest, has a specific need for new baseload capacity and this need is projected to increase. The baseload capacity supply portfolio in the Dominion Zone is currently out of balance with baseload requirements, because development of new baseload capacity has not kept pace with recent growth in baseload requirements. Instead, the growth in baseload energy consumption has been met predominantly by the recent development of gas-fired units, which are more suitable as cycling or mid-range resources.

As discussed in Section 8.3.1.1.2, over the past 10 years from 1997 to 2006, DVP's baseload requirement has grown by over 2000 MW, based on analysis of DVP weather-normalized annual energy sales. Over the same period, there has been virtually no development of additional

1. In May 2005, DVP joined PJM Interconnection LLC (PJM) and transferred control of the transmission facilities that it owns and operates in its control area to PJM. With its integration into PJM, DVP separated its electric generation and traditional customer delivery businesses (referred to now as "load serving entity" or "LSE") into two distinct operations within PJM's system. When DVP joined PJM, it resulted in the creation of the PJM South Region, which is also known as the Dominion Zone, the region of interest (ROI) for the purposes of this COL Application. The Dominion Zone is currently coterminous with the power system control area of DVP and includes the electric distribution service territories (service territory) of DVP, ODEC, North Carolina Electric Cooperatives (NCEMCS) and other municipals. DVP operates as an LSE in the Dominion Zone.

baseload resources in the Dominion Zone, as only combined cycles and combustion turbines have been added since 1997 as shown in Table 8.3-3. Indeed, a major new baseload facility has not been built in the Dominion Zone since 1996.[1]

As discussed in Section 8.4, there is a current need for baseload capacity in the Dominion Zone, and baseload capacity requirements in the Dominion Zone are projected to increase by 2000 MW by 2015 and by 4000 MW by 2022.[2] To meet its baseload requirements, DVP is currently in the process of developing two baseload generation units: a 585 MW coal facility (that will allow the supplemental use of opportunity fuels, such as biomass and waste coal, for up to a total of 20 percent of the plant's output) located in Virginia City, Virginia (the "Virginia City facility") and Unit 3. Currently, DVP has a Certificate of Public Convenience and Necessity (CPCN) application pending before the Virginia State Corporation Commission (Virginia SCC) requesting approval of the Virginia City facility. The Virginia City facility will be located in the American Electric Power Zone of PJM, but is included in the need for power analysis in Section 8.4 for completeness because it is being developed by DVP to provide baseload power to the Dominion Zone. Within the Dominion Zone itself, the proposed Unit 3 is the only major baseload facility over 100 MW currently under study in the PJM Generation Interconnection Queue. Both the Virginia City facility and Unit 3 are required to meet DVP's baseload requirements to achieve a reliable, cost efficient baseload generation portfolio.

The primary benefit of the proposed Unit 3 is the provision of baseload capacity necessary to meet the needs of customers in the region served by DVP and ODEC,[3] and to maintain a reliable, stable supply of electricity within the Dominion Zone. The proposed Unit 3 will provide approximately 1500 MW of average net summer capacity. Conservatively assuming an average capacity factor of 90 percent, the plant average annual electrical-energy generation is approximately 12,000,000 megawatt hours.[4] Unit 3 would provide a benefit to DVP's service territory by both increasing and diversifying DVP's baseload capacity portfolio and helping to meet the growing baseload needs in the Dominion Zone. It is important for DVP to continue to diversify its generation asset portfolio to manage and diversify risks, such as natural gas and oil price volatility, supply constraints, and potential future environmental regulations.

1. The most recent major baseload facility built in the Dominion Zone is DVP's Birchwood Power coal-fired facility, which began commercial operation in 1996 (Reference 9).
2. If measured by the need to maintain peak summer margin, 4,000 MW of capacity would be required by 2017, as discussed in Section 8.2.2.11
3. ODEC owns a 11.6 percent interest in NAPS. The need for power analysis presented in this COLA is for the total Dominion Zone, which includes ODEC. The need for power analysis assesses the need for Unit 3 as a whole unit.
4. Nuclear units in Virginia on average operated with a 93% capacity factor in 2005. See Section 8.3.1.1.1, particularly Table 8.3-1.

8.0.1.2 Fuel Diversity, Dampened Price Volatility, and Enhanced Reliability

Energy diversity is a key to providing a reliable and affordable electrical power supply system. Achieving a balanced portfolio of fuels and technologies best manages a variety of risks, including commodity price volatility, fuel supply disruptions, and changes in regulatory practices. (Reference 3) Due to these risks and Virginia's energy capacity requirements, it is vital that Virginia continue to grow a diverse energy portfolio of energy supply such as new clean coal-fired generation, natural gas generation, renewable generation, and nuclear generation. In fact, a balanced energy portfolio has been the key to providing the U.S. with a growing supply of affordable electricity for the past 30 years. (Reference 4)

Maintaining fuel diversity is a matter of maintaining a balance of fuel mixes. Relying heavily on natural gas, for example, increases risk exposure to natural gas price volatility and supply disruptions. The high natural gas prices and the intense, recurring periods of price volatility experienced in recent years have been driven, at least in part, by demand for natural gas used in the electric generation sector. The large number of new gas-fired electric plants built in the U.S. during the last decade has increased electric sector demand for natural gas. Natural gas plants have accounted for more than 90 percent of all new electric generating capacity added in the U.S. over the past five years. Natural gas has many desirable characteristics and should be part of, but not dominate, the fuel mix because "over-reliance on any one fuel source leaves consumers vulnerable to price increases, volatility and supply disruptions." (Reference 5)

The Maryland Public Service Commission (MDPSC) has expressed specific concerns regarding the future of PJM's fuel diversity, specifically:

> The [MDPSC] Commission is concerned about the lack of fuel diversity exhibited by generation additions. Combustion turbine capacity in eastern PJM is expected to remain the predominant source of near generation for the next five years at least. Natural gas prices have of course risen sharply in recent years and remain volatile…. This trend toward reliance on natural gas as a fuel resource must be closely monitored. It is to be noted that in the PJM region, many projects have been withdrawn due to profit forecasts, general financial market instability, and more recently due to the much higher fuel costs for gas-fired plants making them less economic to operate. (Reference 10)

In addition, natural gas is a finite energy source that has uses not readily served by other fuel choices, such as many manufacturing processes. This assessment led the U.S. House of Representatives to prepare a majority staff report in 2006 to include the following finding: (Reference 6)

> Nuclear energy must become the primary generator of baseload electricity, thereby relieving the pressure on natural gas prices and dramatically improving atmospheric emissions.

Development of a new nuclear unit at the NAPS site advances the Congressional goals of obtaining a diversified mix of electrical generating sources and creating new nuclear baseload generating capacity. In addition, new nuclear plants provide forward price stability that is difficult to achieve from generating plants fueled with natural gas. While the risk of natural gas price volatility can be hedged in part through long-term contracts, this risk can be further managed by increasing fuel diversity through the development of new nuclear and clean coal capacity. To better optimize its future capacity portfolio, DVP is currently in the process of developing both the Virginia City facility and Unit 3. Although nuclear plants are capital-intensive to build, the operating costs are relatively small, stable, and dampen volatility elsewhere in the electricity market. (Reference 5) DVP also plans to construct the Virginia City facility in the coalfield region of Virginia to use local Virginia coal, which will make the project less susceptible to disruptions in coal supply and price volatility.

The proposed Unit 3 will also reduce the dependence of the Dominion Zone on power imported from adjacent regions. The 2007 Virginia Energy Plan (Reference 11) sets a goal of increasing in-state energy production by 20 percent by 2017. The Virginia Energy Plan further states, "Increasing in-state production of energy will keep funds otherwise spent on energy imports in Virginia's economy and decrease the potential risk Virginia customers face from disruptions in energy supplies." Based on U.S. EIA data for 2005, the Commonwealth of Virginia was the second largest importer of electricity in the United States on a total MW-hr basis.[1] Based on the same data, the Commonwealth of Virginia imported the third largest percentage of consumed power of PJM states, with imports meeting approximately 30 percent of Virginia's total state-wide electric consumption.[2]

8.0.1.3 Emissions Avoidance

Fossil fuel-fired electrical generation plants produce more air emissions (e.g., nitrogen oxides, sulfur dioxide, and carbon dioxide) associated with air quality, climate change, aesthetic and health concerns than does nuclear energy. As noted in the U. S. House of Representatives 2006 report on securing America's energy future, (Reference 6) the power generation sector accounts for the following emissions in the U.S. with respect to all industrial sources:

- 64% sulfur dioxide
- 26% nitrogen oxides
- 33% mercury
- 36% carbon dioxide

Beyond steam and water vapor, modern nuclear reactors produce virtually no air emissions. Nuclear power generation, therefore, leads to significant local, national, and global air quality

1. Based on analysis of 2005 state level sales and generation, data provided by the U.S. EIA in its "Electric Power Annual 2005" publication. State net import/export levels were estimated assuming a 6% loss factor. (Reference 5)
2. (MW-hr In-State Generation) – (MW-hr In-State Sales) / (100%–6%)

benefits. (Reference 7) Section 9.2 and NUREG-1437 Supplement 7, Section 8.2 compare the emissions from coal- and gas-fired alternatives. (Reference 8)

The beneficial impacts of avoided air emissions from building NAPS Unit 3 in lieu of equivalent fossil fuel plants are summarized in Table 8.0-2. As indicated in Table 8.0-2, a new nuclear unit the size of the proposed NAPS Unit 3 provides a substantial reduction of emissions over natural gas-fired and coal-fired generation alternatives. Assuming that NAPS Unit 3 replaces construction of a comparably sized gas- or coal-fired plant, NAPS Unit 3 represents a substantial benefit in terms of air emission avoidance.

8.0.1.4 **Carbon Dioxide Emissions**

The 2007 Virginia Energy Plan (Reference 11) established the goal to reduce carbon dioxide emissions by 30 percent by 2025, bringing emissions back to 2000 levels. Currently, nuclear power is the only available and proven technology that provides a viable alternative to fossil-fired plants for baseload electrical generation. Unit 3 will significantly contribute to the achievement of Virginia's goal to reduce carbon dioxide emissions to year 2000 levels by 2025.

8.0.1.5 **Tax Revenues**

Taxes are transfer payments that would share and distribute the economic benefit of Unit 3 with state and local governments. While tax revenues are not independent benefits, they are described below to properly describe the allocation of benefits.

The proposed NAPS Unit 3 would make tax payments to the Commonwealth of Virginia and counties for the 40 operating years of the license. Additionally, in 2006, Virginia Economic Development Partnership (VEDP) used IMPLAN, a commercially available input-output modeling program, to estimate the economic impact of the jobs created by the addition of a new nuclear generating unit at the NAPS. (Reference 1) Dominion provided the following key parameters for this analysis: 750 new direct jobs during the plant operation period with an average annual salary of $67,000 and 2,000 direct jobs during the construction period.

During the plant construction period, VEDP estimates that the direct and additional jobs created due to construction of a new unit at NAPS should generate annually $4.8 million in state tax revenue and $3.5 million in tax revenue for the local counties. Tax revenue for the local counties consists of $3.1 million in property taxes and $400,000 in sales and use taxes annually. At the above rate, the direct and additional jobs due to the proposed Unit 3 should result in $24.9 million in total tax revenues to the Commonwealth of Virginia and local counties over the projected 3-year construction period. This amount consists of $14.4 million in total state taxes to Virginia, $9.3 million in total property tax and $1.2 million in total sales and use tax revenues allocated to the local counties.

During the plant operation period, VEDP estimates that the direct and additional jobs created due to a new unit at NAPS should generate annually $14.8 million in state tax revenue and $27.7 million in tax revenue for the local counties. Tax revenue for the local counties consists of $3.5 million in property taxes and $24.2 million in sales and use taxes annually. At the above rate, the direct and additional jobs due to the proposed Unit 3 should result in $1.7 billion in taxes to the Commonwealth of Virginia and the local counties over the 40-year operating license. This amount consists of $592 million in total state taxes to Virginia, $140 million in total property tax and $968 million in total sales and use tax revenues to the local counties.

The additional tax revenues generated from construction and operation of Unit 3 should benefit the state and local county government agencies because the revenues would support the development of infrastructure and services that support the community and promote further economic development.

8.0.1.6 **Local and State Economy**

The construction of NAPS Unit 3 would require a workforce of about 2000 people (conservatively estimated) and would generate additional income for the Commonwealth of Virginia and local economy for a period of three years. The subsequent operation of the proposed Unit 3 would require an operational workforce of about 750 people and would generate additional income and value for the Commonwealth of Virginia and local economy for a period of at least 40 years.

Based on the VEDP estimates, (Reference 1) the construction and operation of the proposed Unit 3 would increase the Commonwealth of Virginia's economic output by $42.5 million annually. If the direct value of the new unit output is included, state and county output attributable to the operation of Unit 3 would be significantly higher.

VEDP estimates (Reference 1) that the construction of the proposed Unit 3 would require the hiring of 2000 workers during three years of construction, some of which are expected to come from outside the local area. These construction workers and their employers would pay income taxes and support additional employment in the local areas through their spending. VEDP estimates that 1236 additional indirect jobs would be created as a result of the construction. Temporary construction workers and their families increase rental and property demand, spending on goods and services, and sales taxes that benefit the local economy.

In addition, VEDP estimates (Reference 1) that the operation of Unit 3 would create 750 direct jobs for Louisa County for 40 years. These permanent operational workers would pay income taxes and support additional employment in the local areas through their spending. VEDP also estimates that 1553 additional indirect jobs would be created as a result of operation of Unit 3. The communities potentially impacted socio-economically by construction and operation of Unit 3 are Louisa, Orange, and Spotsylvania Counties, all in central Virginia. Louisa County, where NAPS is located, would see the greatest impact. All these counties have experienced steady growth in population and economic activity during the last decade. Moreover, an additional nuclear unit will increase career opportunities within Dominion's nuclear organization, allowing for new opportunities in the nuclear operations for entry-level employees, as well as additional opportunities for promotion and retention of the exceptionally qualified staff.

8.0.1.7 **Other Benefits**

Section 10.3 (also ESP-ER Section 10.3) describes the relationship between short-term uses and long-term productivity of the human environment. These benefits are summarized in Table 8.0-1 and Table 8.0-2.

Table 8.0-1 Monetary and Non-Monetary Benefits of NAPS Unit 3

Category of Benefit	Description of Benefit
Net Electrical Generating Benefits	
Net Generating Capacity	~1,500 MWe
Electricity Generated (operating at 90% cap.)	~12,000,000 MW-hrs
Taxes and Revenue During Plant Operation Period (Transfer Payments - Not Independent Benefits)	
Annual State Taxes	NAPS Unit 3 pays $14.8 million.
Annual Property Taxes	NAPS Unit 3 pays $3.5 million.
Annual Sales Taxes	NAPS Unit 3 pays $24.2 million.
Effects on Regional Productivity	
Construction Workers	Approximately 2,000 workers create an incremental increase of 1,236 indirect jobs, within the region.
Operational Workers	750 new workers create an incremental increase in 1,553 indirect permanent jobs within the region for at least 40 operating years.
Socioeconomics	Increased tax revenue supports improvements to public infrastructure and social services. The increased revenue spurs future growth and development.
Technical and Other Non-Monetary Benefits	
Fuel Diversity	Reduces exposure to supply and price risk associated with reliance on any single fuel source.
Price Volatility	Dampens potential for fuel price volatility.
Fossil Fuel Supplies	Offsets usage of finite fossil fuel supplies.
Electrical Reliability	Enhances electrical reliability.
Emissions Reduction	Significant beneficial impact in terms of avoidance of air emissions as shown in Table 8.0-2.
Carbon Dioxide Emissions	Baseload generation with virtually no carbon dioxide emissions.
Wastes	Compared with fossil-fueled plants, nuclear plants produce less nonradioactive waste products.

Table 8.0-2 Avoided Air Emissions

	Gas-Fired Plant	Coal-Fired Plant
Pollutant	**Tons per Year (tpy)**	**Tons per Year (tpy)**
SO_2	141	4,163–9,579
NO_x	414	2,081–4,257
CO	248	4,683–6,386
PM	455	937–2,129
VOC	87	182–346

Notes:

- Assumes use of reasonable air control mitigation technology.
- Avoided gas-fired emissions are pro-rated assuming a multi-unit 1500 MW(e) gas-fired combined cycle including an SCR with steam/water injection with 80 percent removal efficiency operating at a 90 percent capacity factor.
- Avoided coal-fired emissions are pro-rated assuming a 1500 MW(e) state-of-art pulverized coal plant, burning 2.65 percent sulfur Eastern bituminous coal and operating at a 90 percent capacity factor.

Section 8.0 References

1. Virginia Economic Development Partnership, *The Estimated Economic Impact of an Expansion of the North Anna Power Station on Virginia*. November 14, 2006.

2. U.S. Nuclear Regulatory Commission, *NUREG-1811, Environmental Impact Statement for an Early Site Permit at the North Anna ESP Site*. Washington, D.C., December 2006.

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4. Center for Energy and Economic Development (CEED), "Fuel Diversity," 2006 (www.ceednet.org/ceed/index.cfm?cid=7500,7583) accessed September 4, 2007.

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8.1 Power System

This section describes and assesses the regional power system in which the proposed facility would operate. This section describes: i) DVP's power system control area, ii) DVP's and ODEC's electric distribution service territories, iii) the PJM market, in which DVP and ODEC operate and of which DVP's control area comprises the "PJM South Region"; and iv) the Regional Reliability Organization—SERC Reliability Corporation (SERC)—to which DVP and ODEC belong. This section also defines the appropriate region of interest for assessing the need for power. As discussed further below, legislation was recently passed in Virginia that redefined investor-owned electric utilities' native load obligations.

8.1.1 Region of Interest – Dominion Zone

In May 2005, DVP joined PJM and transferred control of the transmission facilities that it owns and operates in its control area to PJM. With its integration into PJM, DVP separated its electric generation and traditional customer delivery businesses (referred to now as "load serving entity" or "LSE") into two distinct operations within PJM's system. When DVP joined PJM, it resulted in the creation of the PJM South Region, which is also known as the Dominion Zone, the region of interest (ROI) for the purposes of this COL Application. The Dominion Zone is currently coterminous with the power system control area of DVP and includes the electric distribution service territories of DVP, ODEC, North Carolina Electric Cooperatives (NCEMCS) and other municipals. DVP operates as an LSE in the Dominion Zone.

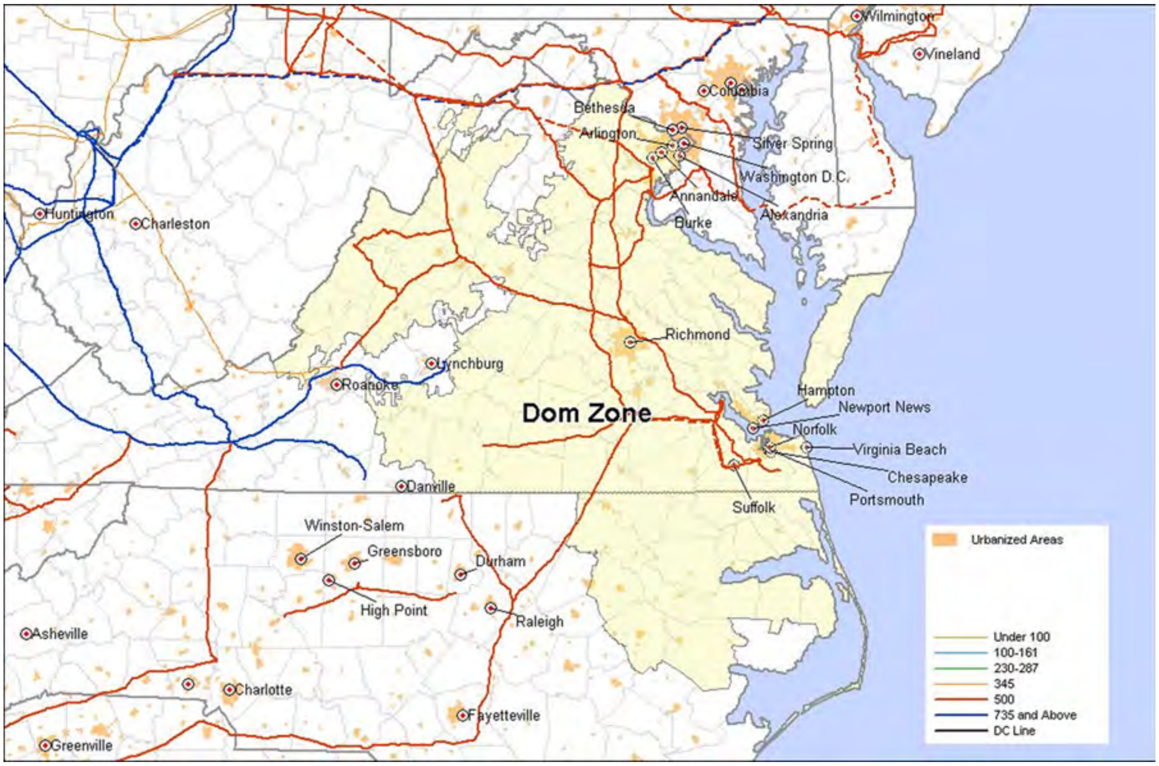
DVP serves approximately 90 percent of the electric load in the Dominion Zone including both peak demand and total energy requirements.[1] ODEC also operates within the Dominion Zone and owns an 11.6 percent interest in NAPS and is a co-applicant of this COLA. The need for power analysis presented in Section 8.4 relies upon baseload growth projections based on historical growth observed by DVP in the Dominion Zone. It is assumed that ODEC has a similar electric demand profile to DVP, given that both LSEs operate in service territories that either abut or overlap each other. Demand forecasts specific to ODEC's service territory are not available. The following information on ODEC and its service territory is presented to provide a complete picture of the Dominion Zone.

8.1.2 ODEC Electric Service Territory

ODEC serves a small percentage of the Dominion Zone load through its nine members that distribute electrical services in the Virginia mainland (i.e., BARC Electric Cooperative, Community Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Northern Virginia Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric

1. This assessment is based on analysis of DVP's 2006 actual peak demand and annual energy compared to 2006 historical PJM integrated hourly loads for the Dominion Zone (Reference 9).

Figure 8.1-1 Map of Major Transmission Lines into Dominion Zone



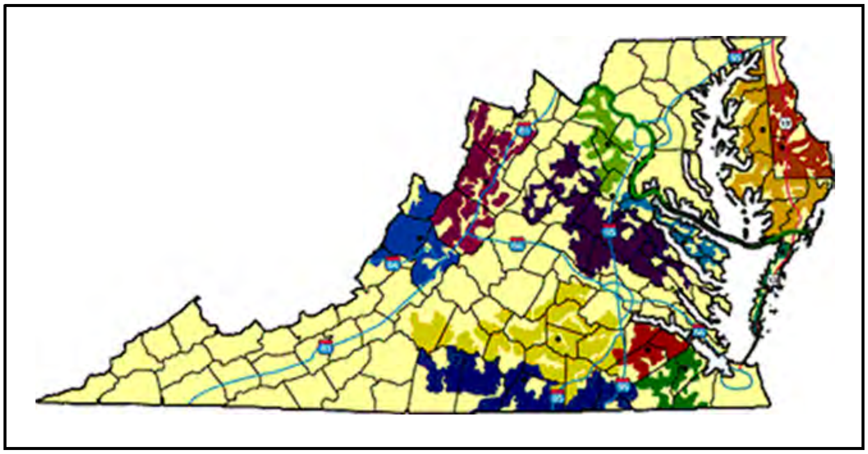
(Source: Energy Velocity)

Cooperative, Shenandoah Valley Electric Cooperative, and Southside Electric Cooperative). As shown in Figure 8.1-2, the territory of ODEC's franchise covers about a third of the Virginia land mass. (Reference 1) In addition to its 11.6 percent ownership share in NAPS, ODEC owns several other generating facilities in Virginia including a 50 percent ownership share of the 880 MW coal-fired Clover Power Station and two 100 percent owned gas-fired combustion turbine facilities at Marsh Run and Louisa County. (Reference 2)

8.1.3 **DVP's Electric Service Territory**

DVP's electric service territory encompasses most of the population of the Commonwealth of Virginia as well as sections of North Carolina (see the shaded area in Figure 8.1-3). DVP's service territory in Virginia comprises about 65 percent of the state's total land area, but accounts for over 80 percent of its total load and includes many of the fastest growing counties in Virginia. (Reference 3) In North Carolina, DVP serves the northeastern corner of the state excluding several municipalities. As discussed in Section 8.1.3.1, DVP has native load obligations throughout its service territory in Virginia and North Carolina.

Figure 8.1-2 Map of ODEC Service Territory



(Source: www.odec.com/members/territory.htm)

DVP serves the fast-growing Northern Virginia area. This area comprises the counties of suburban Washington DC, six of which, Loudoun, Spotsylvania, Culpeper, Stafford, King George and Prince William, are among the 100 fastest-growing counties in the nation according to the U.S. Census Bureau. (Reference 10) In addition, DVP's service territory includes the cities of Richmond, Norfolk, Williamsburg, Fredericksburg, Virginia Beach, and Charlottesville.

The estimated population for the Commonwealth of Virginia as of July 2005 was 7,567,465 as published by the U.S. Census Bureau (Reference 11) and is on pace for approximately 1.2 percent–1.3 percent per annum growth based on the growth experienced from 2000 to 2005. DVP estimates that its Virginia service territory population has grown at about 1.3 percent–1.6 percent per annum since 2000, leading to its 2005 population estimate of 6,289,297.[1]

The population growth for the state of North Carolina has ranged from about 1.4 percent–1.7 percent per annum since 2000, to the Census Bureau's July 2005 estimate of 8,683,242. (Reference 12) Population growth in the counties in which DVP's service territory is located in North Carolina has ranged from about 0.3 percent–1.1 percent per annum since 2000, to the 2005 estimate of 552,856.

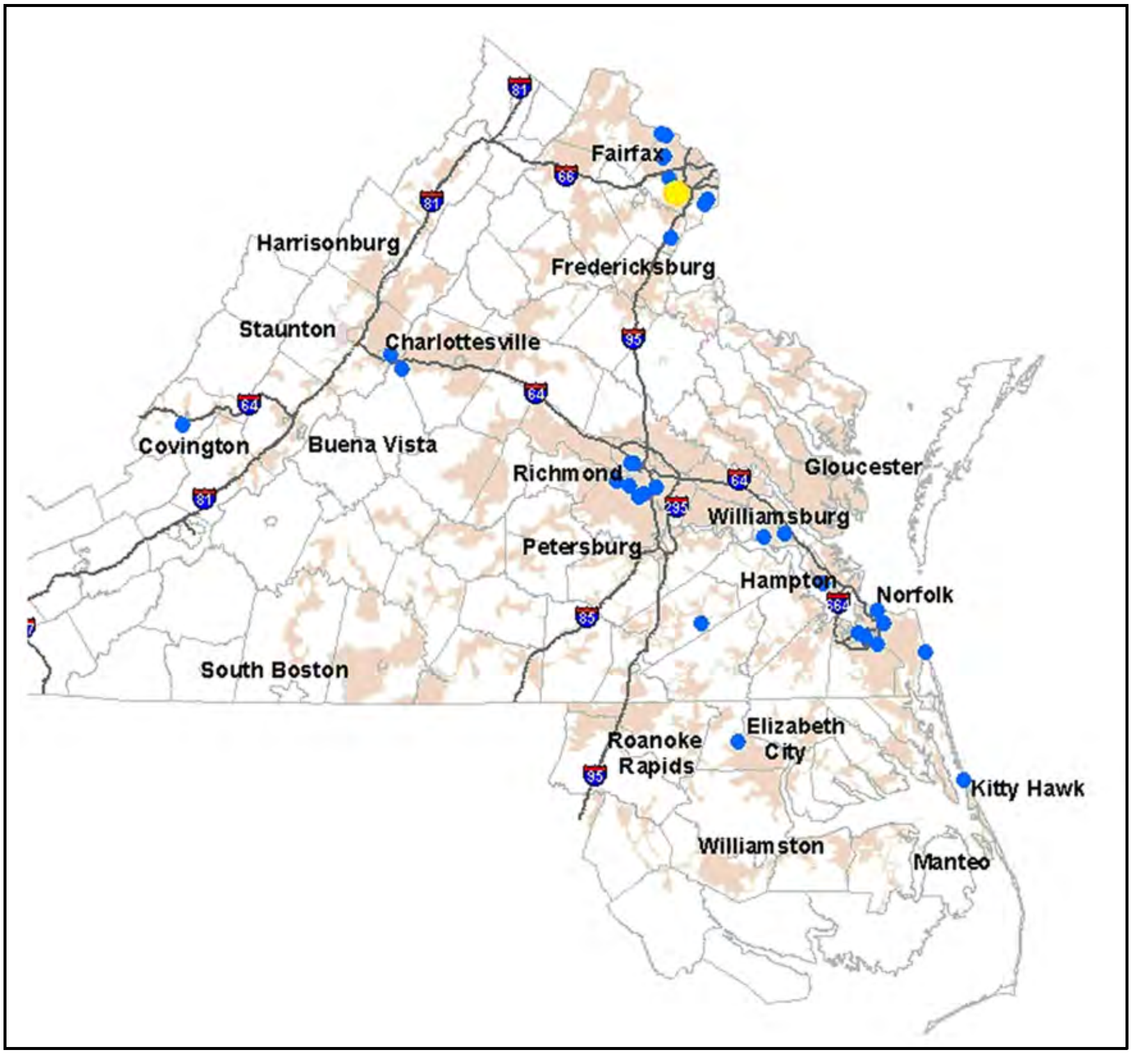
The estimated population growth rates for counties in which DVP has service territory are outlined in Table 8.1-1 and the counties and cities in which DVP's service territory is located are listed in Table 8.1-2. Dominion stated in a recent presentation during the Lehman Brothers 2007 CEO Energy Conference that it expects to add 50,000+ new customer connections each year for 2008 through 2010. (Reference 4)

1. This estimate was developed by cross referencing the population estimates published by the U.S. Census Bureau and resulting growth rates with information published in the EIA-861 database regarding the counties where Virginia Electric & Power Co distributes electricity.

The breakdown of residential, commercial and industrial customers served by DVP as reported by the EIA in its EIA-861 database is provided in Table 8.1-3. Roughly 40 percent of the total load reported was residential, 50 percent was commercial and the remaining 10 percent industrial.

As shown in Table 8.1-3, the average electric sales per customer has been steadily increasing across all three of DVP's customer segments. The commercial segment has experienced the most growth in use per customer, increasing at a 6.9 percent compound annual growth rate between 2001 and 2005.

Figure 8.1-3 Map of DVP's Electric Service Territory



(Source: www.dom.com)

Table 8.1-1 Population Statistics

Virginia Statistics

	Entire State	Growth	Counties Listed in Table 8.1.3.C	Growth
7/1/2000	7,104,078	—	5,842,936	—
7/1/2001	7,191,941	1.2%	5,929,555	1.5%
7/1/2002	7,286,061	1.3%	6,022,298	1.6%
7/1/2003	7,383,387	1.3%	6,115,649	1.6%
7/1/2004	7,481,332	1.3%	6,209,980	1.5%
7/1/2005	7,567,465	1.2%	6,289,297	1.3%

North Carolina Statistics

	Entire State	Growth	Counties Listed in Table 8.1.3.C	Growth
7/1/2000	8,078,429	—	532,020	—
7/1/2001	8,198,279	1.5%	533,649	0.3%
7/1/2002	8,312,755	1.4%	538,594	0.9%
7/1/2003	8,422,375	1.3%	542,632	0.7%
7/1/2004	8,540,468	1.4%	546,816	0.8%
7/1/2005	8,683,242	1.7%	552,856	1.1%

(Source: U.S. Census Bureau)

Table 8.1-2 List of Counties and Cities Included in Service Territory Estimates

Virginia Counties/Cities	Virginia Counties/Cities (cont'd.)	North Carolina Counties/Cities
Albemarle County	Northumberland County	Beaufort County
Alleghany County	Nottoway County	Bertie County
Amelia County	Orange County	Camden County
Amherst County	Page County	Chowan County
Appomattox County	Pittsylvania County	Currituck County
Arlington County	Powhatan County	Dare County
Augusta County	Prince Edward County	Edgecombe County
Bath County	Prince George County	Gates County
Bedford County	Prince William County	Halifax County
Botetourt County	Richmond County	Hertford County
Brunswick County	Rockbridge County	Hyde County
Buckingham County	Rockingham County	Martin County
Campbell County	Shenandoah County	Northampton County
Caroline County	Southampton County	Pasquotank County
Charles City County	Spotsylvania County	Perquimans County
Charlotte County	Stafford County	Pitt County
Chesterfield County	Surry County	Tyrrell County
Clarke County	Sussex County	Washington County
Culpeper County	Westmoreland County	
Cumberland County	York County	
Dinwiddie County	Alexandria city	
Essex County	Buena Vista city	
Fairfax County	Charlottesville city	
Fauquier County	Chesapeake city	
Fluvanna County	Clifton Forge city	
Gloucester County	Colonial Heights city	
Goochland County	Covington city	
Greene County	Emporia city	

Table 8.1-2 List of Counties and Cities Included in Service Territory Estimates

Virginia Counties/Cities	Virginia Counties/Cities (cont'd.)	North Carolina Counties/Cities
Greensville County	Fairfax city	
Halifax County	Falls Church city	
Hanover County	Franklin city	
Henrico County	Fredericksburg city	
Isle of Wight County	Hampton city	
James City County	Hopewell city	
King And Queen County	Lexington city	
King George County	Manassas city	
King William County	Newport News city	
Lancaster County	Norfolk city	
Loudoun County	Petersburg city	
Louisa County	Poquoson city	
Lunenburg County	Portsmouth city	
Madison County	Richmond city	
Mathews County	South Boston city	
Mecklenburg County	Staunton city	
Middlesex County	Suffolk city	
Nelson County	Virginia Beach city	
New Kent County	Waynesboro city	
	Williamsburg city	

Table 8.1-3 Sales Information by Rate Class

Sales by Rate Class (MW-hr)

	State of VA				State of NC				Total Service Territory			
	Res	Com	Ind	Total	Res	Com	Ind	Total	Res	Com	Ind	Total
2001	23,514,526	22,836,750	9,425,048	55,776,324	1,268,223	702,603	1,481,527	3,452,353	24,782,749	23,539,353	10,906,575	59,228,677
2002	25,674,265	23,559,477	9,243,469	58,477,211	1,391,162	737,587	1,592,430	3,721,179	27,065,427	24,297,064	10,835,899	62,198,390
2003	25,822,627	33,397,129	8,962,099	68,181,855	1,423,184	887,559	1,563,093	3,873,836	27,245,811	34,284,688	10,525,192	72,055,691
2004	26,849,662	34,899,900	9,050,999	70,800,561	1,487,529	924,918	1,792,027	4,204,474	28,337,191	35,824,818	10,843,026	75,005,035
2005	28,289,553	36,303,545	8,621,448	73,214,546	1,575,311	930,029	1,709,116	4,214,456	29,864,864	37,233,574	10,330,564	77,429,002

Customer Count by Rate Class (#)

	State of VA				State of NC				Total Service Territory			
	Res	Com	Ind	Total	Res	Com	Ind	Total	Res	Com	Ind	Total
2001	1,797,885	192,122	686	1,990,693	93,033	14,449	88	107,570	1,890,918	206,571	774	2,098,263
2002	1,836,500	195,715	657	2,032,872	94,621	14,864	84	109,569	1,931,121	210,579	741	2,142,441
2003	1,870,131	225,811	630	2,096,572	95,884	17,474	79	113,437	1,966,015	243,285	709	2,210,009
2004	1,903,696	228,909	606	2,133,211	96,906	17,483	79	114,468	2,000,602	246,392	685	2,247,679
2005	1,939,288	232,881	585	2,172,754	98,235	17,634	70	115,939	2,037,523	250,515	655	2,288,693

Table 8.1-3 Sales Information by Rate Class

Average Sales per Customer (MW-hr)

	State of VA				State of NC				Total Service Territory			
	Res	Com	Ind	Total	Res	Com	Ind	Total	Res	Com	Ind	Total
2001	13	119	13,739	28	14	49	16,836	32	13	114	14,091	28
2002	14	120	14,069	29	15	50	18,958	34	14	115	14,623	29
2003	14	148	14,226	33	15	51	19,786	34	14	141	14,845	33
2004	14	152	14,936	33	15	53	22,684	37	14	145	15,829	33
2005	15	156	14,738	34	16	53	24,416	36	15	149	15,772	34

% of Total MW-hr by Rate Class

	State of VA				State of NC				Total Service Territory			
	Res	Com	Ind	Total	Res	Com	Ind	Total	Res	Com	Ind	Total
2001	42%	41%	17%	100%	37%	20%	43%	100%	42%	40%	18%	100%
2002	44%	40%	16%	100%	37%	20%	43%	100%	44%	39%	17%	100%
2003	38%	49%	13%	100%	37%	23%	40%	100%	38%	48%	15%	100%
2004	38%	49%	13%	100%	35%	22%	43%	100%	38%	48%	14%	100%
2005	39%	50%	12%	100%	37%	22%	41%	100%	39%	48%	13%	100%

(Source: EIA-861 Database)

8.1.3.1 **Status of Electricity Market Reforms in DVP's Service Territory**

In 2007, the Virginia General Assembly passed House Bill 3068 and Senate Bill 1416 (the Legislation), which were signed into law by Virginia's governor. A primary objective of the Legislation is to ensure a reliable and adequate supply of electricity by investor-owned electric utilities for their native load obligations[1] and to return Virginia's electric system to an incentive form of "cost-of-service" regulation beginning July 1, 2007. One of the goals of the Legislation is to encourage the construction of new baseload generation, including nuclear generation, to serve in-state system requirements by providing higher rates of return on common equity for these facilities. Unit 3 is being proposed to meet native load obligations pursuant to this Legislation. This Legislation also requires that 75 percent[2] of the total annual margins from off-system sales be applied to the utility's fuel expenses, reinforcing that these facilities are primarily intended to serve native load customer requirements.

DVP and other electric utilities in North Carolina have continued to be responsible for supplying their native load obligations. (Reference 13)

8.1.4 **Dominion Zone Oversight**

The Dominion Zone is subject to oversight from four separate entities with respect to reserve margin standards, system reliability, and planning. A summary of each entity's oversight function is provided below.

8.1.4.1 **PJM**

PJM is an independent regional transmission organization (RTO) responsible for operating the wholesale energy market in the largest centrally dispatched control area in North America encompassing all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia (see Figure 8.1-4). PJM also has primary responsibility for administering a long-term PJM Regional Transmission Expansion Planning Process (RTEPP) and the Reliability Pricing Model (RPM) which provides a long-term price signal for existing and new generating capacity resources to ensure reliability for the PJM control area.

1. There are approximately 100 Virginia jurisdictional customers with loads greater than 5 MW representing a total coincident peak load of approximately 1200 MW and these customers may, if they choose, purchase power from other providers. In addition, the Legislation allows non-residential customers to aggregate their loads to greater than 5 MW and be served by a competitive supplier. However, the Virginia SCC must find that neither the incumbent electric utility nor its retail customers will be adversely affected and that demand from customers that are allowed to buy power from competitors is less than 1% of the electric utilities' total peak demand.
2. The Virginia SCC may require less than 75% of such margins to be so credited if it finds by clear and convincing evidence that such a requirement is in the public interest.

As a PJM member, DVP, as a LSE, is a signatory to PJM's Reliability Assurance Agreement among Load Serving Entities in the PJM Region (RAA),[1] which obligates DVP to own or procure an amount of capacity in order to maintain overall system reliability. The process and framework established by PJM's RAA is the most comprehensive and rigorous for ensuring the reliability of resources in the Dominion Zone. PJM performs a technical analysis on an annual basis that calculates the appropriate generating capacity including reserve margin required to meet the RAA-defined reliability criteria.[2] This technical analysis is based on a loss of load expectation (LOLE) of one day in ten years, which is also the standard adopted by SERC and the Reliability First Corporation (RFC), which is the regional reliability organization which covers much of the PJM market. Following a period of review and comment from the Planning Committee, the RAA-Reliability Committee approved a 15 percent installed reserve margin (IRM) target for the PJM region. This region-wide IRM target is used for RPM and is the basis for allocating a capacity obligation to each LSE within PJM based on that LSE's share of the PJM summer peak load.

Each LSE is responsible for installing or purchasing capacity, on a daily basis, to meet its obligation. The rationale for imposing capacity obligations on PJM LSEs is that installation of generating capacity requires time, coordination of electric system resources, and financial backing and, therefore, must be planned for in advance of need. To meet its capacity, long-term reliability obligations and customer energy requirements within PJM in a cost-effective manner, DVP is proposing to build Unit 3 as well as the Virginia City facility.

In order to balance the requirements of buyers and loads with offers of suppliers and by so doing manage the reliability of the system, PJM administers an hourly market (both day ahead and real time) for energy and the RPM annual market for capacity. While the energy market is designed to balance day-to-day (and hour-to-hour) supply and demand within PJM, the RPM capacity market is designed to provide a price signal to ensure that the long-term peak requirements of the PJM system can be met by available capacity resources. PJM defines the purpose of the RPM market as "to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the RTEPP." (Reference 14)

The Dominion Zone is one of the 23 Locational Deliverability Areas (LDA) in PJM. These 23 LDAs, most of which reflect service territory boundaries of PJM member electric utilities, were identified by PJM's load deliverability analyses conducted pursuant to the RTEPP protocol and the PJM Manuals as "constrained areas that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations."[3] Each of the

1. Reference 7.
Parties previously have entered into similar commitments related to sub-regions of the PJM Region through the East RAA, the West RAA, and the South RAA. In June 2007, these agreements were replaced with a single reliability assurance agreement among all Load-Serving Entities in the PJM Region.
2. PJM outlines the process for establishing a reserve margin target and allocating responsibility for meeting this target among members in its Manual 20.

23 LDAs are modeled in the RPM Base Residual Auction. Capacity to serve LSEs in constrained areas, such as the Dominion Zone, must be located within the constrained area or the LSE must enter into a bilateral transaction for capacity into the constrained area with another entity through Capacity Transfer Rights (CTRs). A discussion of the capacity resources located in the Dominion Zone is presented in Section 8.3.

A defining characteristic of each LDA is its transfer capability with adjacent electric transmission networks. Through the RTEPP planning exercise, PJM identifies each LDA's capacity emergency transfer limit (CETL) and capacity emergency transfer objective (CETO), where CETL is the actual emergency import capability, expressed in megawatts, of the sub-area and CETO is the import capability required for the sub-area to meet the approved LOLE negligible level of one day in 25 years.[1]

In the 2007 Federal Energy Regulatory Commission (FERC) Order on Rehearing and Clarification Accepting Compliance Filing (Reference 15), PJM specifies the CETL and CETO for the Dominion Zone to be approximately 3100 MW and 1155 MW, respectively. Even with the new Meadow Brook - Loudoun 500 kV line sponsored by DVP and other baseline transmission upgrades included in the PJM RTEPP, PJM believes that additional transmission system expansion and new generating sources will still be required to meet expected peak load supply requirements in the Dominion Zone beyond 2011.[2]

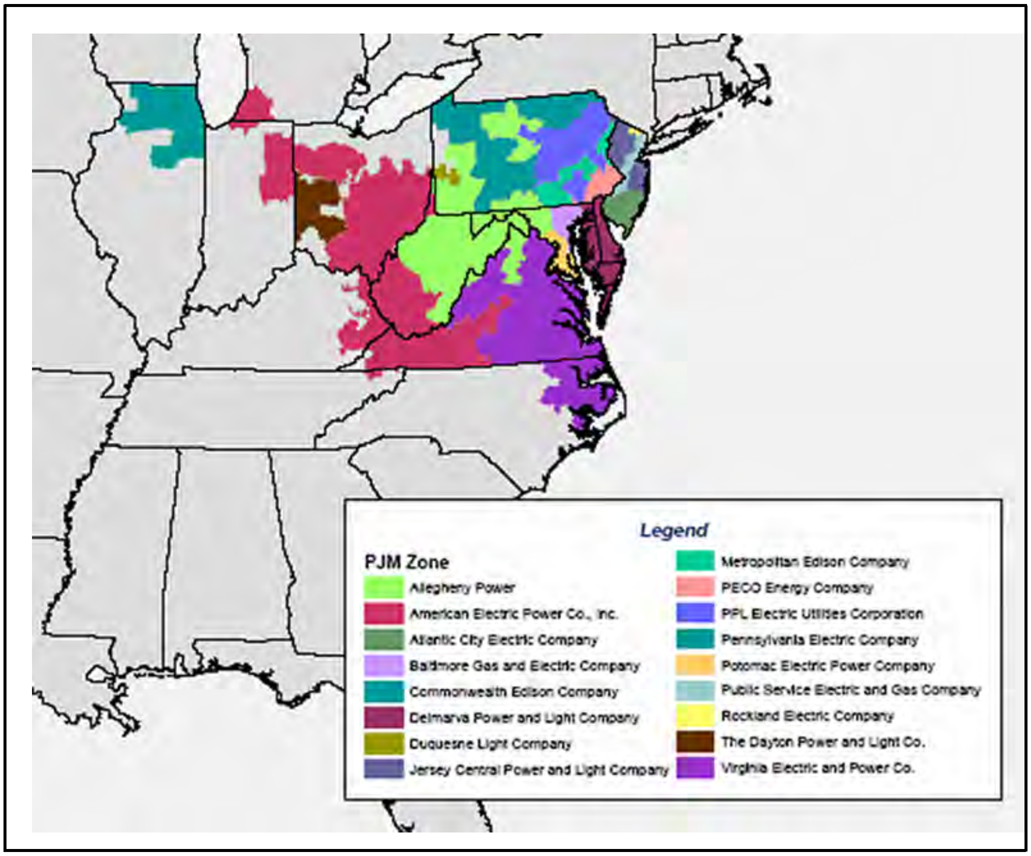
A breakdown of the 3100 MW CETL by major transmission corridor is not available, though a map of the major transmission lines (345 kV and above) can be found in Figure 8.1-1. This map also outlines urbanized zones near major cities encompassed in the Dominion Zone. These urbanized zones/major cities correlate well to the major load zones served by DVP in the PJM RTO zonal footprint (specifically, Dominion Zone).

8.1.4.2 **Virginia SCC**

The Virginia SCC must consider and rule on the application for the CPCN that DVP must file for Unit 3. Under Va. Code §56-580.D, a utility must demonstrate to the Virginia SCC that a proposed facility: i) will have no material adverse effect upon reliability of electrical service provided by any regulated public utility, ii) is required by the public convenience and necessity, and iii) is not otherwise contrary to the public interest. In 2007, the Virginia General Assembly amended the Virginia Utility Electric Restructuring Act, Code of Virginia (Title 56, Chapter 23) to accommodate the new Legislation designed to ensure reliable and adequate supply of electricity. Part of this Legislation requires each electric utility, such as Dominion, to file periodically with the Virginia SCC

3. Reference 7, Schedule 10.
1. The CETO planning standard refers to the probability of a sub-area shedding load due solely to its inability to import needed and available capacity assistance. The CETO one in 25 years LOLE criterion is distinct from the one in ten years criterion that applies to generation adequacy only and not to transmission import capabilities (Reference 5).
2. Reference 8 at 98 and 102.

Figure 8.1-4 PJM RTO Map



Note: Dominion Zone is indicated in legend as Virginia Electric and Power Co.
(Source: www.pjm.com)

its 10-year plan for its projected generation and transmission requirements to serve its native load, including how the utility will obtain such resources, their capital requirements, and the anticipated sources of such funding (Va. Code § 56-585.1.A.3).

As prescribed by the Virginia General Assembly, the Virginia SCC also has the responsibility to fix, for each Virginia public utility, just and reasonable rates that it may charge for its services to its customers. The Virginia SCC also has authority over the manner in which the utility companies provide service to their customers and requires public utilities to provide reasonable and reliable service and to adopt safety rules and regulations for the protection of the public.

8.1.4.3 North Carolina Utilities Commission (NCUC)

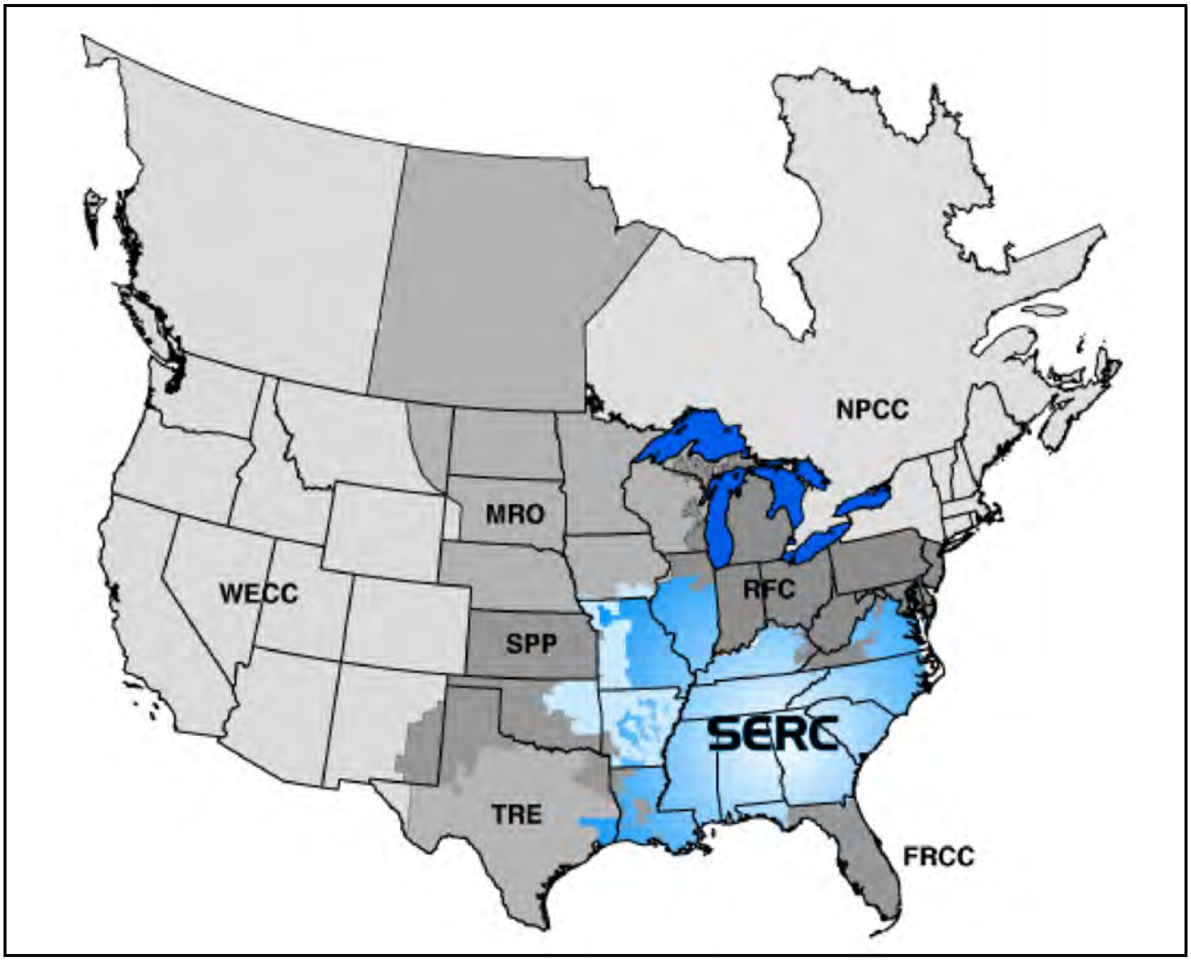
The NCUC requires all public utilities to first obtain a certificate of public convenience and necessity from the NCUC before beginning the construction or operation of any utility plant or system in North Carolina or acquiring ownership or control thereof. In August 2007 the Governor of North Carolina signed into law Senate Bill 3 (Session Law 2007-397). Under the law, for generation facilities constructed outside of North Carolina, a utility seeking rate recovery must file a petition with the NCUC, and if need is shown, the NCUC shall approve an estimate of construction costs and construction schedule if the plant is intended to serve North Carolina customers. The new law also contains provisions regarding review of the development costs for nuclear generation.

As a general rule, the NCUC has the responsibility under the law to fix, for each North Carolina public utility, the rates that it may charge for its services to its customers. These rates are required to be just and reasonable and fair both to the public utility and to its customers. In addition, the NCUC has authority over the manner in which the utility companies provide service to their customers and requires public utilities to provide reasonable and reliable service and to adopt safety rules and regulations for the protection of the public. (Reference 16)

8.1.4.4 **SERC**

DVP's and ODEC's service territories are located in the VACAR sub-region of SERC (Figure 8.1-5 identifies the area covered by SERC.). SERC is responsible for proposing and enforcing reliability standards within the SERC region based on authority delegated to it from the North American Electric Reliability Corporation. SERC is also responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in the SERC region. SERC promotes the development of reliability and adequacy arrangements among the power supply systems; administers a regional compliance and enforcement program to achieve the reliability benefits of coordinated planning and operations; and provides a mechanism to resolve disputes on reliability issues. (Reference 6)

Figure 8.1-5 SERC Region



Source: www.serc1.org/Images/USCanMap500x500.gif

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8.2 Power Demand

8.2.1 Power and Energy Requirements

8.2.1.1 Load Forecast

Under the PJM RAA approved by FERC (Reference 5), PJM is responsible for producing a load forecast that is the basis for determining “capacity obligations” for each LSE.[1] Each LSE is required to procure enough capacity, or generation capability, to satisfy its load obligation (with reserve margin). As described below, the PJM load forecast process is systematic, comprehensive, subject to confirmation, and responsive to forecasting uncertainty. Thus, as allowed by NRC’s ESRP, PJM’s load forecast is used as the “demand” component of the need for power evaluation.

PJM produces a systematic load forecast every year for a 15-year planning horizon. The 2007 Load Forecast for the Dominion Zone is presented in Table 8.2-1. The forecast represents summer peak load estimates under normal peak weather conditions in the absence of any load reductions due to active load management, voltage reductions or voluntary curtailments. Traditionally, the Dominion Zone is “summer-peaking”, i.e., the absolute peak load for the entire year occurs during the summer months. Capacity obligations of each LSE in PJM are determined for the RPM capacity market based on summer peak load. Thus, for reliability planning purposes, the summer peak load forecast is used to evaluate the region’s generation adequacy.

According to PJM’s *2007 Load Forecast Report*, the summer peak load for the Dominion Zone will increase from 19,167 MW in 2007 to 23,222 MW in 2017, an increase of 4055 MW at a compound average annual growth rate of 1.9 percent. PJM predicts that demand growth in the Dominion Zone will exceed growth rates in all other PJM geographic zones, including PJM West, PJM Mid-Atlantic, and the PJM RTO. (Reference 7)

1. Under this RAA, PJM is authorized to guide the reliability planning process in accordance with the reliability principles and standards of other organizations such as the NERC.

Table 8.2-1 Dominion Zone - Summer Peak Loads (MW) and Growth Rates

	MW	Growth %
2007	19,167	0.9
2008	19,583	2.2
2009	19,956	1.9
2010	20,347	2.0
2011	20,746	2.0
2012	21,110	1.8
2013	21,519	1.9
2014	21,923	1.9
2015	22,334	1.9
2016	22,769	1.9
2017	23,222	2.0
2018	23,619	1.7
2019	24,042	1.8
2020	24,478	1.8
2021	24,868	1.6
2022	25,320	1.8
Average Annual Growth Rate (10-Year)		1.9
Average Annual Growth Rate (15-Year)		1.9

8.2.1.2 **PJM Load Forecast**

The PJM demand forecast satisfies the NRC's evaluation criteria of being: 1) systematic; 2) comprehensive; 3) subject to confirmation; 4) and responsive to forecast uncertainty. The basis of this assessment is presented below.

8.2.1.2.1 **Systematic Process**

PJM has a systematic process for load forecasting. The forecast was developed using accepted techniques and employs a wide range of explanatory variables. The PJM load forecasts are based on a multiple variable Ordinary Least Squares regression using economic and calendar variables for each of the 23 LDAs in PJM. *Manual 19* provides an overview of the load forecasting process (Reference 6):

> The PJM Load Forecast Model produces a 15-year monthly forecast of unrestricted peaks assuming normal weather for each PJM zone and the RTO. Forecasts are developed for each zone's non-coincident peak and the zone's share of the PJM coincident peak. The

econometric models are supplemented with a Monte Carlo simulation to derive a distribution of forecasts over a wide range of weather conditions.

The regressions are specified using zonal metered load data which are adjusted to account for estimated load reductions for recognized demand management efforts. The actual loads used in the regressions are the maximum value for each day, adjusted to reflect unrestricted (before the impact of load management) loads. Calendar effects are then captured by specifying the days of the week, month of the year, holidays, hours of daylight and Daylight Savings Time. Holiday seasonal lighting load is reflected using a trend variable. Weather is reflected in the models as Temperature-Humidity Index and heating and cooling degree-days.[1] Measures of economic and demographic activity are included in the forecast model, representing total U.S., state, or metropolitan areas, depending upon their predictive value. The original economic model specification was based on the U.S. Gross Domestic Product. This specification was updated to reflect Gross State Product and Gross Metropolitan Area Product (Richmond, Virginia Beach and Roanoke for the Dominion Zone model) for Metropolitan Statistical Areas. PJM's Manual 19 provides a detailed description of the load forecasting methodology.

To reflect the variability of weather conditions, for each PJM zone, a distribution of non-coincident peak (NCP) forecasts is produced using a Monte Carlo simulation process. The weather distributions are developed using observed historical weather data. The simulation process produces a distribution of monthly forecast results by selecting the 12 monthly peak values per forecast year for each weather scenario. For each year, by weather scenario, the maximum daily NCP load for a zone over each season is found. For each zone and year, a distribution of zonal NCP by weather scenario is developed. The median values are used as the base (50/50) forecast.

8.2.1.2.2 **Comprehensive**

PJM evaluated a comprehensive set of model parameters and model specifications. The PJM NCP model specification consists of over 50 independent variables which were reviewed above. In PJM's forecasting approach, while the parameter estimates do not vary by month, they do vary across the 18 electric distribution company zones.

A range of different model specifications were evaluated and the preferred specification selected based on its superior performance according to accepted statistical techniques. Specifically, the preferred model specification was chosen based on model backcasting performance after reviewing several alternative specifications. The *PJM Load/Energy Forecasting Model White Paper*

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1. THI = DB - 0.55 * (1 – HUM) * (DB – 58)
   Where: THI = Temperature humidity index;
   DB = Dry bulb temperature (°F);
   HUM = Relative Humidity (where 100% = 1).
   THI readings are divided into separate morning, afternoon, evening, and night effects, as well as weekends.

(*White Paper*) serves as documentation of the implemented peak and energy forecast models as well as other methods and specifications that were tested, but not adopted.

8.2.1.2.3 **Subject to Confirmation**

The PJM load forecast and the forecast results are subject to confirmation by multiple parties. The load forecast is a critical element of the process that is used to establish the capacity obligations of each LSE, which represent significant financial obligations. Thus, the load forecast receives considerable scrutiny from PJM members to ensure that it represents a reliable estimate of future peak loads and basis upon which to evaluate future capacity requirements. The load forecast must meet the forecasting standards of the Reliability Assurance Agreement and PJM *Manual 19: Load Data Systems*. The Load Analysis Subcommittee (LAS) is organized as a member oversight group that monitors each load forecast produced by PJM.

Under PJM Manual 19, the PJM Load Forecast is reviewed by the LAS, and presented to the Planning Committee for endorsement. Final approval is received from the PJM Board of Managers. A member of the Planning Committee may submit an appeal (detailing the issue and outlining a solution) for a review of part or all of the forecast, which will be forwarded by the Chair of the Planning Committee to PJM, upon a vote of the Committee. The LAS is comprised of representatives from electrical distribution companies that are members of PJM.

The PJM load forecast has also been independently confirmed by the Brattle Group, who were engaged by PJM to provide an independent assessment of PJM's load forecast. (Reference 8) PJM was prompted to conduct this independent evaluation of the model because, among other issues, the 2006 peak load forecast understated the actual peak by 9.36 percent. Weather conditions for the summer 2006 peak were extreme and when the PJM load forecast was re-simulated using those actual weather and economic conditions, the forecast error was only 0.7 percent. The Brattle Group concluded that "the model is doing a good job of forecasting peak demand and the main source of error is weather."[1]

8.2.1.2.4 **Responsive to Forecast Uncertainty**

The predictive capability of the PJM load forecast for the Dominion Zone is indicated by its adjusted R-Squared of 0.961, indicating the over 96 percent of the dependent variable's (i.e., load) variance from the mean is explained by the regression's independent variables and specified parameter estimates.[2]

The Brattle Group review of the peak demand forecast methodology indicates that the primary source of forecast error and uncertainty are weather conditions. PJM addressed the forecast uncertainty associated with weather through the use of a Monte Carlo simulation based on actual

1. Reference 8 at 25.
2. Ibid.

weather conditions. As such the forecast methodology and forecast results adequately account for forecast uncertainty.

8.2.2 Factors Affecting Growth of Demand

This section reviews the factors that affect growth in power demand in the Dominion Zone, including a discussion of the potential impacts of demand side management (DSM) programs on load growth in the Dominion Zone.

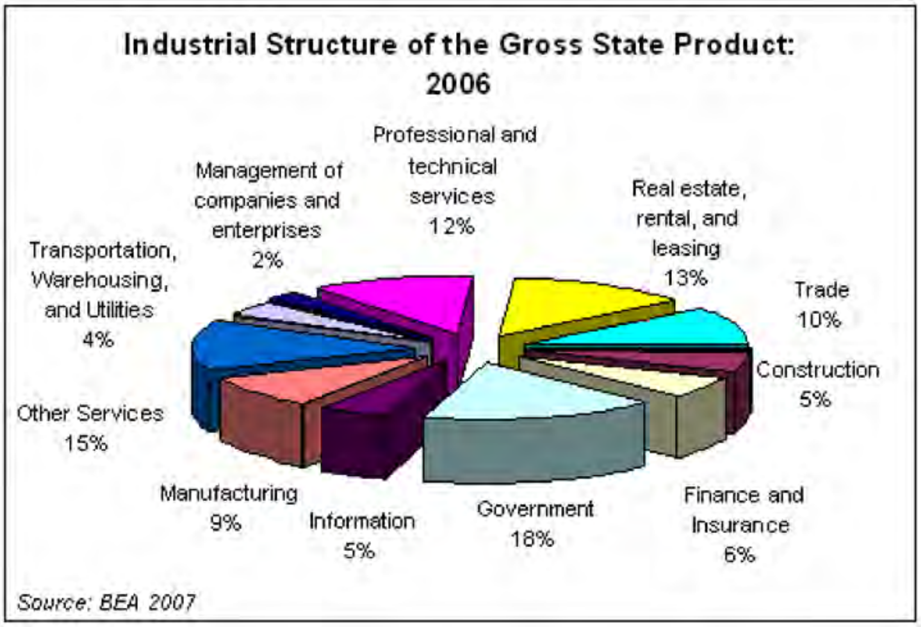
8.2.2.1 Economic and Demographic Trends

Section 8.2.2.2 discusses inputs to PJM's load forecast model, which include factors that affect load growth. Specifically, in the PJM load forecast model, calendar effects are captured by specifying the days of the week, month of the year, holidays, hours of daylight and Daylight Savings Time. Holiday seasonal lighting load is reflected using a trend variable. Weather is reflected in the models as Temperature-Humidity Index and heating and cooling degree-days. Measures of economic and demographic activity are included in the forecast model, representing total U.S., state, or metropolitan areas, depending upon their predictive value. The original economic model specification was based on the U.S. Gross Domestic Product. This specification was updated to reflect Gross State Product and Gross Metropolitan Area Product (Richmond, Virginia Beach and Roanoke for the Dominion Zone model) for Metropolitan Statistical Areas. PJM's Manual 19 provides a detailed description of load forecasting methodology.

According to the PJM's *2007 Load Forecast Report*, the summer peak load for the Dominion Zone will increase from 19,167 MW in 2007 to 23,222 MW in 2017, an increase of 4,055 MW at a compound annual growth rate of 1.9 percent. (Reference 13)

As identified by PJM's specification of its load forecast model, a key driver in demand growth in the Dominion Zone is the growth in the commercial sector. As shown in Table 8.1-3, the total energy requirements of the commercial sector increased by 12 percent per year from 2001 to 2005, such that by 2005 the commercial sector represented almost 50 percent of DVP's total energy sales. As shown in Table 8.2-1, which demonstrates the diversity of Virginia's Gross State Product which is a source of strength to the state's economy, a significant portion of these commercial sector energy sales are attributable to the government sector; thus, there is likely to be less variability in DVP's sales from swings in the business cycle, reducing the level of forecast uncertainty.

Figure 8.2-1 Industrial Structure of the Gross State Product, 2006



PJM has also recognized the significant economic growth potential in Virginia, stating:

> The northern Virginia area of PJM continues to experience significant economic growth, growth that requires access to additional sources of electricity and the transmission infrastructure to provide it. (Reference 6)

As discussed previously in Section 8.1.3, DVP estimates the population growth in the counties in its Virginia and North Carolina service territories since 2000 at about 1.3 percent–1.6 percent per annum and 0.3 percent–1.1 percent per annum, respectively. DVP expects significant growth in baseload requirements through both new customer additions, which DVP estimates at approximately 50,000+ new customer connections each year from 2008 to 2010 (Reference 5), and continued increase in average use-per-customer.

Historical DVP weather-normalized average hourly sales over the recent five-year period from 2002 to 2006 has increased at a compound annual growth rate of 2.4 percent. A similar review of weather-normalized peak load over the same five year period from 2002 to 2006 reveals a compound annual growth rate of 1.9 percent, which is fully consistent with PJM's forecasted peak load growth.

8.2.2.2 Energy Efficiency, Conservation and DSM

Electricity demand can also be influenced by DSM programs which are essentially interventions in the market to promote the adoption of more efficient end-uses and to change consumer behavior. This section evaluates the potential impact of such programs on demand growth. Because this analysis is for Unit 3, which would provide baseload power, the focus of the impact of DSM programs is on the impact of such DSM programs on energy requirements, rather than peak demand. In the context of DSM program design, the analysis of the effects is on conservation and energy efficiency programs that are targeted at reducing overall energy requirements rather than demand management programs that are focused on reducing peak demand.

8.2.2.2.1 Current DSM Programs in PJM

PJM has several programs that offer incentives to customers to reduce consumption during peak demand. For example, PJM's Emergency Load Response Program (Reference 8) is designed to encourage customers to reduce load during an emergency event in exchange for compensation from PJM. In addition, the Economic Load Response Program (Reference 9) is designed to encourage customers to reduce load when Locational Marginal Prices are high, in exchange for compensation from PJM. These programs are established programs that have been in place since 2002. According to PJM, more than 6000 commercial and industrial facilities (with demand greater than 100 kW) and 45,000 small commercial and residential customers participate in demand response programs offered by PJM. (Reference 7) These programs focus on reducing peak demand and will have virtually no impact on baseload requirements.

8.2.2.2.2 Current DSM Programs in DVP's Service Territory

DVP offers several tariff-based DSM options for both residential and non-residential customers. DVP offers new residences in North Carolina that meet the Energy Saver Home (ESH) Plus Standards for energy efficiency a 5 percent conservation rate discount through its ESH Plus program. DVP also offers Time-of-Usage rate schedules to North Carolina residential customers through Schedule 1P and Schedule 1T and to Virginia residential customers through Schedule 1S and Schedule 1T. (Reference 14) Examples of non-residential tariff-based DSM programs include the Schedule 10 – Large General Service, (Reference 7) which is designed to promote energy conservation on peak days through pricing. This schedule is applicable to customers in both Virginia and North Carolina service territories electing to receive 500 kW or more of Electricity Supply Service and Electric Delivery Service from the Company. For larger customers in North Carolina, with annual average demand of 5000 kW or more, DVP offers the Schedule 6VP - Large General Service, by which a customer's loads are categorized as baseload and peak load, with the prices applicable to peak loads varying by day according to day type. (Reference 14) In addition, for up to 150 hours per year, a Capacity Surcharge rate is applicable to both the base and peak loads. Dominion Virginia Power notifies customers taking service under this schedule to curtail consumption during hours when peak loads are expected to be high, most often during the summer months. During the past two years, customer curtailments reduced load by an estimated 20–22 MW.

In addition to the tariff-based DSM options mentioned above, DVP also offers DSM education programs, which are designed to educate customers and promote energy efficiency and/or conservation. With the exception of education programs, which are focused on capital improvements, the typical DSM programs are designed to reduce consumption during times of peak demand and focus on reliability.

8.2.2.2.3 Virginia DSM Programs

As discussed in Section 8.1.3.1, Legislation was recently passed in Virginia that provides for investor-owned electric utilities to meet native load obligations. This Legislation also establishes a goal for the year 2022 of "reducing the consumption of electric energy by retail customers" in Virginia by ten percent of the electric energy consumed by retail customers in 2006. Furthermore, it directs the Virginia SCC to conduct a proceeding to:

> (i) determine whether the ten percent electric energy consumption reduction goal can be achieved cost-effectively through the operation of such programs, and if not, determine the appropriate goal for the year 2022 relative to base year of 2006; (ii) identify the mix of programs that should be implemented in the Commonwealth to cost-effectively achieve the defined electric energy consumption reduction goal by 2022, including but not limited to demand side management, conservation, energy efficiency, real time pricing and consumer education; (iii) develop a plan for the development and implementation of recommended programs, with incentives and alternative means of compliance to achieve such goals, (iv) determine the entity or entities that could most efficiently deploy and administer various elements of the plan, and (v) estimate the cost of attaining the energy consumption reduction goal. (Reference 10)

The Legislation indicates that these programs may include activities by electric utilities, public or private organizations, or both electric utilities and public or private organizations. The Virginia SCC is to submit its findings and recommendations to the Governor and General Assembly on or before December 15, 2007. In response to this directive by the General Assembly, the Virginia SCC staff and interested parties (including DVP) are working to develop a long-term energy conservation plan for Virginia.[1]

In July 2007, DVP announced that it had formed a conservation group "to encourage a renewed customer interest in energy efficiency." (Reference 12) The conservation "group will explore new technologies and techniques for residential and business customers to reduce their impact on the environment and help them reduce their demand for electricity."[2] DVP also has identified pilot programs, which are summarized below, to gauge customer interest in and response to certain conservation, energy efficiency, education, demand response, and load management initiatives in Virginia.

1. This long-term energy conservation plan is a separate procedure from the development of the Virginia Energy Plan discussed earlier, which was released September 12, 2007, through the Commonwealth of Virginia Department of Mines, Minerals and Energy (see Section 8.2.2.2.5).
2. Ibid.

8.2.2.2.4 DVP's Pilot DSM Programs

DVP's current conservation and DSM programs focus on customer education and provide rate incentives for load reductions during peak periods. As part of DVP's long-term commitment to conservation, DVP is continuing to evaluate DSM and demand response programs. The pilots will include residential and small commercial energy audits, air-conditioning control programs, a "smart meter" program with critical peak pricing pilot schedule to help customers shift energy usage to off-peak times, and a non-residential distributed generation/ load curtailment pilot program. All programs are subject to approval by the Virginia SCC. If approved and fully populated, the pilot programs are estimated to have a maximum of 30 to 35 MW impact on peak load during 2008. The distributed generation/ load curtailment pilot will run through 2014, and if approved as submitted in the pilot filing, may have up to an estimated 100 MW impact on peak load during that time, if fully populated over that time period, and depending on how qualifying customers receive the program. In addition to the pilots, DVP is a partner in the U.S. EPA/DOE ENERGY STAR program, to promote the purchase and use of energy-efficient products and appliances and energy-efficient building practices for new homes. DVP also is currently collaborating with manufacturers and retailers to make energy-efficient compact fluorescent light bulbs available to customers at a discount. This program will run through 2007, and DVP is seeking Virginia SCC approval to expand and continue it through 2009.

8.2.2.2.5 Virginia Target DSM Goals

As previously noted, the Legislation sets the goal to reduce 2022 electric use by 10 percent of 2006 retail consumption through a mix of conservation, energy efficiency, load management, and DSM programs. This same goal was considered by the ten-year comprehensive Virginia Energy Plan (Virginia Energy Plan),[1] issued by the Commonwealth of Virginia Department of Mines, Minerals and Energy on September 12, 2007. Specifically, the Virginia Energy Plan investigates the legislative goal to reduce, by 2022, electric use by 10 percent of 2006 electric use through energy-efficiency, conservation, and DSM activities. The Virginia Energy Plan refers to calculations based on studies in other states that show that Virginia, with a concerted investment in energy efficiency and conservation activities, has an achievable cost-effective electric energy reduction potential of 14 percent over the next ten years. The achievable cost-effective potential is defined as "the potential for a realistic penetration of energy-efficient measures based on a cost-effectiveness evaluation. High levels of support are required, but measured results should exceed associated program costs."[2] The Virginia Energy Plan acknowledges that meeting the achievable cost-effective potential of 14 percent would require a combination of government, utility, non-profit, industry, and business efforts. The plan ultimately calls for a 10 percent reduction goal, which is consistent with the Legislation target, to provide a measure of conservatism. The Virginia Energy Plan

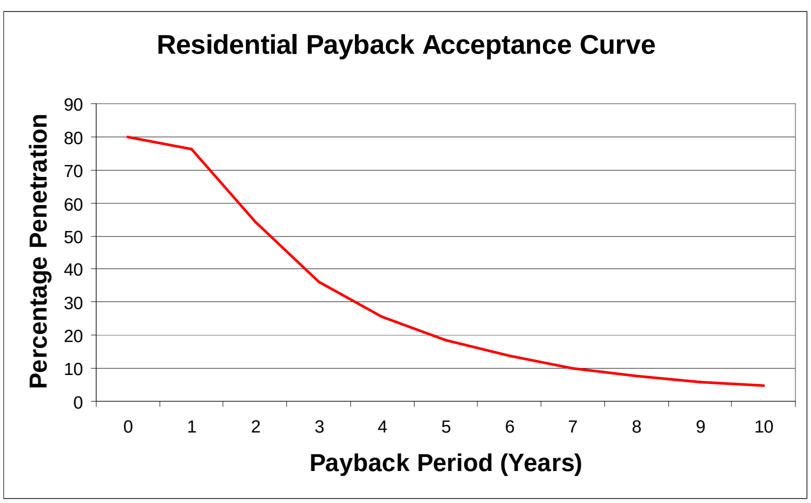
1. Senate Bill 262 (2006), Virginia Energy Plan Va. Code sec. 67-100 et. seq. (Reference 16).
2. Ibid at 63.

acknowledges that Virginia has no established funding source for energy-efficiency and conservation programs and that most states with a successful history of efficiency programs provide significant funding resources. The plan also acknowledges "substantial up-front investment" would be required to achieve the 10 percent reduction goal and estimates "that utilities and consumers together would have to invest an average of approximately $300 million per year over the fifteen-year life of the program ($100 to $120 million by electric utilities, matched by $180 to $200 million by consumers)."[1]

8.2.2.2.6 Challenges to Adoption of Energy Conservation Measures

Experience reveals that while a DSM measure may offer lower life cycle costs, capital improvements are generally not implemented by residential, commercial, and industrial consumers, because of long payback periods. Large government complexes are the exception, because they are more willing to accept payback periods of up to 20 years or longer; however, the majority of those opportunities have been explored and implemented, where they meet the requirements of the government programs. As such, there is little opportunity to increase participation in capital intensive DSM programs until the cost of power increases significantly to shorten expected payback periods. A recent analyst presentation (Reference 15) on DSM portfolio development for the City of Tallahassee estimated DSM market penetration for various payback periods. As shown in Figure 8.2-2, payback periods accepted by customers typically range from 1 to 3 years. This period could be significantly shorter for large industrial customers.

Figure 8.2-2 Residential Payback Acceptance Curve



(Source: Gary Brinkworth and Steve Hastie, Presentation to FEC Advisory Group, DSM Portfolio Development, City of Tallahassee Integrated Resource Planning Study, July 27, 2007)

1. Ibid at 66.

In addition to long payback periods, many consumers do not implement higher efficiency measures because of:

1. a higher first cost (i.e., initial capital cost);
2. limited capital availability for such higher efficiency measures (e.g., for institutional customers such as governments, budgeting processes make it difficult to purchase replacement equipment even when the electricity cost savings can justify the investment given capital budget limits;[1]
3. concerns about its performance (i.e., service quality as well as the consumer's ability to realize the promised level of savings);
4. lack of credible or reliable information regarding the new product or service which makes it harder to assess the tradeoff between higher first cost and lower operating costs;[2]
5. the cost and level of effort required to become informed regarding the performance characteristics of the new appliance or service (i.e., high "transaction costs");
6. lack of required support infrastructure (e.g., trade allies) to install and service the more efficient device;
7. split incentives where the party making the efficiency decision based on the initial capital outlay is different than the party that is responsible for paying for its operating costs over the life of the investment;[3] and
8. limited attention paid to decisions to implement (purchase or replace) such a measure given the small role energy plays in the total budget.

Based on the above, there is a risk that the Legislation's 10 percent target for potential energy savings does not adequately reflect the impact of the challenges to the adoption of more efficient

1. Energy users appear to discount future savings at rates well in excess of market rates for borrowing or saving (see Reference 18).
2. This is characterized by economists as "imperfect information". Another example of imperfect information would be future electricity prices which will determine the value of the energy savings. Behavioral research indicates that when consumers are faced with imperfect information and uncertainty consumers are more reluctant to make decisions. This is critical because many of the DSM measures that produce this savings estimate require consumers to make investment decisions to replace existing appliances with new, more efficient appliances or to purchase a new type of appliance with which they have no experience (e.g., ground source heat pump).
3. This is typical in many real estate transactions where residential builders or commercial real estate developers are most concerned with the construction costs of the facility and where the eventual occupant pays the operating costs. Given that the anticipated electricity bills for the property are typically a minor consideration in the purchase or rental decision, buyers and renters give limited consideration to the relative electricity costs.

appliances or end-use equipment by customers or the need for other initiatives such as potential changes to building codes. Thus, the 10 percent reduction supported by the Legislation and the 14 percent potential savings noted in the Virginia Energy Plan are targets that remain uncertain. Moreover, given that many energy conservation and DSM measures affect peak load demand, these reductions likely would have little, if any, impact on DVP’s ever-growing need for additional baseload resources. Even if these conservation and DSM measures are assumed to reduce baseload demand, as shown in Section 8.4.1, Unit 3 is still necessary to meet the growth in baseload demand.

Section 8.2 References

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2. PJM Interconnection, LLC. *PJM Manual 19: Load Data Systems, Revision 9*. Effective January 1, 2006. (www.pjm.com/contributions/pjm-manuals/pdf/m19.pdf)
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16. The Virginia Energy Plan, Commonwealth of Virginia, Department of Mines, Minerals and Energy, September 12, 2007. (www.dmme.virginia.gov/vaenergyplan.shtml)

17. North Carolina Sustainable Energy Association, Information Request in Docket No. E-100, Sub 103 - 2005 IRP, Dated April 27, 2006.

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8.3 Power Supply

This section reviews the present and planned generating capability within the Dominion Zone and the present and planned purchases and sales of power and energy.

8.3.1 Existing and Planned Generating Capacity in PJM Dominion Zone

8.3.1.1 Existing Generating Capacity

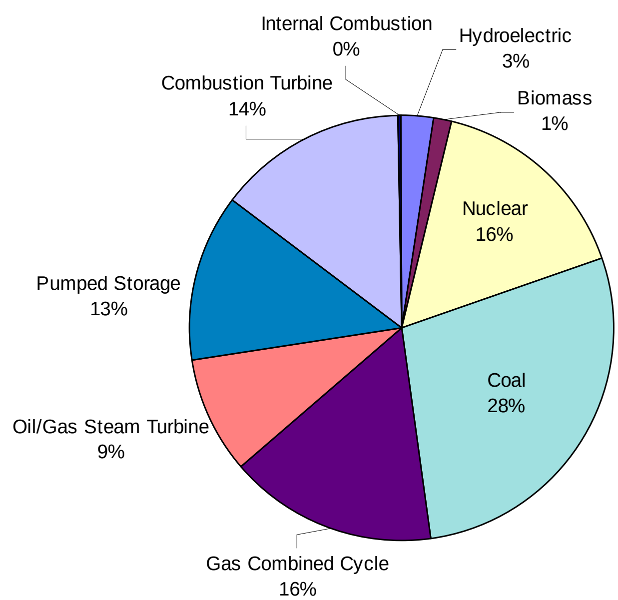
PJM publishes information regarding generating unit ratings in its "2007 PJM EIA-411 Report." This report contains PJM's most recent assessment of each utility system's installed capacity. PJM uses the term "rating" synonymously with installed capacity, and these values are the basis for the following regional capability analysis.

The generating units located within the Dominion Zone currently total a regional installed summer and winter capacity of 21,613 MW and 21,623 MW, respectively. (Reference 9) Oil and/or gas-fired units make up 39 percent of the Dominion Zone's installed summer capacity, while coal-fired and nuclear units account for 28 percent and 16 percent of the region's current capacity, respectively.

Figure 8.3-1 Dominion Zone – Total Installed Capacity by Technology Type, 2007

Technology Type	Summer Capacity (MW)
Hydroelectric	562
Biomass	290
Nuclear	3,432
Coal	6,038
Gas Combined Cycle	3,451
Oil/Gas Steam Turbine	1,916
Pumped Storage	2,763
Combustion Turbine	3,110
Internal Combustion	51
Total	21,613

(Source: 2007 PJM EIA-411 Data)



8.3.1.1.1 Baseload, Intermediate, and Peaking Capacity

Each of the different technology types listed in Figure 8.3-1 above has different performance characteristics, capital costs, and operation and maintenance costs. The generating units with the least expensive variable costs (e.g., nuclear and coal units), operate almost continuously to meet the minimum level of electricity that is demanded by a system, (i.e., the baseload). While hydro and wind are also used to meet demand, these technology types are considered intermittent capacity resources as their operation capability depends on such factors as water flow and wind speeds, respectively.

For purposes of this analysis, baseload capacity is defined to include units with a capacity factor of 65 percent or greater. This baseload capacity factor assumption is consistent with the baseload definitions assumed by the Edison Electric Institute (EEI) and California Senate Bill 1368. (Reference 2)

During peak demand periods when consumers demand more electricity, the generating units with higher variable fuel costs (typically oil or natural gas) and the operational capability to quickly start are called upon by PJM RTO to meet the peak load. "Peaking capacity," while expensive to operate, is relatively less expensive to construct. For purposes of this analysis, peak capacity is defined to include units with a capacity factor of 30 percent or less; this definition of a peaking resource is consistent with methods utilized by market participants (e.g., Calpine), and power pool market administrators (e.g., Ontario Independent Electricity System Operator). (Reference 1 and Reference 7) Given the assumed capacity factor ranges for baseload and peaking capacity, it follows that intermediate capacity includes units with a capacity factor that falls within a range of 30 percent to 65 percent.

Figure 8.3-2 is an illustrative representation of the Dominion Zone's 2006 historical load duration curve and its fit against the current installed capacity in the Dominion Zone. While the 65th percentile hour load is not exactly equal to the amount of required installed baseload capacity, it is a reasonable proxy for baseload capacity requirements after reducing capacity supply by assumed availability rates. Figure 8.3-2 includes the installed capacity listed in Figure 8.3-1 adjusted for assumed unit availability rates presented in Figure 8.3-3

As shown in Figure 8.3-2, baseload capacity in the Dominion Zone is composed predominately of nuclear and coal-fired units. Intermediate capacity is composed of gas-fired combined cycle units, while peaking capacity is composed predominantly of pumped storage, oil and gas-fired units.

Figure 8.3-2 PJM Dominion Zone 2006 Load Duration Curve

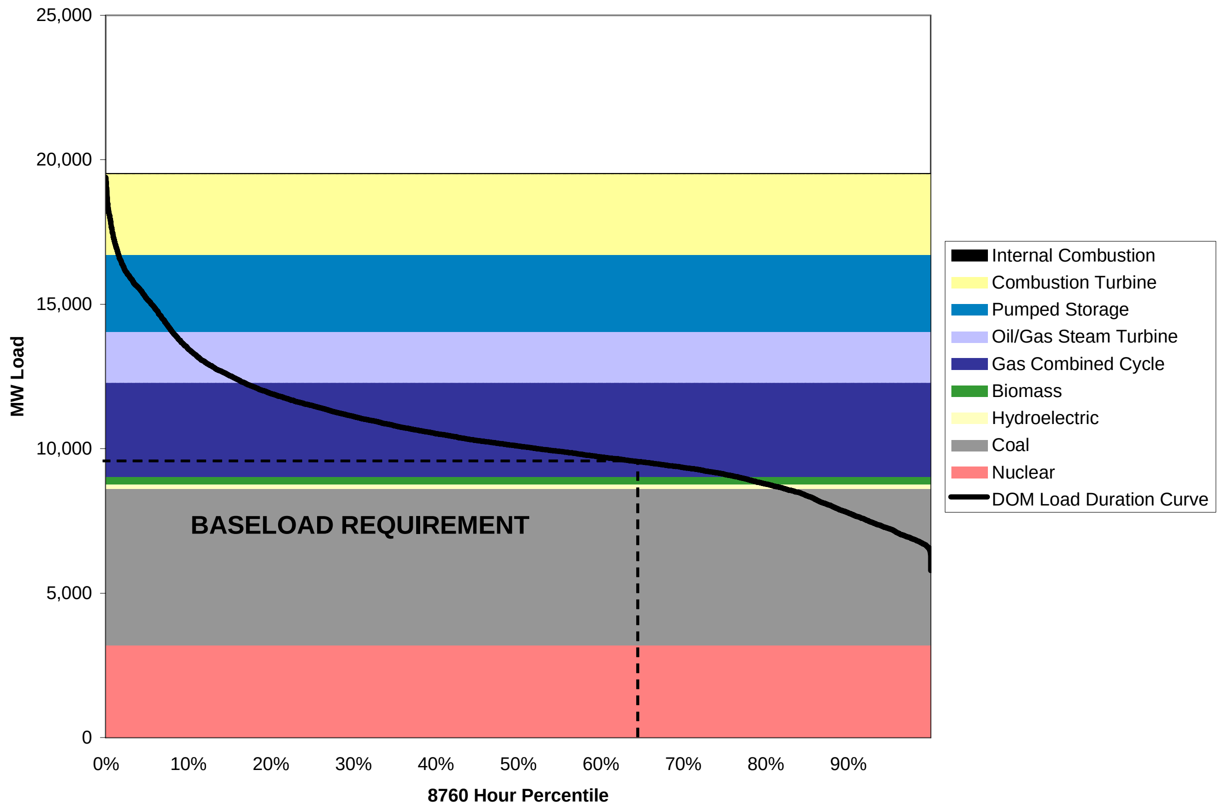


Table 8.3-1 Unit Availability Rates by Technology Type

Unit Availability Rates By Technology Type	(EFORd) Forced Outage Rate	Assumed Planned Outage Rate	Assumed Availability Rate
Hydroelectric	3.89%		25%
Nuclear	4.19%	3.20%	93%
Biomass	6.41%	3.59%	90%
Coal	6.47%	3.53%	90%
Gas Combined Cycle	5.67%	-	94%
Gas/Oil Steam	7.65%	-	92%
Pumped Storage	3.81%	-	96%
Combustion Turbine	10.26%	-	90%
Internal Combustion	13.54%	-	86%

To estimate the unit availability rates shown above for hydroelectric and nuclear sources, historical state level generation and capacity data published by the EIA were reviewed. As shown in Figure 8.3-2, nuclear units in Virginia on average operated with a 93 percent capacity factor in 2005, while hydroelectric units operated with a 25 percent average capacity factor. Because hydroelectric and nuclear units are typically dispatched before other technology types based on lower variable costs, these capacity factors were used as proxy values for hydroelectric and nuclear availability rates.

Table 8.3-2 Virginia Installed Baseload and Renewable Capacity & Generation by Fuel Type, 2005

	Virginia		
Fuel Type	**Summer Capacity (MW)**	**Net Generation (GWh)**	**Average Capacity Factor**
Nuclear	3,432	27,918	93%
Coal	5,783	35,450	70%
Biomass (other renewables)*	577	2,497	49%
Hydroelectric	672	1,484	25%

* Biomass and other renewables include landfill gas, municipal solid waste, wood waste, waste oil and waste coal.
(Source: EIA 2005 State Energy Profile)

Coal-fired and biomass units were both assumed to have a 90 percent availability rate. Availability rates for the typical intermediate and peaking technology types (i.e., gas/oil fired and pumped storage) shown in Table 8.3-1 were assumed to be equal to 1 minus the five-year average Equivalent Forced Outage Rate (EFORd) as published by PJM in its "2001-2005 Generating Unit Statistical Brochure." This is a conservative approach and likely overstates the amount of intermediate and peaking capacity available, as the approach does not account for planned maintenance outages for intermediate and peaking capacity.

8.3.1.1.2 Recently Constructed Generating Capacity

Over the past 10 years from 1997 to 2006, DVP's baseload requirement has grown by over 2000 MW, based on analysis of DVP weather-normalized annual energy sales. Over the same period, there has been virtually no development of additional baseload resources, as only combined cycles and combustion turbines have been added since 1997, which are more suitable as cycling or mid-range resources. As shown in Figure 8.3-2 above, additional nuclear and coal-fired baseload capacity is needed to meet current baseload requirements in the Dominion Zone.

As shown in Table 8.3-3, 22 generating units have been built and placed into commercial operation within the Dominion Zone since 1997, totaling 3657 MW of summer capacity. These recent capacity additions have been predominantly gas-fired. Specifically, over 99 percent of these recent capacity additions are from gas-fired units of which 54 percent are peaking simple-cycle combustion turbines and 45 percent are combined-cycles.

This recent trend of predominantly gas-fired capacity additions in the Dominion Zone is expected to continue based on analysis of the PJM Generation Interconnection Queue.

8.3.1.2 Planned Generating Capacity

One of PJM's primary roles is the oversight of the reliability planning process. (Reference 10) PJM manages incremental generation capacity development through the Generation Interconnection Queue, which is part of a larger RTEPP. Developers wishing to provide new incremental generation capacity must file an interconnection request and enter into PJM's queue-based, 3-study interconnection process, which offers developers the flexibility to consider and explore their respective generation interconnection business opportunities. While a developer can withdraw a project from the Generation Interconnection Queue at any point, the process is structured such that each step imposes its own increasing financial obligations on the developer. (Reference 15) While not all projects in the Generation Interconnection Queue are expected to be built, the Generation Interconnection Queue does provide an authoritative source for future generation investment trends in the PJM RTO.

Table 8.3-4 lists the individual generation interconnection requests for projects located in the Dominion Zone that are under construction, partially in-service or currently active in the PJM Generation Interconnection Queues as of September 13, 2007 plus interconnection requests associated with the Virginia City facility, which will be located in the American Electric Power Zone of PJM.

Table 8.3-3 New Generating Capacity Additions in the Dominion Zone since 1997

	Company	Plant Name	Unit	Fuel	Type	Net Capability (MW)	Commercial Operation Date
1	Dominion Virginia Power	Bellemeade	CC1	NG	Combined Cycle	232	1997
2	Dominion Virginia Power	Remington	GT1	NG	CT	145	2000
3	Dominion Virginia Power	Remington	GT2	NG	CT	146	2000
4	Dominion Virginia Power	Remington	GT3	NG	CT	145	2000
5	Dominion Virginia Power	Remington	GT4	NG	CT	146	2000
6	Ingenco Wholesale Power, LLC	Lanier Diesel		DFO	IC	7	2000
7	Dominion Virginia Power	Four Rivers	1	NG	CT	155	2001
8	Dominion Virginia Power	Ladysmith	GT1	NG	CT	146	2001
9	Dominion Virginia Power	Ladysmith	GT2	NG	CT	151	2001
10	Ingenco Wholesale Power, LLC	Virginia Beach Landfill		LFG	IC	12	2001
11	Ingenco Wholesale Power, LLC	Amelia Landfill	1	DFO	IC	16	2002
12	Dominion Virginia Power	Possum Point	G6S	NG	Combined Cycle	532	2003
13	Old Dominion Electric Cooperative	Louisa	G12	NG	CT	153	2003
14	Old Dominion Electric Cooperative	Louisa	G34	NG	CT	153	2003
15	Old Dominion Electric Cooperative	Louisa	G5	NG	CT	155	2003
16	Old Dominion Electric Cooperative	Marsh Run	CT1	NG	CT	157	2004
17	Old Dominion Electric Cooperative	Marsh Run	CT2	NG	CT	157	2004
18	Old Dominion Electric Cooperative	Marsh Run	CT3	NG	CT	157	2004
19	Coral Power, L.L.C.	Fluvanna	GS12	NG	Combined Cycle	392	2004
20	Coral Power, L.L.C.	Fluvanna	GT12	NG	Combined Cycle	164	2004
21	Coral Power, L.L.C.	Fluvanna	GT22	NG	Combined Cycle	167	2004
22	Coral Power, L.L.C.	Fluvanna	GT32	NG	Combined Cycle	172	2004
					Total	3,657	

Table 8.3-4 Generator Interconnection Requests in the Dominion Zone, as of September 13, 2007

Queue	PJM Substation	MW	MWC	Status	Year	Type	Fuel
P08	Possum Point	600	600	Active	2009	Intermediate/Peaking	Natural Gas
P09	Kerr Dam 115kV	91	91	Active	2008	Intermittent	Hydro
P16	Bath County 4	85	85	Partially In-Service	2009	Intermediate/Peaking	Pumped Storage
	Bath County 1	85	85	Partially In-Service	2008	Intermediate/Peaking	Pumped Storage
	Bath County 6	85	85	Partially In-Service	2007	Intermediate/Peaking	Pumped Storage
P38	Bremo 230kV	675	675	Active	2010	Intermediate/Peaking	Natural Gas
Q43	Clinch River 138kV	534	534	Active	2012	Baseload	Coal
Q65	North Anna 500kV	1594	1594	Active	2015	Baseload	Nuclear
Q69	Shackleford 34.5kV	12	12	Active	2007	Intermediate/Peaking	Methane
Q70	Lawrenceville 34.5kV	11	11	Active	2007	Intermediate/Peaking	Methane
Q71	Cranes Corner 13.2kV	2		Active	2007	Intermediate/Peaking	Methane
R19	Ladysmith 230kV	340	340	Active	2008	Intermediate/Peaking	Natural Gas
R63	Chesterfield 230kV	19	19	Active	2007	Baseload	Coal
R77	Morrisville 500kV	600	600	Active	2010	Intermediate/Peaking	Natural Gas
R80	Possum Point 230kV	60	60	Active	2008	Intermediate/Peaking	Natural Gas
R98	Northeast 34.5kV	14	14	Active	2008	Intermediate/Peaking	Methane
S102	Ladysmith 230kV	170	170	Active	2009	Intermediate/Peaking	Natural Gas
S108	North Anna 500kV	20	20	Active	2010	Baseload	Nuclear
S109	North Anna 500kV	20	20	Active	2010	Baseload	Nuclear
S110	North Anna 500kV	65	65	Active	2010	Baseload	Nuclear
S111	Surry 500kV	15	15	Active	2010	Baseload	Nuclear
S112	North Anna 500kV	65	65	Active	2012	Baseload	Nuclear
S113	Surry 230kV	15	15	Active	2010	Baseload	Nuclear
S114	Surry 230kV	75	75	Active	2010	Baseload	Nuclear
S115	Surry 230kV	75	75	Active	2011	Baseload	Nuclear
S50	Occoquan 230kV	18	18	Active	2007	Intermediate/Peaking	Methane

Table 8.3-4 Generator Interconnection Requests in the Dominion Zone, as of September 13, 2007

Queue	PJM Substation	MW	MWC	Status	Year	Type	Fuel
S52	Morrisville 500kV	600	600	Active	2010	Intermediate/Peaking	Natural Gas
S77	Clover 230kV	16	16	Active	2011	Baseload	Coal
S78	Clover 230kV	19	19	Active	2012	Baseload	Coal
S79	Chesterfield 230kV	27	27	Active	2011	Baseload	Coal
S80	Chesterfield 230kV	20	20	Active	2010	Baseload	Coal
S81	Basin 230kV	45	45	Active	2010	Intermediate/Peaking	Natural Gas
S82	Surry 230kV	20	20	Active	2009	Intermediate/Peaking	Natural Gas
S83	Surry 230kV	20	20	Active	2009	Intermediate/Peaking	Natural Gas
S84	Surry 230kV	20	20	Active	2009	Intermediate/Peaking	Natural Gas
S85	Surry 230kV	20	20	Active	2009	Intermediate/Peaking	Natural Gas
S86	Darbytown 230kv	20	20	Active	2009	Intermediate/Peaking	Natural Gas
S87	Darbytown 230kV	20	20	Active	2009	Intermediate/Peaking	Natural Gas
S88	Darbytown 230kV	20	20	Active	2009	Intermediate/Peaking	Natural Gas
S89	Darbytown 230kV	20	20	Active	2009	Intermediate/Peaking	Natural Gas
S90	Elizabeth River 230kV	20	20	Active	2009	Intermediate/Peaking	Natural Gas
S91	Elizabeth River 230kV	20	20	Active	2009	Intermediate/Peaking	Natural Gas
S92	Elizabeth River 230kV	20	20	Active	2009	Intermediate/Peaking	Natural Gas
S93	Remington 230kV	15	15	Active	2009	Intermediate/Peaking	Natural Gas
S94	Remington 230kV	15	15	Active	2009	Intermediate/Peaking	Natural Gas
S95	Remington 230kV	15	15	Active	2009	Intermediate/Peaking	Natural Gas
S96	Remington 230kV	15	15	Active	2009	Intermediate/Peaking	Natural Gas
S97	South Anna 230kV	20	20	Active	2013	Intermediate/Peaking	Natural Gas
S98	South Anna 230kV	20	20	Active	2013	Intermediate/Peaking	Natural Gas
S99	Possum Point 230kV	20	20	Active	2013	Intermediate/Peaking	Oil
S100	Clinch River 198kV	80	80	Active	2012	Baseload	Coal
T06	Yorktown 230kV	20	20	Active	2014	Intermediate/Peaking	Oil
T10	Cranes Corner 34.5KV	3	3	Active	2007	Intermediate/Peaking	Methane
Total		6,515	6,513				

Table 8.3-4 Generator Interconnection Requests in the Dominion Zone, as of September 13, 2007

Queue	PJM Substation	MW	MWC	Status	Year	Type	Fuel

Note:
MWC = capacity component of total energy output of facility
MW = total energy output of facility
(Source: Analysis of PJM Generation Interconnection Queue as of September 13, 2007.)

Analysis of the individual generation interconnection requests listed in Table 8.3-4 above reveals 51 active generating interconnection requests in the Dominion Zone totaling 6513 MW from primarily natural gas or nuclear fuel sources, as summarized in Table 8.3-5. Again, not all of these projects currently under-study are expected to be built.

Table 8.3-5 Summary of Generator Interconnection Requests in the Dominion Zone, As of September 13, 2007

Fuel Type	MWC	Percent
Natural Gas	3,410	52%
Nuclear	1,944	30%
Coal	715	11%
Pumped Storage	255	4%
Hydro	91	1%
Methane	58	1%
Oil	40	1%
Total	6,513	100%

The nuclear component of projects listed above includes 170 MW of uprates for the existing NAPS Units 1 & 2 and 180 MW of uprates for DVP's Surry Units 1 and 2. The remaining 1594 MW of nuclear capacity listed in the Generation Interconnection Queue is associated with the proposed Unit 3, the subject of this COLA. The 614 MW[1] of coal-fired capacity included in queue positions

1. The Virginia City facility is projected to have a net summer rating of 585 MW based on the current status of the design process for the plant. However, DVP requested a transmission interconnection of 614 MW with PJM to allow for potential increases to the net summer rating or to plant output if design changes allow for such an increase. It should be noted that the PJM transmission interconnection request process is such that a company must ask for the maximum transmission output foreseeable at stated conditions for a unit, since it is possible to lower the amount requested but, to increase that amount, PJM would require the entire interconnection process to be repeated, costing additional time and money.

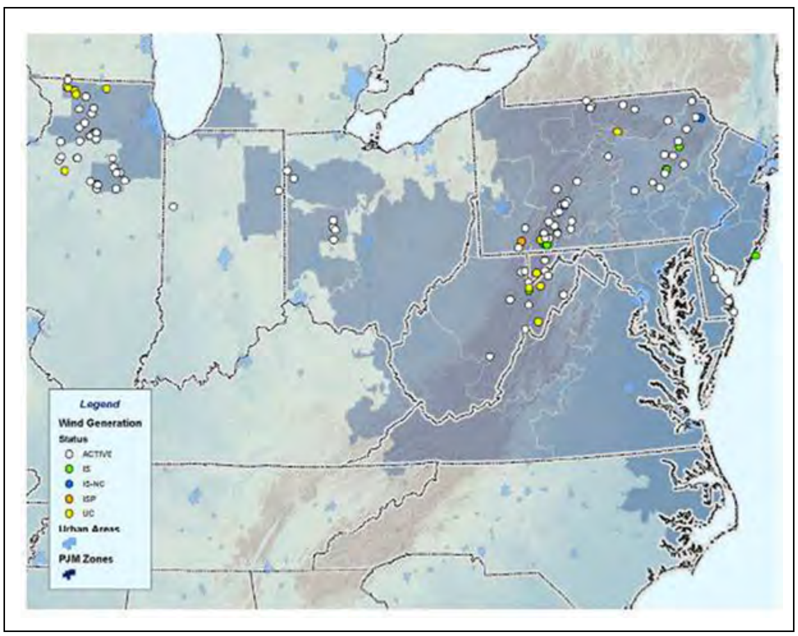
Q43 and S100 for interconnections at Clinch River 138 kV and Clinch River 198 kV substations, respectively, are associated with the Virginia City facility, which will be located in the American Electric Power Zone of PJM.

Excluding the proposed Unit 3, there are currently 1065 MW of other baseload capacity projects listed in the interconnection queue. Unit 3 is the only baseload capacity project currently listed in the Generation Interconnection Queue for the Dominion Zone that is over 100 MW.

The pumped storage and conventional hydro projects listed in the interconnection queue primarily represent improvements to existing generating facilities, rather than new facilities. (Reference 15)

Currently, there are no wind-powered generation projects listed in the Generation Interconnection Queue for the Dominion Zone. Wind-powered generation projects require geographic areas with favorable wind characteristics such as speed, duration, and frequency of occurrence. See Section 9.2.2.1.1 for a discussion of the feasibility of wind-powered generation projects in the Dominion Zone.

Figure 8.3-3 Clustered Location of Wind-Powered Generation Projects in PJM



(Source: PJM 2006 RTEP)

8.3.1.3 **Renewable Portfolio Standards**

Both Virginia and North Carolina have recently adopted Renewable Portfolio Standards (RPS), but with different requirements and RPS targets as described in more detail below. Based on EIA state-wide generation by fuel source data and EIA's own definition of renewable resources, which may or may not agree with Virginia and North Carolina's RPS definitions for qualifying renewable resources, renewable sources, excluding hydroelectric projects, currently supply about 3.2 percent and 1.4 percent of the net generation produced state-wide in Virginia and North Carolina, respectively. (Reference 6) While the development of new renewable sources may increase, most new renewable sources alone are unlikely to replace the need for additional baseload generation, because most renewable projects fit into one of the following categories: 1) utility-scale facilities (over 100 MW) such as wind, solar, or hydro that have capacity factors of between 20 percent and 40 percent and are recognized by PJM as being intermittent generation resources, or 2) smaller facilities (<10 MW) with capacity factors greater than 65 percent but are limited by available viable sites and therefore cannot, on their own, meet the projected growth rate for baseload electricity demand in Virginia. As discussed in Section 9.2.2.1, while DVP plans to undertake all commercially reasonable efforts to meet renewable portfolio standards and emerging state initiatives, renewable resources are not of the scale or type needed to provide power to meet the baseload needs of the Dominion Zone.

Virginia enacted a voluntary renewable energy portfolio goal as part of the recent Legislation. Under the RPS goal, investor-owned utilities are encouraged to produce or procure, by 2022, 12 percent of the amount of electricity sold in 2007 (the “base year”) from eligible renewable sources. The following schedule of intermediate RPS goals was adopted. (Reference 4)

- RPS Goal I: 4 percent of base year sales in 2010
- RPS Goal II: Average of 4 percent of base year sales in 2011 through 2015, and 7 percent of base year sales in 2016
- RPS Goal III: Average of 7 percent of base year sales in 2017 through 2021, and 12 percent of base year sales in 2022[1]

North Carolina enacted a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) in August 2007 requiring all investor-owned utilities in the state to supply 12.5 percent of 2020 retail electricity sales in the state from eligible renewable energy resources by 2021. The overall target for renewable energy includes technology-specific targets of 0.2 percent solar by 2018, 0.2 percent energy recovery from swine waste by 2018, and 900,000 megawatt-hours (MW-hrs) of electricity derived from poultry waste by 2014. Large hydroelectric units over 10 MW are not considered eligible energy resources in North Carolina. The North Carolina REPS compliance schedule is listed below with each year’s percentage requirement referring to the previous year’s electricity sales.

- 2010: 0.02 percent solar
- 2012: 3 percent (including 0.07% + 0.07 percent swine waste + 170,000 MW-hrs poultry waste)

1. According to Va. Code §56-585.2(A), base year sales are calculated as “Total electric energy sold to Virginia jurisdictional retail customers by a participating utility in calendar year 2007, excluding an amount equivalent to the average of the annual percentages of the electric energy that was supplied to such customers from nuclear generating plants for the calendar years 2004 through 2006.

- 2013: 3 percent (including 0.07% solar + 0.07% swine waste + 700,000 MW-hrs poultry waste
- 2014: 3 percent (including 0.07% solar + 0.07% swine waste + 900,000 MW-hrs poultry waste)
- 2015: 6 percent (including 0.14% solar + 0.14% swine waste + 900,000 MW-hrs poultry waste)
- 2018: 10 percent (including 0.20% solar + 0.20% swine waste + 900,000 MW-hrs poultry waste)
- 2021: 12.5 percent (including 0.20% solar + 0.20% swine waste + 900,000 MW-hrs poultry waste)

Up until 2021, 25 percent of the REPS requirements may be met through savings due to the implementation of energy efficiency measures. Beginning in calendar year 2021 and each year after, 40 percent of the REPS requirements may be met through savings due to the implementation of energy efficiency measures.

Senate Bill 3 allows electric power suppliers to recover the incremental costs incurred to comply with the REPS requirements and fund research through an annual rider, which is not to exceed the following per-account annual charges:

Table 8.3-6 North Carolina Annual Rider Caps

Customer Class	2008-2011	2012-2014	2015 and thereafter
Residential per account	$10.00	$12.00	$34.00
Commercial per account	$50.00	$150.00	$150.00
Industrial per account	$500.00	$1,000.00	$1,000.00

8.3.2 Purchases and Sales

Based on U.S. EIA data, in 2005, the Commonwealth of Virginia was the second largest importer of electricity in the United States on a total MW-hr basis. Based on the same data, the Commonwealth of Virginia imported the third largest percentage of consumed power of PJM states, with imports meeting approximately 30 percent of Virginia’s total state-wide electric consumption. (Reference 5) The District of Columbia, Delaware, Maryland, and New Jersey also rely heavily on imported power and compete with Virginia for available power supplies from West Virginia, Pennsylvania and Illinois. North Carolina is less reliant on imports, but does import approximately 5 percent of its annual energy consumption. (Reference 5)

8.3.2.1 Existing Purchase Agreements

As shown in Table 8.3-7, DVP currently contracts for 2089 MW of capacity through existing Power Purchase Agreements (PPAs). All 2089 MW of this capacity comes from generation located within the Dominion Zone, of which 50 percent is from coal-fired baseload capacity. In addition, 809 MW of this contracted capacity is scheduled to expire by end of 2015, of which 379 MW is baseload.

Table 8.3-7 Summary of DVP's Power Purchase Agreements

PPAs currently held by DVP as of 9/1/2007

Capacity Type	Summer Capacity (MW)	Percent of Total
Coal	960	46
Coal/Wood	74	4
Baseload Capacity Subtotal	1034	50
Gas/Oil	942	45
Hydro	5	0
Landfill Gas	12	1
Solid Waste	83	5
Intermittent/Intermediate Capacity Subtotal	1055	50
Total Capacity	2076	100

PPAs Expiring Prior to end-of-2015 as of 9/1/2007

Capacity Type	Summer Capacity (MW)	Percent of Total
Coal	305	38
Coal/Wood	74	9
Baseload Capacity Subtotal	379	47
Gas/Oil	337	42
Hydro	5	1
Landfill Gas	12	1
Solid Waste	76	9
Intermittent/Intermediate Capacity Subtotal	430	53
Total Capacity	809	100

Relying on the future availability of long-term PPAs from developers of new baseload resources in other regions outside Virginia introduces uncertainty as to capacity and energy supply for DVP. Under the terms of Virginia's recent Legislation, DVP has an obligation to meet the demands of its native-load customers and the Virginia General Assembly has made the policy determination to promote the construction of baseload generation for this purpose. Power project developers may not have energy and capacity available to provide to DVP in the future. There may also be competition for the available long-term baseload PPAs among the other load centers surrounding the Dominion Zone.

In 2006, DVP executed 22,061,563 MW-hrs of power purchases, over 25 percent of its total energy requirements, of which 9,689,362 MW-hrs was contracted through PPAs and the remaining 12,372,221 MW-hrs was from non-firm purchases from other utilities; of that amount, 11,536,695 MW-hrs were purchases from the PJM spot energy market. These non-firm purchases are summarized below in Table 8.3-8. (Reference 8)

Table 8.3-8 Summary of DVP's Non-Firm Purchases from Other Utilities, 2006

Name of Company or Public Authority	MW-hr Purchased
ABN-AMRO Power Swaps	
American Electric Power	
Carolina Power & Light Co	293
Cincinnati Gas & electric	
Constellation Energy Commodities	
Duke Energy Trading & Marketing	2,550
Duke Power Company	475
Duke Power Company, LLC	2,800
Duke Power, a Division of Duke	1,220
Dynegy Power Marketing, Inc	
Exelon Generation Company	
NCEMC	38,750
North Carolina Municipal	(450)
Old Dominion Electric Coop	6,424
Pennsylvania-New Jersey-Maryland	11,536,695
PPL Energyplus, LLC	
PSEG Energy Resources & Trading	
Sempra Energy Trading Corp.	
South Carolina Electric	2,302
WPS Energy Services, Inc.	
All Companies (Estimate)	781,162
Total Non-Firm Purchases	12,372,221

(Source: Virginia Electric and Power Company FERC Form 1, 2006)

8.3.2.2 **Power Sales**

As shown in Table 8.3-9, DVP sold 3,757,598 MW-hrs for resale in 2006. The majority of these sales for resale was within the Dominion Zone and was sold specifically to ODEC and NCEMC under purchase agreements with a set pricing schedule, but load-based requirements. These sales were usually met with intermediate and peaking units.

DVP currently has one long-term power sales contract with NCEMC for 150 MW through a combined cycle call option agreement that is due to expire at the end of 2014.

Table 8.3-9 Summary of DVP Sales for Resale, 2006

Name of Company or Public Authority	Classification	Average Monthly Billing Demand (MW)	Average Monthly NCP Demand	Average Monthly CP Demand	MW-hr Sold
Town of Enfield	Requirements Service				39,920
North Carolina Electric	Requirements Service				230,100
Old Dominion Electric Cooperative	Requirements Service				838,947
Old Dominion Electric Cooperative	Long Term				723,509
Craig-Botetourt Electric Coop.	Requirements Service	4	6	5	27,882
Town of Windsor	Requirements Service	8	8	8	46,464
Virginia Municipal Electric Assoc.	Requirements Service	178	259	193	1,727,215
Connectiv Energy Commodities	Other Service				
Constellation Energy Commodities	Other Service				
Pennsylvania-New Jersey-Maryland	Other Service				45,476
Pepco Energy Services, Inc.	Other Service				
Potomac Electric & Power	Other Service				
Exelon Generation Company	Other Service				
North Carolina Municipal	Other Service				78,085
Town of Enfield	Other Service				
North Carolina Electric	Other Service				
Subtotal	Requirements Service	190	273	206	2,910,528
Subtotal	Non-Requirements Service	-	-	-	847,070
Total	Total	190	273	206	3,757,598

Notes:

(1) Requirements Service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as or second only to the supplier's service to its own ultimate customers.

Table 8.3-9 Summary of DVP Sales for Resale, 2006

Name of Company or Public Authority	Classification	Average Monthly Billing Demand (MW)	Average Monthly NCP Demand	Average Monthly CP Demand	MW-hr Sold

(2) Long-Term Service means five years or longer.

(3) Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month.

(4) Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak.

(Source: Virginia Electric and Power Company FERC Form 1, 2006)

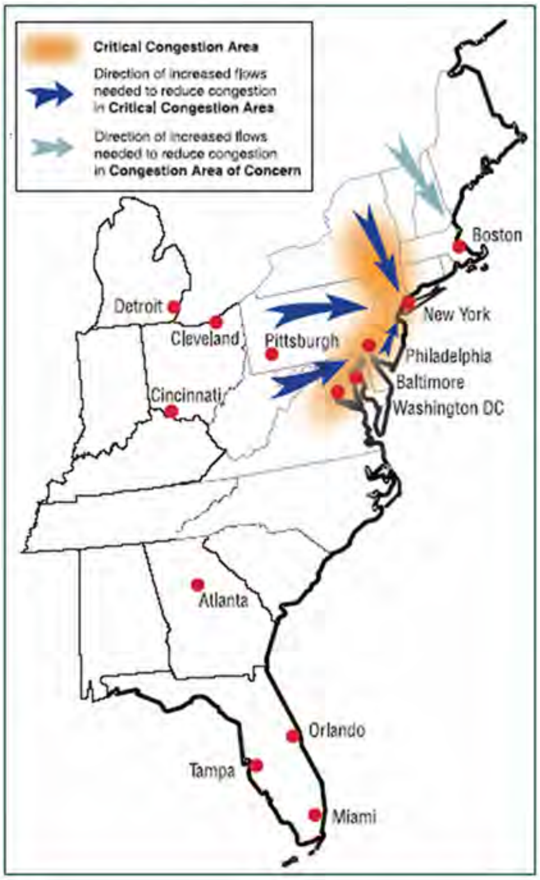
8.3.2.3 Transmission and Additional Constraints on Power Purchases

In addition to concerns of long-term supply assurance, reliance on power imported from other states increases demand on west-to-east transmission capabilities, resulting in heightened vulnerability to transmission-related interruptions. In fact, the U.S. Department of Energy (DOE) has identified the Atlantic coastal area from Metropolitan New York southward through northern Virginia shown in Figure 8.3-4 as one of two Critical Congestion Areas[1] within the U.S., stating:

The area from greater New York City south along the coast to northern Virginia is one continuous congestion area, covering part or all of the states of New York, Pennsylvania, New Jersey, Delaware, Maryland, Virginia, and the District of Columbia. This area requires billion of dollars of investment in new transmission, generation, and demand-side resources over the next decade to protect grid reliability and ensure the area's economic vitality. Planning for the siting, financing, and construction of these facilities is urgent. (Reference 3)

1. Southern California is the second Critical Congestion Area identified by the U.S. DOE.

Figure 8.3-4 Atlantic Coast Critical Congestion Area



(Source: National Electric Transmission Congestion Study, U.S. Department of Energy, August 2006)

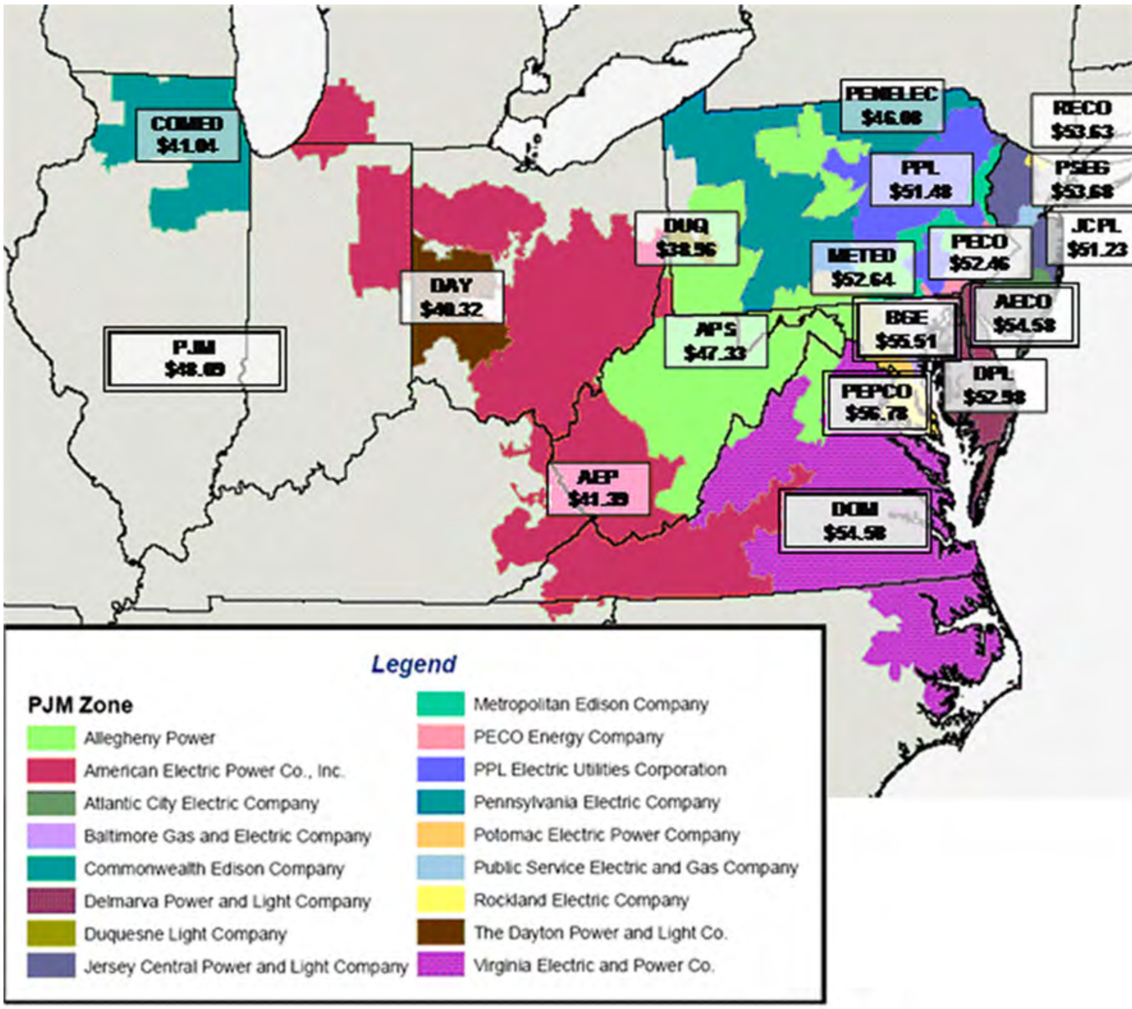
On October 5, 2007, DOE published a notice of designation of the Mid-Atlantic Area National Interest Electric Transmission Corridor, which includes part of DVP's service territory.[1] The designation is based on DOE's determination that the corridor is experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers.[2]

The Virginia SCC has also expressed concerns regarding congestion in northern Virginia and the Dominion Zone in particular. (Reference 16) The impact of congestion on the Dominion Zone's cost

1. The following counties and cities in Virginia are included in the Mid-Atlantic Area National Interest Electric Transmission Corridor: Arlington County, VA, Clarke County, VA, Culpeper County, VA, Fairfax County, VA, Fauquier County, VA, Frederick County, VA, Loudon County, VA, Madison County, VA, Page County, VA, Prince William County, VA, Rappahannock County, VA, Rockingham County, VA, Shenandoah County, VA, Stafford County, VA, Warren County, VA, City of Alexandria, VA, City of Harrisonburg, VA, City of Fairfax, VA, City of Falls Church, VA, City of Manassas, VA, City of Manassas Park, VA, and City of Winchester, VA. 72 Fed. Reg. at 56992, 57025 (Oct. 5, 2007).
2. Ibid.

of power is illustrated in Figure 8.3-5, which shows the simple average Day-Ahead Locational Marginal Price (LMP) by PJM zone for the twelve month period ended December 31, 2006.

Figure 8.3-5 PJM 2006 Zonal Day Ahead LMP



A review of the 2006 simple average day-ahead zonal LMPs reveals that the Dominion Zone, along with Potomac Electric Power Company (PEPCO), Baltimore Gas and Electric (BGE), and Atlantic City Electric Company (AECO) zones were the most expensive PJM zones. On average, the Dominion Zone LMP was 13.5 percent higher than the average PJM LMP. Zones to the west (i.e., American Electric Power Co. (AEP), Allegheny Power (APS) and Duquesne Light Company (DUQ)) were less expensive zones compared to the Dominion Zone. The zonal average LMP differentials shown in Figure 8.3-5 are conservative, as these 2006 average LMPs are not load-weighted annual averages.[1]

Virginia's reliance on imported power increases its vulnerability to transmission-related interruptions. PJM, in its 2006 RTEPP, raises concerns over its aging transmission infrastructure; more than 50 percent of the 188 500/230 kV transformers in-service in the PJM system are 30 years old or older. Over the last several years, the PJM system has experienced an increasing number of transformer failures and degradation of older transformers. (Reference 15)

8.3.3 Potential Retirements

There are currently no announced plans for generator deactivations in the Dominion Zone (Reference 15); however, as of October 2, 2007, there were 1821 MW of planned future deactivations in PJM for 2008 through 2012 with generator deactivations located in Illinois, New Jersey, Delaware and the District of Columbia. All of these planned generator deactivations in PJM are for facilities 35 years or older. (Reference 13) In addition, PJM reports 3587 MW of known generator deactivations in Western PJM[1] between 2003 and 2008, of which 66 percent are from deactivations of units with ages that range from 20 to 30 years and 26 percent are from deactivations of units with ages that range from 30 to 40 years. For Eastern PJM,[2] PJM reports 2846 MW of known generator deactivations between 2003 and 2008, of which 50 percent are from deactivations of units over 40 years old. PJM identifies new environmental regulations in west/central Pennsylvania as having a bearing on PPL Electric Utilities Corporation's pollution control investment-versus-retirement decisions at Martins Creek.[3]

Approximately 31 percent of the coal-fired generating capacity currently installed in PJM is from units that will be 50 years or older in 2015. This is equivalent to approximately 20,252 MW.[4]

1. The load weighted LMP price is a better indicator of market prices in that the actual costs incurred to serve load will vary with the respective load and price for the varying time intervals. LMPs paid by loads vary hourly (Reference 16).
1. The Western PJM area comprises five transmission owner zones: Allegheny Power (AP), American Electric Power (AEP), Commonwealth Edison (COMED), Dayton Power and Light (Dayton) and Duquesne Light Company (DLCO) (Reference 15).
2. The Eastern PJM area is comprised of the following six zones: Atlantic City Electric Company (AE), Delmarva Power and Light (DPL), Jersey Central Power and Light (JCPL), PECO Energy (PECO), Public Service Electric and Gas (PSEG) and Rockland Electric (Rockland) (Reference 15).
3. Reference 15 at 56 and 82.
4. Based on analysis of 2007 PJM EIA-411 Data (Reference 9).

Section 8.3 References

1. *Calpine Contractual Portfolio*, November 3, 2005.
2. California Senate Bill No. 1368, Chapter 598, Approved by Governor September 29, 2006.
3. U.S. Department of Energy. *National Electric Transmission Congestion Study*, August 2006.
4. Database of State Incentives for Renewables & Efficiency (DSIRE), June 7, 2007. (www.eere.energy.gov/states/maps/renewable_portfolio_states.cfm)
5. Energy Information Administration, *Electric Power Annual 2005 - State Data Tables*, November 2006. (www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html)
6. Energy Information Administration**,** *2005 State Energy Profile.*
7. IESO Market Evolution Program (MEP) Breakout Feedback Session, February 18, 2003.
8. Virginia Electric and Power Company, FERC Form 1, 2006.
9. PJM Interconnection, LLC. *2007 PJM EIA-411 Report*, July 25, 2007. (www.pjm.com/documents/downloads/reports/2007-pjm-411.pdf)
10. PJM Interconnection, LLC. *Planning.* (www.pjm.com/planning/expansion-planning/tran-plan-process.html)
11. PJM Interconnection, LLC. *2001-2005 NERC Generating Unit Statistical Brochure*, January 11, 2007. (www.pjm.com/planning/res-adequacy/resource-reports.html)
12. PJM Interconnection, LLC. *Hourly Load Data, 2006*. (www.pjm.com/markets/jsp/loadhryr.jsp)
13. PJM Interconnection, LLC. *Pending Generator Deactivation Requests as of 10/2/2007*. (www.pjm.com/planning/project-queues/gen-retire.html)
14. PJM Interconnection, LLC. *Generation Interconnection Queue as of 9/13/2007*. (www.pjm.com/planning/project-queues/queues.html)
15. PJM Interconnection, LLC. *PJM 2006 Regional Transmission Expansion Plan*, February 27, 2007.
16. Virginia State Corporation Commission, *The Development of a Competitive Retail Market for Electric Generation within the Commonwealth of Virginia - Part II Status of Retail Access and Competition in the Commonwealth*, September 1, 2006.

8.4 Assessment of Need for Power

This Section 8.4 identifies the need for power within the Dominion Zone. The Dominion Zone summer peak demand and baseload demand forecasts used in this assessment are discussed in more detail in Section 8.2. Current installed capacity and planned new capacity additions are discussed in Section 8.3.

8.4.1 Need for Baseload Capacity

This section assesses the need for baseload capacity within the Dominion Zone. Unit 3 is proposed and will operate as a baseload facility to help meet this need.

The current baseload demand in the Dominion Zone has been estimated by reviewing 2006 historical PJM integrated hourly loads for the Dominion Zone, sorting the 8760 hourly loads (i.e., 24 hours × 365 days) in declining order to create the load duration curve shown in Figure 8.3-2, and selecting the 65th percentile hour load equal to 9538 MW as the proxy for 2006 baseload demand. It is assumed that this baseload demand would continue to grow at a compound annual growth rate of 2.4 percent, equal to the compound annual growth rate observed in historical DVP weather-normalized average hourly sales over the recent five year period from 2002 to 2006. A review of historical DVP weather-normalized peak load over the same five year period from 2002 to 2006 reveals a compound annual growth rate of 1.9 percent, which is fully consistent with PJM's forecasted peak load growth.

While the 65th percentile hour load is not exactly equal to the amount of required installed baseload capacity, it is a reasonable proxy for baseload capacity requirements after reducing capacity supply by assumed availability rates. For purposes of this analysis, baseload capacity is defined to include capacity from currently operating and planned coal and nuclear facilities.[1] These capacity values are reduced by the assumed unit availability rates presented earlier in Table 8.3-1. The derivation of these unit availability rates is discussed in Section 8.3.1.

This analysis assumes Dominion's Virginia City facility and all proposed baseload capacity projects in the Dominion Zone currently included in the PJM Generation Interconnection Queue listed in Table 8.3-4 will be built, with the exception of the proposed Unit 3. This is a conservative assumption because it does not take into account the probability that they might not all be built. A developer can withdraw from the interconnection queue process at any point in time. In fact, in the PJM 2007 EIA-411 report, which includes information about regional electricity supply and demand projections for a ten-year advanced period,[2] PJM does not identify any planned additions specific to the Dominion Zone.

1. In the assessment for need for baseload capacity, baseload capacity excludes combined-cycle units, which are more suitable as cycling or mid-range resources due to recent high natural gas prices and price volatility.

The impact of any potential baseload capacity retirements both in and out of the Dominion Zone is conservatively excluded from the need for baseload capacity analysis.

For the purpose of this analysis, it is conservatively assumed that the DSM targets established in the Legislation and Virginia Energy Plan will be met in full and it is further assumed that baseload demand will be reduced by those target levels. These conservative assumptions overstate the impact to baseload demand because typical DSM programs serve to reduce peak load demand. The analysis is based on an assumption that over the thirteen consecutive years, from 2010 to 2022, the realized percent savings in baseload energy consumption will increase exponentially each year to meet the targeted 10 percent reduction in electric energy by 2022. These assumptions are made for both DVP's Virginia and North Carolina service territories in the Dominion Zone.

2. The annual PJM EIA-411 report includes information regarding historical and projected peak demand, existing transmission lines and proposed bulk power transmission line additions and company level data regarding existing installed capacity, proposed changes to existing generators, proposed new generators, and projected capacity purchases and sales. Each of the Regional Councils of the North American Electric Reliability Council (NERC) is asked to submit Form EIA-411 data compiled from data furnished by utilities and other electricity suppliers within their Council areas to NERC. NERC then compiles and coordinates these data and provides them to the Energy Information Administration. The data collected on form EIA-411 are used by the U.S. Department of Energy to monitor the current status and trends of the electric power industry and to evaluate the future of the industry.

Table 8.4-1 Need for Baseload Capacity

Values shown in MW, unless otherwise noted.		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2022	CAGR 2007–2022
Baseload Demand															
Baseload Demand - 65% Percentile Hour	[1]	9,763	9,993	10,229	10,470	10,717	10,970	11,229	11,494	11,765	12,043	12,327	12,618	13,851	2.4%
DSM% Reduction from 2006 Consumption	[2]	0.00%	0.00%	0.00%	1.0%	1.21%	1.47%	1.78%	2.15%	2.61%	3.16%	3.83%	4.64%	10.0%	
DSM Baseload MW Reduction		-	-	-	(95)	(116)	(140)	(170)	(205)	(249)	(302)	(365)	(443)	(954)	
Baseload Demand - DSM Adjusted		9,763	9,993	10,229	10,375	10,602	10,830	11,059	11,289	11,516	11,741	11,961	12,175	12,897	
Baseload Supply															
Baseload Installed Capacity - Availability Adjusted		8,621	8,621	8,621	8,621	8,621	8,621	8,621	8,621	8,621	8,621	8,621	8,621	8,621	
Planned Baseload Additions - Availability Adjusted															
Coal		17	17	17	35	74	644	644	644	644	644	644	644	644	
Nuclear		-	-	-	195	265	325	325	325	325	325	325	325	325	
Subtotal-Planned Baseload Additions		17	17	17	230	338	969	969	969	969	969	969	969	969	
Total Baseload Capacity Supply		8,638	8,638	8,638	8,851	8,960	9,590	9,590	9,590	9,590	9,590	9,590	9,590	9,590	
Baseload Capacity Surplus/(Deficiency)		(1,125)	(1,355)	(1,591)	(1,524)	(1,642)	(1,241)	(1,470)	(1,699)	(1,926)	(2,151)	(2,372)	(2,585)	(3,308)	

Notes:

[1] Based on analysis of Dominion Zone 2006 historical actual hourly load data. Assumes baseload demand will increase at same compounded annual growth rate observed in VEPCO historical weather-normalized average sales for 2002 through 2006.

[2] DSM% Savings in Year (T) = 3E-170e^(0.1919*T)

As shown in Table 8.4-1 above, the results of the need for baseload capacity analysis indicate that there is currently a need for additional baseload capacity within the Dominion Zone. Unit 3 is not anticipated to be in-service until 2015, by which time the baseload capacity deficiency is projected to be over 1900 MW, even after including capacity supplied by DVP's Virginia City facility, other planned baseload capacity projects in the Dominion Zone, and conservatively assuming that DSM targets established by Virginia and existing PJM programs will reduce baseload demand. This additional need for baseload capacity is greater than the potential capacity that would be available from the proposed Unit 3 and could be even greater if DSM savings are less than the above conservative baseload estimates or if not all planned baseload projects are built. Thus, even conservatively assuming that DSM measures are adopted and that they actually reduce DVP's baseload requirements (a highly unlikely event given that DSM programs most often reduce peak load) there is still a need for nearly 2000 MW of baseload capacity by 2015 for DVP to meet its service obligations to native load customers. As a result of these projections, DVP is seeking approvals for the Virginia City facility as well as Unit 3 to assure it can meet the reliability requirements of the Virginia SCC and PJM.

8.4.2 Installed Reserve Margins - Peak Demand Supply/Demand Analysis

Projected installed reserve margins for the Dominion Zone are presented in this section, assuming that all proposed projects in the Dominion Zone currently included in the PJM Generation Interconnection Queue listed in Table 8.3-4 will be built with the exception of the proposed Unit 3. This is a conservative assumption because it does not take into account the probability that they might not all be built. A developer can withdraw from the interconnection queue process at any point in time.

Similar to the Need for Baseload Capacity analysis presented above, the impact of any potential retirements both in and out of the Dominion Zone is conservatively excluded from the calculation of installed reserve margins.

The reserve margin calculation (expressed as percentage) is defined as follows:

$$\frac{\text{Estimated Generating Capability} + \text{Import Capability} - \text{Estimated Peakload Responsibility}}{\text{Estimated Peakload Responsibility}}$$

Table 8.4-2 shows that the projected installed reserve margin, excluding import capacity, falls to 14.3 percent by 2017, which is below the 15 percent installed reserve margin (IRM) planning standard currently approved by PJM. (Reference 2) Thus, without the additional capacity from Unit 3 in 2015, the Dominion Zone will be relying heavily on imported power for reliability.

Table 8.4-2 Determination of Installed Reserve Margin

Values shown in MW, unless otherwise noted.		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2022	CAGR 2007-2022
Summer Peak Demand	[1]	19,167	19,583	19,956	20,347	20,746	21,110	21,519	21,923	22,334	22,769	23,222	23,619	25,320	1.9%
Installed Summer Capacity	[2]	21,613	21,613	21,613	21,613	21,613	21,613	21,613	21,613	21,613	21,613	21,613	21,613	21,613	
Planned Capacity Additions	[3]	148	738	1,873	4,023	4,141	4,839	4,899	4,919	4,919	4,919	4,919	4,919	4,919	
Maximum Import Capability (CETL)	[4]	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	
Total Capacity Supply		24,861	25,451	26,586	28,736	28,854	29,552	29,612	29,632	29,632	29,632	29,632	29,632	29,632	
Calculated % Reserve Margin (with Imports)		29.7%	30.0%	33.2%	41.2%	39.1%	40.0%	37.6%	35.2%	32.7%	30.1%	27.6%	25.5%	17.0%	
Calculated % Reserve Margin (without Imports)		13.5%	14.1%	17.7%	26.0%	24.1%	25.3%	23.2%	21.0%	18.8%	16.5%	14.3%	12.3%	4.8%	

Notes:

[1] PJM Load Forecast 2007

[2] PJM-Dominion Zone Installed Capacity as of 1/1/2007; Source: PJM 2007 EIA-411 Data

[3] PJM Generation Interconnection Queue as of 9/13/2007

[4] Order on Rehearing and Clarification and Accepting Compliance Filing, Federal Energy Regulatory Commission, Docket No ER05-1410-002 et al., June 25, 2007

8.4.3 Summary of Need for Power

As identified in Table 8.4-1, the Dominion Zone has a specific need for new baseload capacity and this need is projected to increase. The baseload capacity supply portfolio in the Dominion Zone is currently out of balance with the need for baseload generation. Development of new baseload capacity has not kept pace with recent growth in baseload energy consumption. Instead, the growth in baseload energy consumption has been met predominantly by the recent development of gas-fired units, which are more suitable as cycling or mid-range resources, and imported power. In fact, a major new baseload facility has not been built in the Dominion Zone since 1996, and the proposed Unit 3 is the only major baseload facility over 100 MW within the Dominion Zone currently under study in the PJM Generation Interconnection Queue. (Reference 3)

Without the additional capacity from the proposed Unit 3 project in 2015, the Dominion Zone will continue to rely heavily on imported power for reliability. Reliance on power imported from other states increases demand on west-to-east transmission capabilities, resulting in heightened vulnerability to transmission-related interruptions.

The predominance of new gas-fired generation and lack of new baseload capacity has decreased fuel diversity, leaving customers more vulnerable to volatility in oil and natural gas prices and disruptions in other fuel supplies. This vulnerability is magnified because of recent additions of gas fired capacity in the PJM region that have increased dependence on natural gas and oil to approximately 35 percent of total PJM capacity. Moreover, PJM's current dependence on 20,252 MW of baseload coal-fired capacity from units that will be fifty years or older in 2015 leaves customers within PJM, including in the Dominion Zone, who depend on the PJM market for purchases of energy and capacity, vulnerable to increased costs due to a multitude of reasons such as operating cost, declining availability, derates or retirements. Expanding nuclear power within DVP's generation portfolio affords DVP the ability to provide much needed additional fuel diversity and a reliable baseload generation resource with stable operating and fuel cost for its retail customers.

The proposed Unit 3 (approximately 1500 MW) would help alleviate the current baseload supply imbalance, lessen the region's vulnerability to transmission-related interruptions, and manage risks associated with volatility in oil and natural gas prices and disruptions in other fuel supplies. Upon commercial operation, Unit 3 will increase the percentage of nuclear capacity within the Dominion Zone from the current 16 percent to 20 percent in 2015. When coupled with the Virginia City facility, Unit 3 will not only increase diversity of generation technologies for the baseload generation resources in the Dominion Zone, but also enhance the fuel supply diversity of the baseload generation resources.

Section 8.4 References

1. PJM Interconnection, LLC. *PJM Load Forecast Report*. January, 2007. (www.pjm.com/planning/res-adequacy/downloads/2007-load-report.pdf)
2. PJM Interconnection, LLC. *2007 PJM Reserve Requirement Study*, Markets and Reliability Committee, Agenda Item 8, August 1, 2007.
3. PJM Interconnection, LLC. *2007 PJM EIA-411 Report*, July 25, 2007. (www.pjm.com/documents/downloads/reports/2007-pjm-411.pdf)
4. FERC Order on Rehearing and Clarification and Accepting Compliance Filing, Docket Nos. ER05-1410-002, EL05-148-002, ER05-1410-003, EL05-148-003. Federal Energy Regulatory Commission, Issued June 25, 2007.
5. PJM Interconnection, LLC. *Generation Interconnection Queue as of 9/13/2007*. (www.pjm.com/planning/project-queues/queues.html)

Chapter 9 Alternatives to the Proposed Action

This chapter assesses the feasibility and potential impact of various alternatives to developing the proposed Unit 3 project while still providing the necessary power to meet projected baseload demand. The alternatives considered and addressed include taking no-action and energy resource alternatives both with and without the development of new generating capacity. This assessment demonstrates that there are few alternatives reasonably capable of meeting DVP's baseload need, and those few alternatives are not environmentally preferable to Unit 3.

While reasonably feasible alternatives are not environmentally preferable to Unit 3, DVP believes that such alternatives are important generation resources that are properly included in a balanced generation portfolio. Indeed, DVP is currently seeking a Certificate of Public Convenience and Necessity (CPCN) from the Virginia State Corporation Commission (Virginia SCC) to construct a 585 MW clean coal unit in Virginia City, Virginia (the "Virginia City facility"). While DVP believes Unit 3 offers many advantages as part of a baseload generation portfolio, DVP believes that additional, alternative sources such as the Virginia City facility will also be required to provide a balanced, fuel-diverse supply to meet DVP's large projected baseload supply obligations.

Section 9.1 provides a discussion of the no-action alternative and its implications on system reliability, fuel diversity and the future price of electricity to consumers. Energy resource alternatives are discussed in Section 9.2.

9.1 No-Action Alternative

The no-action alternative is a scenario under which the NRC denies the application and the proposed Unit 3 is not constructed. Under this scenario, the environmental impacts of constructing and operating Unit 3 would be avoided, but the primary benefit of the project—the needed baseload power—would either remain unfulfilled or have to be provided by an alternative energy resource. The viability and environmental impacts of energy alternatives are addressed in Section 9.2.

Leaving the need unfulfilled is neither desirable nor consistent with DVP's public service obligations. Without the additional capacity from the proposed Unit 3 project or an energy alternative, the Dominion Zone will continue to rely heavily on imported power or as yet unplanned alternative generation, in order to meet its baseload service and reliability obligations. As discussed in Section 8.0.1.2, based on 2005 U.S. EIA data, the Commonwealth of Virginia, statewide, was the second largest importer of electricity in the United States on a total MW-hr basis and imported the third largest percentage of consumed power of PJM states. Too great a dependence on power imported from other states is undesirable for Virginia because of the increased demand that it places on west-to-east transmission capabilities, and associated increased vulnerability to transmission-related interruptions. Moreover, imported power may not be a viable alternative for meeting baseload obligations due to competition for baseload capacity resources from surrounding areas (see Section 8.3.2).

As demonstrated in Section 8.4.2, by 2017, projected planned capacity additions will not be sufficient to maintain the 15 percent installed reserve margin (IRM) planning standard.[1] Reliability of service to DVP customers could be at risk even sooner than 2017, given uncertainty surrounding whether planned projects will actually be developed and current power supply vulnerability to equipment failure and unplanned shut-downs for maintenance.

As discussed in Section 8.4, there is a current need for additional baseload capacity. Without the development of new baseload capacity, such as Unit 3 and the Virginia City facility, the supply portfolio in the Dominion Zone will become increasingly reliant on gas and oil-fired units and will need those resources to operate at higher capacity factors than typical cycling or mid-range resources in order to meet increasing growth in baseload demand. Gas and oil-fired units have higher variable operating costs than baseload generation resources. The benefit of adding this low variable cost option to meet baseload demand cannot be enjoyed without NRC action. The mismatch of generation technology type to operational requirement will cause system inefficiencies resulting in increased electricity prices. Moreover, customers will be more vulnerable to oil and natural gas price volatility and disruptions in fuel supplies. While the risk of oil and natural gas price volatility can be hedged in part through long-term contracts, this risk can be further managed by increasing fuel diversity through the development of new nuclear and clean coal capacity. Hence, the development of Unit 3 will help manage risks associated with oil and natural gas price volatility and enable DVP to retain its supply portfolio balance.

9.2 Energy Alternatives

This section describes the environmental impact and viability of various energy sources to serve as alternatives to the baseload generation that would be provided by Unit 3. The alternatives considered and addressed include: power purchases from other generators or the market, reliance on improvement in energy efficiency or demand side management, and other new generating resources from both renewable resources as well as fossil fuels.

Alternatives that do *not* require new generating capacity are assessed in Section 9.2.1. Alternatives that do require new generating capacity are assessed in Section 9.2.2. Certain alternatives reviewed in Section 9.2.2 are eliminated on the basis of being unavailable in the relevant region (i.e., the Dominion Zone) or not commercially feasible; those which may be viable are discussed in Section 9.2.3, which includes an assessment of environmental impact, reliability and general economic competitiveness of each technology.

Consistent with NUREG-1555, (Reference 1) this analysis considers the impact of the integrated PJM market, projected reserve margins, peak loads and load duration curves, transmission inter-tie capability, as well as plant retirements, expected new generation, plant availability and the effect of conservation and load management. Each of these elements, and its impact on the need for power,

1. Excluding imports.

is addressed in Sections 8.2 and 8.3. Accordingly, Section 9.2 does not repeat those factors but focuses on the ability of alternative sources to meet the baseload need that is projected for the 2015 timeframe, inclusive of the impact of the above-mentioned factors.

9.2.1 Alternatives Not Requiring New Generating Capacity

This section discusses possible methods of supplying the projected demand for baseload energy *without* constructing new generating capacity. The specific options considered include: the viability of purchasing power from other resources, plant reactivation and extended service life, and obviating the need for generation through energy conservation and demand side management measures.

9.2.1.1 Power Purchases

The option of supplying DVP's increasing power requirements to serve native load with power purchases is theoretically possible through purchases from the wholesale market, a specific generating asset or a neighboring utility. However, as discussed in Section 8.1.4, the Dominion Zone is one of 23 Locational Deliverability Areas (LDA) identified by PJM as "constrained areas that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations."[1] In constrained areas, such as the Dominion Zone, baseload capacity for load serving entities (LSEs) must be located within the constrained area or the LSE must enter into a bilateral transaction for capacity into that constrained area.

The option of purchasing energy and capacity from neighboring utilities or resources outside of the Dominion Zone is limited by both transmission import capability as well as other demand centers competing for the same energy and capacity purchases. Based on EIA data, Virginia currently relies on over 3000 MW of imports from neighboring regions, which is close to the transmission system's 3100 MW maximum transfer limit (CETL) into the Dominion Zone. (Reference 3) Significant incremental imports on a firm baseload basis would require major transmission system upgrades or reliance on an already strained transmission system, as discussed in Section 8.3.2. Even with the new Meadow Brook - Loudoun 500 kV line sponsored by DVP and other baseline transmission upgrades included in the PJM RTEPP, PJM believes that additional transmission system expansion and new generating sources will still be required to meet expected peak load supply requirements in the Dominion Zone beyond 2011.[2] Further, any upgrades to enable a power import comparable to Unit 3 would need to cross multiple utility service territories and may prove cost prohibitive.

Under the terms of Virginia's recent Legislation, DVP has an obligation to meet the demands of its native-load customers, (Reference 5) but power project developers may not have energy and capacity available to provide to DVP in the future. In addition to transmission limits, the availability

1. Reference 2, Schedule 10.
2. Reference 4 at 98 and 102.

of energy and capacity from resources outside of Virginia will be reduced by competition from other load centers surrounding the Dominion Zone. Specifically, the District of Columbia, Delaware, Maryland, and New Jersey are also experiencing significant growth and already rely heavily on imports from adjoining regions. Based on EIA generation and consumption data, the District of Columbia imports approximately 98 percent of its annual energy consumption; while Delaware and Maryland import approximately 37 percent and 27 percent, respectively, of their annual energy consumption. Virginia currently imports approximately 30 percent of its annual energy consumption;[1] North Carolina is less reliant on imports, but does import approximately 5 percent of its annual energy consumption. The Public Service Commission of Maryland in its "Electric Supply Adequacy Report of 2007," has expressed concerns regarding the uncertainty of electric reliability in Maryland, citing expected demand growth between 1 percent and 2 percent per year, development of little new in-state electric generation, potential de-rates or retirements of fossil-fired generating capacity, and limited transmission capability during peak demand periods.[2] The projected growth of utilities' energy requirements in the region, combined with the planned retirements of 1821 MW of capacity in PJM between September 2008 and May 2012, (Reference 8) render long-term baseload purchases from neighboring utilities unlikely. By 2011, PJM is projecting that reserve margins in the central portion of Maryland and other eastern regions of PJM will be barely adequate to ensure reliability.[3] Thus, power purchases cannot be reasonably expected to provide power for a term that would be equivalent to the life of Unit 3.

In addition, based on current projects in the PJM transmission queue, it appears that baseload resources most likely will be coal-fired generation. Based on analysis of the PJM Generation Interconnection Queue as of September 13, 2007, there are currently 13,353 MW of baseload capacity projects[4] currently under study[5] for the surrounding regions outside the Dominion Zone including in all or parts of VA, NC, WV, PA, OH, and IN.[6] Eighty two percent of this planned baseload capacity is coal and the remaining 18 percent is nuclear. The baseload requirement for these surrounding regions in total is approximately 3.5 times greater than the baseload requirement for the Dominion Zone.[7] Approximately 77 percent of these baseload capacity projects currently under study are coal-fired. Of the remaining baseload capacity projects under study, 18 percent is from nuclear, 3 percent from hydro and 2 percent from other renewables. Section 9.2.2 examines

1. Reference 6 (Based on analysis of 2005 state level sales and generation data provided by the U.S. Energy Information Administration in its "Electric Power Annual 2005" publication. State net import/(export) levels were estimated assuming a 6% loss factor).
2. Reference 7, p9.
3. Reference 7, p3.
4. Baseload capacity is assumed to include coal and nuclear.
5. Includes projects listed as Active, Under Construction, or Partially In-Service with planned in-service dates after 1/1/2007.
6. As shown in Figure 8.3-5, the average cost of power in these regions is typically lower than in the Dominion Zone.

the environmental impact and feasibility of coal-fired and gas-fired sources and concludes that neither generating source is environmentally superior to Unit 3.

In conclusion, with regard to power purchases as an alternative not requiring new generation, DVP considers the likelihood of resource availability to be low, the potential for additional import delivery through the transmission system to be constrained at best and the potential term of such a purchase to be inferior to the Unit 3 option. Accordingly, this alternative is not deemed reasonable or feasible.

9.2.1.2 Plant Reactivation or Extended Service Life

DVP has no opportunities to meet its incremental baseload needs through extending the service life of existing plants. There are currently no planned plant retirements in the Dominion Zone through 2021, the sixth year of commercial operation of the proposed Unit 3.

Similarly, there are no viable opportunities for DVP to meet its baseload and reliability needs through re-activating plants. DVP has no plants that are viable candidates for reactivation. Any plant re-activation within the Dominion Zone would require returning to service units that are already retired or mothballed and are likely to need significant and capital intensive upgrades to meet current and expected future environmental requirements.

Even if there were plants with the potential for re-activation or extended service, the plant must first resolve the initial reasons the plant was, or is planned to be, shut down. These reasons typically include failure to be economic in the market or an inability to meet environmental standards; otherwise the plant would not have been retired. Moreover, the plants that have been shutdown, and those that are planned to be retired in the SERC reliability region are, for the most part, fossil fuel stations. Section 9.2.3 examines the environmental impact and feasibility of these technologies and concludes that none of these generating sources are environmentally superior to Unit 3. These technologies also would not provide many of the benefits of Unit 3 discussed in Chapter 8.

9.2.1.3 Conservation (Energy Efficiency)

Section 8.2.2.2 details the PJM efforts and the efforts in both Virginia and North Carolina to encourage conservation and energy efficiency. As noted in that section, conservation efforts are not expected to have a significant impact on baseload power needs but rather on peak requirements. In addition, Section 8.4 demonstrates that the growth in baseload need is projected to be over and above the potential effects of the conservation and efficiency targets established by both states and the existing PJM programs. Even if the state targets are met and the PJM programs continue, they

7. Based on analysis of 2006 historical PJM integrated hourly loads, the average 2006 demand for the Western PJM area (i.e., the service territories of Allegheny Power (AP), American Electric Power (AEP), Commonwealth Edison (COMED), Dayton Power and Light (Dayton) and Duquesne Light Company (DLCO)) was 36,607 MW, which is approximately 3.5 times the average 2006 demand for the Dominion Zone, which was 10,456 MW. (The Western PJM area excludes parts of Pennsylvania.)

will not alter the need for baseload power from Unit 3. Conservation programs have DSM components which are primarily aimed at managing the efficiency gains from peak load, not baseload. If the conservation programs met with extraordinary success, the impact of these programs, at best, could only moderate load growth and slightly defer the need for additional baseload power, but not the need for Unit 3 as shown in Section 8.4. DVP does not consider conservation alone to be a feasible alternative to the proposed Unit 3.

9.2.2 **Alternatives Requiring New Generating Capacity**

This section analyzes possible alternative sources of energy and whether they could reasonably be expected to provide additional generating capacity to commercially serve DVP's baseload power and reliability obligations in a manner that is environmentally preferable to the proposed alternative. Each potential resource is assessed in terms of its potential to provide the required baseload power offered by Unit 3. If a generating source is determined to be viable pursuant to the review in this Section 9.2.2, it is then compared with the proposed project, Unit 3, in Section 9.2.3. This section includes an assessment of currently available technologies as well as those that are projected to be available within the relevant timeframe. Technologies reviewed include fossil fuels, taking into account national policy regarding the use of such fuels, as well as alternative/renewable resources available within the region. Specifically this section covers:

Renewable Fuels:

- Wind
- Geothermal
- Hydropower
- Municipal solid waste and landfill gas
- Biomass/wood waste
- Agriculture-derived biomass (e.g. energy crops)
- Photovoltaic cells and solar thermal

Other Alternatives:

- Integrated gas-fired combined cycle (IGCC)
- Other advanced systems (e.g. fuel cells, synthetic fuels, etc.)

Non Renewable Fuels:

- Petroleum liquids
- Natural gas
- Coal

For the purposes of this Section 9.2.2, DVP assesses renewable resources capable of running exclusively on a renewable fuel. Alternatives involving combinations of facilities are addressed in Section 9.2.2.4.

In performing this evaluation, DVP has used the NRC's Generic Environmental Impact Statement (GEIS) (References 15 and 13) to inform its analysis. The GEIS is useful for the analysis of alternative sources because for License Renewal plants the NRC has determined that evaluation of these alternatives enables the agency to consider the relative environmental consequences of each alternative. To generate the reasonable set of alternatives used in the GEIS, the NRC included commonly known or anticipated generation technologies.

9.2.2.1 Renewable Fuels

Generally, renewable resources are not of the scale or type to provide baseload power comparable to the output of Unit 3. Table 9.2-1 depicts the average capacity factors achieved by various renewable resource types nation-wide using data from EIA.

Table 9.2-1 Average Capacity Factors for Renewable Resources[a]

Capacity Factor By Sector (%)	2001	2002	2003	2004	2005	Average
Biomass	32.7	34.4	35.8	34.6	35.1	34.5
Wood/ Wood Waste	16.1	17.6	18.5	18.0	19.5	17.9
MSW/Landfill Gas	64.2	64.2	64.1	66.8	67.0	65.3
Other Biomass[b]	20.8	32.5	52.2	43.5	33.4	36.5
Geothermal	70.8	73.5	77.2	78.6	73.4	74.7
Conventional Hydroelectric	30.9	37.5	39.4	39.0	39.3	37.2
Solar	15.8	16.0	15.4	16.5	15.3	15.8
Wind	19.9	26.8	21.3	25.0	23.4	23.3

a. References 10 and 11 (the capacity factor was calculated using the following formula:
Capacity Factor = Annual generation (MW-hr)/(Annual net summer capacity * 24 hours * 365 days)).

b. Includes agriculture by-products/crops, sludge waste, tires, and other biomass solids, liquids, and gases.

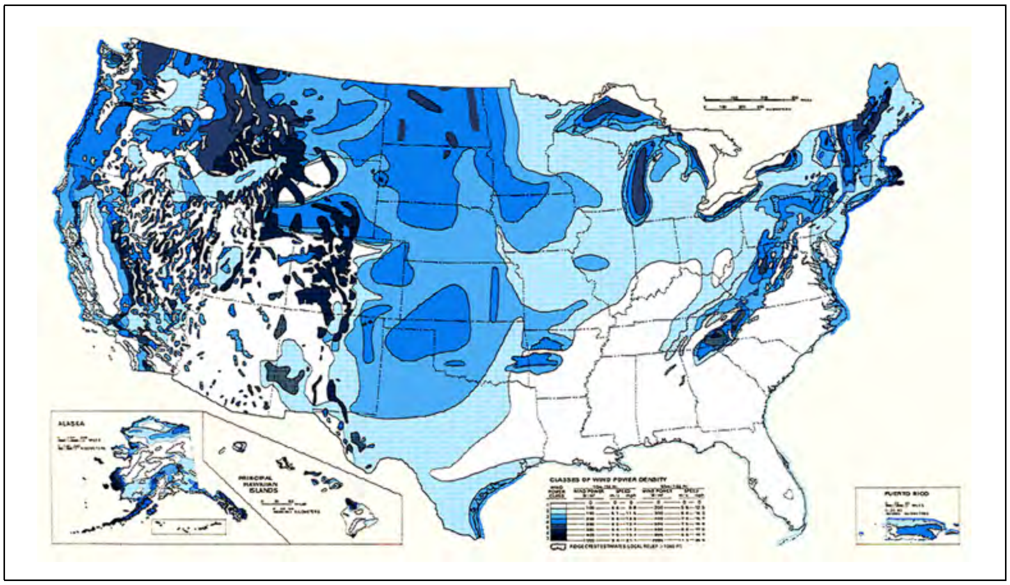
These data indicate that even where viable, most renewable resources are not generally able to provide baseload power or higher capacity outputs equivalent to Unit 3. The non-baseload nature of these resources may be overcome in the future with the development of nano-supercapacitors, energy storage devices such as compressed air systems or large-scale battery systems, and deployment of significant transmission system enhancements. EPRI forecasts that by the mid-2020's nano-capacitor technology may become available for deployment. Large-scale energy storage devices also have not been advanced to the point of economic feasibility. Until these technologies are advanced, non-baseload resources such as solar and wind cannot provide baseload power.[1]

Any comparison of economic or environmental viability between non-baseload or mid-range capacity and baseload capacity would need to account for the diminished average available capacity by proportionately reducing the non-baseload or mid-range capacity ratings by an assumed technology-specific availability rating. However, DVP notes that the resulting average available capacity is not equivalent to the reliability of a baseload unit.

9.2.2.1.1 Wind

GEIS Supplement 7 concludes that Virginia is a Class 1 Wind Power region.[2] Figure 9.2-1 shows the annual average wind power in the United States.

Figure 9.2-1 United States Annual Average Wind Power



Source: Reference 14

Given that wind power is an intermittent resource, in order to compare a wind resource with Unit 3, in terms of average available capacity, one must adjust for the expected capacity factor of that resource. As noted above, EIA data indicate that wind power in the United States has achieved average capacity factors of approximately 23 percent in the 2001–2005 timeframe. The GEIS projects that the average annual capacity factor for wind power will be 29 percent in 2010. (Reference 15) Further, there is poor correlation between wind output and peak demand; in particular, wind tends to be unavailable on a hot summer day when both baseload and peaking

1. Reference 12, pp3–6.
2. Reference 13, Section 8.2.5.2.

resources are most needed. On average, wind resources would require 3.5 times as many MW of installed capacity to provide an average available capacity level equivalent to that from baseload nuclear resources with a capacity factor of 90 percent. However, even after adjusting for average available capacity, this capacity is not equivalent to that of a reliable baseload resource, given that in any point in time, generation can range from zero MW to full capacity.

The GEIS and other public data indicate that wind power requires from 60,000 to 150,000 acres per 1000 MW of capacity depending on location and other siting parameters. (References 15 and 16) In sum, wind power is not a reasonable alternative to provide for the baseload need that would be served by Unit 3 because of wind power's lower capacity factor and land requirements.

9.2.2.1.2 **Geothermal**

GEIS Supplement 7 (References 15 and 16) determined that the average annual capacity factor for geothermal power was 90 percent, making it suitable as a source of baseload generation. The EIA data provided in Table 9.2-1 shows that on average, geothermal resources in the United States achieved capacity factors of approximately 75 percent, in the 2001–2005 timeframe.

While industrial-scale geothermal power generally is available as a baseload resource, it is only available in Virginia or North Carolina for use with ground coupled heat pumps. Figure 8.4 of the GEIS shows that areas with potential for geothermal project development are found in the western United States. Based on 2005 data, the EIA found that there is no industrial-scale geothermal potential in the Dominion Zone. Further, DOE reports that North Carolina and Virginia have only low to moderate temperature resources, and electricity generation from these is not possible. (Reference 17)

Because there is no industrial-scale geothermal potential in the Dominion Zone or even nearby, it is not a reasonable alternative to Unit 3.

9.2.2.1.3 **Hydropower**

GEIS Supplement 7 [1] found that Virginia had 617 MW of undeveloped hydropower resources, which is not enough to equal the output of the proposed project. The GEIS[2] estimates that a 1000 MW hydropower project would require about 1 million acres of land. Based on the project size of Unit 3, approximately 1.5 million acres would have to be flooded in order to be equivalent in capacity. This would create a land use impact of over 2300 square miles.

Hydropower is not a reasonable alternative to the proposed Unit 3 due to the limited availability of identified sites within the Dominion Zone and the amount of land needed.

1. Reference 13, Section 8.2.5.4.
2. Reference 15, Section 8.3.4.

9.2.2.1.4 **Municipal Solid Waste and Landfill Gas-Fired Facilities**

The GEIS[1] found that municipal solid waste (MSW) projects could achieve a capacity factor of approximately 85–90 percent, making it a potential source of baseload generation. However, the EIA data provided in Table 9.2-1 shows that on average, landfill gas and MSW resources in the United States achieved more modest capacity factors of approximately 65 percent in the 2001–2005 timeframe.

According to the EIA, in 2005, there were 3055 MW of installed MSW projects throughout the U.S., representing a 7 percent reduction from the 3292 MW installed nationwide in 2001. (Reference 11) Currently there are three MSW facilities, including industrial cogeneration, in the Dominion Zone totaling 207 MW of summer capacity. (References 18 and 19) Site development of MSW projects is limited to landfill sites and is driven by waste management considerations, such as limited availability of sites for landfills due to permitting requirements and zoning restrictions. EPA data indicate that MSW facilities require, on average, 15,000 tons of waste material per year for each MW of capacity. (Reference 20) Accordingly, to provide even 20 percent of the capacity of Unit 3 would mean incinerating an incremental 4.5 million tons of MSW per year, which is over two times the amount of MSW incinerated in Virginia in 2006.[2]

An MSW facility has a footprint similar in size to that of a fossil fuel-fired generator, but also requires landfill space to deposit non-hazardous ash residue. Net landfill space is reduced overall as a result of the combustion process.

The mandatory Renewable Portfolio Standard recently enacted in North Carolina considers landfill gas-fired facilities to be a renewable technology. The Chicago Climate Exchange considers certain landfill gas-fired generation facilities to qualify as emission offset projects.

A report by the National Renewable Energy Laboratory (NREL) presents the current availability of methane from landfills by state. The annual potential amount of this resource is 275,000 tons in Virginia. (Reference 23) Given the dispersed nature of this energy source and the relatively small amount, landfill gas generating facilities could only serve a small portion of an overall energy portfolio.

Due to low generation outputs, MSW and landfill gas are not reasonable alternatives to Unit 3 as potential baseload resources.

9.2.2.1.5 **Biomass (Wood), Wood Waste**

Wood-burning projects can have capacity factors competitive with traditional baseload sources of generation, although the EIA data provided in Table 9.2-1 shows that on average wood waste

1. Reference 15, Section 8.3.7.
2. In 2006, 16.8 million tons of MSW were received in the state of Virginia, including 7.3 million tons of MSW imported from other states. Of this total, 2.1 million tons of MSW was incinerated (Reference 36).

resources in the United States achieved capacity factors below 20 percent, in the 2001 – 2005 timeframe, with other biomass resources averaging 36 percent capacity factor.

Presently, wood waste burning projects are effectively limited to small-scale facilities because large-scale facilities are not economical. These developments are opportunistic and located near pulp, paper and paperboard industrial locations from which waste is available. EIA data indicate that in all of Virginia and North Carolina there are only 15 generating stations that are capable of burning wood waste, including industrial cogeneration, with a combined total summer capacity of 835 MW. However, many of these plants burn multiple fuels. Pro-rating the capacity of the amount of energy generated using wood-waste as a fuel yields 287 MW. (References 18 and 19) The counties and cities listed in Table 8.1-2 have 8 units totaling 579 MW capable of burning wood waste, which on a prorated basis yields 162 MW of wood waste potential.[1]

Additional development of wood waste generation is limited by the location and availability of additional wood waste resources. A report recently issued by DOE and USDA found that the amount of forestland-derived biomass that could be sustainably consumed nationally is approximately 368 million dry tons annually, which is more than 2.5 times the current national level. (Reference 25) However, the report cites accessibility of terrain, transportation costs, labor availability, and needed equipment improvements as major limiting factors in the expansion of biomass production. Section 8.3.6 of the GEIS found that the construction impacts per MW of installed capacity of a wood-burning project were similar to a coal project. These impacts are examined further in Section 9.2.3.

A report by NREL presents the current availability of biomass resources by state. (Reference 23) Table 9.2-2 shows the annual wood-derived biomass resource potential in Virginia.

Table 9.2-2 Wood-Derived Biomass Resource Potential

	Virginia (thousand tons)
Forest Residues	2,403
Primary Mill	2,147
Secondary Mill	62
Urban Wood	813
Total Wood Biomass	5,425

In order to provide a similar capacity to Unit 3, approximately 8.6 million tons per year of biomass fuel would be needed. The Virginia RPS, described in Section 8.3.1.3 also provides state-wide, cumulative limitations on the use of certain types of biomass at 1.5 million tons for utilities that have

1. Ibid. (References 18 and 19).

received Virginia SCC approval to participate in a renewable energy portfolio standard program and who seek to meet statutorily-defined RPS goals.[1]

Wood waste material being used exclusively in a utility boiler has the characteristic of having a maximum installed capacity of approximately 65 to 100 MW. Additionally, saturation of this technology option in the DVP service territory could lead to fuel price volatility for DVP rate payers as the market dealing with woody biomass as a fuel for utility scale operations is not considered fluid, indeed the Legislation's 1.5 million ton statewide cap on certain types of biomass has the effect of limiting the potential of fuel volatility. While smaller installations of biomass power plants are considered viable options that support the Virginia RPS targets, the volumes needed to equal that of Unit 3 are considered to be unattainable; therefore, wood waste power is not a reasonable baseload alternative when compared to Unit 3.

9.2.2.1.6 **Agriculture-Derived Biomass**

A report recently issued by DOE and the U.S. Department of Agriculture found that biomass resources made available from agriculture could sustainably increase by a factor of five over the next 35 to 40 years. Currently 194 million dry tons of biomass, including manure and corn stover, is made available annually in the U.S. from agriculture, though only a small fraction of this total amount is converted into biofuel or bioenergy. (Reference 25) Technological processes for converting forms of biomass such as corn stovers and manure into energy are still in the developmental phase.

Some states have an abundance of agriculture-derived biomass in the form of animal waste products. These states want to use this resource as a multi-tiered solution that addresses RPS goals as well as provide economic relief for a sector of their supporting economy. Section 8.3.1.3 found that North Carolina has established targets to recover energy from swine waste and from poultry waste beginning in 2012. Such generating facilities are limited in capacity, availability and are not a viable alternative to Unit 3.

A report by NREL presents the current availability of biomass resources by state. (Reference 23) Table 9.2-3 shows the annual agriculture-derived biomass resource potential in Virginia is only

1. *See* Va. Code § 56-585.2(F), which states that utilities participating in RPS programs shall collectively "use or cause to be used no more than a total of 1.5 million tons per year of green wood chips, bark, sawdust, a tree or any portion of a tree which is used or can be used for lumber and pulp manufacturing by facilities located in Virginia towards meeting RPS goals." The 1.5 million tons is apportioned among the utilities based on each utility's share of "total electric energy sold to Virginia jurisdictional retail customers" during 2007 "excluding an amount equivalent to the average of the annual percentages of the electric energy that was supplied to such customers from nuclear generating plants for the calendar years 2004 through 2006." Note that, even if Dominion Virginia Power were allotted full use of the 1.5 million tons in accordance with the RPS program, that would allow DVP to produce only 190 to 200 MW of electricity. The statute also allows other biomass fuels to be used without limitation, including slash, logging and construction debris, yard waste, non-merchantable waste paper, and agricultural and vineyard materials.

822,000 tons. Based on the foregoing, agriculture-derived biomass power is not a reasonable baseload alternative when compared to Unit 3.

Table 9.2-3 Agriculture-Derived Biomass Resource Potential

	Virginia (Thousand tons)
Switchgrass	297
Crop Residues	502
Methane from Manure Management	23
Total Agriculture Biomass	822

Energy Crops

Currently, the use of energy crops in the U.S. is largely focused on producing ethanol for use in the transportation sector. Energy crops as feedstock for large-scale generation have not enjoyed the same attention or level of development. Section 8.3.8 of the GEIS states that energy crop technology is uneconomical when compared with traditional sources of baseload generation. According to the U.S. Climate Change Technology Program (Section 2.3.8), (Reference 26) energy crop technology for generation is not expected to approach goal levels until 2020, mainly due to cost inefficiencies and a lack of commercial demonstration. Factors that may hinder growth in biomass resource include urbanization of farm lands, increased demand in the international meat and food grain markets, and soil erosion caused by harvesting of biomass residues.

Because of the lower efficiency of these plants (approximately 30 percent), the land use requirements are many thousands of times greater than the land required to support nuclear. On an energy equivalent basis, the acreage required to support 1000 MW of baseload generation is approximately 600,000 acres. (Reference 27) Section 8.3.8 of the GEIS indicates that a crop-fired plant would have similar construction impacts and operational impacts as a wood-fired plant.

Switchgrass is an energy crop that has been tested at two coal plants owned by Southern Company. During a three-year demonstration period at the Gadsden Plant in Alabama between 2002 and 2004, switchgrass contributed between 7 percent and 10 percent of the energy produced. (Reference 28) One acre of a switchgrass plot can grow the energy equivalent of about 2–6 tons of coal per year. (Reference 28) On an energy equivalent basis, the acreage required to produce 1000 MW of baseload generation entirely from switchgrass is between 0.5 and 1.5 million acres. (Reference 29) The land area to produce switchgrass is not significantly different from that required for other energy crops. Additionally, this crop has only been used in relatively small proportion to fossil fuels in co-firing tests. It is not yet commercially viable to use switchgrass as either a secondary, much less primary, fuel source.

Due to their limited commercial potential and large land use requirements, energy crops are not a reasonable alternative to Unit 3.

9.2.2.1.7 Photovoltaic Cells, Solar Thermal Power

Consideration of solar technologies as an alternative to Unit 3 must first focus on whether they can be built as baseload capacity. Due to their intermittent nature during the day and lack of economic thermal storage devices for use at night, solar is not considered a baseload replacement option compared to Unit 3. Concentrated solar power and photovoltaic distributed generation generally are installed at the end-user location. According to GEIS Supplement 7, (Reference 13) photovoltaic cells have an average annual capacity factor of 25 percent. These estimates are high compared to EIA data in Table 9.2-1, which indicate that only 16 percent average annual capacity factors have been achieved across all solar technologies. Storage capability is not commercially available to serve as baseload generation. As noted by EPRI, improved technology for energy storage is necessary to enable deployment of solar as a baseload resource, but those advances are not projected to be achieved in time to meet the baseload need for the Dominion Zone.

GEIS Supplement 7 (Section 8.2.5.3) established that the areas surrounding the proposed project site for Unit 3 had a daily average generation potential of 4 kW-hrs per square meter compared with 7 to 8 kW-hrs per square meter achievable in certain parts of the western United States. It estimates land requirements of about 35,000 acres per 1000 MWe for photovoltaic and about 14,000 acres per 1000 MW for solar systems.

The use of solar energy for baseload, large-scale installations is not a reasonable alternative to Unit 3 due to its intermittent nature, and moderate solar insolation within the region of interest.

9.2.2.2 Other Alternatives

9.2.2.2.1 Coal-fired IGCC

An alternative coal-based technology is integrated gas-fired combined cycle technology (IGCC). This technology converts coal or petroleum coke or other products into synthetic gas (syngas) which is then used in a traditional gas-fired combined cycle plant. IGCC also offers the possibility, in the future, of capturing CO_2 before combustion. To date, carbon capture and sequestration (CCS) has not been proven on a commercial scale.

The NRC has recently observed that IGCC is not a reasonable alternative to a large nuclear power generation facility because: 1) existing IGCC plants have considerably smaller capacity, 2) system reliability of existing IGCC plants has been lower than pulverized coal plants, 3) existing IGCC plants have had extended shakedown periods, and 4) lack of overall plant performance warranties for IGCC plants have hindered commercial financing.[1] DVP also notes that existing U.S. plants received governmental subsidies and proposed new IGCC plants are being located in states

1. Reference 35, Volume 1 at 9-6.

offering tax incentives in support of the technology, a step that the Commonwealth of Virginia has not taken.

Accordingly, IGCC with or without CCS, as a form of coal-fired technology, is not considered as a reasonable alternative to Unit 3.

9.2.2.2.2 **Fuel Cells**

According to the EIA's Annual Energy Outlook for 2007,[1] fuel cells are not projected to provide any measurable source of electric generation through 2030. On a per-kW basis, the installed costs (EIA assumes that the installed cost of a 10 MW fuel cell unit in 2006 is $4,520/kW (Reference 32)), plus variable operating plus maintenance costs for a fuel cell facility greatly exceed those of any other commercial-scale generating technology. The capital cost of advanced fuel cells is projected to remain uncompetitive with traditional sources of generation and the U.S. does not have an established hydrogen fuel supply structure. Hydrogen fuel is expensive and, like natural gas from which it is derived, it has a volatile price history. Because of its high marginal cost, a fuel cell would most likely be used in periods of peak electricity demand. Moreover, because fuel cell technology has a short operating history, the lifespan of a fuel cell unit is uncertain.

Dominion recently invested in the Raleigh, N.C.-based Microcell Corp. in order to accelerate the development of new fuel cell technology. (Reference 33) Microcell is a leader in proton exchange membrane microfiber fuel cells that operate on a cylindrical platform for applications ranging from back-up power to automotive.

Although DVP strongly supports the development of fuel cell technology, at this time, fuel cells are not a reasonable alternative to Unit 3.

9.2.2.3 **Non Renewable Fuels**

9.2.2.3.1 **Petroleum Liquids**

DVP currently operates 29 primarily oil-fired combustion turbines and two oil-fired steam turbines at eight different sites within the Dominion Zone, with a total maximum deliverable capacity (MDC) of 2246 MW. This equates to approximately 12 percent of installed capacity of DVP's Virginia and North Carolina power fleet.(Reference 24) A petroleum liquids alternative to the proposed unit would result in an approximate doubling of DVP's exposure to petroleum price volatility. From an environmental perspective, Section 8.3.11 of the GEIS finds that oil units have comparable air emissions to coal units.[2] In addition, the marginal cost of producing electricity with oil-fired generation is much higher than the marginal cost of energy produced by a nuclear unit, and as a result oil-fired generation is less desirable as a baseload generation source. At a time when oil

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1. Reference 31, Tables A8 and A9.
2. Coal emissions are discussed in Section 9.2.3.

commodity price levels remain high when compared with the commodity cost of coal or nuclear fuel, this is not an economically competitive option.

Petroleum liquid generation is not a reasonable baseload alternative to Unit 3 on either an environmental or economic basis.

9.2.2.3.2 **Natural Gas-Fired Generation**

DVP chose to evaluate gas-fired generation, using combined-cycle technology because the technology is mature, economical and feasible; and DVP has experience operating several combined-cycle gas units. One of DVP's most recently commissioned combined-cycle plants, Possum Point Unit 6, became commercially operable in July 2003. Possum Point 6 has a capacity of approximately 540 MW. For the purposes of this analysis, DVP assumed a new combined-cycle plant would have a capacity of approximately 550 MW; thus, DVP evaluated three units, in order to be compatible with the project, for a total capacity of 1650 MW. Combined-cycle technology is considered a competitive alternative and is evaluated further in Section 9.2.3.

9.2.2.3.3 **Coal-Fired Generation**

In 2004, the General Assembly amended the Virginia Electric Utility Restructuring Act to add a new subsection §56-585.G to encourage the construction of a coal-fired generation facility in the coalfield region of Virginia that would use coal from that region. Consistent with the 2004 Virginia legislation, DVP supports the development of coal technologies. Accordingly, coal is considered a potential alternative, and thus discussed further in Section 9.2.3. DVP currently has a CPCN application before the Virginia SCC for the Virginia City facility, a proposed 585 MW coal facility (that will allow the supplemental use of biomass and waste coal for up to 20 percent of the plant's output). Much like Unit 3, the Virginia City facility is a required resource to meet the company's current and growing baseload requirements. The Virginia City facility is expected to have a commercial operations date of 2012.

9.2.2.4 **Evaluation of Combinations of Alternatives**

This section examines whether combinations of alternatives could generate baseload power in an amount equivalent to the proposed Unit 3. There are numerous possible combinations of power sources and the amount of output of each source. For the renewal of licenses pursuant to 10 CFR 54, the NRC has already determined that expansive consideration of combinations would be too unwieldy given the purposes of the alternatives analysis. (Reference 15)

The following analysis provides the basis for evaluating whether a combination of alternative energy sources is a viable option and, if so, whether it provides any difference in environmental impacts with respect to evaluating possible alternatives to Unit 3. Section 9.2.2.4.1 evaluates whether any combination of renewables with non-renewable fuels is a viable and reasonable means of providing baseload power in the Dominion Zone. Section 9.2.2.4.2 evaluates whether any combination of non-renewable fuels provides a different set of environmental impacts than individual non-renewable fuel facilities such that a separate analysis of the environmental impacts of the combination is necessary.

9.2.2.4.1 Combinations of Alternatives Involving Renewable Fuels

As discussed in Section 9.2.2.1, renewable resources are not of the scale or type to provide baseload power. Wind and solar are not feasible on their own to generate the equivalent baseload capacity or output of Unit 3 because of the intermittent nature of the resources, as discussed in Section 9.2.2.1.1 and Section 9.2.2.1.7. As discussed below, no combination of a renewable fuel facility and a non-renewable fuel facility is a viable alternative to provide baseload generation in the Dominion Zone at the equivalent capacity of Unit 3.

Wind and Non-Renewable Fuels

As discussed above, wind power is considered by the industry as an intermittent, non-baseload generation resource. Accordingly, any combination of wind power with a non-renewable fuel facility would require not only that two facilities would be built—the wind facility and the non-renewable fuel facility—with the concomitant construction impacts of each, but that based on wind power's lower capacity factor the reduction in emissions would conservatively be only approximately 23 percent. Accordingly, a combination of a wind power with non-renewable fuel facility is not a viable or reasonable alternative to Unit 3.

Photovoltaic Cells, Solar Thermal Power and Non-Renewable Fuels

A combination of photovoltaic cells, solar thermal power, and non-renewable fuel alternatives would require, and have the impacts of, construction of two separate facilities. Also like wind power, a conservative assumption for the effect of such a facility on the air emissions and solid waste associated with a non-renewable fuel facility would be an approximate reduction of 16 percent to 25 percent. Due to the low capacity factor of a solar resource, although the combination of solar and non-renewable fuels may be viable on a small-scale, it is not a reasonable alternative to Unit 3.

Biomass, Wood Waste, Fuel Crops and Non-Renewable Fuels

As described above, there are not large-scale installations for the use of various types of biomass facilities in the Dominion Zone. Many of these opportunities would result in only small-sized facilities with lower capacity output compared to Unit 3. A combination of such a facility with a non-renewable fuel facility also has land impacts in the case of fuel crops. In addition, the combination of biomass, wood waste, or fuel crops and a non-renewable fuel facility is not a viable or reasonable alternative to Unit 3.

MSW and Non-Renewable Fuels

As described in Section 9.2.2.1.4, MSW projects could achieve capacity factors of 85–90 percent. However, site development of MSW projects is limited to landfill sites and is driven by waste management considerations. There are limited identified opportunities for such facilities in the Dominion Zone and a comparable-sized facility to Unit 3 would require 4.5 million tons of MSW.

Pairing a smaller facility with a non-renewable fuels facility would only proportionally reduce the amount of MSW needed for such a facility. Thus, a combination MSW and non-renewable fuel alternative is not a viable or reasonable alternative to Unit 3.

9.2.2.4.2 Combinations of Alternatives Involving Non-Renewable Fuels

Any combination of coal- and natural gas-fired facilities would have the characteristics set forth in Section 9.2.3. In the analysis presented in Section 9.2.3, neither coal- nor natural gas-fired generation is environmentally preferable to Unit 3. Thus, no combination of coal- and natural gas-fired generation will be environmentally preferable to Unit 3. Likewise, as discussed in Section 9.2.2.3.1, oil-fired generation is not a reasonable alternative to Unit 3 on an environmental or economic basis. Further because oil-fired generation has comparable emissions to a coal-fired plant, no combination of oil-, coal- or natural gas-fired facilities is environmentally preferable to Unit 3. Accordingly, combinations of non-renewable fuels are not environmentally superior to Unit 3, are already bounded by the analysis in Section 9.2.3, and therefore do not need to be assessed separately from the analysis in Section 9.2.3.

9.2.3 Assessment of Alternative Energy Sources and Systems

This section analyzes the possible alternative energy sources and systems, and evaluates their ability to have an appreciable reduction in overall environmental impact. The alternative energy sources evaluated in this section are coal and natural gas.

9.2.3.1 Coal-Fired Generation

For purposes of assessing the alternatives to Unit 3, a generic pulverized coal facility with supercritical boiler is analyzed. Specifically, the coal-fired alternative assumes three approximately 507 MW net output, pulverized coal-fired units with a wet scrubber for flue gas desulfurization (FGD) with approximately 95 percent SO_x removal efficiency, as well as low NO_x burners, overfire air, and SCR with approximately 80 percent NO_x removal efficiency. Particulate matter (PM-10) is reduced in a dry electrostatic precipitator (ESP).

The following emissions data represent pro-rated emissions assuming proxy state-of-the-art coal plants were sized similarly to Unit 3 (approximately 1500 MW) and operated at a 90 percent capacity factor burning 2.65 percent sulfur Eastern bituminous coal.

9.2.3.1.1 Air Quality Impacts

Dust emissions from construction activities for a coal-fired generation plant would be similar to those from any similar construction project. Such emissions would be temporary, mitigated using best management practices, and therefore small.

During its operating life, the emissions profile regarding air quality from coal-fired generation will vary significantly from that of nuclear power generation because of emissions of sulfur oxides (SO_x), nitrogen oxides (NO_x), carbon monoxide (CO), particulates, and other constituents. DVP has assumed generically that a plant design that would be selected and managed to minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. The estimated coal-fired alternative emissions for SO_x, NO_x, CO, and particulate matter (PM), are provided in Table 9.2-4.

Table 9.2-4 provides DVP's emissions calculation formula and estimates for three typical plant configurations, normalized to 1500 MW, which are then used to present the range of emissions for the generic plant described in Section 9.2.3.1.

Table 9.2-4 Coal-fired Power Plant Emission Calculations

Typical PC Power Plant A Emission Calculations

Typical Plant A output =	600	MW	
Typical Plant A heat rate =	8800	Btu/kW-hrs	
Typical Plant A heat input =	5280	MMBtu/hr	Heat Input = Heat Rate × Net output/1000
NAPS-U3 output =	1500	MW	(MMBtu/hr) = (Btu/kW-hrs) × (MW)/1000
Unit 3/Plant A Output ratio	2.500	ratio	
Hours per year	8760	hours/year	
Conversion factor lb/ton	2000	lb/ton	
Annual Capacity factor	90	%	

Emitted Compound	Plant A Emissions (lb/MMBtu)	Annual emission (tons) from Coal-Fired Plant Equivalent to NAPS-Unit 3 Electrical Generation						
		Emission	heat input	Hrs/ year	cap. fac	output ratio	lb/ ton	tons/ year
PM with Condensables	0.018	0.018*	5280*	8760*	0.9*	2.5/	2000 =	937
NO_x	0.04	0.04*	5280*	8760*	0.9*	2.5/	2000 =	2081
SO_2 Controlled	0.08	0.08*	5280*	8760*	0.9*	2.5/	2000 =	4163
VOC	0.0035	0.0035*	5280*	8760*	0.9*	2.5/	2000 =	182
CO	0.09	0.09*	5280*	8760*	0.9*	2.5/	2000 =	4683

Table 9.2-4 Coal-fired Power Plant Emission Calculations

Typical PC Power Plant B Emission Calculations

Typical Plant B output =	700	MW	
Typical Plant B heat rate =	8900	Btu/kW-hrs	
Typical Plant B heat input =	6230	MMBtu/hr	Heat Input = Heat Rate × Net output/1000
NAPS-U3 output =	1500	MW	(MMBtu/hr) = (Btu/kW-hrs) × (MW)/1000
Unit 3/Plant B Output ratio	2.143	ratio	
Hours per year	8760	hours/year	
Conversion factor lb/ton	2000	lb/ton	
Annual Capacity factor	90	%	

Emitted Compound	Plant B Emissions (lb/MMBtu)	Annual Emission (tons) from Coal-Fired Plant Equivalent to NAPS-Unit 3 Electrical Generation						
		Emission	**heat input**	**Hrs/ year**	**cap. fac**	**output ratio**	**lb/ ton**	**tons/ year**
PM with Condensables	0.029	0.029*	6230*	8760*	0.9*	2.143/	2000=	1526
NO_x	0.06	0.06*	6230*	8760*	0.9*	2.143/	2000=	3158
SO_2 Controlled	0.13	0.13*	6230*	8760*	0.9*	2.143/	2000=	6841
VOC	0.005	0.005*	6230*	8760*	0.9*	2.143/	2000=	263
CO	0.105	0.105*	6230*	8760*	0.9*	2.143/	2000=	5526

Table 9.2-4 Coal-fired Power Plant Emission Calculations

Typical PC Power Plant C Emission Calculations

Typical Plant C output =	800	MW	
Typical Plant C heat rate =	9000	Btu/kW-hrs	
Typical Plant C heat input =	7200	MMBtu/hr	Heat Input = Heat Rate × Net output/1000
NAPS-U3 output =	1500	MW	(MMBtu/hr) = (Btu/kW-hrs) × (MW)/1000
Unit 3/Plant C Output ratio	1.875	ratio	
Hours per year	8760	hours/year	
Conversion factor lb/ton	2000	lb/ton	
Annual Capacity factor	90	%	

Emitted Compound	Plant C Emissions (lb/MMBtu)	Annual emission (tons) from Coal-Fired Plant Equivalent to NAPS-Unit 3 Electrical Generation						
		Emission	heat input	Hrs/ year	cap. fac	output ratio	lb/ ton	tons/ year
PM with Condensables	0.04	0.04*	7200*	8760*	0.9*	1.875/	2000=	2129
NO_x	0.08	0.08*	7200*	8760*	0.9*	1.875/	2000=	4257
SO_2 Controlled	0.18	0.18*	7200*	8760*	0.9*	1.875/	2000=	9579
VOC	0.0065	0.0065*	7200*	8760*	0.9*	1.875/	2000=	346
CO	0.12	0.12*	7200*	8760*	0.9*	1.875/	2000=	6386

Table 9.2-4 Coal-fired Power Plant Emission Calculations

Typical PC Power Plant Range of Emissions

Emitted Compound	Emission Range tons/year	Plant A	Plant B	Plant C	High	Low
PM with Condensables	940–2130	937	1526	2129	2130	940
NO_x	2080–4260	2081	3158	4257	4260	2080
SO_2 Controlled	4160–9580	4163	6841	9579	9580	4160
VOC	180–350	182	263	346	350	180
CO	4680–6390	4683	5526	6386	6390	4680

Notes:

1) The above is based on a typical state-of-the-art supercritical coal fired power plant burning Eastern Bituminous coal with 0.7% to 4.0% sulfur and typical higher heating values between 12,630 to 15,600 Btu/lb.

2) The emissions are in tons/year prorated to the electrical generation output of NAPS Unit-3 (1500 MW)

3) The PM with condensable is PM10, because the air quality controls system (baghouse) removes most of the particulate matter >10 microns in size.

4) The NO_x is reduced by SCR with approximately ~80% removal efficiency.

5) Although coal-fired plants may also be subject to other air emission limits including Hg, Pb, NH_3, HCl, etc., these were not calculated.

6) Annual Capacity factor is 90%. The high, low values, and the range have been rounded to the nearest 10 tons/year.

7) Emissions are based on a base loaded plant and thus, they do not include startup or part-load emissions.

The US Environmental Protection agency has indicated that the average CO_2 emissions rate for a coal-fired plant is 2249 lb/MW-hrs. Thus, an approximately 1500 MW coal-fired plant would emit approximately 13.5 million tons of CO_2 annually. The supporting calculations are provided in Table 9.2-5.

Table 9.2-5 CO_2 Emissions of Coal Technologies

Coal (Assumes Annual Capacity Factor of 90%)

Emissions Rate: 2,249 lb/MW-hrs[a]

Annual CO_2 Emissions:

$$2249\text{lb/MW-hrs} \times \frac{1}{2000}\text{ton/lb} \times 1500\text{ MW} \times 90\% \times 8760\text{ hours/year} = 13{,}298{,}337\text{ tons/year}$$

a. Reference 41

9.2.3.1.2 Water Quality and Use

DVP expects that a coal-fired alternative would use conventional mechanical draft cooling towers. DVP forecasts that plants may have a range of water consumption, and three examples of water consumption are provided in Table 9.2-6.

Table 9.2-6 Coal-Fired Power Plant Water Consumption

Coal Fired Plants				
	Plant MW	Total Use (gpm)	Use Per MW (gpm)	Use per MW (Rounded per Section 3.3) (gpm)
Example 1	858	8477	9.88	9
Example 2	1600	18150	11.34	11
Example 3	568	7969	14.03	15

Blowdown from the cooling towers and other plant discharges would meet limits established in a VPDES permit. Accordingly, the impact of such discharges on water quality and aquatic life would be small.

Impacts to aquatic resources and water quality would be minimized through the use of mechanical draft towers. Consumptive use of water could be considered small to moderate depending on plant location and application of further mitigation measures. Consumptive water use would not differ significantly from a similarly sized nuclear unit with the same cooling water system.

9.2.3.1.3 Coal Combustion Byproduct (CCB) Management

DVP concurs with the GEIS assessment that the coal-fired alternative would generate substantial solid waste.[1] DVP's calculations regarding the range of CCB produced are set forth in Table 9.2-7.

1. Reference 37, Section 8.3.9.

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Supercritical Plant Ash Generation Rate Calculations

	Typical Plant A	Typical Plant B	Typical Plant C
Net Electrical Output (E), MW	600	700	800
Plant Heat Rate (HR), BTU/kW-hr	8800	8900	9000
Coal Higher Heating Value (HV) - Low, BTU/lb	12630	12630	12630
Coal Higher Heating Value (HV) - High, BTU/lb	15600	15600	15600
Coal Firing Rate (F) - Low, tons/hr	169	200	231
Coal Firing Rate (F) - High, tons/hr	209	247	285
Percent Ash,% (Attachment 4)	3.3	9.1	11.2
Ash Generation Rate (A) - Low, tons/hr	5.6	18.2	25.8
Ash Generation Rate (A) - High, tons/hr	6.9	24.7	31.9
Annual Ash Recovery - Low, tons/yr	43985	143116	203567
Annual Ash Recovery - High, tons/yr	54328	194253	251437
Plant Power Adjustment Ratio (equal to 1500 MW divided by the rating of the Typical Plant, MW)	2.500	2.143	1.875
Equivalent Annual Recovery 1500 MW - Low, tons/yr	109963	306676	381689
Equivalent Annual Recovery 1500 MW - High, tons/yr	135821	416256	471444
Equivalent Annual Recovery per MW Net Output - Low, tons/yr	73	204	254
Equivalent Annual Recovery per MW Net Output - High, tons/yr	91	278	314

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Supercritical Plant Ash Generation Rate Calculations

	Typical Plant A	Typical Plant B	Typical Plant C

$$F = \frac{(E)MW(HR)\,{}^{BTU}\!/_{kWhr}(1000)\,{}^{kW}\!/_{MW}}{(HV)\,{}^{BTU}\!/_{lb}(2000)\,{}^{lb}\!/_{ton}} = \frac{(E)(HR)}{2(HV)}\,{}^{tons}\!/_{hr}$$

$$A = \frac{(\%\,Ash)(F)}{100}\,{}^{tons}\!/_{hr}$$

Annual Ash Recovery = $\frac{(0.9)(8760)\,{}^{hr}\!/_{yr}\,(99.9)\%\,(A)\,{}^{tons}\!/_{hr}}{(100)\%} = \frac{(0.9)(8760)(99.9)}{100}\,{}^{tons}\!/_{yr}$

These results are based on the following assumptions:

1. The plant capacity factor is assumed to be 90% based on Owner input.

2. The ash recovery efficiency is assumed to be 99.9%.

3. Plant heat rates are assumed to range from 8800 BTU/kW-hrs to 9000 BTU/kW-hrs.

4. Two values of coal higher heating value are assumed: 12,630 BTU/lb and 15,600 BTU/lb.

5. Assumed low, intermediate, and high values of ash content in the coal are obtained from Table 17 of *Steam/its generation and use*, 39th Edition, Babcock and Wilcox for coals ranked 9, 10, and 8, respectively.

6. All calculations are for continuous base load operation and do not include startup, shutdown and/or part load operation.

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant A- Gypsum production

Typical Plant A Output	600	MW net
Typical Plant A heat rate	8800	Btu/kW-hrs
NAPS U3	1500	MW net
Plant size ratio	2.5	ratio
Capacity factor	90	%
Hours of opp. per year	8760	hrs/year
SO_2 removal rate	98	%
Limestone purity	95	%
Limestone Utilization factor	97	%
Coal sulfur content	0.7	%

Molecular weights	
Sulfur	32.064
SO_2	64.06
$CaCO_3$	100.09
Gypsum	172.174
lb/ton conversion	2000

Heat Input =	Heat Rate	×	Net Output/1000
(MMBtu/hr) =	(Btu/kW)	×	(MW) / 1000

	Net Output	Heat Input		Coal heating value	Coal firing rate		Gypsum Production		Limestone Usage	
	MW		mmBtu/hr	Btu/lb		lb/hr	tons/year		tons/year	
Typical Plant A	600		5,280.00	15,600	5280x1E6/15600=	338,462	49,147.33		31,004.71	
NAPS U3 estimates:	1500	5280*2.5 =	13,200.00	15,600	13200x1E6/15600=	846,154	49147.33*2.5=	122,868	31004.71*2.5=	77,512

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant A- Gypsum production

		Typical Plant A calculations:				
Sulfur load to firing chamber	=	0.007*	338,462	=	2,369	lb/hr
	Net Output	Heat Input		Coal heating value	Coal firing rate	
	MW		mmBtu/hr	Btu/lb		lb/hr
		2369/	32.064	=	73.89	lb-moles/hr
SO_2 in flue gas	=	73.89*	64.06	=	4,733	lb/hr
$S + O_2 \rightarrow SO_2$						

SO_2 captured and reacted	=	0.98*	4,733	=	4,639	lb/hr
		4639/	64.06	=	72.41	lb-moles/hr
SO2 reaction with gypsum production						
$SO_2+CaCO_3 + ½O_2 + 2H_2O\ (CaSO_4.2H_2O)+ CO_2$						
Only reaction considered						
$CaCO_3$ consumed	=	72.41*	100.09	=	7,248	lb/hr
Considering limestone purity and utilization factors						
Limestone required	=	7248/	0.97/0.95	=	7,865	lb/hr
Limestone required annually	=	8760/2000 *0.9*	7,865	=	31,005	tons/year
Gypsum produced	=	72.41*	172.174	=	12,468	lb/hr
Gypsum produced annually	=	8760/2000 *0.9*	12,468	=	49,147	tons/year

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant B- Gypsum production

Typical Plant B Output	700	MW net
Typical Plant B heat rate	8900	Btu/kW-hrs
NAPS U3	1500	MW net
Plant size ratio	2.142857	ratio
Capacity factor	90	%
Hours of opp. per year	8760	hrs/year
SO_2 removal rate	98	%
Limestone purity	95	%
Limestone Utilization factor	97	%
Coal sulfur content	2.2	%

Molecular weights	
Sulfur	32.064
SO_2	64.06
$CaCO_3$	100.09
Gypsum	172.174
lb/ton conversion	2000

Heat Input =	Heat Rate	×	Net Output/1000
(MMBtu/hr) =	(Btu/kW)	×	(MW) / 1000

	Net Output	Heat Input		Coal heating value	Coal firing rate		Gypsum Production		Limestone Usage	
	MW		mmBtu/hr	Btu/lb	lb/hr		tons/year		tons/year	
Typical Plant B	700		6,230.00	14,115	6230x1E6/ 14115=	441,374	201,429.19		127,072.10	
NAPS U3 estimates:	1500	6230*2.142857=	13,350.00	14,115	13350x1E6/14115=	945,802	201429.19*2.142857=	431,634	127072.1*2.142857=	272,297

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant B- Gypsum production

		Typical Plant B calculations:				
Sulfur load to firing chamber	=	0.022*	441,374	=	9,710	lb/hr
		9710/	32.064	=	302.84	lb-moles/hr
SO_2 in flue gas	=	302.84*	64.06	=	19,400	lb/hr
$S + O_2 \rightarrow SO_2$						
SO_2 captured and reacted	=	0.98*	19,400	=	19,012	lb/hr
		19012/	64.06	=	296.78	lb-moles/hr
SO2 reaction with gypsum production						
SO_2+$CaCO_3$ +½O_2 + 2H_2O ($CaSO_4$.2H_2O)+ CO_2						
Only reaction considered						
$CaCO_3$ consumed	=	296.78*	100.09	=	29,705	lb/hr
Considering limestone purity and utilization factors						
Limestone required	=	29705/	0.97/0.95	=	32,235	lb/hr
Limestone consumed annually	=	8760/2000*0.9*	32,235	=	127,072	tons/year
Gypsum produced	=	296.78*	172.174	=	51,098	lb/hr
Gypsum produced annually	=	8760/2000*0.9*	51,098	=	201,429	tons/year

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant C- Gypsum production

Typical Plant C Output	800	MW net
Typical Plant C heat rate	9000	Btu/kW-hrs
NAPS U3	1500	MW net
Plant size ratio	1.875	ratio
Capacity factor	90	%
Hours of opp. per year	8760	hrs/year
SO_2 removal rate	98	%
Limestone purity	95	%
Limestone Utilization factor	97	%
Coal sulfur content	4.00	%

Molecular weights	
Sulfur	32.064
SO_2	64.06
$CaCO_3$	100.09
Gypsum	172.174
lb/ton conversion	2000

Heat Input =	Heat Rate	X	Net Output/1000
(MMBtu/hr) =	(Btu/kW)	X	(MW) / 1000

	Net Output	Heat Input		Coal heating value	Coal firing rate		Gypsum Production		Limestone Usage	
	MW	mmBtu/hr		Btu/lb		lb/hr	tons/year		tons/year	
Typical Plant C	800		7,200.00	12,630	7200x1E6/12630=	570,071	473,022.39		298,407.33	
NAPS U3 estimates:	1500	7200*1.875=	13,500.00	12,630	13500x1E6/12630=	1,068,884	473022.39*1.875=	886,917	298407.33*1.875=	559,514

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical PC Coal Fired plant C- Gypsum production

Typical Plant C calculations:						
Sulfur load to firing chamber	=	0.04*	570,071	=	22,803	lb/hr
		22803/	32.064	=	711.17	lb-moles/hr
SO_2 in flue gas	=	711.17*	64.06	=	45,557	lb/hr
$S + O_2\ SO_2$						
SO_2 captured and reacted	=	0.98*	45,557	=	44,646	lb/hr
		44646/	64.06	=	696.94	lb-moles/hr
SO2 reaction with gypsum production						
SO_2+$CaCO_3$ +½O_2 + 2H_2O ($CaSO_4$.2H_2O)+ CO_2						
Only reaction considered						
$CaCO_3$ consumed	=	696.94*	100.09	=	69,757	lb/hr
Considering limestone purity and utilization factors						
Limestone required	=	69757/	0.97/0.95	=	75,699	lb/hr
Limestone required annually	=	8760/2000*0.9*	75,699	=	298,407	tons/year
Gypsum produced	=	696.94*	172.174	=	119,996	lb/hr
Gypsum produced annually	=	8760/2000*0.9*	119,996	=	473,022	tons/year

Table 9.2-7 Coal-Fired Power Plant Ash Generation

Typical Supercritical PC Fired plant

Gypsum Production & Limestone Consumption summary:

	Annual Range	Plant A	Plant B	Plant C	High	Low
	Tons/year	**Tons/year**	**Tons/year**	**Tons/year**	**Tons/year**	**Tons/year**
Gypsum Produced	123000 - 887000	122,868	431,634	886,917	887,000	123,000
Limestone Consumed	78000 - 560000	77,512	272,297	559,514	560,000	78,000

Notes:

1) The calculation is based on Eastern Bituminous Coal with a typical sulfur content of 0.7 to 4.0% (0.7%, 2.2%, & 4.0% used) typical higher heating values of 12,630 to 15,600 Btu/lb.

2) Calculation based on typical pulverized coal fired supercritical plants with heat rates between 8800 to 9000 Btu/kW-hrs.

3) The calculation uses a 90% capacity factor. All annual rates are based on the 90% capacity factor.

4) Gypsum production for typical plant is based on a 98% SO_2 removal efficiency.

5) The calculation has been corrected for the expected net output from NAPS-U3 of 1500 MW net.

6) Gypsum production for typical plant is based on a 90% dry gypsum (for landfill).

7) Limestone purity is assumed to be 95%, and utilization factor is assumed to be 97%, this is typical.

8) The High, Low, and the annual range has been rounded of to the nearest 1,000.

Based on the calculations in Table 9.2-6, DVP believes that CCB disposal for the coal-fired alternative would have moderate impacts; the impacts would be clearly noticeable, but would not destabilize resources, and that further mitigation would be unwarranted.

9.2.3.1.4 Socioeconomic Impact

A coal-fired alternative would offer a number of local and regional economic benefits including: construction jobs, permanent jobs, property taxes to its host community for the life of the facility, consumption of a large quantity of coal produced by Virginia mines, and the additional economic multiplier effect of such a project on the regional economy. Construction of a similarly-sized facility, using clean-coal technology, would have an overnight cost in the range of $2,500 to $3,000 (depending on technology and location) per kW. The construction of a generic 1500 MW coal-fired plant would offer similar incremental employment opportunities when compared to Unit 3. The GEIS estimated that a 1000 MW coal-plant would require a peak load workforce of 1200 to 2500 workers during construction.[1] Given that the alternative described in this section is larger than 1000 MW, DVP expects that the construction workforce would be modestly larger than that identified by the NRC. Further operation of the plant would require permanent employment of approximately 200 plant operators. A coal project would further enhance the Virginia economy through local property tax contributions and consumption of large amounts of regional coal and limestone every year, creating approximately 360 mining jobs. In addition, like the proposed Unit 3, a coal-fired station is expected to provide significant tax revenue for the local economy. Overall, similar to Unit 3, the socioeconomic impact of a coal-fired plant would be small to moderately beneficial.

9.2.3.1.5 Other Impacts

Other impacts from a coal-fired alternative include impact on terrestrial habitat on approximately 300 acres for the construction of the power block and coal storage area. As with any large construction project, some erosion, sedimentation, and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. It is assumed that construction debris from clearing and grubbing could be disposed of onsite and municipal waste disposal capacity would be available.

The GEIS indicates that a 1000 MW coal-fired facility would require approximately 1700 acres which is comparable to the total NAPS site area.[2] Moreover, even if sited elsewhere, beneficial reuse of land formerly used for surface coal mining or other mine related activities may be possible, minimizing land use and impacts on terrestrial habitat and other ecological resources.

Air emissions would be required to meet standards established under the Clean Air Act. These standards are established at levels deemed protective of the public health. Accordingly, health

1. Reference 37, Section 8.3.9 and Reference 45, Section 8.2.1.
2. Reference 37, Section 8.3.9 and Reference 45, Section 8.2.1.

impacts would be small. The potential for accidents affecting public health or the environment is also small.

The plant structures would be an incremental visual impact. Plant operations and routine noise would also contribute to an impact on aesthetics. Such impact could range from small to moderate depending on plant location and mitigation measures.

Impacts on cultural resources would not be markedly different from impacts associated with other alternative generating facilities of similar size. With proper consideration of cultural resources during siting, and appropriate survey and recovery techniques during construction, such impacts would be small.

9.2.3.1.6 **Conclusion**

Current supercritical coal plant designs, utilizing FGD, SCR and ESP equipment, provide a substantial reduction in airborne emissions when compared to a traditional pulverized coal unit without such emission reduction technologies. However, even with the advanced design for emission reduction systems, a coal plant would not appreciably reduce the environmental impacts relative to proposed Unit 3. As a result, DVP concludes that a supercritical pulverized coal plant is not environmentally preferable to the proposed project.

9.2.3.2 **Natural Gas**

For purposes of assessing the generic alternatives to Unit 3, and in part based on equipment availability, a standard gas-fired facility is used as a proxy. Specifically, DVP has based this analysis on a three unit natural-gas-fired, combined-cycle plant, with each unit generating approximately 500 MW of net capacity. Each unit consists of two 165 MW gas turbines (e.g., General Electric Frame 7FA), and two heat-recovery steam generators followed by a nominal 170 MW capacity Steam Turbine Generator were considered for a total of approximately 1500 MW net. DVP based its emission control technology and emission control assumptions on alternatives that the EPA has identified as being available for minimizing emissions. The facility is assumed to include SCR with steam/water injection with 80 percent removal efficiency.

DVP has assumed that there would be sufficient natural gas available although no studies have been undertaken to confirm that sufficient baseload gas supplies could be economically delivered.

While combined-cycle technology is a potential source of baseload generation due to its mature technology and efficient operating characteristics, the costs of natural gas have become very volatile in recent years making it a less attractive source of baseload power than the proposed Unit 3. Moreover, as noted in Section 8.0.1.2, natural gas plants have accounted for more than 90 percent of all new electric generating capacity added in the U.S. over the past five years. Natural gas has many desirable characteristics and should be part of, but not dominate, the fuel mix because "over-reliance on any one fuel source leaves consumers vulnerable to price increases, volatility and supply disruptions." (Reference 42)

9.2.3.2.1 **Air Quality Impacts**

Natural gas is a relatively clean combusting fossil fuel. High efficiency is achieved in a combined cycle operation through the utilization of a heat recovery steam generator. With little or no firing of natural gas into the heat recovery steam generator, the combined cycle alternative would have similar types of emissions to those of the coal-fired alternative.

Table 9.2-8 and Table 9.2-9 summarize the emissions estimates for the combined-cycle gas alternative, assuming a capacity factor of 90 percent.

Table 9.2-8 Gas-Fired Generation (Combined-Cycle) Operational Characteristics

Assumption	Source
Station Capacity 1500 MW (net)	Assumed Capacity of three combined-cycle units
Heat Rate 7000 Btu/kW-hrs	DVP's experience with similar units
Primary Fuel Natural Gas	
Emissions Control Technology SCR (Selective Catalytic Reduction)	
Emissions Removal Rate (Reference 39) 80%	Assumed Removal Rate for NO_x and CO
NO_x Emissions Rate (References 43 and 44) 0.01 lb/MMbtu	Water-steam injection with SCR- control technology
SO_x Emissions Rate (Reference 40) 0.0034 lb/MMbtu	
CO Emissions Rate (Reference 40) 0.006 lb/MMbtu	Water-steam injection with SCR- control technology
PM-10 Emissions Rate (References 43 and 44) 0.011 lb/MMbtu	
VOC Emissions Rate (Reference 40) 0.0021 lb/MMbtu	
Capacity Factor (High) 90%	

Table 9.2-9 Emissions Logic – Gas-fired Combined Cycle, 90% Capacity Factor

Annual Gas Burn

$$1500\ \text{MW} \times \frac{7000\ \text{BTU}}{\text{kW-hr}} \times \frac{1\ \text{MMBTU}}{10^6\ \text{BTU}} \times \frac{1000\ \text{kW}}{1\ \text{MW}} \times \frac{90\%}{\text{Capacity Factor}} \times \frac{8760\ \text{hours}}{1\ \text{year}} = 82{,}782{,}000\ \text{MMBTU/year}$$

NO_x Emissions

$$\frac{0.01\ \text{lb}}{\text{MMBTU}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times \frac{82{,}782{,}000\ \text{MMBTU}}{\text{year}} = 414\ \text{tons/year}$$

SO_x Emissions

$$\frac{0.0034\ \text{lb}}{\text{MMBTU}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times \frac{82{,}782{,}000\ \text{MMBTU}}{\text{year}} = 141\ \text{tons/year}$$

CO Emissions

$$\frac{0.006\ \text{lb}}{\text{MMBTU}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times \frac{82{,}782{,}000\ \text{MMBTU}}{\text{year}} = 248\ \text{tons/year}$$

PM-10 Emissions

$$\frac{0.011\ \text{lb}}{\text{MMBTU}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times \frac{82{,}782{,}000\ \text{MMBTU}}{\text{year}} = 455\ \text{tons/year}$$

VOC Emissions

$$\frac{0.0021\ \text{lb}}{\text{MMBTU}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times \frac{82{,}782{,}000\ \text{MMBTU}}{\text{year}} = 87\ \text{tons/year}$$

Clean Air Act requirements and the Virginia Department of Environmental Quality's regulations are also applicable to the gas-fired generation alternative. Air quality impacts would therefore be moderate, but any emission from a natural gas-fired combined cycle unit would be in excess of those from nuclear generation.

The US Environmental Protection Agency has indicated that the average CO2 emissions rate for a gas-fired plant is 1135 lb/MW-hrs. Thus, an approximately 1500 MW gas-fired unit would emit approximately 6.7 million tons annually. The supporting calculations are provided in Table 9.2-10.

Table 9.2-10 CO_2 Emissions of Natural Gas Technologies

Natural Gas (Assumes Annual Capacity Factor of 90%)

Emissions Rate: 1,13 lb/MW-hrs (Reference 41)

Annual CO_2 Emissions:

$$\frac{1135\text{ lb}}{\text{MW-hr}} \times \frac{1\text{ ton}}{2000\text{ lb}} \times 1500\text{ MW} \times 90\% \times \frac{8760\text{ hours}}{\text{year}} = 6{,}711{,}255\text{ tons/year}$$

Like a coal or nuclear plant, construction of a gas-fired unit would result in some fugitive dust emissions typical of any construction project of similar size. Such impacts would be temporary, controlled by best management practices, and therefore small.

9.2.3.2.2 Water Quality and Use

DVP expects that a gas-fired combined cycle alternative would use conventional mechanical draft cooling towers. A gas-fired combined-cycle plant may have a range of water consumption, three examples of which are provided in Table 9.2-11. The consumptive use of water could be considered small to moderate depending on plant location and application of further mitigation measures.

Table 9.2-11 Recent Gas-Fired Power Plant Water Consumption

Gas Fired Plants

	Plant MW	Total Use (gpm)	Use (gpm/MW)	Use (rounded per Section 3.3) (gpm/MW)
Example 1	600	2603	4.34	4
Example 2	1611	10340	6.42	6
Example 3	514	3892	7.57	8

Blowdown from the cooling towers and other plant discharges would meet limits established in a VPDES permit. Accordingly, the impact of such discharges on water quality and aquatic life would be small.

9.2.3.2.3 **Waste Management**

Gas-fired generation generates almost no waste, with the exception of the spent catalyst used for NO_x control. DVP concludes that gas-fired generation waste management impacts would be minimal.

9.2.3.2.4 **Socioeconomic Impact**

The GEIS concluded that the construction workforce and local and state tax revenue would be smaller than a coal unit's.[1] Additionally, the construction period would be shorter than either coal or nuclear. The GEIS estimated that the full-time workforce of an approximately 1500 MW(e) plant would be 150, the lowest of any technology.[2] Based on experience DVP anticipates this number to be lower and estimates approximately 30 to 50 workers for a plant this size. However, socioeconomic impacts would result from the workforce needed to operate the gas-fired facility, as well as local tax revenues from the facility.

9.2.3.2.5 **Other Impacts**

The GEIS estimated that 110 acres would be needed for a plant site.[3] In addition to site specific impact, the terrain near the site may be affected by the underground construction of a natural gas pipeline. To the extent practicable, the pipeline route would utilize previously disturbed rights-of-way to minimize impacts. The pipeline construction management practices would be expected to minimize soil loss and restore vegetation immediately after the excavation is backfilled. There would be some disturbance of wildlife and habitat during pipeline construction. DVP expects these impacts would be minimized and that they would not result in a long-term reduction in the local or regional diversity of plants and animals.

Air emissions would be required to meet standards established under the Clean Air Act. These standards are established at levels deemed protective of the public health. Accordingly, health impacts would be small. The potential for accidents affecting public health or the environment is also small.

The plant structures would be an incremental visual impact. Plant operations and routine plant noise would contribute to a small aesthetic impact.

Impacts on cultural resources would not be markedly different from impacts associated with other alternative generating facilities of similar size. With proper consideration of cultural resources during siting, and appropriate survey and recovery techniques during construction, such impacts would be small.

1. Reference 45, Section 8.2.2
2. Reference 37, Section 8.3.10; Reference 45, Section 8.2.2
3. Reference 37, Section 8.3.10; Reference 45, Section 8.2.2

9.2.3.2.6 Conclusion

Current combined cycle plant designs, utilizing low NO_x burners and SCR equipment, provide for minimal airborne emissions. However, even with heat recovery steam generators, the advanced design for power generation realized in a combined cycle plant would not appreciably reduce the environmental impacts relative to proposed Unit 3. As a result, DVP concludes that a gas-fired combined cycle plant is not environmentally preferable to the proposed Unit 3 project.

9.2.4 Conclusion

As analyzed in this Chapter 9, based on environmental impacts, DVP has concluded that neither a coal-fired nor a gas-fired plant would provide an appreciable reduction in overall environmental impact relative to a nuclear plant and neither is environmentally preferable to the proposed Unit 3.

Table 9.2-12 Impacts Comparison Summary

Impact Category	Proposed Action Unit 3	Coal-Fired Generation	Gas-Fired Generation
Land Use	Small	Small	Small
Water Quality/Use	Small	Small to Moderate	Small to Moderate
Air Quality	Small	Moderate	Moderate
Ecological Resources	Small	Small	Small
Threatened and Endangered Species	Small	Small	Small
Human Health	Small	Small	Small
Socioeconomics	Small to Moderately Beneficial	Small to Moderately Beneficial	Small to Moderately Beneficial
Waste Management	Small	Moderate	Small
Aesthetics	Small	Small to Moderate	Small
Cultural Resources	Small	Small	Small
Accidents	Small	Small	Small

Notes:

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

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

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

Section 9.2 References

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9.3 Alternative Sites

Alternative sites are evaluated in ESP-ER Section 9.3 and finally resolved in FEIS Section 9.3. In accordance with 10 CFR 51.92(e)(3), and consistent with SECY-06-0220 at p.7, no further discussion is required.

9.4 Alternative Plants and Transmission Systems

The information for this section is provided in ESP-ER Section 9.4, and the evaluation of system design alternatives for heat dissipation systems and circulating water systems is resolved in FEIS Section 8.2.

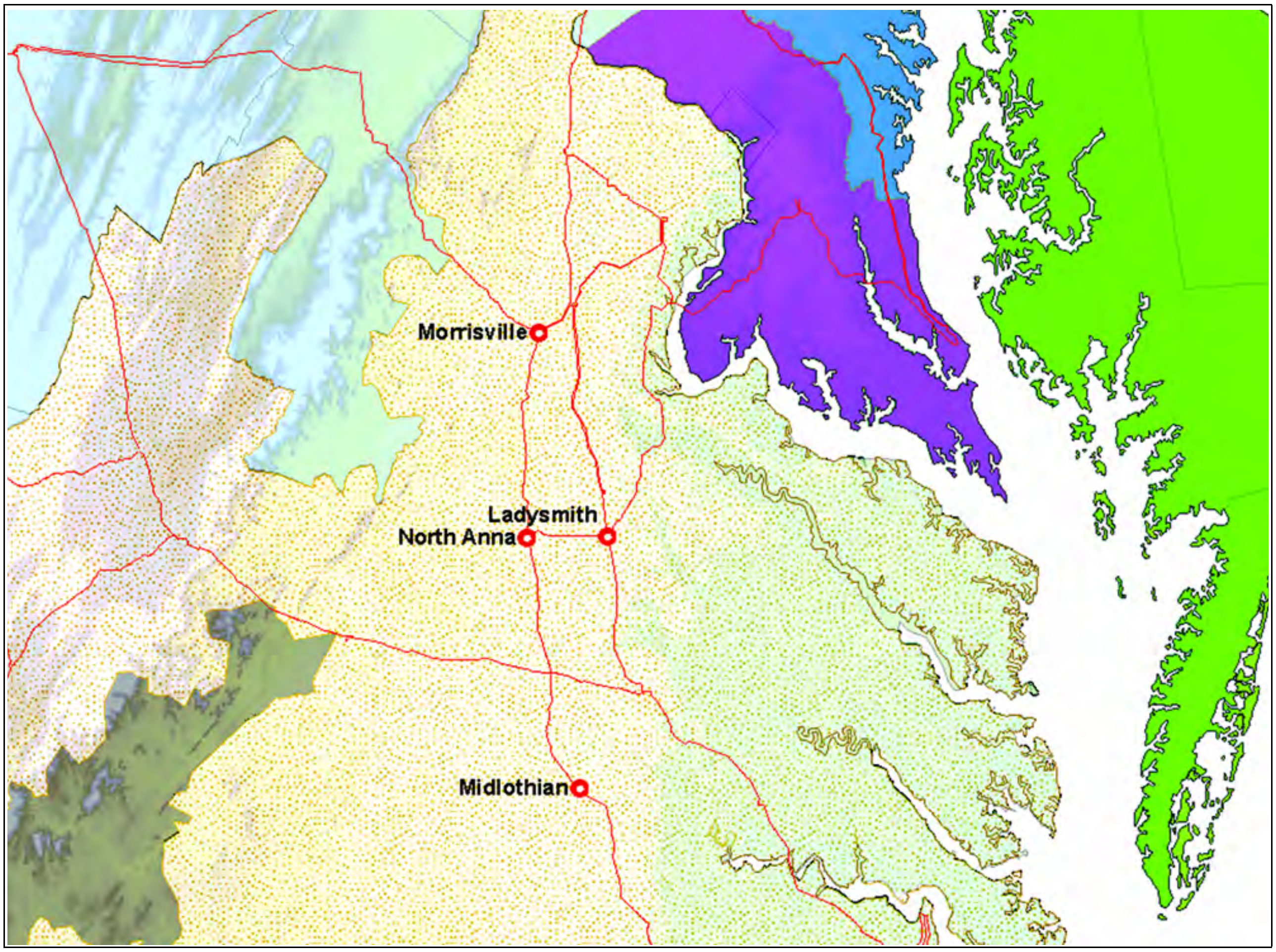
At the time of the ESP-ER and based on an initial evaluation, the existing transmission lines were thought to have sufficient capacity for the total output of the existing and new units. On that basis, it was determined that there were no environmentally equivalent or more advantageous alternatives to “no action.” However, it has now been determined that a new transmission line and other system reinforcements are required for grid reliability in association with the interconnection of Unit 3. Thus, the ESP-ER discussion is supplemented by the following information concerning the transmission lines.

PJM Generator Interconnection Q65 North Anna 500kV (1594 MW) System Impact Study (Reference) determined that an additional 500 kV transmission line from the North Anna Substation to the Ladysmith Switching Substation is required for grid stability in association with the interconnection of Unit 3. As part of the study, three existing corridors were considered for this new line: 1) NAPS-to-Ladysmith (east); 2) NAPS-to-Midlothian (south); and 3) NAPS-to-Morrisville (north) (see Figure 9.4-1). Only these corridors were considered because they would require no new land use and they already connect to NAPS at the 500 kV level. Construction of new 500 kV substations would be cost-prohibitive and require more land use.

The PJM Study selected the NAPS-to-Ladysmith (east) corridor as the best alternative because it is sufficiently wide for a new 500 kV line, including the space needed for structure separation. Additionally, it is the shortest existing corridor. The NAPS-to-Midlothian (south) and NAPS-to-Morrisville (north) corridors are at least twice the length of the NAPS-to-Ladysmith corridor.

Because new transmission corridors are not required, the impacts of the new transmission line will be SMALL as described in Sections 4.1, 4.2, 4.3, 4.4, 5.1, and 5.6. New corridors for the new transmission line would pose greater impacts on land use, ecological systems, cultural resources, and local populations. Thus, the development of a new transmission corridor for installation of the new 500 kV line is not an environmentally preferable alternative.

Figure 9.4-1 Existing Corridors or Routes Considered for the New North Anna Transmission Line



Section 9.4 References

PJM Generator Interconnection Q65 North Anna 500kV (1594 MW) System Impact Study, PJM System Planning Division, June 2007.

Chapter 10 Environmental Consequences of the Proposed Action

The potential environmental consequences of constructing and operating new units at the NAPS site are discussed in the ESP-ER Chapter 10 and associated issues are resolved in FEIS Section 10.1 and discussed in FEIS Sections 10.2, 10.4, and 10.5. Supplemental information is provided below.

10.1 Unavoidable Adverse Environmental Impacts

This section addresses the additional environmental impacts that have been identified in this ER.

10.1.1 **Unavoidable Adverse Environmental Impacts During Construction**

Table 10.1-1 lists the expected impacts from the construction of proposed Unit 3, and the mitigation measures that are practical to reduce these impacts. Those instances where adverse environmental impacts would remain after all reasonable means have been taken to avoid or mitigate them are identified in Table 10.1-1. A "Y", under the column labeled "Unavoidable Adverse Impacts" indicates that there are such impacts, and "N" indicates that the specified mitigation measures are sufficient to reduce the impacts to insignificant or small.

10.1.2 **Unavoidable Adverse Environmental Impacts During Operation**

Table 10.1-2 lists the expected impacts from the operation of proposed Unit 3, and the mitigation measures that are practical to reduce these impacts. Those instances, where adverse environmental impacts would remain after practical means to avoid or mitigate them have been applied, are identified in Table 10.1-2. A "Y" under the column labeled "Unavoidable Adverse Impacts" indicates that there are such impacts, and "N" indicates that the specified mitigation measures are sufficient to reduce the impacts to insignificant or small.

10.1.3 **Summary of Adverse Environmental Impacts**

As may be seen from Table 10.1-1 and Table 10.1-2, all the newly identified potential adverse environmental impacts associated with construction and operation of the proposed Unit 3 are reduced to insignificant or eliminated through the application of the listed mitigation measures. These mitigation measures, as well as those identified in the ESP-ER, are incorporated into the EPP.

10.1.4 **Irreversible and Irretrievable Commitment of Resources**

Irreversible or irretrievable commitment of resources are addressed in Section 10.2.

Table 10.1-1 Newly Identified Construction-Related Unavoidable Adverse Environmental Impacts

Category/ ER Section	Construction-Related Issue/ Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
The Site and Vicinity Section 4.1.1	Modifications to offsite roadways, bridges, and railway crossings to accommodate heavy hauls – Additional land use outside NAPS site boundary.	Upon completion of the transports, temporary structures would be removed, interferences would be reinstalled, and disturbed areas would be restored back to their original condition or better.	N
Transmission Line Rights-of-Way and Offsite Areas Section 4.1.2	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Additional land use outside North Anna site boundary.	The new transmission line would be located in an existing corridor and constructed and maintained under practices and procedures applicable to the existing transmission lines.	N
Transmission Line Rights-of-Way and Offsite Areas Section 4.1.2	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Additional land use outside North Anna site boundary.	Clearing methods for small trees, bushes and vegetation would be performed in a manner which would protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately three inches in diameter and above would be removed from the buffer, leaving material less than three inches undisturbed.	N
Transmission Line Rights-of-Way and Offsite Areas Section 4.1.2	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Additional land use outside North Anna site boundary.	Once all the construction of transmission lines has been completed, Dominion would restore disturbed areas by means such as: 1) rehabilitating land by discing, fertilizing, seeding, and installing erosion control devices (e.g., water bars and mulch); 2) properly removing and disposing debris left or caused by construction; and 3) restoring damaged property to its original condition and to the satisfaction of the property owner.	N

Table 10.1-1 Newly Identified Construction-Related Unavoidable Adverse Environmental Impacts

Category/ ER Section	Construction-Related Issue/ Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Transmission Line Rights-of-Way and Offsite Areas Section 4.1.2	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to cultural or prehistoric resources.	Appropriate actions would be taken (e.g., stop work) following discovery of potential historic or archeological resources.	N
Surface Water Hydrologic Alterations Section 4.2.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impact to surface water bodies and wetlands.	Clearing methods for small trees, bushes and vegetation would be performed in a manner which protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately three inches in diameter and above would be removed from the buffer, leaving material less than three inches undisturbed.	N
Surface Water Hydrologic Alterations Section 4.2.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impact to surface water bodies and wetlands.	To the extent practicable, construction would avoid shorelines and wetland areas. Should wetlands be impacted, the U.S. Army Corps of Engineers (and other appropriate agencies) would be consulted, and permits and approvals would be obtained as necessary.	N
Surface Water Hydrologic Alterations Section 4.2.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impact to surface water bodies and wetlands.	Soil disturbances would be controlled within an approximately 100-foot buffer of streams and ditches with running water. Erosion and sedimentation control measures and buffer zone maintenance around water bodies to reduce runoff and erosion. These measures would be left in place, until stabilization of the area is achieved. Work sites would be stabilized prior to moving to the next area.	N

Table 10.1-1 Newly Identified Construction-Related Unavoidable Adverse Environmental Impacts

Category/ ER Section	Construction-Related Issue/ Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Hydrologic Alterations Section 4.2.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impact to surface water bodies and wetlands.	Potential impacts to streams and creeks would be mitigated by performing work related to stream crossings in accordance with state standards and specifications. In addition, streams and creeks would be crossed at right angles at one location on the corridor using culverts, temporary bridges, or large aggregate stone. Materials would be removed from the temporary crossing at the completion of the project.	N
Terrestrial Ecosystem- Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	Once all the construction of transmission lines has been completed, Dominion would restore disturbed areas by means such as: (1) rehabilitating land by discing, fertilizing, seeding, and installing erosion control devices (e.g. water bars and mulch); (2) properly removing and disposing debris left or caused by construction; and (3) restoring damaged property to its original condition and to the satisfaction of the property owner.	N
Terrestrial Ecosystem- Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	The new transmission line would be located in an existing corridor and constructed and maintained under practices and procedures applicable to the existing transmission lines.	N
Terrestrial Ecosystem- Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	Clearing methods for small trees, bushes and vegetation would be performed in a manner which would protect natural resources and control erosion of the landscape and siltation of streams. Trees and brush located within an approximately 100-foot buffer of a stream or ditch with running water would be hand-cleared and material approximately three inches in diameter and above would be removed from the buffer, leaving material less than three inches undisturbed.	N

Table 10.1-1 Newly Identified Construction-Related Unavoidable Adverse Environmental Impacts

Category/ ER Section	Construction-Related Issue/ Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Terrestrial Ecosystem-Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	Land clearing necessary to accommodate the new transmission tower foundations would be controlled by existing transmission line procedures, good construction practices, and established best management practices, as well as applicable regulations.	N
Terrestrial Ecosystem-Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	Soil disturbances would be avoided or reduced to the extent practicable within an approximately 100-foot buffer of streams and ditches with running water. Erosion and sedimentation control measures and buffer zone maintenance around water bodies would be implemented to reduce runoff and erosion. These measures would be left in place, until stabilization of the area is achieved. Work sites would be stabilized prior to moving to the next area.	N
Terrestrial Ecosystem-Transmission Corridors Section 4.3.1.1	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts to terrestrial ecosystem.	Dust suppression techniques would be utilized and equipment maintenance employed to reduce airborne emissions	N
Socioeconomic Impacts Section 4.4	Based on a recent evaluation of the existing transmission lines, network improvements would be required to reliably connect Unit 3. This would include an additional 500 kV line, and associated equipment. – Potential impacts on public access to the area for recreational activities.	As a safety precaution, during installation of the transmission line across Lake Anna, access to the area would be temporarily restricted from recreational use.	N

Table 10.1-2 Newly Identified Operations-Related Unavoidable Adverse Environmental Impacts

Category/COL ER Section	Operations-Related Issue/Adverse Environmental Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Water-Use Impacts Section 5.2.2	A new wet cooling tower and separate sanitary waste system would be added for Unit 3 – Potential for additional chemical effluents.	Nonradioactive effluents, including sanitary waste and blowdown from the Unit 3 cooling towers, would be governed by limits established in VPDES permit.	N
Water-Use Impacts Section 5.2.2	A new wet cooling tower and separate sanitary waste system would be added for Unit 3 – Potential for additional chemical effluents.	Operation of a dechlorination system to neutralize chlorine in the circulating water and plant service water cooling tower blowdown before discharge to the WHTF and eventually to the North Anna Reservoir. (Section 5.2.2)	N
Nonradioactive-Waste-System Impacts Section 5.5.1	Separate Unit 3 sanitary waste system would be added – Potential for additional chemical effluents.	Sanitary wastes from the new sanitary system will be managed on site and disposed of off site in compliance with applicable laws, regulations, and permit conditions imposed by federal, Virginia, and local agencies (Section 5.5.1)	N
Nonradioactive-Waste-System Impacts Section 5.5.1	A new wet cooling tower and separate sanitary waste system would be added for Unit 3 – Potential for additional chemical effluents.	Nonradioactive effluents, including sanitary waste and blowdown from the Unit 3 cooling towers, would be governed by limits established in VPDES permit.	N

10.2 Irreversible and Irretrievable Commitments of Resources

Irreversible and irretrievable commitments of resources are addressed in ESP-ER Section 10.2 and were resolved in FEIS Section 10.5, with the exception of an actual estimate of construction materials. The following supplemental information is provided to address the estimate of construction materials.

The irreversible and irretrievable commitments of material resources during the construction of proposed Unit 3 would be similar to that of any major construction project. Unlike the earlier generation of nuclear power plants, asbestos and materials considered hazardous will not be used, in accordance with safety regulations and practices. A Department of Energy report (Reference) provides the following new reactor construction estimates:

- 12,239 cubic yards of concrete and 3,107 tons of rebar for a reactor building
- 2,500,000 LF of cable for a reactor building
- 6,500,000 LF of cable for a single unit
- Up to 275,000 LF of piping (≥2.5") for a single 1300 MWe unit

The amounts of these materials are typical of other large power-generating facilities, such as hydroelectric and coal-fired power plants, that are constructed throughout the United States. The use of construction materials in the quantities associated with those expected for a nuclear power plant, while irreversible and irretrievable unless they are recycled at decommissioning, would be of small consequence, with respect to the availability of such resources.

The conclusion in the FEIS that the irreversible and irretrievable commitments would be of only small consequence will remain valid.

Section 10.2 References

Application of Advanced Construction Technologies to New Nuclear Power Plants, MPR-2610, Rev. 2, September 24, 2004, U.S. Department of Energy, Washington, D.C.

10.3 Relationship Between Short-Term Uses and Long-Term Productivity of the Human Environment

The relationship between short-term uses and long-term productivity of the human environment is addressed in ESP-ER Section 10.3. Further information on the benefits of the proposed action is provided in Chapter 8.

The principal short-term benefit of construction and operation of the proposed Unit 3 would be the production of electricity. The enhancement of regional productivity resulting from the electricity produced by Unit 3 would not be equaled by any other use of the NAPS site. In addition, most long-term impacts resulting from land-use preemption by plant structures would be eliminated by removing these structures or by converting them to other productive uses during decommissioning.

No new unavoidable adverse environmental impacts of construction and operation of the proposed Unit 3 have been identified to have significant impact on long-term productivity. Therefore, none of the adverse environmental impacts represent a long-term effect that would preclude any options for future use of the NAPS site.

10.4 Benefit – Cost Balance

The benefits and costs associated with construction and operation of proposed Unit 3 are summarized in Tables 10.4-1 and 10.4-2, respectively.

10.4.1 Benefits

The evaluation of monetary and non-monetary benefits of constructing and operating proposed Unit 3, including benefits related to tax revenues and to local and state economies, is provided in Chapter 8. These benefits are summarized in Table 10.4-1.

10.4.2 Costs

This section identifies both internal and external costs associated with the construction and operation of proposed Unit 3. The term "internal" generally refers to the monetary costs associated with a project, while the term "external" refers to non-monetary environmental costs of constructing and operating a new plant. These costs are summarized in Table 10.4-2.

Many of the cost attributes described in this section are detailed in Section 10.1 (Unavoidable Adverse Environmental Impacts), Section 10.2 (Irreversible and Irretrievable Commitments of Resources), and Section 10.3 (Relationship Between Short-term Uses and Long-term Productivity of the Human Environment) of the ESP-ER and this ER.

10.4.2.1 Internal Costs

This section describes the monetary costs of constructing and operating the proposed Unit 3. Internal costs include capital costs of the plant and transmission lines and operating costs, including staffing and maintenance (O&M), and fuel, as well as decommissioning costs.

10.4.2.1.1 Construction

The estimated cost of constructing Unit 3 is provided in COLA Part 1.

10.4.2.1.2 Operation

The U.S. Department of Energy study (Reference 2, Table 3.9, p. 111) estimates the annual O&M costs of a 1340 MWe ESBWR plant to be $74,178,482, which is calculated as $6.83 per MW-hr. This cost is expressed as unit of electric net generation, or megawatts electric, and reflects all costs that are incurred to operate and maintain the plant. Included in this cost are salaries and benefits for the plant staff, parts, material and equipment costs for maintaining plant equipment, fees, insurance, overhead costs, and short-term contract services.

Nuclear fuel cost and decommissioning cost are calculated separately. The Organisation for Economic Co-Operation and Development (OECD) Study (Reference 1, Table 3.9, p. 44) estimates that the average fuel cost for a nuclear generating plant is $4.64 per MW-hr at a 5 percent discount rate. A decommissioning cost estimate is provided in Part 1 of this COL Application.

10.4.2.2 External Costs

This section describes the external (non-monetary) environmental and social costs of constructing and operating proposed Unit 3. The environmental effects of construction and operation of proposed Unit 3 are described in Section 10.1 and ESP-ER Section 10.1. Details are also provided in Tables 10.1-1 and 10.1-2 of the ESP-ER and this ER regarding potential mitigation measures for each unavoidable adverse impact related to a construction or operation activity.

10.4.2.2.1 Land Use

Approximately 128 acres (52 ha) will be affected by the construction of proposed Unit 3 as a result of permanent facilities. An additional 68 acres (27.5 ha) will be disturbed on a short-term basis as a result of temporary activities and construction of temporary facilities and laydown areas. Clearing and removal of trees growing within the NAPS site will be required. Loss of land use is an external cost of the construction of Unit 3. A detailed description of land use impacts is provided in Section 4.1 and ESP-ER Section 4.1.

10.4.2.2.2 Hydrological and Water Use

Section 4.2 and ESP-ER Sections 4.2 and 5.2 describe hydrologic alterations for construction and operation. As discussed in these sections, there are some costs associated with providing water for various needs during construction and operation. The majority of water used for Unit 3 operations will be surface water drawn from the North Anna Reservoir. As resolved in FEIS Section 5.3.2, this water use represents only a small fraction of available water even at low flow conditions. The FEIS concluded that the impact of Unit 3 operation on downstream water users would be SMALL for most and MODERATE for drought years. There are also costs associated with groundwater consumption. The effects related to groundwater use are described as small (see ESP-ER

Sections 2.3.2.2 and 5.2, and FEIS Section 2.6.2). Use of groundwater by the site will not affect off-site users in terms of either water availability or water quality.

Relatively small levels of nonradioactive and radioactive effluents will be introduced into the lake. Water quality impacts of chemical effluents discharged during Unit 3 operations are discussed in Section 5.2.2 and will be SMALL. FEIS Section 5.9.3.3 resolved that effects upon humans as a result of liquid radiological effluents released from new units would be SMALL. Cooling water blowdown that discharges to the North Anna Reservoir results in a thermal plume. FEIS Section 5.4.2.4 resolved that effects of a thermal plume on Lake Anna would be SMALL and localized.

10.4.2.2.3 **Terrestrial and Aquatic Biology**

Ecological effects, related to plant construction and operation, are described in Section 4.3 and in ESP-ER Sections 4.3 and 5.3, respectively. Some cost due to mortality of wildlife during construction is anticipated. These losses are not expected to be large enough to affect the long term stability of wildlife populations. FEIS Section 5.4.1 resolved that effects on terrestrial ecosystems would be SMALL. The cooling system, in addition to the makeup water intake structures, is designed to reduce loss of aquatic biota as a result of impingement and entrainment. The construction of the new intake structure will result in only minor and temporary effects to aquatic biology. In FEIS Section 5.4.2.8, the NRC determined that effects upon aquatic ecosystems as a result of operations of new nuclear units would be SMALL.

Relatively small amounts of air emissions from diesel generators, auxiliary boilers and equipment, and vehicles are generated from nuclear power plant operation.

Cooling tower drift deposits some salt on the surrounding vicinity, but the level is unlikely to result in any measurable impact on plants and vegetation. The Unit 3 cooling towers are designed to abate atmospheric vapor plume produced.

Small amounts of hazardous effluents are components of the Unit 3 plant discharges into Lake Anna. Relatively small amounts of hazardous wastes will be generated that need to be managed and disposed of pursuant to the Resource Conservation and Recovery Act (RCRA). Section 3.6 and ESP-ER Section 3.6 discuss nonradioactive waste systems.

10.4.2.2.4 **Hazardous and Radioactive Emissions, Effluents, and Wastes**

Operation of proposed Unit 3 will include minor radioactive air emissions to the atmosphere. Relatively small levels of radioactive effluents will be generated and discharged into Lake Anna.

Low-Level radioactive wastes will be generated that need to be stored, treated, and disposed of in a licensed landfill. High-level radioactive spent fuel will be generated that will need to be isolated (or possibly reprocessed) in a geological repository for thousands or tens of thousands of years. FSAR Chapter 11 describes the radioactive waste management systems.

10.4.2.2.5 Materials, Energy, and Uranium

Construction of proposed Unit 3 will result in an irreversible and irretrievable commitment of materials and energy (see Section 10.2 and ESP-ER Section 10.2). Operation of the new reactor will contribute to the depletion of uranium.

10.4.2.2.6 Potential for Nuclear Accident

The potential effects of various types of nuclear accidents are described in FEIS Section 5.10. In Section 5.10.3, the NRC concluded that the potential environmental impacts from a postulated accident from the operation of two additional advanced light water reactor (LWR) nuclear units at NAPS would be SMALL.

10.4.2.2.7 Socioeconomic Costs

Sections 4.4 and 5.8 and ESP-ER Sections 4.4 and 5.8 describe socioeconomic costs related to construction and operation of new units at NAPS. Additional public and social services may be required to meet the demands of people moving into the area during construction and operation of the new unit at NAPS. Increased tax revenues from those individuals and from NAPS should offset these costs.

10.4.3 Summary

As described in Section 8.4, there is a growing baseload demand and growing baseload supply shortfall for the region of interest. Without additional capacity, Dominion's electricity network will fail to maintain an adequate power reserve margin, will fail to meet its public service obligations to provide adequate power, and will jeopardize Dominion's commitment to provide power to other electric service providers within the region. Proposed Unit 3 will help meet growing baseload shortfall in the region by supplying an average annual electrical-energy generation of about 12,000,000 MW-hrs.

Proposed Unit 3 is designed to generate electricity that results in significant reduction in CO_2 emissions with respect to comparably-sized coal- or gas-fired alternatives. As described in this section, proposed Unit 3 would also have important strategic implications in terms of lessening the dependence of the U.S. on foreign energy supplies, and their potential interruption, as well as vulnerability to volatile price changes or political whims. While the additional direct and indirect creation of jobs places some temporary burden on local services and infrastructure, the annual taxes and revenue generated by the new workers contribute to the local economy and fuels future growth.

On balance, the benefits of the new plant would significantly outweigh the economic, environmental, and social costs.

Section 10.4 References

1. "Projected Costs of Generating Electricity, 2005 Update," Nuclear Energy Agency, Organisation for Economic Co-operation and Development (OECD), and International Energy Agency. (www.oecdbookshop.org/)

2. "Study of Construction Technologies and Schedules, O&M Staffing and Cost, Decommissioning Costs and Funding Requirements for Advanced Reactor Designs," U. S. Department of Energy, Washington, D. C, May 27, 2004.

Table 10.4-1 Monetary and Non-Monetary Benefits of Proposed Unit 3

Category of Benefit	Description of Benefit
Net Electrical Generating Benefits	
Net Generating Capacity	~1,500 MWe
Electricity Generated (operating at 90% cap.)	~12,000,000 MW-hrs
Taxes and Revenue During Plant Operation Period (Transfer Payments – Not Independent Benefits)	
Annual State Taxes	NAPS Unit 3 pays $14.8 million.
Annual Property Taxes	NAPS Unit 3 pays $3.5 million.
Annual Sales Taxes	NAPS Unit 3 pays $24.2 million.
Effects on Regional Productivity	
Construction Workers	Approximately 2,000 workers create an incremental increase of 1,236 indirect jobs, within the region.
Operational Workers	750 workers create an incremental increase in 1,553 indirect permanent jobs within the region for at least 40 operating years.
Socioeconomics	Increased tax revenue supports improvements to public infrastructure and social services. The increased revenue spurs future growth and development.
Technical and Other Non-Monetary Benefits	
Fuel Diversity	Reduces exposure to supply and price risk associated with reliance on any single fuel source.
Price Volatility	Dampens potential for fuel price volatility.
Fossil Fuel Supplies	Offsets usage of finite fossil fuel supplies.
Electrical Reliability	Enhances electrical reliability.
Emissions Reduction	Significant beneficial impact in terms of avoidance of air emissions as shown in Table 8.0-2.
Carbon Dioxide Emissions	Baseload generation with no carbon dioxide emissions.
Wastes	Compared with fossil-fueled plants, nuclear plants produce less nonradioactive waste products.

Table 10.4-2 Internal and External Costs of Proposed Unit 3

Category of Cost	Description of Cost
Internal Costs	
Construction (Overnight Cost)	$3,000 to $4,000 per kW
Operation	$6.83 per MW-hr for O&M $4.64 per MW-hr for fuel cycle
Decommissioning (NRC Minimum)	$518,033,205
External Costs	
Land and Land Use	SMALL. Unit 3 occupies approximately 128 acres (52 ha.) of the approximately 1043 acres (422 ha.) existing NAPS site.
Hydrological and Water Use	SMALL for most years; MODERATE during drought years. There are some costs associated with providing water for various needs during construction and operation. Cooling water is taken from Lake Anna. Relatively small levels of hazardous and/or radioactive effluents introduced into Lake Anna. Thermal plume resulting from cooling water blowdown discharged to Lake Anna. The effect of consumption of cooling water is relatively small.
Terrestrial and Aquatic Species	SMALL. Some cost to wildlife due to mortality during construction operations is anticipated. However, these costs do not affect long term wildlife populations. Wildlife mortality, including aquatic biota, during operations is expected to be minimal.
Radioactive Effluents and Emissions	SMALL. Radioactive waste is generated. The plant produces radioactive air emissions. Relatively small levels of radioactive effluents are introduced into Lake Anna.
Hazardous and Radioactive Waste	SMALL. Storage, treatment, and disposal of high-level radioactive spent nuclear fuel. Commitment of underground geological resources for disposal of radioactive spent fuel.
Air Emissions	SMALL. Air emissions from diesel generators, auxiliary boilers and equipment, and vehicles that have a small impact on workers and local residents. Cooling tower drift that deposits some salt on the surrounding vicinity, but the level is unlikely to result in any measurable impact on plants and vegetation. Cooling tower atmospheric plume discharge abated with design.
Materials, Energy, and Uranium	SMALL. Irreversible and irretrievable commitments of materials and energy, including depletion of uranium.

Table 10.4-2 Internal and External Costs of Proposed Unit 3

Category of Cost	Description of Cost
Potential Nuclear Accident	SMALL. Potential risks are small.
Socioeconomics	SMALL. Construction of Unit 3 may pose additional costs to public and social services in the area. However, these costs are believed to be more than offset by increased tax revenues generated directly and indirectly by plant construction and operation.