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Dominion®

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Clerk's Office
N.C. Utilities Commission

August 31, 2011

VIA OVERNIGHT DELIVERY

Ms. Renne Vance, Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, North Carolina 27603-5918

**Re: Integrated Resource Plan of Dominion North Carolina Power
Docket No. E-100, Sub 128**

(9) W/Conf.
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Jones
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PS
Exec. Dir.
3 Legal
3 Accts
3 Elec.
2 Econ

Dear Ms. Vance:

Pursuant to N.C. Gen. Stat. § 62-2 and 62-110.1 and Commission Rule R8-60(h)(2), Virginia Electric and Power Company d/b/a Dominion North Carolina Power ("DNCP" or "Company") encloses for filing with the Commission its updates to the Integrated Resource Plan for 2011 (the "2011 IRP"). Pursuant to Rule R8-67(b), DNCP's Renewable Energy and Efficiency Portfolio Standards ("REPS") Compliance Plan is being filed with this IRP as "NC IRP Addendum 1."

Portions of the 2011 IRP contain confidential information regarding the Company's forecasts for market commodity prices, busbar costs and assumptions, construction forecasts and other proprietary information. If this information were to be publicly disclosed, it would allow competitors, vendors and other market participants to gain an undue advantage, which may ultimately result in harm to ratepayers. Therefore, enclosed are the original and thirty (30) copies of the 2011 IRP with the confidential information redacted. In addition, enclosed under separate cover marked as **"Confidential"** are the original and seventeen (17) copies of the unredacted 2011 IRP. The highlighted portions in either yellow or green shall be considered ***confidential***. DNCP will make this information available to other parties pursuant to an appropriate nondisclosure agreement. These documents are to be ***filed under seal***.

In addition, the FERC Form 715 is considered ***confidential*** because it contains critical energy infrastructure information, including the Company's transmission capacity and known constraints. In keeping with our practice last year, the Company is filing four (4) copies of the most recent FERC Form 715 ***under seal*** and respectfully requests that the Commission treat this information as ***confidential*** and protect it from public disclosure pursuant to N.C. General Stat. § 132-1.2.

This 2011 IRP is also being filed with the Virginia State Corporation Commission pursuant to Va. Code § 56-597. North Carolina and Virginia have similar requirements for IRP filings, but each requires its biennial filing in alternate years. *Pursuant to Rule R8-60(h)(2), the major changes from the 2010 IRP to* this 2011 IRP are:

- The annual load forecast is updated.

- Plan includes the conversions of three coal-fired power stations, Altavista, Hopewell, and Southampton, to biomass fuel by the end of 2013, subject to regulatory approval.
- Also, the Plan includes additional efforts to reduce emissions from the Company's existing generation fleet include plans to repower its coal-fired Bremo Units 3 and 4 with respective summer capacities of 71 MW and 156 MW in 2014, subject to regulatory approval.
- Based on the draft and final form of environmental regulations along with current market conditions, the Plan includes the following impacts to the existing generating resources in terms of retrofitting, repowering and retiring, which may be revised when the regulations are finalized:
    - Retrofit: Possum Point Unit 5 (779 MW) and Yorktown Unit 3 (804 MW) are in the Plan to be retrofitted with a SNCR unit by 2015.
    - Repower: Coal-fired Yorktown Unit 2 (156 MW) is in the Plan to be repowered by natural gas and oil by 2015.
    - Retire: Chesapeake Energy Center Units 1 (111 MW) and 2 (111 MW) and Yorktown Unit 1 (159 MW) are in the Plan to be retired by 2015. Chesapeake Energy Center Units 3 (156 MW) and 4 (217 MW) are in the Plan to be retired by 2016. Yorktown Units 2 (156 MW) and 3 (804 MW) are in the Plan to be retired by 2022. Appendix 3J lists the retirements included in the Plan.
- The Plan includes six Demand-Side Management Programs filed for approval in Virginia, including a Residential Bundle Program.
- The AMI meter deployment plans have changed.

Attached to this letter is an index identifying the provisions of the Commission's IRP requirements under Rules R8-67, R8-62(p) and the corresponding sections of the 2011 IRP.

Pursuant to the Commission's Order in Docket No. E-100, Sub 109, the Company will meet with the Public Staff within 30 days of the filing date to discuss detailed information concerning its transmission line inter-tie capabilities, transmission line loading constraints, and planned new construction and upgrades within their respective control areas for the planning period under consideration.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

Horace P. Payne, Jr.
Senior Counsel

Enclosures

Rule	Section
E-100, Sub 109, 3	4.2.2 - Long-Term Capacity Planning Process - Reserve Requirements
E-100, Sub 109, 4	Filed Separately Under Seal in this Docket
E-100, Sub 109, 5	Addressed in Cover Letter
E-100, Sub 109, 6	Appendix 3B - Other Generation Units
E-100, Sub 109, 7	5.1.3 - Assessment of Alternative Supply-Side Resources
E-100, Sub 109, 7	5.2 - Levelized Busbar Costs
E-100, Sub 109, 8	3.1.7 - Wholesale & Purchased Power
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Dominion Virginia Power's and Dominion North Carolina Power's Report of Its Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

Public Version

Case No. PUE-2011-00092
Docket No. E-100, Sub 128

Filed: September 1, 2011

DOMINION VIRGINIA POWER'S AND DOMINION NORTH CAROLINA POWER'S 2011 REPORT OF ITS INTEGRATED RESOURCE PLAN

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LIST OF ACRONYMS

Acronym	Acronym Meaning
AMI	Advanced Metering Infrastructure
APWR	Advanced Pressurized-Water Reactor
ATC	Available Transfer Capability
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
BTMG	Behind-the-Meter Generation
CC	Combined Cycle
CCS	Carbon Capture and Sequestration
CDG	Commercial Distributed Generation Program
CFB	Circulating Fluidized Bed
CFL	Compact Florescent Light
CO_2	Carbon Dioxide
COL	Combined Construction Permit and Operating License
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical Peak Pricing
CS	Curtailable Service
CSP	Concentrating Solar Power
CT	Combustion Turbine
DG	Distributed Generation
DOM LSE	Dominion Load Serving Entity
DOM Zone	Dominion Zone within the PJM Interconnection, L.L.C. Regional Transmission Organization
DSI	Dry Sorbent Injection
DSM	Demand-Side Management
EM&V	Evaluation, Measurement, and Verification
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Early Site Permit
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GSP	Gross State Product
GWh	Gigawatt Hour(s)
Hg	Mercury
HVAC	Heating, Ventilating, and Air Conditioning
ICF	ICF International, Inc.
IDR	Interval Data Recorder
IGCC	Integrated-Gasification Combined Cycle
IRP	Integrated Resource Planning
kV	Kilovolt(s)
kW	Kilowatt(s)
LOLE	Loss of Load Expectation
LSE	Load Serving Entity

Acronym	Acronym Meaning
MW	Megawatt(s)
MWh	Megawatt Hour(s)
North Anna 3	North Anna Unit 3
NCGS	North Carolina General Statute
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corporation
NO_x	Nitrogen Oxide
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NUG	Non-Utility Generation or Non-Utility Generator
ODEC	Old Dominion Electric Cooperative
PC	Pulverized Coal
PHEV	Plug-in Hybrid Electric Vehicle
PJM	PJM Interconnection, L.L.C.
PV	Photovoltaic
REC	Renewable Energy Certificate
REPS	Renewable Energy and Energy Efficiency Portfolio Standard (NC)
RFC	Reliability First Corporation
RFP	Request for Proposals
RIM	Ratepayer Impact Measure
RPM	Reliability Pricing Model
RPS	Renewable Energy Portfolio Standard (VA)
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCC	State Corporation Commission of Virginia
SERC	Southeastern Reliability Corporation
SG	Standby Generator
SNCR	Selective Non-Catalytic Reduction
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SRP	Stakeholder Review Process
STAP	Short-Term Action Plan
T&D	Transmission and Distribution
TEAC	Transmission Expansion Advisory Committee
TOP	Transmission Operator
TRC	Total Resource Cost
VACAR	Virginia-Carolinas Reliability Agreement
VCHEC	Virginia City Hybrid Energy Center
VDEQ	Virginia Department of Environmental Quality
VOWDA	Virginia Offshore Wind Development Authority

Chapter 1

Executive Summary

CHAPTER 1 – EXECUTIVE SUMMARY

1.1 INTEGRATED RESOURCE PLAN OVERVIEW

Virginia Electric & Power Company d/b/a Dominion Virginia Power and Dominion North Carolina Power (collectively, the "Company") files its 2011 Integrated Resource Plan ("2011 Plan" or "Plan") in accordance with § 56-599 of the Code of Virginia ("Va. Code") and the Virginia State Corporation Commission's ("SCC") guidelines issued on December 31, 2008, as well as § 62-2 of the North Carolina General Statutes ("NCGS") and Rule R8-60 of the North Carolina Utilities Commission's ("NCUC") Rules of Practice and Procedure.

On September 1, 2010, the Company filed its 2010 Integrated Resource Plan ("2010 Plan") with the SCC (Case No. PUE-2010-00107) and NCUC (Docket No. E-100, Sub 128). On November 10, 2010, the SCC issued its Final Order stating that the 2010 Plan, filed pursuant to Va. Code § 56-599 C and the guidelines established by the SCC in Case No. PUE-2008-00099 ("Guidelines") was compliant with the applicable law and Guidelines. The Company's 2010 Plan remains pending before the NCUC.

The 2011 Plan was prepared for the Dominion Load Serving Entity ("DOM LSE"), and represents the Company's service territories in the Commonwealth of Virginia and North Carolina as part of the PJM Interconnection, LLC ("PJM") Regional Transmission Organization ("RTO"). More specifically, the 2011 Plan was developed to meet rising customer demand for electricity at the lowest reasonable cost. The Appendices associated with this 2011 Plan only provide information and data associated with and applicable to the DOM LSE and do not include other data associated with other entities that are part of the Dominion Zone ("DOM Zone").

On September 15, 2010, October 6, 2010 and February 24, 2011, the Company initiated its Stakeholder Review Process ("SRP") wherein the Company convened meetings of interested stakeholders. The Company designed the SRP to be a forum to inform stakeholders about the Integrated Resource Planning ("IRP") process and to provide more specific information about the Company's planning process, including its IRP and demand-side management ("DSM") initiatives. In addition, the SCC directed the Company to coordinate with interested parties in sharing DSM program evaluation, measurement and verification ("EM&V") results and in developing future DSM program proposals. The Company developed its 2011 Plan with careful consideration of the suggestions, feedback, and comments received during the SRP. It is anticipated that, in the future, stakeholder meetings will be convened at least twice yearly with the next meeting planned to be held in October 2011.

The 2011 Plan is a long-term planning document and should be viewed in that context. The Company used the Strategist model ("Strategist"), a computer modeling and resource optimization tool, to develop its Plan over a 25-year period, which includes the effects of service lives, from 2012 to 2036 ("Study Period") using 2011 as the base year. For purposes of this Plan, the Company displays text, numbers, and appendices for a 15-year period from 2012 to

2026 ("Planning Period") using 2011 as the base year. The 2011 Plan is based on the Company's current assumptions regarding load growth, commodity price projections, DSM programs, and many other regulatory and market developments expected to occur during the Study Period based on this snapshot in time.

The 2011 Plan includes sections on load forecasting (Chapter 2), existing and proposed resources (Chapter 3), planning requirements, constraints (Chapter 4), and future resources (Chapter 5). Additionally, the 2011 Plan includes Chapter 6 titled "Development of the Integrated Resource Plan" outlining several alternative plans that were compared by weighing the costs and benefits of these plans using a variety of sensitivities and scenarios. This analysis allowed the Company to examine alternate plans related to uncertainties including environmental issues, capacity availability, and commodity prices. The 2011 Plan also contains a Short-Term Action Plan ("STAP") (Chapter 7) which discusses the Company's specific actions currently being taken to implement activities that support the 2011 Plan over the next five years (2012-2016).

1.2 COMPANY DESCRIPTION

The Company, headquartered in Richmond, Virginia, currently serves approximately 2.4 million electric customers covering approximately 30,000 square miles in Virginia and North Carolina. The Company's regulated electric portfolio consists of 18,735 megawatts ("MW") of generation capacity, including approximately 1,747 MW of non-utility generation ("NUG") resources, over 6,100 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV, and more than 56,600 miles of distribution lines at voltages ranging from 4 kV to 34.5 kV in Virginia, North Carolina, and West Virginia. In May 2005, the Company became a member of PJM, the operator of the wholesale electric grid in the Mid-Atlantic region of the United States. As a result, the Company transferred operational control of its transmission assets to PJM.

The Company has a diverse mix of generating resources consisting of Company-owned nuclear, fossil, hydro, pumped storage, and biomass facilities. Additionally, the Company purchases capacity and energy from NUGs and the PJM market.

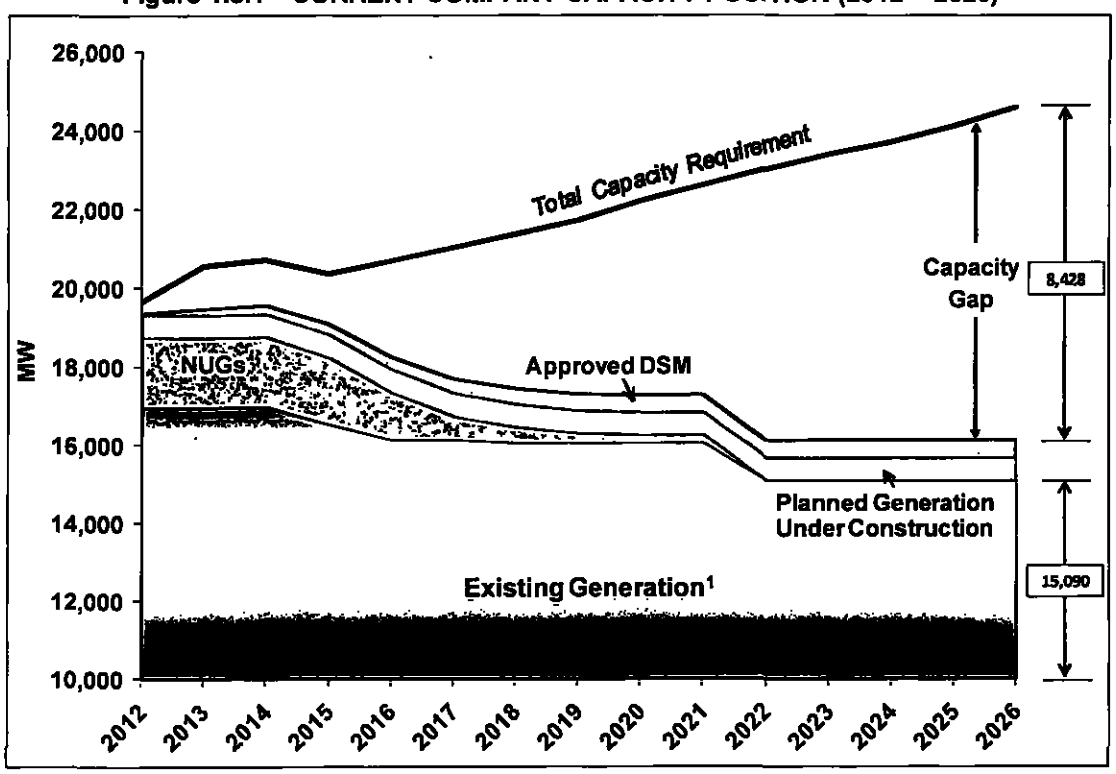
1.3 2011 INTEGRATED RESOURCE PLANNING PROCESS

The Company's objective in developing the 2011 Plan was to identify the mix of resources necessary to meet future energy and capacity needs in an efficient and reliable manner at the lowest reasonable cost while considering uncertainties related to current and future regulations. The Company's options for meeting these future needs were: i) supply-side resources, ii) demand-side resources, and iii) market purchases. The Company also remains committed to meeting its renewable energy and energy efficiency goals in a cost-effective manner.

In order to meet future customer needs at the lowest reasonable cost while maintaining reliability, the Company must take into consideration the uncertainties and risks related to the energy industry. One of the main uncertainties of the 2011 Plan is assumptions related to the United States Environmental Protection Agency ("EPA") draft and final regulations concerning air, water and solid waste constituents (as shown in Figure 3.1.3.1). In addition, assumptions related to cost and performance of advanced energy technologies, as well as continued load growth in the Company's service territory over the Study Period were considered. The Company's IRP process has identified the supply-side resources, demand-side resources, and transmission options that mitigate these risks at the lowest reasonable cost.

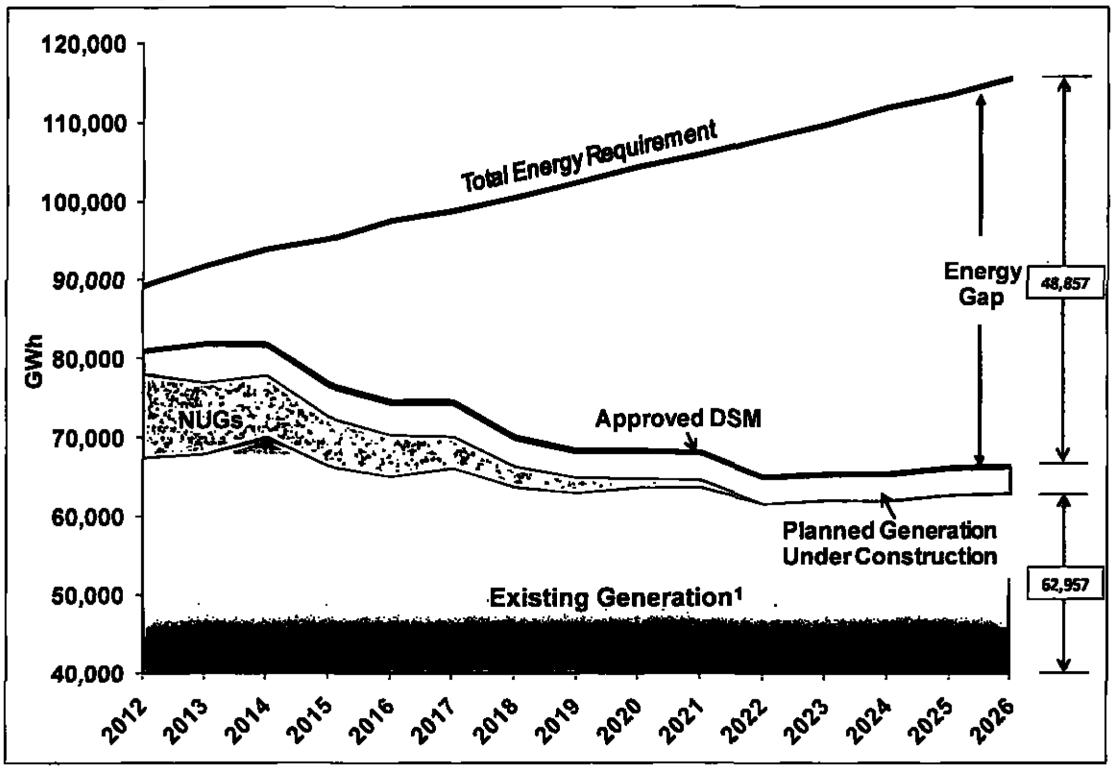
The Company developed a comprehensive IRP process that gave preference to options that offered reasonable costs at an acceptable level of risk, maintained or increased the level of customer service, and provided reliable generation and infrastructure to meet customers' needs over the long-term. Various planning groups throughout the Company provided input and insight into evaluating all viable options including existing generation, DSM programs, and new traditional and alternative resources to meet the growing demand in the Company's service territory. The IRP process began with the development of the Company's long-term load forecast which indicates that over the Planning Period the region is expected to have future annual increases in energy requirements of 1.89% and peak demand of 1.93%. Collectively, these elements assisted in determining new capacity and energy requirements as illustrated in Figure 1.3.1 and Figure 1.3.2.

Figure 1.3.1 CURRENT COMPANY CAPACITY POSITION (2012 – 2026)



Note: 1) Accounts for unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Figure 1.3.2 CURRENT COMPANY ENERGY POSITION (2012 – 2026)



Note: 1) Accounts for unit retirements and rating changes to existing units *in the Plan.*

1.4 2011 PREFERRED INTEGRATED RESOURCE PLAN

To assess the uncertainty and risks associated with external market and environmental factors, the Company developed four alternative plans representing plausible future paths. The Company evaluated the four alternative plans using 15 scenarios and sensitivities as well as one basecase as discussed in Chapter 6. The Company selected the plan that contained the mix of supply- and demand-side options to meet expected future resource needs at the lowest reasonable cost as its Preferred Plan. The Preferred Plan displayed in Figure 1.4.1 represents the single plan that most effectively balanced the many competing drivers and risks identified in this 2011 Plan.

Figure 1.4.1 2011 PREFERRED INTEGRATED RESOURCE PLAN

Year	Supply-side Resources				Demand-side Resources
	New	Retrofit	Repower	Retire	
2012	VCHEC				Approved DSM Proposed & Future DSM
2013			AV, HW, SH – Biomass		↓
2014	Halifax		BR3 – Gas BR4 – Gas		↓
2015	Warren	PP5 – SNCR YT3 – SNCR	YT2 – Gas/Oil	CEC 1-2 YT1	↓
2016	CC			CEC 3-4	↓
2017					↓
2018					↓
2019	CC				↓
2020	CT				↓
2021	CT				↓
2022	North Anna 3			YT 2-3	↓
2023	CT				↓
2024	CT				↓
2025	CT				↓
2026	CT				↓

Key: Retrofit: Additional environmental control reduction equipment; Repower: Convert fuel to biomass or repower by natural gas; Retire: Remove a unit from service; AV: Altavista; BR: Bremo; CEC: Chesapeake Energy Center; CC: Combined Cycle; CT: Combustion Turbine (2 units); Halifax: Halifax County Solar; HW: Hopewell; PP: Possum Point Unit; SH: Southampton; SNCR: Selective Non-Catalytic Reduction; VCHEC: Virginia City Hybrid Energy Center; Warren: Warren County Power Station; YT: Yorktown Unit

Note: 1) DSM capacity savings continue to increase throughout the Planning Period.

The Preferred Plan includes approved DSM programs reaching approximately 500 MW by 2026 and one planned generation resource under construction, Virginia City Hybrid Energy Center ("VCHEC"), of approximately 585 MW, which includes approximately 29 MW initially, ramping up to 59 MW of renewable generation in the future.

In addition to existing generation and DSM resources, the 2011 Plan includes:

- Proposed and future DSM programs reaching approximately 440 MW by 2026;
- Halifax County Solar of 4 MW with battery storage;
- Planned generation resources under development of approximately 2,790 MW, which includes Warren County Power Station and North Anna Unit 3 ("North Anna 3");
- A mix of potential conventional generation resources including combined cycle ("CC") and combustion turbine ("CT")[1] plants totaling approximately 5,075 MW that will continue to be studied as the resource need is established;
- PJM market purchases and NUG capacity under contract.

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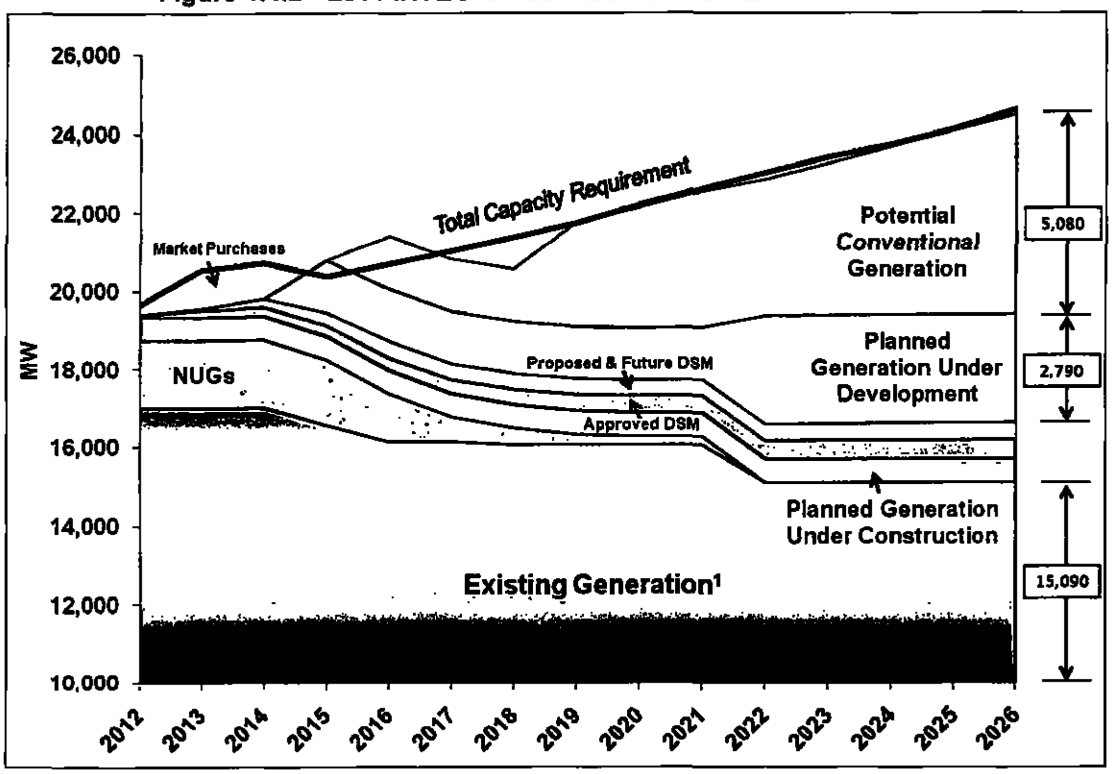
[1] All references regarding new CT units throughout this document refer to installation of a bank of two CT units.

On June 27, 2011 the Company filed an application with the SCC for approval to convert Altavista, Hopewell, and Southampton power stations totaling 153 MW to biomass fuel by the end of 2013. In addition, the Company currently plans to repower Bremo Power Station Units 3 and 4 totaling 227 MW by natural gas in 2014.

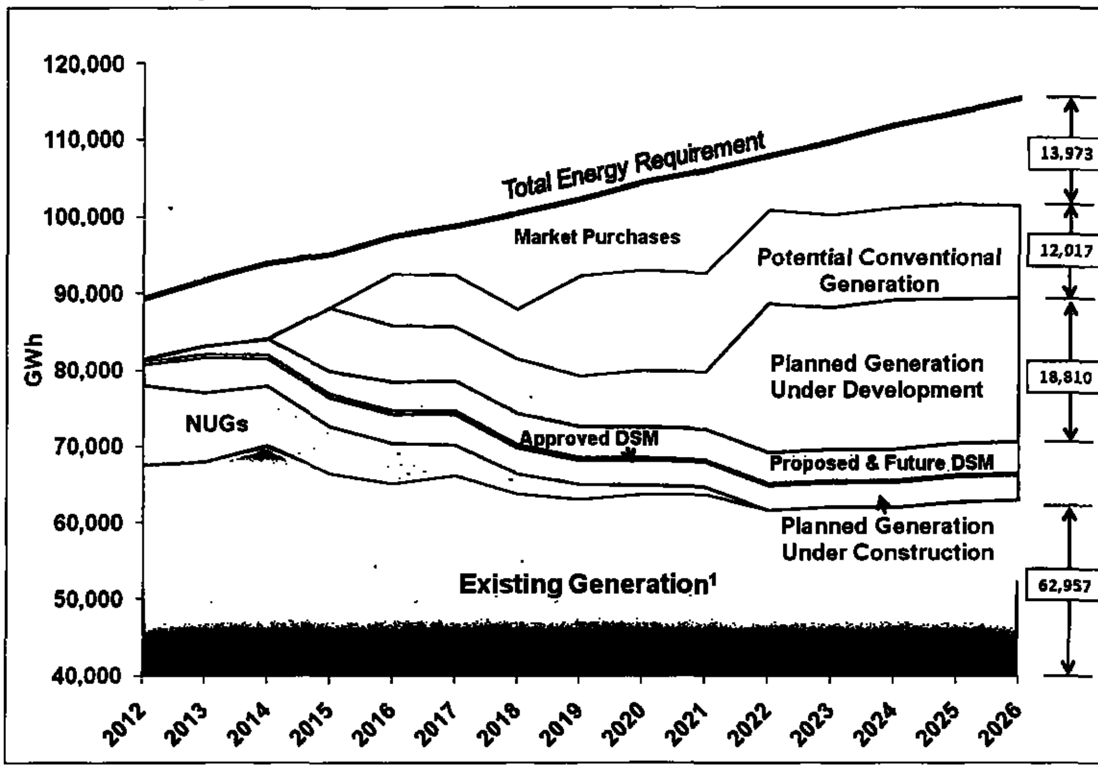
To meet the projected electric customer demand and annual reserve requirements throughout the Planning Period, the Company has identified a need of additional resources that total over 8,400 MW to fill the capacity gap shown in Figure 1.3.1. To meet this need, the Company plans to use a balanced mix of resources including supply-side resources, demand-side resources, and market purchases as illustrated by Figures 1.4.2 and 1.4.3.

Figure 1.4.2 2011 INTEGRATED RESOURCE PLAN – CAPACITY



Note: 1) Accounts for unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Figure 1.4.3 2011 INTEGRATED RESOURCE PLAN – ENERGY



Note: 1) Accounts for unit retirements and rating changes to existing units in the Plan.

The 2011 Plan balances the Company's commitment to operate in an environmentally responsible manner with its obligation to provide reliable and cost-effective service. Since several EPA regulations are still in draft form (as further shown in Figure 3.1.3.1), various alternatives were analyzed on the Company's environmentally "at risk" units to determine the most cost-effective plan. Small coal-fired units that have limited environmental controls are the "at risk" units. *Large coal-fired units are controlled and continue to operate with relatively small* additional expenses. Similarly nuclear and hydro units are minimally impacted. In order to comply with draft and final environmental regulations, and depending on the specific situation for each generating unit, the analysis determined one of three options for each "at risk" unit: 1) retrofitting with additional environmental control reduction equipment, 2) fuel repowering to biomass or natural gas, or 3) retiring the unit.

Based on the draft and final form of environmental regulations along with current market conditions, the 2011 Plan includes the following impacts to the existing generating resources in terms of retrofitting, repowering and retiring, which may be revised when the regulations are finalized:

1. Retrofit
   - 1,583 MW of heavy oil-fired generation installed with new Selective Non-Catalytic Reduction ("SNCR") controls by 2015

2. Repower
   - 153 MW of small coal-fired generation repowered from coal to biomass by the end of 2013
   - 383 MW of small coal-fired generation repowered from coal to natural gas and oil by 2015
3. Retire
   - 754 MW of small coal-fired generation retired by 2016
   - 960 MW of heavy oil-fired and natural gas-fired units retired by 2022

The 2011 Plan provides the Company with the ability to respond to uncertainties brought on by potential changes in market conditions, environmental regulations, and customer demand. The 2011 Plan represents the Company's commitment to meet environmental regulations while meeting future demand effectively through a balanced portfolio. This includes a combination of conventional and renewable generation facilities as well as DSM programs to provide a reliable supply of energy to customers. The Company remains committed to selecting the resources that best match the needs of its customers, while providing the fuel diversity needed to minimize risks associated with changing market conditions. This 2011 Plan represents an analysis of resources that is expected to provide service at the lowest reasonable cost to its customers under a wide range of potential market conditions.

Chapter 2 | Load Forecast

CHAPTER 2 – LOAD FORECAST

2.1 FORECAST METHODS

The Company used econometric models with an end-use orientation to forecast energy sales at the customer class level and hourly loads at the system level. Separate monthly sales equations were developed for residential, commercial, industrial, public authority, street and traffic lighting, and wholesale customers, as well as other Load Serving Entities ("LSEs") within the DOM Zone. The monthly sales equations were specified in a manner that produced estimates of non-weather sensitive load, heating load, and cooling load. Hourly equations were used to model peak demands and energy output for the DOM Zone.

Variables included in the monthly sales equations were as follows:

- *Residential Sales equation*: Income, electric prices, unemployment rate, number of customers, appliance saturations, weather, billing days, and calendar month variables to capture seasonal impacts
- *Commercial Sales equation*: Virginia Gross State Product ("GSP"), electric prices, natural gas prices, number of customers, weather, billing days, and calendar month variables to capture seasonal impacts
- *Industrial Sales equation*: Employment in manufacturing, Virginia GSP, electric prices, weather, billing days, and calendar month variables to capture seasonal impacts
- *Public Authorities Sales equation*: Real output (the constant dollar value of all goods and services provided by state and local government), number of customers, weather, billing days, and calendar month variables to capture seasonal impacts
- *Street and Traffic Lighting Sales equation*: Number of customers and calendar month variables to capture seasonal impacts
- *Wholesale Customers and Other LSEs Sales equations*: A measure of non-weather sensitive load derived from the residential equation, heating and air-conditioning appliance stocks, number of days in the month, weather, and calendar month variables to capture seasonal and other effects

The hourly DOM Zone model was estimated in two stages. In the first stage, the DOM Zone load was modeled as a function of time trend variables and a detailed specification of weather involving interactions between both current and lagged values of temperature, humidity, wind speed, sky cover, and precipitation for five stations. The parameter estimates from the first stage were used to construct two composite weather variables, one to capture heating load and one to capture cooling load. In addition to the two weather concepts derived from the first stage, the second stage equation used estimates of non-weather sensitive load derived from the monthly sales model as well as residential heating and cooling appliance stocks as explanatory variables. In addition, the hourly model used calendar month variables to capture time of day, day of week, holiday, and other seasonal effects as well as unusual events such as hurricanes. Separate equations were estimated for each hour of the day.

Hourly models for wholesale customers and other LSEs within the DOM Zone were modeled as a function of the DOM Zone load since they face similar weather and economic activity. The

DOM LSE load was derived by subtracting the other LSEs from the DOM Zone load. DOM LSE load and firm contractual obligations were used as the total load obligation for the purpose of this 2011 Plan.

Forecasts were produced by simulating the model over actual weather data from the past 20 years along with projected economic conditions. Sales estimates from the monthly equations and energy output projections from the hourly model were reconciled appropriately. Monthly sales by customer class, peak demand, and system energy were calculated as expected values across the simulations.

2.2 HISTORY & FORECAST BY CUSTOMER CLASS & ASSUMPTIONS

The economic and demographic assumptions that were used as inputs to the Company's Energy Sales and Peak Demand Model were supplied by Moody's Economy.com. Figure 2.2.1 summarizes the final forecast of energy sales and peak loads over the next 15 years. Growth in the DOM Zone peak load and annual energy output since 1997 and a 15-year forecast are shown in Figure 2.2.2 and Figure 2.2.3. Additionally, Figure 2.2.4 summarizes the main economic drivers behind sales and peak load forecasts. A 10-year history and 15-year forecast of sales and customer count at the system-level, as well as for Virginia and North Carolina individually, are provided in Appendices 2A to 2F. Appendix 2G provides a summary of the summer and winter peaks used for modeling purposes. Additionally, the three-year historical load and 15-year projected load for wholesale customers is provided in Appendix 3L. The Company's wholesale and retail customer load are estimated to grow at similar rates of nearly 2% over the Planning Period as shown in Figure 2.2.1. Historical and projected rates can diverge for a number of reasons which include actual versus normal (forecast) weather and the economic variables utilized in the load forecast versus what actually transpires in the economy.

Figure 2.2.1 SUMMARY OF ENERGY SALES & PEAK LOAD FORECAST

	2012	2026	Compound Annual Growth Rate (%) 2012-2026
DOMINION LSE			
Total Energy Sales (GWh)	85,873	111,594	1.89%
Residential	31,048	39,988	1.82%
Commercial	33,041	48,239	2.74%
Industrial	8,463	9,333	0.70%
Resale	1,946	2,539	1.92%
Public Authorities	11,079	11,136	0.04%
Street and Traffic Lighting	295	359	1.41%
Seasonal Peak (MW)			
Summer	16,999	22,201	1.93%
Winter	15,291	19,569	1.78%
DOM ZONE			
Seasonal Peak (MW)			
Summer	19,385	25,092	1.86%
Winter	17,586	22,325	1.72%
ENERGY OUTPUT (GWh)	100,282	130,523	1.90%

Note: All sales and peak have not been reduced for the impact of DSM.

Figure 2.2.2 DOM ZONE PEAK LOAD

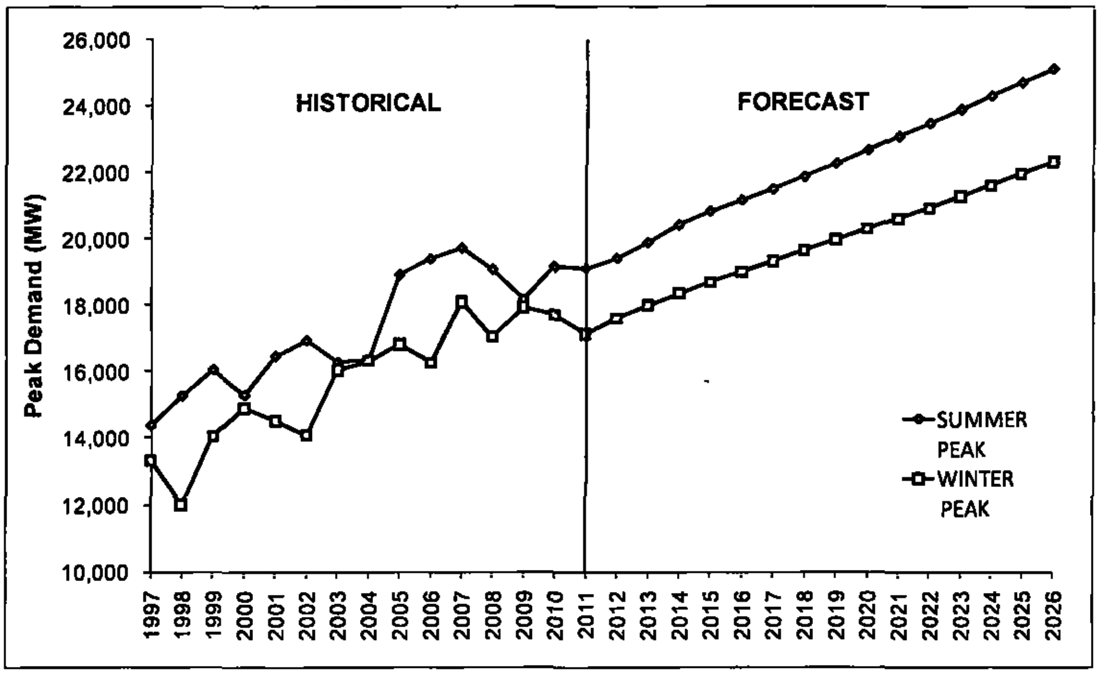


Figure 2.2.3 DOM ZONE ANNUAL ENERGY

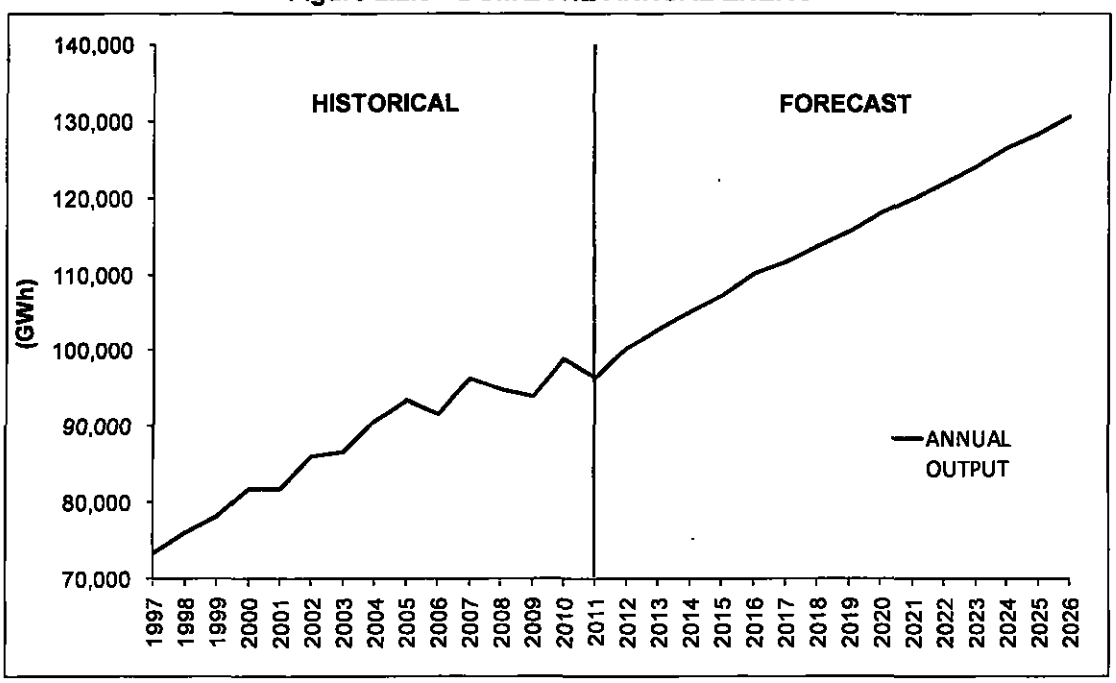


Figure 2.2.4 MAJOR ASSUMPTIONS FOR THE ENERGY SALES & PEAK DEMAND MODEL

	2012	2026	Compound Annual Growth Rate (%) *(2012 - 2026)*
DEMOGRAPHIC:			
Customers (000)			
Residential	2,194	2,638	1.33%
Commercial	236	277	1.13%
Population (000)	8,136	9,285	0.95%
ECONOMIC:			
Employment (000)			
Manufacturing	237	231	-0.19%
Government	701	747	0.45%
Income ($)			
Per Capita Real Disposable	36,480	43,178	1.21%
Price Index			
Consumer Price (1982-1984) = 100	227	314	2.35%
VA Gross State Product (GSP)	410	573	2.43%

The forecast of the Virginia economy drove the Company's energy sales and load forecasts. Although Virginia has been impacted by the recent recession, the Commonwealth fared well compared to the nation in terms of job losses. As of April 2011, the seasonally adjusted unemployment rate in Virginia approached 6.1%, nearly 3% below the national unemployment rate. Virginia's unemployment rate ranks among the lowest in the nation.

The slump in the housing sector that led the current economic downturn resulted in more than a 60% decline in housing starts in the state between 2005 and 2009. While recovery in housing remains slow, Virginia is expected to show a minor improvement in housing starts in 2011 that is expected to continue into 2012. Additionally, the unemployment rate is expected to continue its slow decline through the remainder of the year and onward.

On a long-term basis, the economic outlook for Virginia is positive. Over the next 15 years, real per-capita income in the state is expected to grow about 1.2% per year, on average. Virginia real GSP is projected to grow more than 2.4% per year, on average, over the next 15 years. During the same period, the Virginia population is expected to grow steadily at around 1% per year.

2.3 SUMMER & WINTER PEAK DEMAND & ANNUAL ENERGY

The three-year actual and 15-year forecast of summer and winter peak, annual energy, DSM peak and energy, and system capacity are shown in Appendix 2H. Additionally, Appendix 2I provides the required reserve margins for a three-year actual and 15-year forecast.

2.4 ECONOMIC DEVELOPMENT RATES

The Company has one customer in Virginia receiving service under economic development rates. The total load associated with these rates was approximately 2.5 MW in 2010. There are no customers under a self-generation deferral rate.

Chapter 3 | Existing & Proposed Resources

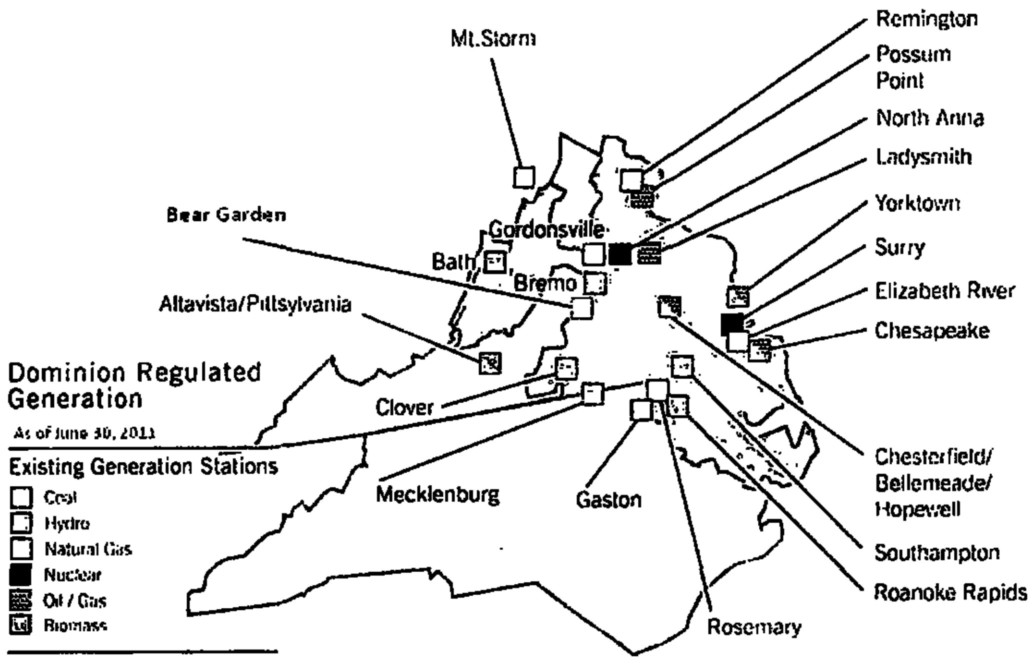
CHAPTER 3 – EXISTING & PROPOSED RESOURCES

3.1 SUPPLY-SIDE RESOURCES

3.1.1 EXISTING GENERATION

The Company's existing generating resources are located at multiple sites distributed throughout its service territory as shown in Figure 3.1.1.1. This diverse fleet of 100 generation units includes 4 nuclear, 22 coal, 1 biomass, 2 natural gas, 2 heavy oil, 8 CC, 41 combustion turbines, 6 pumped storage, and 14 hydro units with a summer capacity of approximately 16,987 MW.[2] The Company's operational goal is to manage this fleet in a manner that provides reliable, cost-effective service under varying load conditions.

Figure 3.1.1.1 EXISTING GENERATION RESOURCES



On May 23, 2011, Bear Garden CC Power Station, located in Buckingham County, Virginia, came into service. Construction first began on this 590 MW[3] CC Unit in April 2009. Bear Garden will contribute significant incremental, intermediate capacity to the Company's service territory.

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[2] All references to MW in Chapter 3 refer to summer capacity unless otherwise noted. Winter capacities for Company-owned generation units are listed in Appendix 3A.

[3] Summer capacity of Bear Garden is 590 MW, which the Company used for modeling purposes in development of this 2011 Plan. Nominal capacity of unit is 580 MW.

The Company not only owns a variety of generation resources that operate using different fuel types, but it also has a wide age range of capacity. The largest proportion of the Company's generation resources has operated for 30 to 40 years, followed by a large number of units that have operated for 20 to 30 years. Figure 3.1.1.2 shows the demographics of the entire generation fleet.

Figure 3.1.1.2 GENERATION FLEET DEMOGRAPHICS

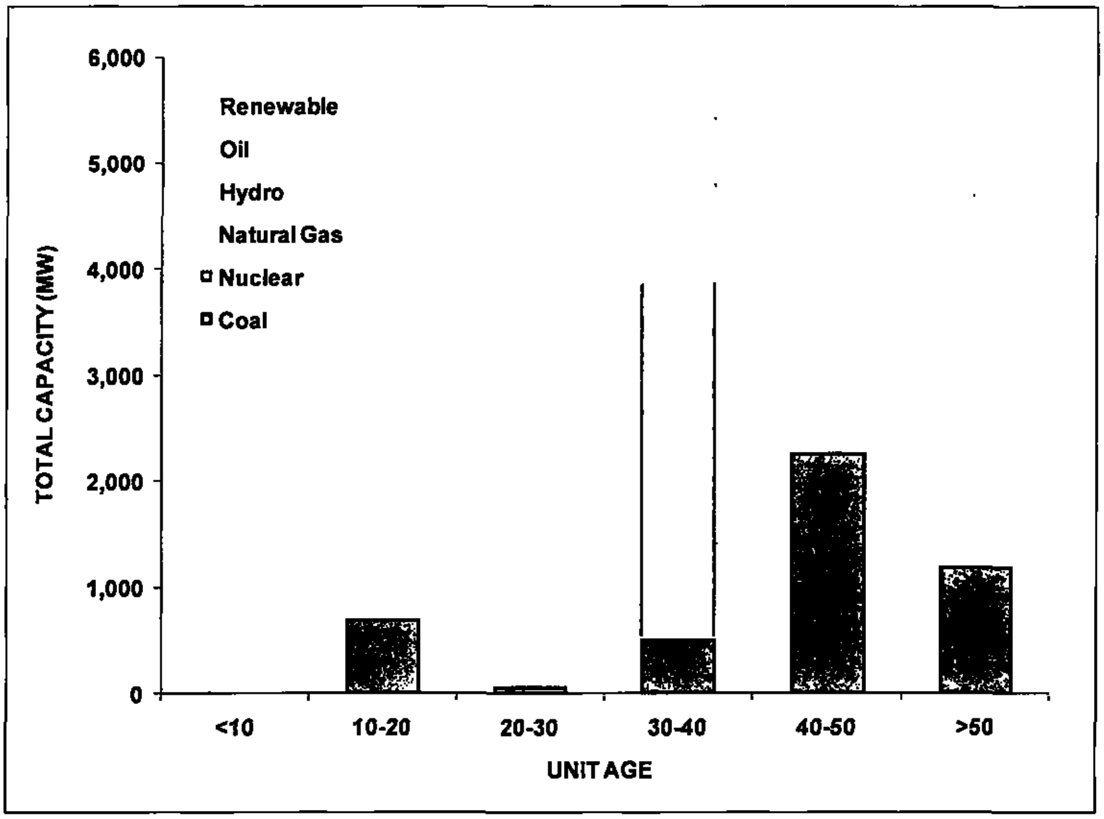


Figure 3.1.1.3 illustrates that the Company's existing generation fleet is comprised of a mix of approximately 16,987 MW of resources with varying operating characteristics and fueling requirements. The Company's mix of generation resources includes more than 400 MW of renewable generation and approximately 1,747 MW of NUGs, which provide firm capacity and associated energy to meet the Company's load requirements. An important aspect of the 2011 Plan is the Company's use of diverse capacity and energy resources to meet its customers' needs.

FIGURE 3.1.1.3 2011 CAPACITY RESOURCE MIX BY UNIT TYPE

Generation Resource Type	Net Summer Capacity (MW)	Percentage (%)
Coal	4,675	23.3%
Nuclear	3,325	16.5%
Natural Gas - Boiler	316	1.6%
Natural Gas - Combined Cycle	2,196	10.9%
Natural Gas - Turbine	2,411	12.0%
Pumped Storage - Hydro	1,802	9.0%
Light Fuel Oil - Turbine	257	1.3%
Heavy Fuel Oil - Boiler	1,604	8.0%
Renewable - Hydro	318	1.6%
Renewable - Biomass	83	0.4%
NUG - Coal	743	3.7%
NUG - Natural Gas Turbine	942	4.7%
NUG - Renewable	63	0.3%
Purchases	1,356	6.7%
Total - NUG Contracted	1,747	8.7%
Total - Owned	16,987	84.6%
Total - Owned and NUG Contracted	18,735	93.3%
Total	20,091	100.0%

Due to differences in the operating and fuel costs of various types of units and PJM system conditions, the Company's energy mix is not equivalent to its capacity mix. The Company's generation fleet is economically dispatched by PJM within its larger footprint, ensuring that customers in the Company's service area receive the benefit from all resources in the PJM power pool regardless of whether the source of electricity is Company-owned, contracted, or third-party units. PJM dispatches resources within the DOM Zone from the lowest bid units to the highest bid units, while maintaining its mandated reliability standards. Figures 3.1.1.4 and 3.1.1.5 provide the Company's 2011 capacity and energy mix (projected) with percentages.

Figure 3.1.1.4 2011 CAPACITY MIX

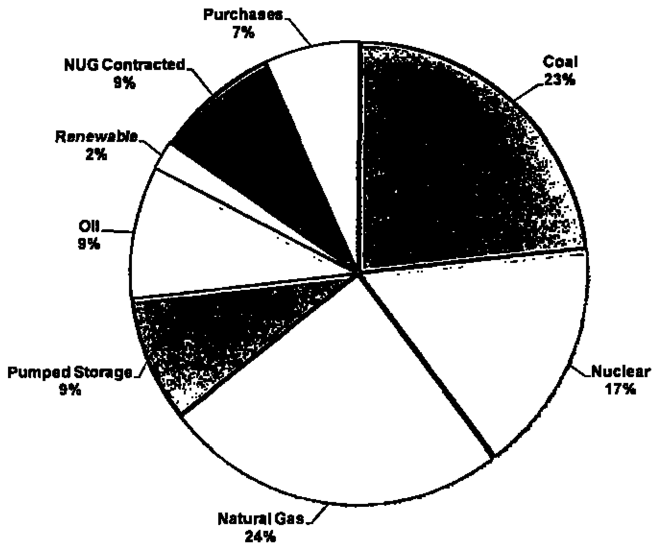
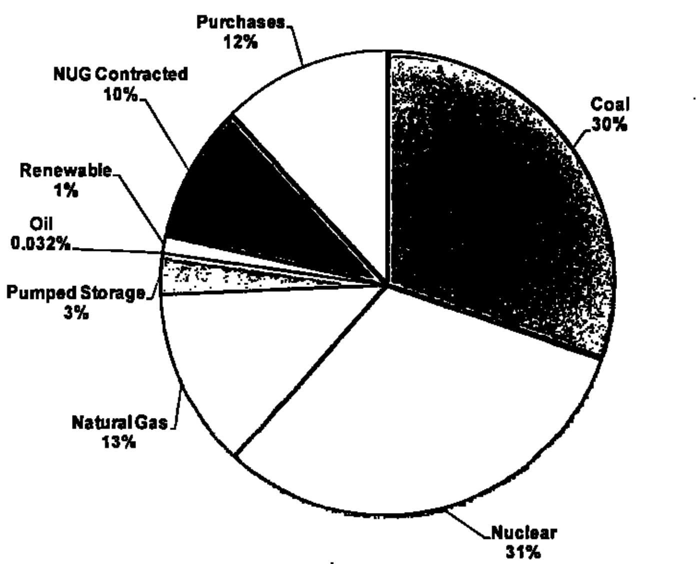


Figure 3.1.1.5 2011 ENERGY MIX (PROJECTED)



Appendices 3A, 3C, 3D, and Extraordinarily Sensitive 3E provide basic unit specifications and operating characteristics of the Company's supply-side resources, both owned and contracted. Additionally, Appendix 3F provides a summary of the existing capacity, including NUGs, by fuel class. Appendices 3G and 3H provide energy generation by type as well as the system output mix. Appendix 3B provides a listing of other generation units including units in cold storage, NUGs, behind-the-meter generation ("BTMG"), and customer-owned generation units.

3.1.2 EXISTING RENEWABLE RESOURCES

The Company currently owns and operates several renewable resources including its wood-burning Pittsylvania Power Station (83 MW), one of the largest biomass facilities in the United States. Additionally, the Company owns and operates four hydro facilities that includes Gaston Hydro Station (220 MW), Roanoke Rapids Hydro Station (95 MW), Cushaw Hydro Station (2 MW), and North Anna Hydro Station (1 MW). The Company has existing contracts for approximately 25 MW of BTMG renewable capacity, as well as one contracted renewable NUG facility at Ogden-Martin Fairfax that will provide approximately 63 MW in 2011.

3.1.3 PLANNED CHANGES TO EXISTING GENERATION

Efficiency, output, and environmental characteristics of plants are reviewed as part of the Company's normal course of business. Many of the uprates and derates discussed in this section occur during routine maintenance cycles or are associated with standard refurbishment. However, several plant ratings have been and will continue to be adjusted to conform with PJM market rules and environmental standards.

The Company continues to evaluate opportunities for existing unit uprates as a cost-effective means of increasing generating capacity and improving system reliability. Between 2009 and 2011 the Company's investment in its existing generation fleet has yielded net capacity uprates of 172 MW.

The EPA has proposed and finalized a significant number of new regulations that are expected to affect certain units in the Company's current fleet of generation resources. These regulations, as shown in Figure 3.1.3.1, are designed to regulate the air, water, and solid waste constituents.

Figure 3.1.3.1 EPA REGULATIONS

Constituent[1]		Key Regulation[2]	Expected Rule[3]
Air	Hg/HAPS	Utility HAPS (MACT) (HG/Air Toxics Rule)	11/2011
	SO_2	CSAPR	FINAL
		SO_2 NAAQS	FINAL
	NO_x	Ozone Standard Revision	8/2011
		CSAPR	FINAL
		CSAPR II	12/2012
	CO_2	GHG Tailoring Rule	FINAL
		EGU NSPS	5/2012
		Federal Cap & Trade	NA
Solid Waste	Ash	CCB	12/2012
Water	316(b)	316(b) Impingement	7/2012
		316(b) Entrainment	
	Effluent	Effluent Discharges	1/2014

***Notes:** 1) Constituent: Hg=Mercury; HAPS=Hazardous Air Pollutants; SO_2=Sulfur Dioxide; NO_x=Nitrogen Oxide; CO_2=Carbon Dioxide; GHG=Greenhouse Gas; Water 316(b)=Clean Water Act § 316(b) Cooling Water Intake Structures*
***2)** Key Regulation: MACT=Maximum Achievable Control Technology; CSAPR and CSAPR II=Cross-State Air Pollution Rule; SO_2 NAAQS=Sulfur Dioxide National Ambient Air Quality Standards; EGU NSPS=Electric Generating Units New Source Performance Standard; CCB=Coal Combustion Byproducts*
***3)** Expected Rule: NA=Not Available*

Compliance with existing and future environmental regulations is an important part of the Company's planning process and a key corporate focus. On May 7, 2008, the Company commissioned a new pollution control system which included a scrubber at Chesterfield Unit 6. An additional scrubber at Chesterfield Unit 5 was completed on June 30, 2011. It is anticipated by the end of 2011, Chesterfield Units 3 and 4 will also be connected to the Chesterfield Unit 5 scrubber. Both scrubbers are anticipated to provide a 95% reduction in sulfur dioxide ("SO_2") emissions and an 80% reduction in mercury ("Hg") emissions.

Based on the draft and final form of environmental regulations along with current market conditions, the 2011 Plan includes the following impacts to the existing generating resources in terms of retrofitting, repowering and retiring, which may be revised when the regulations are finalized:

Retrofit

Possum Point Unit 5 (779 MW) and Yorktown Unit 3 (804 MW) are in the Plan to be retrofitted with a SNCR unit by 2015.

Repower

Coal-fired Yorktown Unit 2 (156 MW) is in the Plan to be repowered by natural gas and oil by 2015.

On June 27, 2011, the Company filed an application with the SCC for approval to convert three of its Virginia coal-fired power stations, Altavista, Hopewell, and Southampton, to biomass fuel (Case No. PUE-2011-00073). The three power stations are all similar and went into operation in 1992. Conversion of these stations is expected to result in overall reductions of SO_2, nitrogen oxide ("NO_x"), Hg and particulate emissions. The proposed conversions are projected to increase the capacity factors of these units, provide economical baseload energy and provide environmental and energy benefits to the Commonwealth of Virginia over the next 25 years. If the proposed conversions are approved by the Virginia Department of Environmental Quality ("VDEQ") and the SCC, the power stations could begin burning biomass by the end of 2013.

Additional efforts to reduce emissions from the Company's existing generation fleet include plans to repower its coal-fired Bremo Power Station by natural gas subject to regulatory approval. The station is the Company's oldest coal-fired power station in Virginia. The two coal units currently in use at the station were put into service in 1950 and 1958. Bremo Units 3 and 4 with respective summer capacities of 71 MW and 156 MW are planned to repower in 2014. This conversion is expected to reduce the Company's emissions of SO_2, NO_x and carbon dioxide ("CO_2"), while maintaining the Bremo site and providing capacity.

Appendix 3I provides a listing of uprates and derates to the Company's existing generation.

3.1.4 POTENTIAL GENERATION RETIREMENTS

In order to comply with environmental regulations, a number of factors are driving the Company's decisions to either retrofit aging coal- and oil-fired generating units with newer technology or retire those particular units from service. Figure 3.1.3.1 summarizes these environmental regulations.

As part of the 2011 IRP process, the Company analyzed a number of options for several of the older coal- and oil-fired units that may not be compliant with impending environmental rules that begin to take effect in 2015, if they include requirements as detailed in their current draft forms. This analysis included a review of the costs to retrofit the units with new environmental control equipment, repower the units by natural gas or convert the units to burn biomass as a fuel source, or retire the units from service. The analysis incorporated assumptions regarding fuel prices, energy prices, costs associated with retrofits and repowering, pending environmental regulations, cost of existing equipment, fuel availability and operating costs. This analysis sought to balance these competing costs and environmental regulations with the goal of maintaining system reliability. It should be noted that this analysis is based on the Company's current assumptions for these drivers.

Based on requirements of draft and final form of environmental regulations along with current market conditions, the 2011 Plan includes the following potential retirement options for existing generating resources.

Chesapeake Energy Center Units 1 (111 MW) and 2 (111 MW) and Yorktown Unit 1 (159 MW) are in the Plan to be retired by 2015. Chesapeake Energy Center Units 3 (156 MW) and 4 (217 MW) are in the Plan to be retired by 2016. Yorktown Units 2 (156 MW) and 3 (804 MW) are in the Plan to be retired by 2022. Appendix 3J lists the retirements included in the Plan.

In addition to retirements in the Plan, the coal unit at North Branch Power Station, located in Bayard, West Virginia, is currently in cold reserve status. As a result of a mitigation agreement between the National Park Service and the Company, the terms of which are a condition to the Prevention of Significant Deterioration permit for the Warren County Power Station, the unit will be retired from service once the Warren County Power Station begins its commercial operation.

The Company is also evaluating future blackstart resources based on the generation retirements that are anticipated over the next several years. Potential retirements include some generation facilities that are currently designated as blackstart units. Blackstart generators are generating units that are able to start without an outside electrical supply or are able to remain operating at reduced levels when automatically disconnected from the grid. The North American Electric Reliability Corporation ("NERC") Reliability Standard EOP-005 requires the Transmission Operator ("TOP") to have a plan that allows for restoring its system following a complete shutdown (i.e., blackout). As the TOP, PJM assigns this analysis to the Company in its role as the Transmission Owner, but also performs an internal study to verify all requirements are met.

Currently, the Company's tentative plan is to request approximately 250 MW of additional blackstart generation in increments of at least 50 MW per year for five years between 2013 and the end of 2018. The Company will employ PJM's Black Start Replacement Process to solicit additional blackstart generation to ensure a resilient and robust ability to meet blackstart and restoration requirements. This replacement process is described in Section 10 of PJM Manual 14D – Generator Operational Requirements. In accordance with the PJM process, once the Company officially notifies PJM of the intent to retire blackstart capacity, PJM will work with the Company to determine future blackstart capacity needs and PJM will post a Request for Proposals ("RFP") for blackstart service. The initial RFP is expected to occur within the first quarter of 2012 and subsequent RFPs may be issued at a later date. PJM and the Company will work together to select the preferred replacement blackstart units.

3.1.5 PLANNED GENERATION UNDER CONSTRUCTION

The Company is committed to meeting its expected load growth in a cost-effective manner. To meet this load, the Company filed for a Certificate of Public Convenience and Necessity ("CPCN") with the SCC to construct and operate VCHEC, a 585 MW clean coal powered electric generation facility located in Wise County, Virginia. On March 31, 2008, the SCC granted the CPCN and shortly thereafter in June 2008 the Company began construction of the station. As of August 2011, the project was approximately 90% complete and proceeding on schedule. The station's targeted commercial operation date is summer 2012.

VCHEC is expected to be one of the cleanest coal-burning power stations in the United States. The plant will use circulating fluidized bed ("CFB") technology to burn a wide range of coals and waste coal from abandoned mines in the area. Additionally, the station's advanced design will allow the plant to consume up to 20% biomass fuel such as wood waste and wood byproducts, which are renewable fuel resources. The station's two CFB boilers will also consume limestone to aid in the reduction of SO_2 emissions. The technology available at VCHEC will foster the station's compliance with existing and proposed environmental regulations related to SO_2, NO_x, and Hg emissions.

This project is summarized in Figure 3.1.5.1. Appendix 3K provides VCHEC's in service date and summer and winter capacity.

Figure 3.1.5.1 PLANNED GENERATION UNDER CONSTRUCTION

Forecasted COD[1]	Unit Name	Location	Unit Type	Primary Fuel	Capacity (Net MW)	
					Summer	Winter
2012	Virginia City Hybrid Energy Center	Wise County, VA	Baseload	Coal/Biomass	585	635

Note: 1) Commercial Operation Date

3.1.6 NON-UTILITY GENERATION

A portion of the Company's load and energy requirements are supplemented with contracted NUG units and market purchases. The Company has existing contracts with NUGs for capacity of 1,747 MW consisting of seven baseload units and two intermediate units. NUGs noted as firm capacity resources are included in this 2011 Plan. NUGs located at customer sites or that the Company does not have a contract to purchase capacity from on a firm basis are not included in this Plan.

Each of the NUG facilities listed as a capacity resource in Appendix 3B is under contract to supply capacity and energy to the Company. NUG units are obligated to provide firm capacity and energy at the contracted terms during the life of the contract. The firm capacity from NUGs was included as a resource in meeting the reserve requirements. However, the Company has been notified by three of its NUGs that those resources (totaling 316 MW) will be unavailable as a direct resource to the Company after the expiration of the current contracts. The remaining NUG contracts expire at different times during the Planning Period, with the last contract expiring in 2021. For planning purposes, the Company assumed that NUG capacity will no longer be modeled as a firm capacity resource at the expiration of each facility's existing contract. However, the Company leaves open the possibility that some of the NUG contracts may be renewed or extended at the expiration of their current contract terms as the relevant economics warrant. Also, these resources may continue to operate in the PJM market and will be available to the Company as a resource on a contract or spot basis along with other non-Company-owned resources.

Section 6.4 discusses the NUG Extension Plan (Plan B) that considers the extension of NUG contracts until the end of the planning period, exclusive of the three NUGs discussed above.

The purpose of Plan B is to show the change in the system costs with extended NUG contracts compared to the costs of other plans.

3.1.7 WHOLESALE & PURCHASED POWER

Purchased Power

Except for the NUG contracts discussed in Section 3.1.6, the Company does not have any bilateral contractual obligations with wholesale power suppliers or power marketers. As a member of PJM, the Company has the option to self-schedule or buy capacity through the Reliability Pricing Model ("RPM") auction process. The Company has procured its capacity obligation from the RPM market through May 31, 2015.

Wholesale Power Sales

The Company currently provides full requirements wholesale power sales to three entities, which are included in the Company's load obligation/forecast. Additionally, the Company has partial requirements contracts to supply the supplemental power needs of one electric cooperative. Appendix 3L provides a listing of wholesale power sales contracts that the Company has committed to or parties to which the Company expects to sell power during the Planning Period.

BTMG

BTMG occurs on the customer's side of the meter. The Company purchases all output from the customer and services all of the customer's capacity and energy requirements. Since the Company does not own or control these resources, they were not used to develop the 2011 Plan, however they do contribute to the Company's contracted renewable capacity. The unit descriptions are provided in Appendix 3B.

3.1.8 REQUEST FOR PROPOSAL

At this time, the Company does not have any RFPs outstanding to procure supply-side resources.

3.2 DEMAND-SIDE RESOURCES

The Company generally defines DSM as all activities or programs undertaken to influence the amount and timing of electricity use. Demand-side resources encourage the more efficient use of existing resources and delay or eliminate the need for new supply-side infrastructure. The Company's DSM tariffs provide customers with price signals to curtail load at times when system load or marginal cost are high. Additionally, the Company's DSM programs are designed as a way to provide customers the opportunity to manage their electricity usage. In this 2011 Plan, four types of DSM programs are discussed: i) those approved by the SCC, as well as programs most recently approved by the NCUC; ii) those proposed to the SCC on September 1, 2011; iii) those considered future programs which are neither approved or currently filed with either commission for approval, but are potential DSM resources; and iv) those programs rejected from current consideration. All DSM programs were designed and evaluated using a system-level analysis. For reference purposes, Figure 3.2.1 provides a graphical representation of the approved, proposed, future, and rejected programs described in Chapters 3 and 5.

Figure 3.2.1 DSM TARIFFS & PROGRAMS

Tariff	VA Status	NC Status
Standby Generator Tariff	Approved	Approved
Curtailable Service Tariff		
Program	**VA Status**	**NC Status**
Air Conditioner Cycling Program	Approved	Approved
Commercial HVAC Upgrade Program		
Commercial Lighting Program		
Low Income Program		
Residential Lighting Program		
Commercial Distributed Generation Program	Proposed	Pending Review
Commercial Energy Audit Program		Future
Commercial Duct Testing & Sealing Program		
Commercial Refrigeration Program		
Residential Lighting Program (Phase II)		
Residential Bundle Program		
Voltage Conservation Program	Future	
Commercial Re-Commissioning Program		
Commercial Solar Window Film Program		
Commercial Data Center/Computer Room Program		
Commercial Custom Incentive Program		
Residential Cool Roof Program		
Commercial HVAC Tune-Up Program	Rejected	Rejected
Curtailment Service Program		
Energy Management System Program		
ENERGY STAR® New Homes Program		
Geo-Thermal Heat Pump Program		
Home Energy Comparison Program		
Home Performance with ENERGY STAR® Program		
In-Home Energy Display Program		
Premium Efficiency Motors Program		
Programmable Thermostat Program		
Residential Refrigerator Turn-In Program		
Residential Solar Water Heating Program		
Residential Water Heater Cycling Program		
Residential Comprehensive Energy Audit Program		
Residential Radiant Barrier Program		

3.2.1 DSM PROGRAM DEFINITIONS

For purposes of its DSM programs in Virginia, the Company applies the Virginia definitions set forth in Va. Code § 56-576 as provided below.

- Demand Response – Means measures aimed at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.
- Energy Efficiency Program – Means a program that reduces the total amount of electricity that is required for the same process or activity implemented after the expiration of capped rates. Energy efficiency programs include equipment, physical, or program change designed to produce measured and verified reductions in the amount of electricity required to perform the same function and produce the same or a similar outcome. Energy efficiency programs may include, but are not limited to, i) programs that result in improvements in lighting design, heating, ventilation, and air conditioning systems, appliances, building envelopes, and industrial and commercial processes; and ii) measures, such as but not limited to the installation of advanced meters, implemented or installed by utilities, that reduce fuel use or losses of electricity and otherwise improve internal operating efficiency in generation, transmission, and distribution systems. Energy efficiency programs include demand response, combined heat and power and waste heat recovery, curtailment, or other programs that are designed to reduce electricity consumption so long as they reduce the total amount of electricity that is required for the same process or activity. Utilities shall be authorized to install and operate such advanced metering technology and equipment on a customer's premises; however, nothing in this chapter establishes a requirement that an energy efficiency program be implemented on a customer's premises and be connected to a customer's wiring on the customer's side of the inter-connection without the customer's expressed consent.
- Peak Shaving – Means measures aimed solely at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.

For purposes of its DSM programs in North Carolina, the Company applies the definitions set forth in NCGS § 62-133.8 (a) (2) and (4) for DSM and energy efficiency measures as defined below.

- Demand-Side Management – Means activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electricity use from peak to nonpeak demand periods. DSM includes, but is not limited to, load management, electric system equipment and operating controls, direct load control, and interruptible load.
- Energy Efficiency Measure – Means an equipment, physical, or program change implemented after January 1, 2007, that results in less energy used to perform the same function. Energy efficiency measure includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources. Energy efficiency measure does not include DSM.

3.2.2 CURRENT DSM TARIFFS

The Company modeled existing DSM pricing tariffs over its 25-year Study Period based on historical data from the Company's Customer Information System. These projections were modeled with diminishing returns assuming new DSM programs will offer more cost-effective choices in the future. No active DSM resources were discontinued since the Company's 2010 Plan.

<u>**Standby Generator & Curtailable Service Tariffs**</u>

Program Type:	Energy Efficiency - Demand Response
Target Class:	Commercial & Industrial
Participants:	14 customers on Standby Generator in Virginia
	1 customer on Curtailable Service in Virginia
Capacity Available:	See Figure 3.2.2.1

In Virginia, the Company currently offers two DSM pricing tariffs including Standby Generator ("SG") rate schedules and a Curtailable Service ("CS") rate schedule. These tariffs provide incentive payments for dispatchable load reductions that can be called on by the Company when capacity is needed.

The SG rate schedules provide a direct means of implementing load reduction during peak periods by transferring load normally served by the Company to a customer's standby generator. The customer receives a bill credit based on a contracted capacity level or average capacity generated during a billing month when SG is requested. The CS rate schedule requires the participating customer to reduce its electric demand to a contracted firm demand level when requested by the Company in return for a rate reduction credit. Failure to comply with the Company's request to reduce demand to the firm level results in a penalty, based on a demand charge that is approximately four times the per kilowatt ("kW") credit, on the customer's bill. To receive the rate credit, customers commit to participate in the curtailment upon at least two hours' notice. The tariff is primarily aimed at customers with the operational flexibility to store inventory or to curtail or reschedule production.

During a load reduction event, a customer receiving service under the SG rate schedule is required to transfer a contracted level of load to its dedicated on-site backup generator while the customer receiving service under the CS rate schedule is required to reduce load to a contracted firm demand level. At the Company's request, the customer may be asked to reduce load on the Company's system 19 times during the summer (May 16 – September 30) and 13 times during the winter (December 1 – March 31). Additional jurisdictional rate schedule information is available on the Company's website at www.dom.com.

Figure 3.2.2.1 ESTIMATED LOAD RESPONSE DATA

Tariff	Summer 2010		Winter 2010	
	Number of Events	Estimated MW Reduction	Number of Events	Estimated MW Reduction
Standby Generator	16	7	7	5
Curtailable Service	4	2	3	2

3.2.3 CURRENT & COMPLETED DSM PILOTS & DEMONSTRATIONS

<u>Pilots</u>

On September 18, 2007, the Company filed with the SCC for approval of nine conservation, energy efficiency, education, demand response, and load management Pilots. The SCC issued a Final Order on January 17, 2008, approving the Pilots finding that they were necessary to gather information to help the Commonwealth determine methods to achieve the legislative goal affirmed by the Virginia Energy Plan of reducing energy demand by 10% (using 2006 as the base year) by 2022. The Pilots were designed not only to reduce megawatt hour ("MWh") sales and peak demand, but to gain valuable operational information and data on customer usage and customer acceptance of DSM programs.

In March 2009, the Company filed its Final Quarterly Report on the status of the Pilots (Case No. PUE-2007-00089). The Company reported information on the implementation and closure status of each Pilot, an analysis of the seven completed Pilots including a description of the EM&V analyses, and an update on the two uncompleted Pilots. The Pilots have provided valuable information for future programs and numerous learning opportunities for the Company. The Company found that Pilots offering incentives were the most popular among customers. Additionally, the Company experienced greater success with Pilots that did not require in-home customer appointments for installation. The Final Report also noted that customers wanted information at the beginning of their enrollment as to how much savings to anticipate, what to expect on their first bill, and how to determine if they were reducing energy usage. For demand response programs, customers wanted more information on the frequency and duration of demand response events. All of this information is valuable to the Company in developing, marketing, and implementing future DSM programs. The seven completed Pilots discussed in the Final Report included:

1. Direct Load Control – Outdoor Air-Conditioning Control Device Pilot
2. Programmable Thermostats – Indoor Air-Conditioning Control Device Pilot
3. Standard Residential In-Home Energy Audits Pilot
4. ENERGY STAR® Qualified Homes Energy Audits Pilot
5. Energy Efficiency Welcome Kits Pilot
6. PowerCost™ Monitor Pilot
7. Small Commercial On-Site Energy Audits Pilot

Since the final report filed in March of 2009, the Company has filed four follow-up or quarterly reports regarding the status of its Pilots. In its second follow-up report on October 1, 2009, the Company provided an update to two continuing pilots: the Programmable Thermostats with

Advanced Metering Infrastructure ("AMI") and Critical Peak Pricing ("CPP") Pilot and the Distributed Generation ("DG")/Load Curtailment Pilot for Large Non-Residential Customers ("DG Pilot"). The October 2009 Report also provided further information on the PowerCost™ Monitor Pilot and compact fluorescent light ("CFL") price reduction program. On March 1, 2010 the Company filed another follow-up report in which the Company discussed the conclusion of its AMI-CPP Pilot in November 2009 and end of the CFL price reduction program on December 27, 2009. The DG Pilot is the only Pilot from Case No. PUE-2007-00089 that has active participants.

On April 6, 2010, the SCC issued an Order granting the Company's Motion to continue reporting on its DG Pilot on October 31 of each year instead of quarterly reports. The First Annual Report on the DG Pilot was filed on October 29, 2010. Within 90 days of the conclusion of the DG Pilot, the Company must file a final detailed and comprehensive report regarding its future plans for the Pilot.

In addition to the on-going DG Pilot, the Company recently received SCC approval for implementation of other pilots. Descriptions of the Company's other pilots are provided below:

<u>**DG Pilot**</u>

State:	Virginia
Target Class:	Non-Residential
Pilot Type:	Demand Response
Pilot Duration:	Enrollment closed on December 31, 2009 Incentive payments end on December 31, 2014

Pilot Description:
The Company has formed agreements with customers for backup generators to be installed at participants' facilities to be used as replacement power when requested by the Company during periods of high electric demand. A minimum of a 30-minute notice is provided to participants for start and end times of load curtailment events, which the Company may call for up to 200 hours per year. The Company hired an outside contractor, PowerSecure™, to provide backup generation services to participating customers at a discount and dispatch the enrolled generators when requested by the Company in exchange for an incentive payment. The payment is based upon the amount of load curtailment capacity enrolled and the number of hours dispatched.

Current Pilot Status:
At the close of the enrollment period, firm commitments were made by customers to supply approximately 24 MW of backup generator capacity for load curtailment. Of the 24 MW commitment, over 15 MW of capacity is currently operational while the remainder is expected to become available in late 2011. Over 50 load curtailment events have been called during 2009 and 2010. Generally, the events were called during unseasonably warm or cold weather. The

Company continues to use the load curtailment capacity derived from the Pilot to reduce load when called upon during peak load times.

Dynamic Pricing Tariffs Pilot

State:	Virginia
Target Class:	Residential and Non-Residential
Pilot Type:	Peak-Shaving
Pilot Duration:	Enrollment closes December 1, 2012 Pilot concludes November 30, 2013

Pilot Description:

On September 30, 2010, the Company filed an application with the SCC (Case No. PUE-2010-00135) proposing to offer three experimental and voluntary dynamic pricing tariffs to prepare for a potential system-wide offering in the future. The filing was in response to the SCC's July 30, 2010 Order Establishing Pilot Programs issued in Case No. PUE-2009-00084, which, among other things, directed the Company to establish a pilot program under which eligible customers/renewable generators volunteering to participate would be provided the ability to purchase and sell electricity to the Company at dynamic rates.

A dynamic pricing schedule allows the Company to apply different prices as system production costs change. The basic premise is that if customers are willing to modify behavior and use less electricity during high price periods, they will have the opportunity to save money, and the Company in turn will be able to reduce the amount of energy it would otherwise have to generate or purchase during peak periods.

Specifically, the Company proposed a pilot program of 2,000 participants consisting of 1,000 residential customers taking service under experimental dynamic pricing tariff DP-R and 1,000 commercial/general customers taking service under dynamic pricing tariffs DP-1 and DP-2. Participation in the pilot requires either an Advanced Metering Infrastructure ("AMI") meter or an existing interval data recorder ("IDR") meter at the customer location.

Energy usage is recorded every 30 minutes, which enables the Company to offer pricing that varies based on the time of day. In addition, the pricing varies based on the season, the classification for the day, and the customer's demand. Therefore, the AMI or IDR meter coupled with the dynamic pricing schedules allows customers to manage their energy costs based on the time of day.

Additional information regarding the pilot is available at http://www.dom.com/smartprice.

Current Pilot Status:

The filing was approved by the SCC's Order Establishing Pilot Program issued on April 8, 2011. The Company launched this pilot program on July 1, 2011.

Electric Vehicle ("EV") Pilot

State:	Virginia
Target Class:	Residential
Pilot Type:	Peak-Shaving
Pilot Duration:	Enrollment begins October 3, 2011 Pilot concludes November 30, 2014

Pilot Description:

On January 31, 2011, the Company filed an application with the SCC (Case No. PUE-2011-00014) proposing a pilot program to offer experimental and voluntary EV rate options to encourage residential customers who purchase or lease EVs to charge them during off-peak periods. The pilot program provides two rate options. One rate option, a "whole house" rate, will allow customers to apply the time-of-use rate to their entire service, including their premise and vehicle. The other rate option, an "EV only" rate, will allow customers to remain on their existing standard rate for their premise and subscribe to the time-of-use rate only for their vehicle. The program will be open to up to 1,500 residential customers, with up to 750 in each of the two experimental rates. Additional information regarding the Company's EV Pilot Program is available in the Company's application and in the SCC's Order Granting Approval.

Current Pilot Status:

The SCC approved the pilot on July 11, 2011. The Company plans to begin pilot enrollment October 3, 2011 and conclude the pilot November 30, 2014. If supported by the results of the pilot program, the Company plans to request approval of a Virginia service territory EV peak-shaving program in the future.

Demonstrations

The Company is also continuing its demonstration efforts for AMI, herein referred to as the "AMI Demonstration." The AMI Demonstration is an on-going project that will help the Company further evaluate the technology and verify the potential impacts to its system.

AMI Demonstration

State:	Virginia
Target Class:	All-classes
Type:	Energy Efficiency
Duration:	On-going

Demonstration Description:

The Company indicated in its supplemental testimony on February 12, 2010 (Case No. PUE-2009-00081) that it wanted to obtain further information regarding AMI to ensure that the technology, costs and benefits of implementing the technology, and technology's potential for energy reduction were better understood. In 2010, the Company extended its AMI demonstration by installing approximately 32,000 AMI meters in parts of City of Alexandria, Arlington County, Fairfax County, and City of Falls Church, Virginia. The Company's efforts to demonstrate meter technology continue with additional meter exchanges in 2011. The Company plans to install approximately 8,000 meters to evaluate additional technology in Blue Ridge, downtown Richmond, and Williamsburg by the end of 2011.

3.2.4 CURRENT CONSUMER EDUCATION PROGRAMS

The Company's consumer education initiatives include providing demand and energy usage information, educational opportunities, and online customer support options to assist customers in managing their energy consumption. The Company's website has a section dedicated to energy conservation. This section contains helpful information for both residential and non-residential customers, including information about the Company's DSM programs. Through consumer education, the Company is working to encourage the adoption of energy-efficient technologies in residences and businesses in Virginia and North Carolina. Examples of how the Company increases customer awareness include:

Customer Connection Newsletter

State: Virginia and North Carolina

The Customer Connection newsletter is sent to customers as an insert to their monthly power bill six times per year. It contains news on topics such as DSM programs, how to save money or manage electric bills, helping the environment, service issues, and safety recommendations, in addition to many other relevant subjects. For those who receive their electric bills by e-mail, the newsletter is available online. Articles from the most recent Virginia Customer Connection Newsletter are located on the Company's website at http://www.dom.com/dominion-virginia-power/customer-service/your-bill/customer-connection.jsp. Articles from the most recent North Carolina Customer Connection Newsletter are located on the Company's website at: http://www.dom.com/dominion-north-carolina-power/customer-service/your-bill/customer-connection.jsp.

Energy Conservation Blog

State: Virginia and North Carolina

The Company has an "Energy Conservation Blog," which is an online forum for Company experts to answer customer questions on energy-related topics and provide specific examples of measures to take that will help reduce energy consumption. It is also a means to provide information about the Company's DSM programs. The blog is online at: http://e-conserve.blogspot.com/.

Twitter ®

State: Virginia and North Carolina

The Company uses the social media channel Twitter® to provide real-time updates on energy-related topics, promote company messages and provide two-way communication with customers. The Twitter® account is available online at: www.twitter.com/DomVAPower.

"Every Day"

State: Virginia

The Company advertises the "Every Day" campaign, which is a series of commercial and print ads that address various energy issues. These advertisements, along with the Company's other advertisements, are available at:
http://www.dom.com/about/advertising/index.jsp.

News Releases

State: Virginia and North Carolina

The Company prepares news releases and reports on the latest developments regarding its DSM initiatives and provides updates on Company offerings and recommendations for saving energy as new information becomes available. Current and archived news releases can be viewed at: http://www.dom.com/news/index.jsp.

Online Energy Calculators

State: Virginia and North Carolina

Home and business energy calculators are provided on the Company's website to estimate electrical usage for homes and business facilities. The calculators can help customers understand specific energy use by location and discover new means to reduce usage and save money. An appliance energy usage calculator and holiday lighting calculator are also available to customers. The energy calculators are available at:
http://www.dom.com/about/conservation/energy-calculators-help-find-energy-savings.jsp.

Community Outreach - Trade Shows, Exhibits and Speaking Engagements

State: Virginia and North Carolina

The Company conducts outreach seminars and speaking engagements in order to share relevant energy conservation information to both internal and external audiences. The Company also participates in various trade shows and exhibits at energy-related events to inform customers and communities about the importance of implementing energy-saving measures in homes and businesses. Additionally, Company representatives positively impact the communities served through presentations to elementary, middle, and high school students about using energy wisely and environmental stewardship.

The Company also provides helpful materials for students to share with their families. "Project Plant It!" is an innovative program available to elementary school students in Virginia, North Carolina, Massachusetts, Connecticut, Rhode Island, Maryland, and Wisconsin that teaches students about the importance of trees and how to protect the environment. This program includes interactive classroom lessons and provides students with tree seedlings to plant at home or at school. The Company has provided this program free of charge to thousands of elementary school students throughout the Company's service territory and recently distributed the 100,000th seedling through the program.

As part of the Residential Lighting Program, this year the Company held energy efficient lighting outreach events at Lowe's throughout the Virginia service territory with educational activities for kids and information for adults. In April, the Company held a Lighting Program school contest with Culpeper, Virginia elementary schools. The school that accrued the most vouchers and receipts attributed to compact florescent light CFL bulb sales received a $5,000 math and science scholarship to support its math and science initiatives. The Company is planning similar educational contests in October 2011 for communities in Virginia and North Carolina.

Home Energy Reports

State: Virginia

Beginning in May of 2010, the Company partnered with OPOWER® to provide Home Energy Reports to 25,000 customers in the Charlottesville, Virginia area on a bi-monthly basis for one year. The reports are designed to help customers understand their home's energy usage and find ways to make their home more efficient, including references to the Company's energy conservation programs. The Company recently completed this initiative.

Discontinued Consumer Education Programs

The Company has removed its carbon calculator formally available on www.dom.com due to fewer web visitors than anticipated; however, other energy calculators are available for customer use.

3.2.5 DSM TARGETS CASE

On April 30, 2009, the SCC initiated a proceeding to determine achievable, cost-effective energy conservation and demand response targets that could realistically be achieved by each electric utility in the Commonwealth of Virginia. The SCC received input from the three generating electric utilities in the Commonwealth: the Company, Appalachian Power, and Kentucky Utilities. In the filings, the utilities discussed a realistically achievable level of savings, with the Company's testimony stating that a 10% goal using the 2006 base year was an aggressive, but realistic target. Eight interveners filed testimony, with the SCC Staff filing its testimony prior to the evidentiary hearing. During the hearing, the parties generally agreed that this goal was achievable.

On November 15, 2009, the SCC submitted a report to the Virginia Governor and the General Assembly, as required by law, finding that a 10% reduction in electric energy consumption through DSM, demand response, and energy efficiency programs was a realistic and achievable goal. The SCC did find that due to current economic conditions, rate impact implications, and the limited amount of time in which to complete the proceeding and issue the report, it was not recommending mandates to the utilities regarding particular targets to be achieved, required programs, or specific technologies to be used. Instead, the SCC stated that it would evaluate proposals on a case-by-case basis.

3.2.6 APPROVED DSM PROGRAMS

In Virginia, the Company filed for SCC approval of 12 DSM programs ("DSM Programs") on July 28, 2009 (Case No. PUE-2009-00081). On February 12, 2010, the Company filed supplemental testimony in order to withdraw its proposed Voltage Conservation Program and further evaluate the potential impacts of AMI through the on-going AMI Demonstration discussed in Section 3.2.3. On March 24, 2010, the SCC issued its Final Order approving five of the 11 proposed Programs including the: i) Air Conditioner Cycling Program, ii) Commercial Heating, Ventilating, and Air Conditioning ("HVAC") Upgrade Program, iii) Commercial Lighting Program, iv) Low Income Program, and v) Residential Lighting Program.

On March 11, 2010, the NCUC issued an Order requiring the Company to file for approval of demand response programs on or before September 1, 2010 (Docket No. E-22, Sub 418). In response to this Order, the Company filed for approval of six DSM Programs in North Carolina on September 1, 2010, in Docket No. E-22, Subs 465 (Air Conditioner Cycling Program), 466 (Commercial Distributed Generation Program), 467 (Commercial HVAC Upgrade Program), 468 (Residential Lighting Program), 469 (Commercial Lighting Program), and 463 (Low Income Program). These six proposed Programs are similar to the Programs approved in Virginia, with the exception of the Commercial Distributed Generation ("CDG") Program, which was not approved in its initial form by the SCC in Case No. PUE-2009-00081. The CDG Program has since been redesigned to address concerns of both the Virginia and North Carolina Commissions, SCC Staff and North Carolina Public Staff.

On February 22, 2011, the NCUC issued Final Orders approving five Programs including the: i) Air Conditioner Cycling Program, ii) Commercial HVAC Upgrade Program, iii) Commercial Lighting Program, iv) Low Income Program, and v) Residential Lighting Program.

On March 3, 2011, the NCUC issued an Order Scheduling Oral Argument for the Company's CDG Program, which was heard on April 13, 2011. Currently, the NCUC's proceeding regarding the CDG Program review is pending.

Appendices 3M, 3N, 3O, and 3P provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each approved Program. A brief description of each approved Program is available below. Included in the descriptions are the branded names used for customer communications and marketing plans that the Company is employing and plans to achieve each Program's penetration goals.

Air Conditioner Cycling Program

Branded Name: Smart Cooling Rewards
State: Virginia & North Carolina
Target Class: Residential
VA Program Type: *Peak Shaving*
VA Duration: Ongoing
NC Duration: 2011 – 2036

Program Description:
This Program provides participants with an external radio frequency cycling switch that operates on central air conditioners and heat pump systems. Participants allow the Company to cycle their central air conditioning and heat pump systems during peak load periods. The cycling switch is installed by a contractor and located on or near the outdoor air conditioning unit(s). The Company remotely signals the unit when peak load periods are expected, and the air conditioning or heat pump system is cycled off and on for short intervals.

Program Marketing:
Direct mail is currently the most frequently used marketing approach for this type of Program. The Company uses various enrollment methods including business reply cards, online enrollment, and call centers.

Commercial HVAC Upgrade Program

Branded Name: HVAC Rewards
State: Virginia & North Carolina
Target Class: Commercial and Industrial
VA Program Type: Energy Efficiency
VA Duration: Ongoing
NC Duration: 2011 – 2036

Program Description:
The Program provides incentives for HVAC system efficiency upgrades for the commercial sector including chillers, roof-top units, and packaged terminal air conditioners. Participants who enroll in the Program receive a one-time incentive payment for replacing or upgrading inefficient heating and cooling systems. This upgrade helps assure commercial customers that their HVAC systems are running at maximum efficiency while minimizing energy consumption.

Program Marketing:
The Company markets this Program using a Contractor Network. The Program implementation vendor works with and provides content to a contractor base, which performs the actual upgrades and administers the company rebates for customers. As part of this effort, a website was developed, www.DomEnergyConservationPortal.com, where contractors can enroll in the network and submit rebate applications.

Commercial Lighting Program

Branded Name: Lighting Rewards
State: Virginia & North Carolina
Target Class: Commercial and Industrial
VA Program Type: Energy Efficiency
VA Duration: Ongoing
NC Duration: 2011 – 2036

Program Description:
This Program provides commercial and industrial customers with an incentive to upgrade inefficient lighting systems to more cost-effective, energy-efficient lighting systems. Participants will receive a one-time average incentive based on the lighting upgrades selected.

Program Marketing:
The Company markets this Program using a Contractor Network. The Program implementation vendor works with and provides content to a contractor base, which performs the actual upgrades and administers the company rebates for customers. As part of this effort, a website was developed, www.DomEnergyConservationPortal.com, where contractors can enroll in the network and submit rebate applications.

Low Income Program

Branded Name: Home Energy Improvement
State: Virginia & North Carolina
Target Class: Residential
VA Program Type: Energy Efficiency
VA Duration: Ongoing
NC Duration: 2011 – 2036

Program Description:
The Low Income Program provides an energy audit for residential customers who meet the low income criteria defined by state social service agencies. A certified technician performs an audit of participating residences to determine potential energy efficiency improvements. Specific energy efficiency measures applied may include, but are not limited to: envelope sealing, water heater temperature set point reduction, installation of insulation wrap around the water heater and pipes, installation of low flow shower head(s), replacement of incandescent lighting with efficient lighting, duct sealing, attic pressure testing, attic insulation, and air filter replacement.

Program Marketing:
The Company markets this Program using a neighborhood canvassing approach in prescreened areas targeting income qualifying customers. To ensure neighborhood security and program legitimacy, community posters, truck decals, yard signs, and authorization forms have been produced and are displayed in areas where the Program has current activity.

Residential Lighting Program

Branded Name:	Lighting Program
State:	Virginia & North Carolina
Target Class:	Residential
VA Program Type:	Energy Efficiency
VA Duration:	Ongoing
NC Duration:	2011 – 2036

Program Description:

This Program is an extension of the Company's previous CFL price reduction program, which ran from October 2007 to December 2009. As part of this Program, the Company partners with manufacturers and retailers to provide participants with an instant rebate for high-efficiency lighting purchases. CFLs, when compared to incandescent bulbs, give the same amount of visible light, use approximately 75% less energy, and have an approximately 10 times longer rated life. This Program ceases to allow new participants on December 31, 2011.

Program Marketing:

The Program's automatic price discount ensures easy customer participation. The Company uses point-of-purchase marketing material in select retail locations next to the discounted bulbs to inform customers that the Company is providing a price discount.

CDG Program

Branded Name:	Distributed Generation
State:	North Carolina
Target Class:	Commercial and Industrial
NC Program Type:	Demand-Side Management
NC Duration:	2011 – 2036

Program Description:

As part of this Program, a third party contractor will dispatch, monitor, maintain and operate customer-owned generation when called upon by the Company during peak demand periods for up to 120 hours per year, throughout all months. The Company will supervise and implement the CDG Program through the third party implementation contractor. Participating customers will essentially receive reduced cost backup generation service in exchange for their agreement to reduce electrical load on the Company's system. The reduction in cost of the backup generation service is facilitated through a fee paid by the Company to the third party contractor, based upon the amount of load curtailment delivered during control events. At least 80% of the program participation incentive is required to be passed through to the customer, with 100% of fuel and operations and maintenance compensation passed along to the customer. When not being dispatched by the Company, the generators may be used at the participants' discretion or to supply power during an outage, consistent with applicable environmental restrictions. Currently, the NCUC's proceeding regarding the CDG Program review is pending.

Program Marketing:
Marketing will be handled by the Company's implementation vendor.

3.2.7 PROPOSED DSM PROGRAMS

In Virginia, the Company filed for SCC approval of six DSM Programs on September 1, 2011 (Case No. PUE-2011-00093). The six proposed Programs include i) Commercial Energy Audit Program, ii) Commercial Duct Testing & Sealing Program, iii) Commercial Refrigeration Program, iv) CDG Program, v) Residential Lighting (Phase II) Program and vi) Residential Bundle Program.

The Company seeks approval of the Residential Bundle Program as one Program that will be offered to customers as a combined bundle of services. The Residential Bundle Program consists of: i) Residential Home Energy Check-Up Program, ii) Residential Duct Testing & Sealing Program, iii) Residential Heat Pump Tune-Up Program, and iv) Residential Heat Pump Upgrade Program. This Program has also been studied for cost-effectiveness as one Program.

These proposed DSM Programs provide a diversified mix of programs that the Company believes are cost-effective and should be approved as being in the public interest. Provided in this section are the high-level descriptions of these programs. Appendices 3Q, 3R, 3S, and 3T present data for their system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations.

<u>Commercial Energy Audit Program</u>

Target Class:	Non-residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2012 – 2036
NC Duration:	2014 – 2036

Program Description:
As part of this Program, an energy auditor will perform an on-site energy audit of a non-residential customer's facility. The customer will receive a report showing the projected energy and cost savings that could be anticipated from the implementation of options identified during the audit. Once a qualifying customer provides documentation that some of the recommended energy efficiency improvements have been made at the customer's expense, a portion of the audit price will be refunded, up to the full price of the audit.

Commercial Duct Testing & Sealing Program

Target Class: Non-residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2012 – 2036
NC Duration: 2014 – 2036

Program Description:
This Program will promote testing and general repair of poorly performing duct and air distribution systems in non-residential facilities. The Program provides incentives to qualifying customers to have a contractor seal ducts in existing buildings using program-approved methods, including: aerosol sealant, mastic, or foil tape with an acrylic adhesive. Such systems include air handlers, air intake, return and supply plenums, and any connecting duct work.

Commercial Refrigeration Program

Target Class: Non-residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2012 – 2036
NC Duration: 2014 – 2036

Program Description:
This Program provides calculated incentives to qualifying non-residential customers for the installation of program-approved refrigeration measures.

CDG Program

Target Class: Non-residential
VA Program Type: Demand Response / Energy Efficiency
NC Program Type: Demand-Side Management
VA Duration: 2012 – 2036
NC Duration: 2011 – 2036

Program Description:
This Program provides qualifying customers with an incentive to curtail load by operating customer-owned backup generation when called upon to do so up to 120 hours per year. The Program is implemented by a contractor who is responsible for installing equipment to enable remote operation and monitoring of the customer's backup generation equipment and for dispatching load curtailment events under the direction of the Company. Additional Program details are provided in Section 3.2.6.

Residential Lighting Program (Phase II)
Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2012 – 2036
NC Duration: 2014 – 2036

Program Description:
This Program promotes the installation of CFL and light-emitting diode based bulbs in lieu of conventional incandescent bulbs.

Residential Bundle Program
Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2012 – 2036
NC Duration: 2014 – 2036

The Residential Bundle Program includes the four following DSM Programs described below.

Residential Home Energy Check-Up Program
Program Description:
The purpose of this Program is to provide owners and occupants of single family homes an easy and low cost home energy audit. It will include a walk through audit of customer homes, direct install measures, and recommendations for additional home energy improvements.

Residential Duct Testing & Sealing Program
Program Description:
This Program is designed to promote the testing and repair of poorly performing duct and air distribution systems. Qualifying customers will be provided an incentive to have a contractor test and seal ducts in their homes using methods approved for the Program, such as mastic material or foil tape with an acrylic adhesive to seal all joints and connections. The repairs are expected to reduce the average air leakage of a home's conditioned floor area to industry standards.

Residential Heat Pump Tune-Up Program
Program Description:
This Program provides qualifying customers with an incentive to have a contractor tune-up their existing heat pumps once every five years in order to achieve maximum operational performance. A properly tuned system should increase efficiency, reduce operating costs, and prevent premature equipment failures.

Residential Heat Pump Upgrade Program
Program Description:
This Program provides incentives for residential heat pump (e.g., air and geothermal) upgrades. Qualifying equipment must have better Seasonal Energy Efficiency Ratio and Heating Seasonal Performance Factor ratings than the current nationally mandated efficiency standards.

3.2.8 EVALUATION, MEASUREMENT & VERIFICATION

The Company has implemented EM&V plans to quantify the level of energy and demand savings for approved Programs in Virginia and North Carolina. As required by the SCC and NCUC, the Company will provide periodic EM&V reports that include: i) the actual EM&V data; ii) the cumulative results for each Program in comparison to forecasted annual projections; and iii) any recommendations or observations following the analysis of the EM&V data. The Company signed a contract with a third-party vendor, KEMA, Inc., to be responsible for developing, executing, and reporting the EM&V results for the Company's currently approved DSM Programs.

3.3 TRANSMISSION RESOURCES

3.3.1 EXISTING TRANSMISSION RESOURCES

The Company has over 6,100 miles of transmission lines in Virginia, North Carolina, and West Virginia at voltages ranging from 69 kV to 500 kV. These facilities are integrated into PJM.

In Virginia, the Company added two 230 kV lines: i) Chickahominy – Old Church line (March 2011) and ii) Suffolk – Thrasher line (June 2011) and two 500 kV lines: i) Meadowbrook – Loudoun line (April 2011) and ii) Carson – Suffolk line (May 2011). In addition, 230 kV Iron Bridge – Southwest line (May 2011) and 230 kV Pleasant View – Dickerson line (June 2011) were uprated, and 230 kV Brambleton to Pleasant View line was reconductored.

The Company has the following transmission ties with other systems to facilitate economic and emergency transfer of power with neighboring utilities:

- One 500 kV and one 230 kV interconnection with PJM / Potomac Electric Power Company to north of the DOM Zone.
- One 500 kV, four 230 kV, and two 115 kV interconnections with Progress Energy-Carolinas to south of the DOM Zone.
- Seven 500 kV, one 138 kV, and one 115-138 kV transformer interconnections with Allegheny Power to northwest of the DOM Zone.
- One 500 kV, four 138 kV, and two 115-69 kV transformers interconnections with American Electric Power to the west of the DOM Zone.

These ties also serve as a source of mutual support between the Company and other utilities to help ensure reliable service to customers.

3.3.2 EXISTING TRANSMISSION & DISTRIBUTION LINES

North Carolina Plan Addendum 2 contains the list of Company's existing transmission and distribution lines listed in pages 422, 423, 424, 425, 426 and 427, respectively, of the Company's most recently filed Federal Energy Regulatory Commission ("FERC") Form 1.

3.3.3 TRANSMISSION PROJECTS UNDER CONSTRUCTION

The Company currently does not have any transmission interconnection projects under construction (Appendix 3U). A list of the Company's transmission lines and associated facilities that are under construction may be found in Appendix 3V.

Chapter 4 | Planning Assumptions

CHAPTER 4 –PLANNING ASSUMPTIONS

4.1 PLANNING ASSUMPTIONS INTRODUCTION

The Company's 2011 Plan relies upon a number of assumptions and constraints including requirements from PJM. Chapter 4 covers a diverse set of assumptions and requirements related to capacity needs and reserve requirements, renewable energy requirements, commodity price assumptions, and transmission assumptions. The Company updates its planning assumptions annually to maintain a consistent view of relevant markets, the economy, and regulatory drivers.

4.2 PJM CAPACITY PLANNING PROCESS & RESERVE REQUIREMENTS

The Company participates in the PJM capacity planning processes for short- and long-term capacity planning. A brief discussion of these processes and the Company's participation in them is provided in the following sub-sections.

4.2.1 SHORT-TERM CAPACITY PLANNING PROCESS – RELIABILITY PRICING MODEL

As a PJM member, the Company is a signatory to PJM's Reliability Assurance Agreement, which obligates the Company to own or procure sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone through its annual load forecast and reserve margin guidelines. PJM then conducts a capacity auction through its Short-Term Capacity Planning Process - RPM for meeting these requirements three years into the future. This auction process determines the actual reserve margin and the capacity price for each zone for the third planning year.

The Company, as a generation provider, bids its capacity resources, including owned and contracted generation and DSM programs, into this auction. The Company, as an LSE, is obligated to buy enough capacity to cover its capacity requirements from the RPM auction, or through any bilateral trades. Figure 4.2.2.1 provides the Company's estimated 2012 to 2014 capacity positions and associated reserve margins based on PJM's January 2011 Load Forecast and RPM auctions that have already been conducted.

4.2.2 LONG-TERM CAPACITY PLANNING PROCESS – RESERVE REQUIREMENTS

The Company uses PJM's reserve margin guidelines in conjunction with its own load forecast discussed in Chapter 2 to determine its long-term capacity requirement. PJM conducts an annual Reserve Requirement Study to determine an adequate level of capacity in its footprint to meet the target level of reliability measured with a Loss of Load Expectation ("LOLE") that is equivalent to 1 day of outage in 10 years. PJM's 2010 Reserve Requirement Study[4] recommends using a reserve margin of 15.3% to satisfy the reliability criteria required by NERC, RFC, and PJM's Planned Reserve Sharing Group. According to PJM's 2010 Reserve

[4] PJM's current reserve margin study, "2010 Reserve Requirement Study," is available at www.pjm.com.

Requirement Study, the minor changes to the generation and load models that offset each other have resulted in an identical reserve margin with last year's study.[5]

Three assumptions were made by the Company when applying the PJM reserve margin to the Company's modeling efforts. First, since PJM uses a shorter planning period than the Company, the Company took the most recent reserve requirements study and assumed the reserve margin value for the year indicated would continue throughout its Study Period. Second, PJM develops reserve margin estimates for planning years rather than calendar years. Specifically, PJM's planning year occurs from June of one year to May of the following year. Since the Company and PJM are both historically summer peaking entities, calendar and planning year reserve requirements have no impact on planning requirements. For example, the Company uses the 2014 to 2015 planning year assumptions for the 2014 calendar year in its 2011 Plan. The final assumption is in regard to the coincident factor between the DOM Zone coincidental and non-coincidental peak load. The Company is only obligated to maintain a reserve margin for its portion of the PJM coincidental peak load. Since the Company's peak load (non-coincidental) has not historically occurred during the same hour as PJM's peak load (coincidental), a smaller reserve margin is needed to meet reliability targets and is based on a coincidence factor. To create the coincidence factor used in the 2011 Plan, the Company used a four-year (2011-2014) average of the coincidence factor between the DOM Zone coincidental and non-coincidental peak load. The coincidence factor for the Company's load is approximately 96.3% as calculated using PJM's January 2011 Load Forecast. In 2014, applying the PJM Installed Reserve Margin requirement of 15.3% with the Company's coincidence factor of 96.3% resulted in an effective reserve margin of 11.0% as shown in Figure 4.2.2.1. This reserve margin was then used for each year for the remainder of the Planning Period.

FIGURE 4.2.2.1 PEAK LOAD FORECAST & RESERVE REQUIREMENTS

Year	Net Summer Peak[1]	PJM Installed Reserve Margin Requirements[2]	Effective Reserve Margin	Reserve Requirement	Total Resource Requirement[3]
	MW	%	%	MW	MW
2012	16,999	-	18.4%	3,119	20,119
2013	17,447	-	18.1%	3,163	20,610
2014	17,952	-	11.0%	1,975	19,927
2015	18,388	15.3%	11.0%	2,021	20,409
2016	18,686	15.3%	11.0%	2,053	20,739
2017	18,973	15.3%	11.0%	2,085	21,058
2018	19,295	15.3%	11.0%	2,120	21,415
2019	19,604	15.3%	11.0%	2,154	21,758
2020	20,035	15.3%	11.0%	2,202	22,237
2021	20,413	15.3%	11.0%	2,243	22,656
2022	20,771	15.3%	11.0%	2,282	23,053
2023	21,125	15.3%	11.0%	2,321	23,446
2024	21,409	15.3%	11.0%	2,352	23,762
2025	21,765	15.3%	11.0%	2,392	24,157
2026	22,201	15.3%	11.0%	2,439	24,640

Notes: 1) Includes all Load Forecast Adjustments. 2) 2012 – 2014 values reflect the Company's position following RPM base residual auctions that have cleared. 3) Includes wholesale obligations.

[5] 2010 PJM Reserve Requirement Study, Page 2.

In Figure 4.2.2.1, the total resource requirement column provides the total amount of peak capacity including the reserve margin used in the 2011 Plan. This represents the Company's total resource need that must be met through existing resources, construction of new resources, DSM programs, and market capacity purchases. Actual reserve margins in each year may vary based upon the outcome of the forward RPM auctions and annually updated load and reserve requirements. Appendix 2I provides a summary of projected PJM reserve margins for summer peak demand.

PJM's processes are an integral part of the Company's planning processes. For transmission planning, the Company utilizes PJM's regional perspective. For short-term capacity planning up to three years in the future, the Company participates in the RPM process and for long-term capacity planning the Company follows the PJM reserve margin guidelines.

4.3 RENEWABLE ENERGY REQUIREMENTS

4.3.1 VIRGINIA RPS PLAN

On May 18, 2010, the SCC issued its final order granting the Company's July 28, 2009 application to participate in Virginia's voluntary Renewable Energy Portfolio Standard ("RPS") program finding that "the Company has demonstrated that it has a reasonable expectation of achieving 12% of its base year electric energy sales from renewable energy sources during calendar year 2022, and 15% of its base year electric energy sales from renewable energy sources during calendar year 2025" (Case No. PUE-2009-00082). The RPS requirements prescribe that a certain percent of the Company's energy should be obtained from renewable resources. The Company can meet Virginia's RPS program guidelines through the generation of renewable energy, purchase of renewable energy, purchase of Renewable Energy Certificates ("RECs"), or a combination of the three options. The Company achieved its 2010 Virginia RPS Goal. Figure 4.3.1.1 displays Virginia's RPS goals.

Figure 4.3.1.1 VIRGINIA RPS GOALS

Year	Percent of RPS	Annual GWh[1]
2010	4% of Base Year Sales	1,733
2011-2015	Average of 4% of Base Year Sales	1,733
2016	7% of Base Year Sales	3,032
2017-2021	Average of 7% of Base Year Sales	3,032
2022	12% of Base Year Sales	5,198
2023-2024	Average of 12% of Base Year Sales	5,198
2025	15% of Base Year Sales	6,497

Note: 1) Base year sales are equal to 2007 VA jurisdictional retail sales, minus 2004 to 2006 average nuclear generation. Actual goals are based on MWh.

The Company has included renewable resources as an option in Strategist taking into consideration the economics and RPS requirements as applicable to its Plan. Specifically, the Company has filed for approval of amended CPCNs for the conversion of three coal burning units to use biomass for a total of 153 MW. Also under construction is approximately 59 MW of biomass capacity at VCHEC. Additionally, the Company is developing the Halifax County Solar 4 MW facility. The 2011 Plan reiterates the Company's intent to meet Virginia's RPS guidelines at a reasonable cost and in a prudent manner by: i) applying renewable energy from existing generating facilities including NUGs; ii) purchasing cost-effective RECs (including optimizing RECs produced by Company-owned generation where more expensive RECs are sold in the market and less expensive RECs are purchased and applied to the Company's RPS goals); and iii) constructing new renewable resources when and where economically feasible.

4.3.2 NORTH CAROLINA REPS PLAN

NCGS § 62-133.8 requires the Company to comply with the state's Renewable Energy and Energy Efficiency Portfolio Standard Plan ("REPS") requirement. The REPS requirements can be met by generating renewable energy, energy efficiency measures (capped at 25% of the REPS requirements through 2020 and up to 40% thereafter), purchasing renewable energy, purchasing RECs, or a combination of options as permitted by NCGS § 62-133.8 (b) (2). The Company plans to meet a portion of the general REPS requirements using the approved energy efficiency programs discussed in Chapter 3 and 6 of this Plan. The Company achieved compliance with its 2010 North Carolina REPS requirements by purchasing RECs. More information regarding the Company's plans is available in its North Carolina REPS Compliance Plan filed in North Carolina with this 2011 Plan as North Carolina IRP Addendum 1. Figure 4.3.2.1 displays North Carolina's overall REPS requirements.

Figure 4.3.2.1 NORTH CAROLINA REPS REQUIREMENTS

Year	Percent of REPS	Annual GWh[1]
2012	3% of 2011 NC Retail Sales	120
2013	3% of 2012 NC Retail Sales	124
2014	3% of 2013 NC Retail Sales	129
2015	6% of 2014 NC Retail Sales	260
2016	6% of 2015 NC Retail Sales	263
2017	6% of 2016 NC Retail Sales	271
2018	10% of 2017 NC Retail Sales	455
2019	10% of 2018 NC Retail Sales	461
2020	10% of 2019 NC Retail Sales	469
2021	12.5% of 2020 NC Retail Sales	597

Note: 1) Annual gigawatt hour is an estimate only based on the latest forecast sales. The Company intends to comply with the North Carolina REPS requirements, including the set-asides for energy derived from solar, poultry litter, and swine waste through the purchase of RECs and/or purchased energy, as applicable. These set aside requirements represent approximately 0.03% of system load by 2024 and will not materially alter the 2011 Plan.

As part of the total REPS requirements, North Carolina requires certain renewable set aside provisions for solar energy, swine waste, and poultry waste resources as shown in Figure 4.3.2.2, Figure 4.3.2.3, and Figure 4.3.2.4.

Figure 4.3.2.2 NORTH CAROLINA SOLAR REQUIREMENTS

Year	Requirement Target (%)	Annual GWh[1]
2010	0.02% of 2009 NC Retail Sales	0.81[2]
2011	0.02% of 2010 NC Retail Sales	0.87[3]
2012	0.07% of 2011 NC Retail Sales	2.80
2013	0.07% of 2012 NC Retail Sales	2.90
2014	0.07% of 2013 NC Retail Sales	3.00
2015	0.14% of 2014 NC Retail Sales	6.07
2016	0.14% of 2015 NC Retail Sales	6.14
2017	0.14% of 2016 NC Retail Sales	6.32
2018	0.20% of 2017 NC Retail Sales	9.11
2019	0.20% of 2018 NC Retail Sales	9.23
2020	0.20% of 2019 NC Retail Sales	9.38
2021	0.20% of 2020 NC Retail Sales	9.56

***Notes:** 1) Annual gigawatt hour is an estimate based on latest forecast sales. 2) The Company achieved compliance with the 2010 NC Solar target by purchasing 806 solar RECs. 3) The Company has purchased solar RECs necessary to satisfy the North Carolina 2011 goal of 866 solar RECs. Please reference the Company's North Carolina 2011 REPS Compliance Plan, attached as North Carolina IRP Addendum 1, for additional details.*

Figure 4.3.2.3 NORTH CAROLINA SWINE WASTE REQUIREMENTS

Year	Target[1]	Dominion Market Share (Est.)	Annual GWh[2]
2012	0.07% of 2011 NC Retail Sales	3.02%	2.80
2013	0.07% of 2012 NC Retail Sales	3.07%	2.90
2014	0.07% of 2013 NC Retail Sales	3.13%	3.00
2015	0.14% of 2014 NC Retail Sales	3.11%	6.07
2016	0.14% of 2015 NC Retail Sales	3.09%	6.14
2017	0.14% of 2016 NC Retail Sales	3.12%	6.32
2018	0.20% of 2017 NC Retail Sales	3.10%	9.11
2019	0.20% of 2018 NC Retail Sales	3.08%	9.23
2020	0.20% of 2019 NC Retail Sales	3.08%	9.38
2021	0.20% of 2020 NC Retail Sales	3.08%	9.56

***Notes:** 1) The Swine Waste Resource requirement is calculated as an aggregate target for NC Electric Suppliers distributed based on market share. 2) Annual gigawatt hour is an estimate only based on the latest forecast sales.*

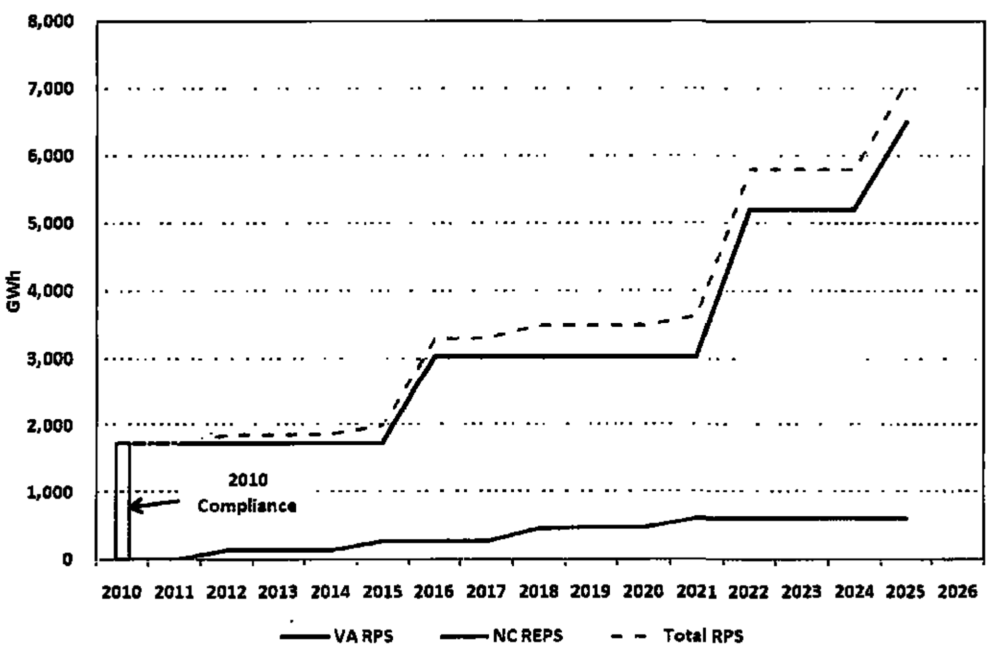
Figure 4.3.2.4 NORTH CAROLINA POULTRY WASTE REQUIREMENTS

Year	Target (GWh)	Dominion Market Share (Est.)	Annual GWh[1]
2012	170	3.02%	5.14
2013	700	3.07%	21.50
2014	900	3.13%	28.16
2015	900	3.11%	27.99
2016	900	3.09%	27.78
2017	900	3.12%	28.10
2018	900	3.10%	27.87
2019	900	3.08%	27.74
2020	900	3.08%	27.69
2021	900	3.08%	27.72

Note: *1) For purposes of this filing, the Poultry Waste Resource requirement is calculated as an aggregate target for NC electric suppliers distributed based on market share.*

The renewable energy requirements for Virginia and North Carolina and their totals have been provided in Figure 4.3.2.5.

Figure 4.3.2.5 RENEWABLE ENERGY REQUIREMENTS



4.4 COMMODITY PRICE ASSUMPTIONS

The Company performed the analysis for the 2011 Plan using energy and commodity price forecasts provided by ICF International, Inc. ("ICF"), a global energy consulting firm, in all periods except the first 18 months of the Study Period. The Company used forward prices for the first 18 months and then blended forward prices with ICF estimates for the next 18 months. Beyond the first 36 months, the Company used the ICF commodity price forecast exclusively. The price curves used during this analysis include air emission costs, RECs, natural gas, coal, capacity, and energy costs.

The methodology used to develop the fuel and power market prices relied on an integrated viewpoint including the effects of various proposed legislation intended to reduce greenhouse gas emissions. Extraordinarily Sensitive Figure 4.4.1 displays the fuel price forecasts while Extraordinarily Sensitive Figure 4.4.2 displays the forward price curves for SO_2, NO_x, and CO_2 emissions allowance prices on a dollar per ton basis. Extraordinarily Sensitive Figure 4.4.3 presents the estimated market clearing power prices for the PJM DOM Zone. The price forecast of PJM-DOM Zone capacity is presented in Extraordinarily Sensitive Figure 4.4.4. Extraordinarily Sensitive Appendix 4A provides delivered fuel price estimates.

Figure 4.4.1 FUEL PRICE FORECASTS

[redacted]

Figure 4.4.2 EFFLUENT PRICE FORECASTS

[redacted]

Figure 4.4.3 POWER PRICE FORECASTS

[redacted]

Figure 4.4.4 CAPACITY PRICE FORECASTS

[redacted]

4.5 TRANSMISSION PLANNING

The Company's transmission planning process, system adequacy, transfer capabilities, and transmission interconnection process are described in the following subsections. As used in this Plan, electric transmission facilities at the Company can be generally defined as those operating at 69 kV and above that connect sources of power with distribution facilities and provide for the interchange of power within and outside of the Company's transmission network.

4.5.1 REGIONAL TRANSMISSION PLANNING & SYSTEM ADEQUACY

The Company's transmission system is designed and operated to ensure adequate and reliable service to its customers while meeting all regulatory requirements and standards. Specifically, the Company's transmission system is developed to comply with the NERC Reliability Standards as well as the Southeastern Reliability Corporation ("SERC") supplements to the NERC standards.

The Company participates in numerous regional, interregional, and sub-regional studies to assess the reliability and adequacy of the interconnected transmission system. The Company is registered with PJM as the Company's Planning Coordinator and with NERC as a Transmission Planner. Accordingly, the Company participates in the PJM Regional Transmission Expansion Plan ("RTEP") to develop the RTO-wide transmission plan for PJM.

The PJM RTEP covers the entire PJM control area and includes projects proposed by PJM, as well as projects proposed by the Company and other PJM members through internal planning processes. The PJM RTEP process includes both a five-year and 15-year outlook. Specifically, for short-term planning, the five-year outlook enables the Company to meet near-term load growth. For example, the PJM RTEP called for the completion of the Meadowbrook – Loudoun 500 kV line by May 2011 in order to provide considerable reliability improvements to the Company's transmission system. The Company met that target date when it energized the Meadowbrook-Loudoun line in April of 2011.

The Company evaluates its ability to support expected customer growth through its internal planning process. The results of this evaluation indicate if transmission improvements are needed, for which the Company seeks an analysis through the PJM RTEP process and, if needed, approval from the appropriate regulatory commission. Additionally, the Company performs seasonal operating studies to identify facilities in the Company's transmission system that could be critical during the upcoming season.

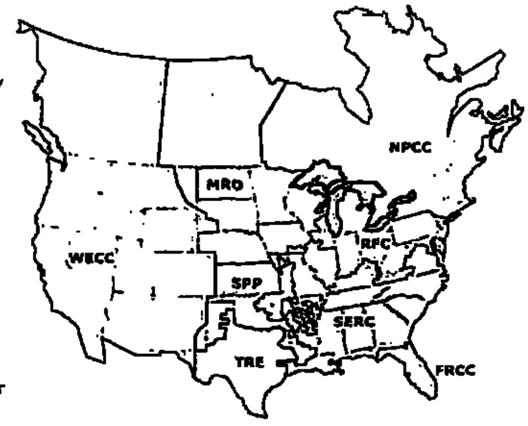
In 2011, the Company began conducting Market Efficiency analysis as part of its overall planning analysis. Market Efficiency planning is a process for evaluating transmission resources in order to achieve economic efficiencies, such as relieving projected transmission congestion.

The parameters and assumptions used in the Company's Market Efficiency analysis, as well as PJM's final results, are reviewed with the PJM Transmission Expansion Advisory Committee ("TEAC"). If the modification to an existing transmission resource identified in the annual RTEP is approved by the TEAC and meets a cost/benefit threshold, then it may be accelerated in that RTEP. If a new Market Efficiency project is identified, meets the cost/benefit threshold, and is approved by the TEAC, then it may also be included in the annual RTEP. Details regarding Market Efficiency Project evaluation are provided by PJM and may found at the website: http://www.pjm.com/~/media/documents/ manuals/m14b.ashx.

These aforementioned evaluations inform the Company's expansion of its transmission infrastructure due to load growth in the DOM Zone. Due to the regional nature of many transmission projects, the Company shares in the cost and benefit of many transmission projects within and outside of the DOM Zone.

The Company is also a member of the Virginia-Carolinas Reliability Agreement ("VACAR"), the Virginia-Carolinas sub-region of SERC (one of the NERC regions). As a member, the Company participates in the VACAR sub-regional, SERC regional, and SERC East-Reliability First Corporation ("RFC") interregional study groups. The groups undertake SERC regional and VACAR sub-regional reliability assessment studies, as well as in SERC East-RFC Interregional reliability assessment studies. These studies assess the transmission systems as planned by the Transmission Planners and Planning Coordinators. The studies identify facilities that could be limiting; however, SERC and VACAR do not attempt to find solutions to any problems identified and do not develop regional or sub-regional transmission plans. Rather, information from these studies is considered by the Transmission Planners and Planning Coordinators in their internal transmission planning processes (Figure 4.5.1.1).

Figure 4.5.1.1 NERC REGIONS



Regional Entities

Florida Reliability Coordinating Council (FRCC)
Midwest Reliability Organization (MRO)
Northeast Power Coordinating Council (NPCC)
Reliability*First* Corporation (RFC)
SERC Reliability Corporation (SERC)
Southwest Power Pool, RE (SPP)
Texas Regional Entity (TRE)
Western Electricity Coordinating Council (WECC)

Note: Retrieved from the NERC website on April 13, 2011; http://www.nerc.com/page.php?cid=1|9|119.

4.5.2 TRANSFER CAPABILITIES

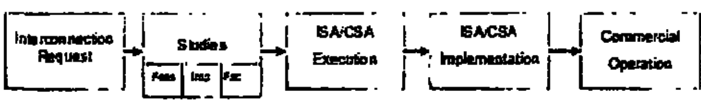
It is important to maintain an adequate level of transfer capability to facilitate economic and emergency power flows between neighboring utilities. Transfer capabilities are determined using first contingency (N-1) criteria as defined by NERC. Under N-1 criteria, system improvements are made based on facility loadings and voltages with a critical facility outage in effect. Transfer capabilities are calculated between two or more control areas using N-1 criteria. Maximum transfer capability between control areas may be limited due to overloading of any facility including the interconnections between the control areas. The limiting facility for a particular transfer can vary depending on the source and sink of the transfer. Available Transfer Capabilities ("ATCs") are calculated and posted by PJM for the PJM market. Since the Company is a member of PJM, it no longer explicitly calculates and posts ATCs. ATCs are updated regularly and posted on PJM's website at http://www.pjm.com/markets-and-operations/etools/oasis/atc-information.aspx.

4.5.3 TRANSMISSION INTERCONNECTIONS

For any new generation proposed within the Company's transmission system, either by the Company or by other parties, the generation owner files an interconnection request with PJM. PJM, in conjunction with the Company, conducts Feasibility Studies, System Impact Studies, and Facilities Studies to determine the facilities required to interconnect the generation to the transmission system (Figure 4.5.3.1). These studies ensure deliverability of the generation into the PJM market. The scope of these studies is provided in the applicable sections of the PJM manual 14A posted at http://www.pjm.com/~/media/documents/manuals/m14a.ashx and the Company's Facility Connection Requirements document is posted on the Company's public website at:
http://www.dom.com/business/electric-transmission/pdf/Facility_Connection_Requirements.pdf

The results of these studies provide the requesting interconnection customer with an assessment of the feasibility and costs (both interconnection facilities and network upgrades) to interconnect the proposed facilities to the PJM system, which includes the Company's transmission system.

Figure 4.5.3.1 PJM INTERCONNECTION REQUEST PROCESS



Note: Projects May Drop Out of the Queue at any Time

Feas – Feasibility studies
Imp – System Impact Studies
Fac – Facility studies
ISA/CSA – Interconnection Service Agreement / Construction Service Agreement

Note: Source: Received via e-mail from PJM on March 20, 2008

The Company's planning objectives include increasing the ability to analyze planning options for transmission as part of the IRP process and the ability to provide the outcomes as input to the PJM planning processes. In order to accomplish this goal, the Company must comply and coordinate with a variety of regulatory groups that address reliability, grid expansion, and costs which fall under the authority of NERC, PJM, FERC, the SCC, and the NCUC. In evaluating and developing this process, balance among regulations, reliability, and costs are critical to providing service to the Company's customers in all aspects, which includes generation and transmission services.

With these considerations, the Company is evaluating and analyzing transmission options that would support siting of potential generation resources in a manner that would offer flexibility in locating these resources such that additional grid benefits could be achieved. Development of this aspect of the Company's long-term planning process is currently being initiated and will need to be developed, in coordination with the PJM process, in order to fully obtain the potential benefit. The Company also conducts power flow studies and financial analysis to determine the interconnection requirement for new supply-side resources.

The Company uses Promod IV®, which performs a security constrained unit commitment and dispatch, to consider the proposed and planned supply-side resources and transmission facilities. Promod IV®, which incorporates extensive details in generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations, is the industry-leading Fundamental Electric Market Simulation software.

Promod IV® model enables the Company to integrate the transmission and generation system planning and specifically to: i) analyze the zonal and nodal level Locational Marginal Pricing impact of new resources and transmission facilities, ii) calculate the value of new facilities due to the alleviation of system constraints and iii) perform transmission congestion analysis.

The model is utilized to determine the most beneficial location for new supply-side resources in order to optimize the future need for both generation and transmission facilities while providing reliable service to all customers in 16 transmission zones of the Company's service area. Promod IV® model evaluates the impact of planned resources under development which are selected by the Strategist model. Promod IV® and Power System Simulator for Engineering were utilized to evaluate the impact of future generation retirements on the reliability of the DOM Zone transmission grid. The generation facilities planned to retire were removed from the model and assessed according to PJM's reliability standards.

Chapter 5

Future Resources

CHAPTER 5 – FUTURE RESOURCES

5.1 FUTURE SUPPLY-SIDE RESOURCES

The Company continues to monitor viable commercial and utility-scale emerging generation technologies. The Company gathers information about potential and emerging generation technologies from a mix of internal and external sources. The Company's internal knowledge base spans various departments including planning, financial analysis, construction, operation, alternative energy solutions, and business development. The dispatchable and non-dispatchable resources examined in this 2011 Plan are defined and discussed in the following subsections.

5.1.1 DISPATCHABLE RESOURCES

Battery Storage

Batteries serve a variety of purposes that make them useful and attractive options to meet energy needs. Batteries can be used to provide energy for power station blackstarts, shave peak load, or shift peak load to off-peak periods. They vary in size, differ in performance characteristics, and are usable in different locations. Recently, batteries have gained considerable attention due to their ability to integrate intermittent generation sources such as wind and solar onto the grid. Battery storage technology increases the dispatchability of Solar Photovoltaic ("PV") systems. The Company plans to deploy this developing technology as a component of the Halifax County Solar project. The primary challenge facing battery systems is the cost; however, other factors such as recharge times, variance in the temperature, energy efficiency, and capacity degradation raise issues for utility-scale battery systems.

Biomass

Biomass generation facilities rely partially or completely on renewable fuel in their thermal generation process. In the Company's service territory, the renewable fuel generally used is waste wood. The Company considers biomass to be carbon neutral from an emissions standpoint. The Company is constructing the 585 MW VCHEC facility, which will be able to utilize up to 20% of its fuel from biomass resources (wood waste and wood byproducts). The Company also filed for SCC approval of its proposal to perform major unit modifications to convert Altavista, Hopewell, and Southampton stations to biomass generation facilities rated at 51 MW each. The existing infrastructure at these facilities can be completed at a lower cost when compared to building new greenfield biomass units, thereby making the major unit modifications a better economic choice. Subject to receiving all necessary regulatory approvals and permits, commercial operation of the converted facilities is expected to begin by the end of 2013.

When considering biomass resources, the Company plans to adhere to certain limitations in Va. Code § 56-585.2 F, which restricts the amount of these biomass resources that can be applied to meet the Company's renewable requirements and goals. As defined in Va. Code § 56-585.2 F and the SCC Final Order issued May 18, 2010, regarding the

Company's Virginia RPS plan (Case No. PUE-2009-00082) the Company is currently limited to 1,108,940 tons of certain types of tree-based materials. As part of the 2011 Plan, the Company considered coal-to-biomass conversions, greenfield biomass plants, and co-firing coal with biomass at existing coal-fired plants.

CFB

This clean coal technology has been operational for the past few decades and is very flexible in terms of fuel quality. It can consume a wide array of coal types including low British Thermal Unit waste coal and wood products. The technology uses upward blowing jets of air to suspend the fuel and results in a more complete chemical reaction allowing for efficient removal of many pollutants such as NO_x and SO_2. The preferred location for this technology is within the vicinity of large quantities of waste coal fields. The Company will continue to follow this technology and its associated economics based on the site and fuel resource availability.

Fuel Cell

Fuel cells are electrochemical cells that convert chemical energy from fuel into electricity and heat. They are similar to batteries in their operation, but where batteries store energy in the components (a closed system), fuel cells consume their reactants. Fuel cell technology has been heavily researched for many years by a variety of institutions. However, this technology has not been used in utility-scale demonstration projects nor been proven reliable or economical. While the Company will continue to evaluate and monitor developments surrounding fuel cell technology, it has determined the resource will not be considered for further analysis at this time.

Gas-Fired CC ("CC" or "CC 2x1" or "CC 3x1")

A natural gas CC plant combines a CT and a steam turbine plant into a single highly efficient power plant. The option the Company considered for its analysis included the CC 2x1 generators and CC 3x1 generators, with heat recovery steam generators and supplemental firing capability.

Gas-Fired CT

Gas-fired CT technology has the lowest capital requirements of any resource considered; however, it has significant variable costs because of its low efficiency. This is a proven technology with cost information readily available. Additionally, the Company has significant operating experience with this technology.

Geothermal

Geothermal technology uses the heat from the earth to create steam which is subsequently run through a steam turbine. As of 2011, the National Renewable Energy Laboratory still has not indicated that there are any viable sites for geothermal technology identified in the eastern portion of the United States.[6] The Company does not view this resource as a feasible option in its service territory at this time; however, it will continue to monitor developments surrounding geothermal technology.

Hydro

Facilities powered by falling water have been operated for over a century. Construction of large-scale hydroelectric dams is currently unlikely; however, smaller-scale plants, or run-of-river facilities, are feasible in the Company's service territory. Due to the site-specific nature of these plants, the Company does not believe it is appropriate to further investigate this type of plant until a viable site is selected.

Integrated-Gasification Combined Cycle ("IGCC") with Carbon Capture and Sequestration ("CCS")[7]

IGCC plants use a gasification system to produce synthetic natural gas from coal in order to fuel a CC. In addition, IGCC systems remove a greater proportion of other air effluents. The gasification system process produces a pressurized stream of CO_2 before combustion, which research suggests provides some advantages in preparing the CO_2 for CCS systems. For planning purposes, the Company assumes carbon legislation would be enacted by 2018; therefore the Company only plans to consider IGCC plants that have CCS systems.

CCS is a technology that collects and traps CO_2 underground. This technology can be combined with many thermal generation technologies to reduce atmospheric carbon emissions; however, it is generally proposed to be used with coal burning facilities. At present, no commercial facility in the United States is using CCS. The Company will continue to follow this technology and its associated economics.

Nuclear

With an increasing need for clean, non-carbon emitting baseload power, many electric utilities are re-examining new nuclear power units. The newest third-generation nuclear power designs feature advanced, passive safety features. The process for constructing a new nuclear unit remains time-consuming with various permits for design, location, and operation required by various government agencies. For further discussion of the Company's efforts to develop a third unit at the North Anna Power Station, see Section 5.3.

Pulverized Coal ("PC") with CCS

PC is a very mature technology with hundreds of plants in operation across the United States and others under various stages of development. Although the PC with CCS technology is still under development, the Company will consider it in its analysis provided its environmental controls are consistent with draft and final EPA regulations. The Company will continue to follow

[6] Retrieved from: http://www.nrel.gov/geothermal/

[7] The Company currently assumes that the captured carbon cannot be sold.

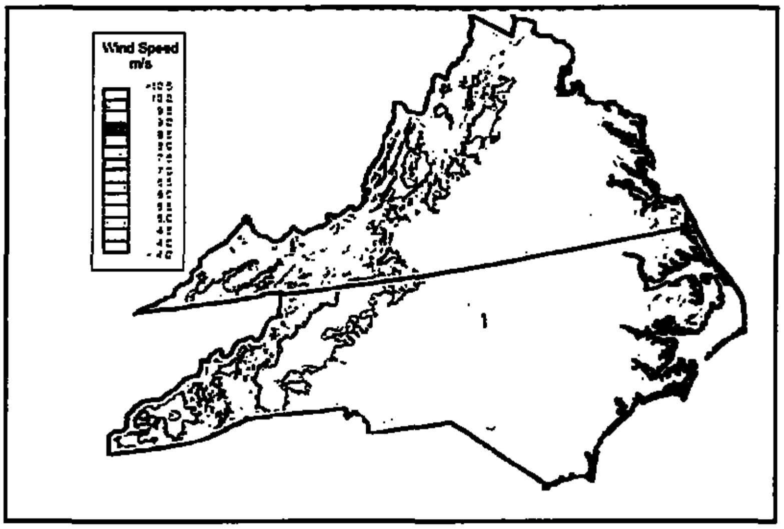
this technology and its associated economics.

5.1.2 NON-DISPATCHABLE RESOURCES

Onshore Wind

Wind resources are one of the fastest growing resources in the United States. The Company has considered onshore wind resources as a means of meeting the RPS goals, REPS requirements, and as a cost-effective stand-alone resource. The suitability of this resource is highly dependent on locating an operating site that can achieve an acceptable capacity factor. Additionally, these facilities tend to operate at times that are non-coincidental with peak system conditions and therefore generally achieve a capacity contribution significantly lower than their nameplate ratings. The Company understands that there is limited land available in its service territory that has sufficient wind characteristics. Figure 5.1.2.1 displays the onshore wind potential of Virginia and North Carolina. It is important to note that the Eastern portion of the United State's wind resources are limited and available only in specialized locations, such as on mountain ridges. This resource was considered for further analysis in the Company's Busbar Curve analysis.

Figure 5.1.2.1 ONSHORE WIND RESOURCES IN VIRGINIA AND NORTH CAROLINA

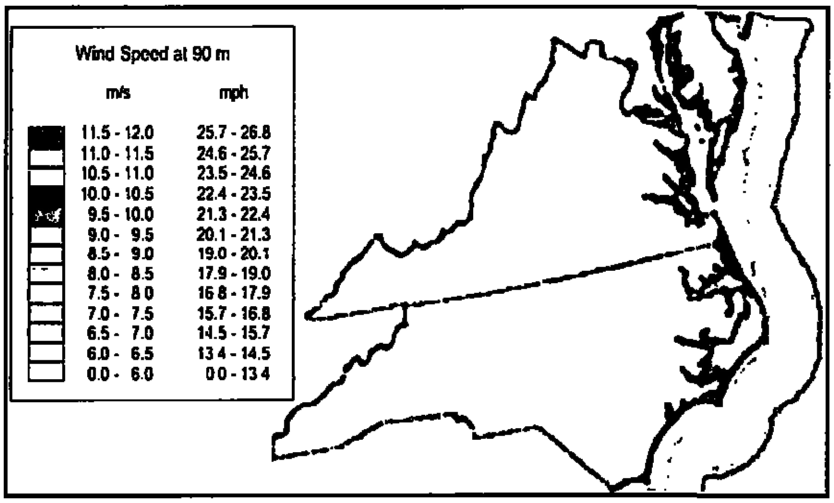


Source: Retrieved from the National Renewable Energy Laboratory on June 21, 2011; http://www.windpoweringamerica.gov/pdfs/wind_maps/us_windmap_80meters.pdf

Offshore Wind

Offshore wind has the potential to provide the largest, scalable renewable resource for Virginia with near-term resource availability of approximately 2,000 MW and potentially up to 3,000 MW as seen in Figure 5.1.2.2. Virginia has a unique offshore wind opportunity due to its shallow continental shelf extending nearly 30 miles off the coast, proximity to load centers, availability of local supply chain infrastructure, and world class port facilities. Additionally, offshore wind resources have a higher production per unit installed than onshore wind resources because winds are typically stronger and more consistent at sea. However, one challenge facing offshore wind development is that it is much more complex and costly to install and maintain than onshore wind. This resource was considered for further analysis in the Company's Busbar Curve analysis.

Figure 5.1.2.2 VIRGINIA AND NORTH CAROLINA OFFSHORE WIND RESOURCES



Source: Retrieved from the U.S. Department of Energy on June 21, 2011;
http://www.windpoweringamerica.gov/windmaps/offshore.asp

Solar Photovoltaic & Concentrating Solar Power ("CSP")

Solar PV and CSP are the two main types of solar technology used in electric power generation. Solar PV systems consist of interconnected PV cells that utilize semiconductor devices to convert sunlight into electricity. Solar PV technology is found in both large-scale and distributed systems and can be implemented where unobstructed access to sunlight is available. CSP systems utilize mirrors to reflect and concentrate sunlight onto receivers to convert solar energy into thermal energy that in turn produces electricity. CSP systems are generally used in large scale solar plants and are mostly found in the southwestern area of the country where solar resource potential is the highest.

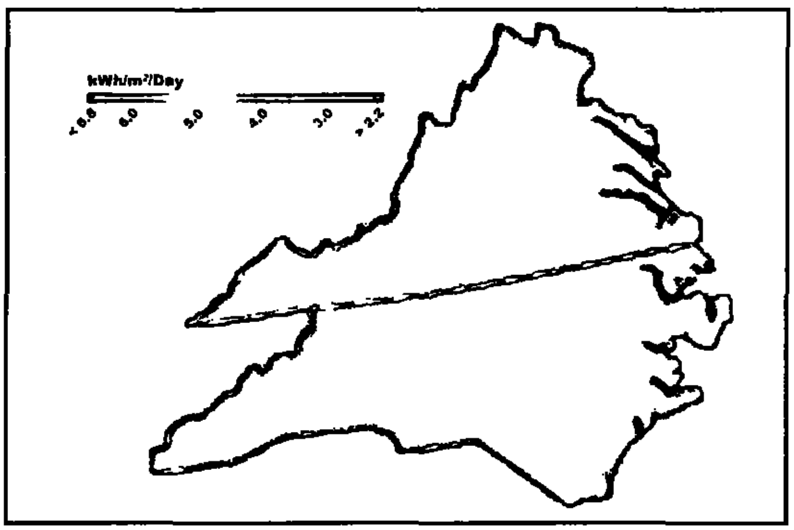
As of 2009 solar PV comprised only 0.1% percent of total electricity generating capacity in the U.S.[8]. However, solar PV technology has continued to evolve and is one of the most rapidly growing renewable energy sectors. Continuing enhancements in inverter technology are increasing the efficiency and output of solar PV systems. Due to the decreasing costs of solar modules and increasing standardization of installation techniques, solar resources are becoming less expensive and more attractive options. For instance, solar PV capacity in the U.S. increased 51% from 2008 to 2009.[8] Additionally, federal tax credits for solar, available through January 1, 2017, have helped make this resource more cost competitive. However,

[8] http://www1.eere.energy.gov/maps_data/pdfs/eere_databook.pdf

installed costs can vary widely depending on system size, technology types, and site specific factors. A solar cell's output depends on various factors, such as its design and materials, the intensity of the solar radiation hitting the cell, and the cell's temperature. Due to its variable nature as a generating resource, solar PV generation is not dispatchable and contributes less to peak load and reserve requirements than conventional generation resources. However, continuing advancements in storage technology may allow solar output to become a more reliable resource in the future. Figure 5.1.2.3 displays the solar PV potential of Virginia and North Carolina.

For further discussion of the Halifax County Solar project and the Community Solar Power Program, see Section 5.4. The Company also will continue to monitor developments surrounding solar PV technology and costs.

Figure 5.1.2.3 SOLAR PV RESOURCES IN VIRGINIA AND NORTH CAROLINA



Source: Retrieved from the National Renewable Energy Laboratory on July 19, 2010; http://www.nrel.gov/gis/images/map_pv_national_lo-res.jpg

Tidal & Wave Power

Tidal and wave power rely on ocean water fluctuations to collect and release energy. Significant research is being conducted by many individuals and firms into the development of tidal- and wave-powered electric facilities. However, neither type of facility has proven to be commercially available. The Company will continue to monitor developments surrounding these technologies.

5.1.3 ASSESSMENT OF ALTERNATIVE SUPPLY-SIDE RESOURCES

The process of selecting alternative resource types started with the identification and review of the characteristics of available and emerging technologies, as well as any applicable statutory requirements. Next, the Company analyzed the current commercial status and market acceptance of alternative resources. This analysis included determining whether particular alternatives were feasible in the short- or long-term based on the availability of resources or fuel within the Company's service territory or power pool. Next, each type of generation technology considered was categorized as baseload, intermediate, or peaking based on its operational characteristics and ability to be dispatched. The technology's ability to be dispatched was based on whether the resource was able to alter its output up or down in an economical fashion to balance the Company's instantly changing demand requirements. Further, this portion of the analysis required consideration of the viability of the resource technologies available to the Company. This step identified the risks that technology investment could create for the Company and its customers, such as site identification, development, infrastructure, and fuel procurement risks.

The feasibility of both conventional and alternative generation resources is considered in utility-grade projects based on capital and operating expenses including fuel and operation and maintenance. Figure 5.1.3.1 summarizes the resource types that the Company reviewed as part of the 2011 IRP process. Those resources considered for further analysis in the busbar screening model are identified in the final column.

Figure 5.1.3.1 ALTERNATIVE SUPPLY-SIDE RESOURCES

Resource	Resource Type	Dispatchable	Primary Fuel	Busbar Resource
Battery Storage	Intermediate	Yes	Varies	No
Biomass	Baseload	Yes	Renewable	Yes
CC 2x1	Intermediate	Yes	Natural Gas	Yes
CC 3x1	Intermediate	Yes	Natural Gas	Yes
CFB	Baseload	Yes	Coal	No
CSP	Intermediate	No	Renewable	Yes
CT	Peak	Yes	Natural Gas	Yes
Fuel Cell	Intermediate	Yes	Natural Gas	No
Geothermal	Baseload	Yes	Renewable	No
IGCC	Baseload	Yes	Coal	No
IGCC CCS	Baseload	Yes	Coal	Yes
Nuclear	Baseload	Yes	Uranium	Yes
PC	Baseload	Yes	Coal	No
PC CCS	Baseload	Yes	Coal	Yes
Hydro Power	Intermediate	No	Renewable	Yes
Solar PV	Intermediate	No	Renewable	Yes
Tidal & Wave Power	Intermediate	No	Renewable	No
Wind Offshore	Intermediate	No	Renewable	Yes
Wind Onshore	Intermediate	No	Renewable	Yes

The resources not included as a busbar resource for further analysis contained barriers such as the feasibility of the resource in the Company's service territory, the stage of technology development, and the availability of reasonable cost information.[9] Although these resources were not considered in this 2011 Plan, the Company will continue researching all utility-scale technologies. The Company is committed to using technologies at reasonable and prudent costs that best meet the energy needs of customers.

5.2 LEVELIZED BUSBAR COSTS

The Company's busbar model was designed to estimate the levelized busbar costs of various technologies on an equivalent basis. The busbar results show the levelized cost of power generation at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. These comparisons include: fuel, heat rate, emissions, variable and fixed O&M costs, expected service life, and overnight construction costs. Options with poor economics were further screened out at this level. Project costs for the technologies considered included a mix of internally developed cost information and data provided publicly by the Energy Information Administration[10] and the Electric Power Research Institute ("EPRI").[11]

Extraordinarily Sensitive Figures 5.2.1 and 5.2.2 display summary results of the busbar model comparing the economics of the different technologies discussed in Sections 5.1.1 and 5.1.2. The results were separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources. For example, onshore wind provides only 13%[12] of its nameplate capacity as firm capacity that is available to meet the Company's PJM resource requirements as described in Chapter 4.

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[9] Please see www.epri.com for more information on confidence ratings

[10] The Energy Information Administration's 2011 Annual Energy Outlook is available at: http://www.eia.doe.gov.

[11] Source: EPRI's Program on Technology Innovation: Integrated Generation Technology Options is available at http://www.epri.com.

[12] Please see http://www.pjm.com/~/media/documents/manuals/m21.ashx for more information on this topic.

Figure 5.2.1 DISPATCHABLE LEVELIZED BUSBAR COSTS

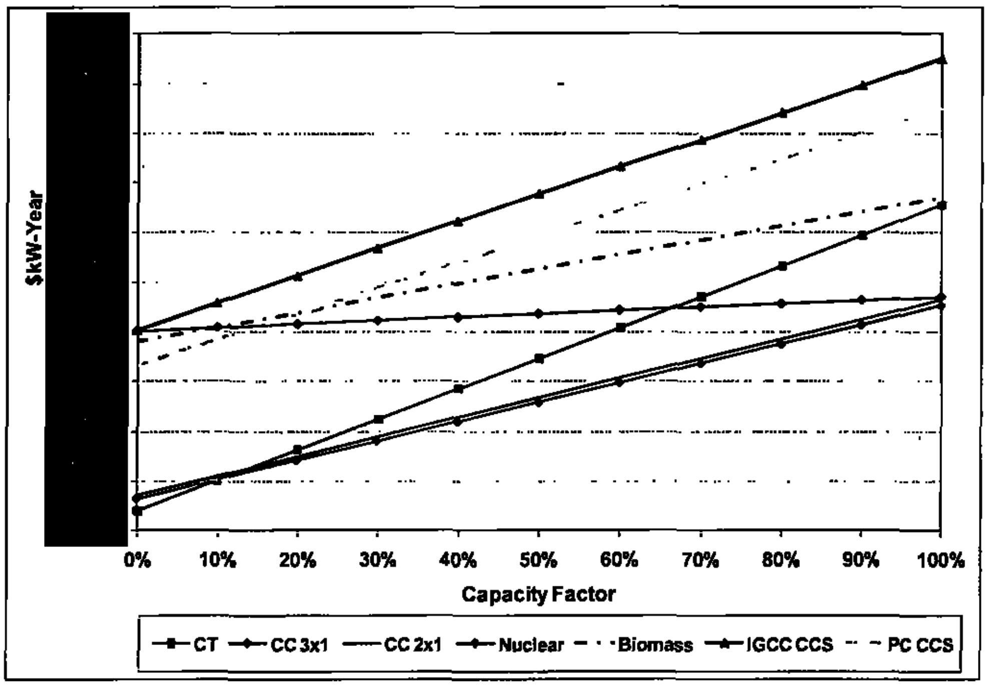
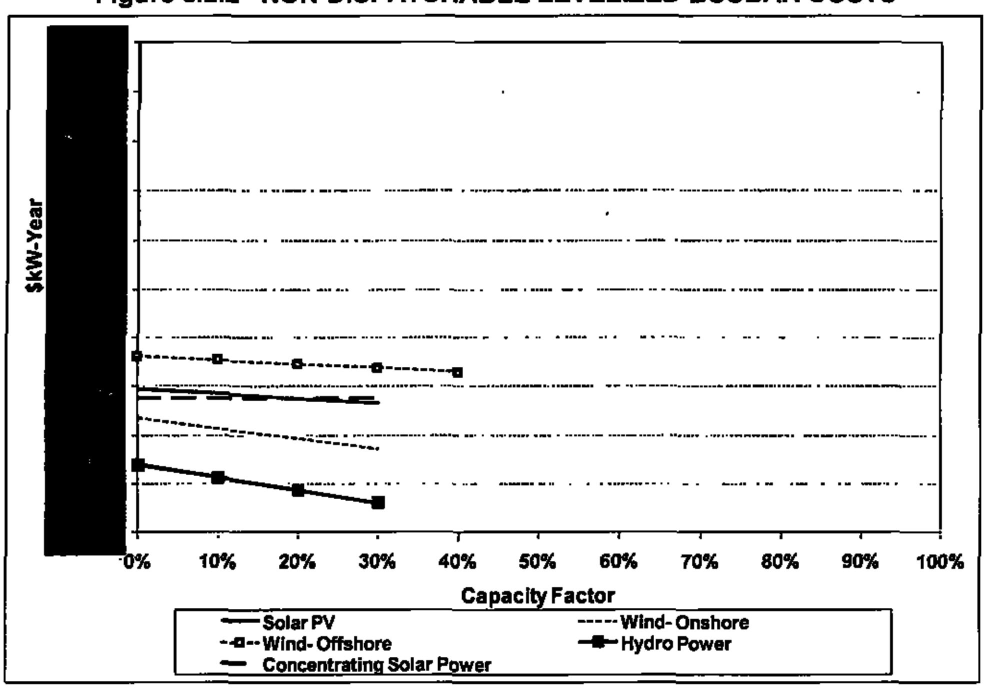


Figure 5.2.2 NON-DISPATCHABLE LEVELIZED BUSBAR COSTS



Extraordinarily Sensitive Appendix 5A contains the tabular results of the screening level analysis. Confidential and Extraordinarily Sensitive Appendix 5B displays the heat rates, fixed and variable operations expenses, maintenance expenses, expected service lives, estimated overnight construction costs, and the first year economic carrying charge.

In Extraordinarily Sensitive Figure 5.2.1, the lower portion of the combined curves represents the lowest cost of all units at an associated operating capacity factor range between 0% and 100%. Resources that lie above the combined curves generally fail to move forward in the resource optimization.

Extraordinarily Sensitive Figure 5.2.1 shows that CT technology is currently the most cost-effective option at capacity factors less than 15% for meeting Company's peaking requirements. The comparison of CC 3x1 and CC 2x1 indicates that the CC 3x1 technology is more economic. Currently, the CC 3x1 technology is the most economical option for capacity factors greater than 15% and, therefore, is an economical way for the Company to meet its intermediate and baseload energy requirements.

Nuclear units have similar total life-cycle costs to CC 3x1 at sufficiently high capacity factors and historically they had relatively more stable fuel costs as nuclear provides fuel diversity, reliability and rate stability. This analysis also indicates that new biomass resources, excluding repowering, are not currently cost-effective. The options for baseload capacity are PC CCS, IGCC CCS, and nuclear. The Company decided not to move forward with coal-fired technologies at this time due to uncertainties surrounding future CO_2 legislation. In summary, the dispatchable technologies that were included for analysis in the 2011 Plan were CT, CC 3x1, and nuclear.

A comparison between dispatchable and non-dispatchable resources is not applicable, thus the resources should not be evaluated in the same graph. Due to the intermittent production and limited dispatchability of the electricity that wind, hydro, and solar plants produce, more capacity would be required to maintain the same level of reliability. Extraordinarily Sensitive Figure 5.2.2 displays the non-dispatchable resources that the Company considered in its busbar analysis. Based on this analysis, the economic order for these non-dispatchable resources is: hydro, onshore wind, solar PV, CSP, and offshore wind. The Company continues to examine appropriate sites for potential hydro facilities; however, it has not located any suitable sites at this time. Onshore wind becomes the next available resource in this category; however, due to the limitations on the amount of onshore wind available within or near the Company's service territory, the Company has approximately 250 MW of onshore wind resources available. Solar PV technology is being considered in limited amounts as the Company plans for the 4 MW *Halifax County Solar project and is planning to seek approval for a 30 MW Community Solar* Power Program as described in Section 5.4. The Company will continue to monitor other developments surrounding solar thermal technologies.

The Company has considered offshore wind resources for further analysis in the Renewable Plan. The potential for offshore wind in the Mid-Atlantic region is currently in the very early stages of study and data collection. While it is a potential renewable option in the future, additional studies are required to better estimate the energy production potential and relative cost data.

The assessment of alternative resource types and the busbar screening process provided a useful foundation in selecting resources for further analysis. However, the busbar curve is somewhat static in nature because it relies on an average of all of the cost data of a resource over its lifetime. Further analysis was conducted in Strategist to incorporate seasonal variations in cost and operating characteristics, while integrating new resources with existing system resources. This analysis more accurately matched the resources found to be cost-effective in this screening process. This match resulted in selecting the type and timing of additional resources that best fit the Company's current and future needs.

5.3 PLANNED GENERATION UNDER DEVELOPMENT

The Warren County Power Station and the North Anna 3 nuclear facility are in various stages of development, as detailed below.

Warren County Power Station

On May 2, 2011, the Company filed an application for SCC approval to construct and operate the Warren County Power Station, a 1,337 MW[13] natural gas-fired CC electric generation facility in Warren County, Virginia. The new generating facility will be a 3x1 CC. Based on the Company's current schedule, this plant will be available to meet 2015 peak capacity and energy demand.

The Warren County Power Station is expected to have significant regional benefits. This highly-efficient generating facility is expected to reduce the Company's reliance on volatile market purchases, thereby enhancing rate stability for its customers. The Company has negotiated an associated firm transportation gas supply agreement and fixed-price contracts to construct the project that were favorably obtained under advantageous market conditions. Additionally, this site is in close proximity to the Northern Virginia load center and provides needed infrastructure that will enhance reliability.

North Anna 3

Nuclear power is an important component of the Company's plan to achieve fuel diversity, stable long-term customer electric rates, system reliability and low greenhouse gas emissions. On November 27, 2007, the United States Nuclear Regulatory Commission ("NRC") issued an Early Site Permit ("ESP") to the Company's affiliate, Dominion Nuclear North Anna, LLC, for a

[13] Summer capacity of Warren County Power Station is 1,337 MW, which the Company used for modeling purposes in development of this 2011 Plan. Nominal capacity of unit is 1,329 MW.

site located at the Company's existing North Anna Power Station for the third unit. Also on November 27, 2007, the Company and Old Dominion Electric Cooperative ("ODEC") filed an application with the NRC for a Combined Construction Permit and Operating License ("COL") to build and operate a new nuclear reactor. On October 31, 2008, the NRC approved the transfer of the ESP to the Company and ODEC. The merger of Dominion Nuclear North Anna, LLC into the Company became effective on December 1, 2008.

The North Anna 3 project could potentially provide the Company's customers with significant economic benefits. A portion of these benefits relates to the location of the project. The two existing nuclear units will allow the third future unit to share some of the costs to meet safety and operating requirements. In March 2009, the Company issued a RFP to license, engineer, procure, and construct a third nuclear unit at the North Anna Power Station. The Company selected Mitsubishi Heavy Industry's United States Advanced Pressurized-Water Reactor ("APWR") for the design of the planned nuclear unit, although no Engineering, Procurement, and Construction contract has been signed to date. The Company filed its amended COL on June 30, 2010 with the NRC referencing the Mitsubishi technology for North Anna 3.

In February 2011, ODEC informed the Company of its intent to no longer participate in the development of North Anna 3. The withdrawal of ODEC from the Project does not change the Company's plans for North Anna 3 and it continues to move forward with the federal COL process. The Company is expecting the results of the NRC review by November 2013.

North Anna 3 would provide much needed baseload capacity to the region by 2022 with little to no greenhouse gas emissions. Although the Company has not committed to build the new unit, it intends to maintain the option to meet projected demand and energy requirements for electricity.

Figure 5.3.1 PLANNED GENERATION UNDER DEVELOPMENT[1]

Forecasted COD	Unit	Location	Primary Fuel	Unit Type	Capacity (Net MW)	
					Summer	Winter
2015[2]	Warren County Power Station	Warren County, VA	Natural Gas	Intermediate	1,337	1,437
2022[2]	North Anna 3	Mineral, VA	Nuclear	Base	1,453	1,500

Key: Warren County: Warren County Power Station

Notes: 1) All Planned Generation Under Development projects and planned capital expenditures are preliminary in nature and subject to regulatory and/or Board of Directors approvals. 2) Date as determined by this 2011 Plan.

Appendix 5C provides the in service dates and capacities for planned generation resources under development.

5.4 ALTERNATIVE ENERGY RESOURCES & TECHNOLOGIES

The Alternative Energy Solutions group conducts technology research in the renewable and alternative energy technologies sector, participates in Federal and state policy development on alternative energy initiatives, and identifies potential alternative energy resource and technology opportunities within the existing regulatory framework for the Company's service territory. The Company is actively pursuing the following technologies and opportunities.

Halifax County Solar with Battery Storage

The Company is in the early stages of developing a 4 MW solar project with advanced battery storage. The facility would be constructed on approximately 50 acres of land in Halifax County, Virginia. The Company estimates that the project will create approximately 100 construction jobs. The Company plans to demonstrate a utility-scale solar with a battery storage project that can effectively manage, store, and optimize solar energy to regulate intermittency, enable peak shaving and increase grid reliability. The Company and the Industrial Development Authority of Halifax County received approval for a $5 million grant from the Virginia Tobacco Indemnification and Community Revitalization Commission in October 2010 to help fund the project. Other participants in the project are the University of Virginia and a battery storage manufacturer. The battery manufacturer is proposing to locate a manufacturing facility and associated jobs in Halifax County. The exact scope and schedule of this project is subject to change in the future.

Offshore Wind

In House Joint Resolution 605, the 2011 Virginia General Assembly expressed support for establishment of a National Offshore Wind Technology Center in Hampton Roads and a goal of development of 3,000 MW of offshore wind by 2025. The Company is actively evaluating offshore wind technology as described in Section 5.1.2. The Department of Interior's Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") is the lead federal agency in charge of leasing areas for offshore wind development on the outer continental shelf. The BOEMRE is expected to release a Call for Information and Nominations for lease blocks off of Virginia's coast before the end of 2011.

The Company is actively participating in offshore wind policy development at the state level in Virginia. The Virginia Offshore Wind Development Authority ("VOWDA") was created through legislation in 2010 to help facilitate offshore wind energy development. The Company is represented at the VOWDA by an appointee of the Governor. As required by this legislation, the Company completed an offshore wind transmission study to determine possible offshore wind interconnection points to the transmission grid. The Company released the results of the study in December 2010, which found that it would be possible to interconnect large scale wind generation facilities with the existing grid in Virginia Beach, Virginia.

The Company is currently performing an additional study to evaluate the requirements necessary to build a high voltage underground transmission line from Virginia Beach into the Atlantic Ocean to support potential multiple offshore wind projects. The Company plans to complete the study in 2011.

Currently, offshore wind is one of the most expensive renewable generation resources. In order for the Company to develop offshore wind resources, costs must be competitive with other forms of conventional or renewable generation. The Company continues to pursue cost reduction efforts and to evaluate the development of offshore wind as a potential source for future generation.

Community Solar Power Program

In response to House Bill 1686, legislation passed by the General Assembly in 2011 that promoted solar distributed generation, the Company is planning to seek approval for a Community Solar Power Program in which solar PV DG would be strategically located in areas of the Company's service territory to study the impact and assess benefits to the distribution system. The program would be structured to include Company-owned solar PV DG systems; both on leased roof space or ground-mounted installations, as well as the purchase of output from customer-owned solar PV DG systems.

The Renewable Plan (Plan D), as described in Section 6.4, incorporates the development of 30 MW of utility-owned solar PV DG which will be tied to specific study objectives and located within the Company's service territory. The installation of these facilities will begin in 2013 and *conclude in 2015. In addition, as part of the study and as an alternative to net metering,* the Community Solar Power Program tariff would provide the opportunity for customers to sell solar generation output and renewable energy certificates to the Company. The Program would allow participation of customer-owned systems up to a maximum amount of 3 MW.

The size of the Company's combined solar distributed PV initiative (Company-owned installations and purchases under the new Community Solar Power Program Tariff) would not exceed 33 MW.

EV Initiatives

Customers in the Company's Virginia service territory have already begun to take delivery of the Chevrolet Volt, General Motor's first plug-in hybrid electric vehicle ("PHEV"). Additionally, General Motors has announced that the Volt will be available in North Carolina before the end of 2011. Nissan is currently taking orders for the Leaf, all-electric vehicle, available for delivery in the Company's service territory later this year. Ford has chosen Richmond, Virginia as an initial launch city for its all-electric Ford Focus to be released in late 2011.

Sales of EVs and PHEVs are expected to follow the historical adoption rate of hybrid vehicles. In this 2011 Plan, the Company used data from the EPRI and Polk Automotive to develop a projection of system level EV and PHEV penetrations across its service territory. The Company developed load shape impacts to evaluate potential capacity and energy impacts of EVs and PHEVs on its system. The Company projects approximately 94,395 EVs and PHEVs will be on the road by 2020, which would equate to an additional 116 MW of potential load and an additional annual energy usage of 276 gigawatt hour ("GWh") from EV charging. In 2036, assuming 681,744 vehicles on the road in the Company's service territory, the Company projects an additional potential load of 841 MW and additional energy usage of 1,991 GWh from vehicle charging. Given these projections, it is important to encourage customers to charge these vehicles during off-peak hours.

On January 31, 2011, in SCC Case No.PUE-2011-00014, the Company filed an application to establish an EV Pilot Program offering experimental and voluntary EV rate options to encourage customers to charge their EVs during off-peak periods. These rate options are further discussed in Section 3.2.3. The SCC approved the pilot on July 11, 2011. Additional information regarding the Company's EV Pilot Program is available in the Company's application and in the SCC's Order Granting Approval.

5.5 FUTURE DSM INITIATIVES

The Company is committed to offering cost-effective DSM programs in its Virginia and North Carolina service territories in order to meet customers' needs and improve the environment. The Company has developed relationships with third-party vendors to assist in evaluating and implementing programs approved by the commission(s).

Beginning in 2010, the Company initiated its SRP and suggestions received during this process were included in developing the 2011 future DSM initiatives. Specifically, at the stakeholders' suggestion, the Company conducted an additional analysis which included evaluating DSM programs based upon the Total Resource Cost ("TRC") test and examining additional programs that may be offered to commercial and industrial customers.

The Company's analysis of future DSM programs begins with a screening process that determines whether a DSM program warrants further evaluation. If a DSM program passes the initial screening, ICF provides the Company with program and modeling assumptions for that program. Next, the programs are evaluated using the Strategist model to ensure each program passes the four cost/benefit tests discussed in Appendix 5D[14]. While these cost/benefit tests are a key component of the Company's analysis, it also considers stakeholder impacts, the potential for achieving a high level of acceptance by customers, and the potential for energy and demand reductions. The Company modeled all new demand-side resources over the Study Period, including input variables from many sources. These projections were based on the best available information, including industry data acquired from ICF, which validated the DSM program design parameters and helped reduce uncertainty and risk. Further, the projected customer penetrations were based on market research for similar programs previously implemented in the United States. Appendix 5E provides the estimated annual energy savings for all DSM programs included in the 2011 Plan.

[14] The Company does not utilize the Societal Test referenced in Appendix 5D in evaluating DSM programs.

5.5.1 STANDARD DSM TESTS

To evaluate DSM programs, the Company utilized four of the five standard tests from the California Standards Practice Manual. Based on the SCC findings and rulings in Case Nos. PUE-2009-00023 and PUE-2009-00081, the Company's future DSM programs are evaluated on both an individual and portfolio basis, with the individual program results given greater weight in determining whether the Company will include a particular program in its future Plans.

The SCC rulings indicated that the Ratepayer Impact Measure ("RIM") score would be given the greatest weight, closely followed by the TRC score and rounded out by consideration of the Participant and Utility Cost scores when approving programs. As a result, the Company has incorporated this guidance into its evaluation process of future DSM programs. Based on the SCC ruling in Case No. PUE-2009-00081, the Company has developed the following criteria as a guideline for Program acceptance.

The Company first reviews a program's individual RIM test score. If a program's RIM score is above 1.0 and the other individual test scores are also above 1.0, then the program is included in the portfolio of DSM programs and is submitted for approval. If a program's individual RIM score is below 1.0, and the Utility and Participant scores are above 1.0, then the Company looks for a *significantly high* TRC score before suggesting that the program be pursued. For the 2011 Plan, the Company used a target TRC score of 2.0 or greater as a guideline for program acceptance.

Although the Company uses these criteria to assess DSM programs there are circumstances that require the Company to deviate from the aforementioned guidelines and further consider certain programs. For instance, in Case No. PUE-2009-00081, the Residential Low Income Program did not meet the Company's cost/benefit criteria but was included in the portfolio of approved DSM Programs because it served important public policy goals of the Commonwealth.

5.5.2 FUTURE DSM PROGRAMS

As part of the IRP planning process, the Company evaluated possible future DSM programs in Virginia and North Carolina, referred to herein as "future programs." These programs have met the Company's evaluation criteria for inclusion in the 2011 Plan as described in Section 5.5.1. Appendices 5F, 5G, 5H, and 5I provide the non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations, respectively, for each future program. A brief description of each potential future DSM program is listed below. For the 2011 Plan, the Company projects that programs will be implemented in North Carolina approximately two years after approval and implementation in Virginia.

Voltage Conservation

Target Class:	All Classes
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2009 – 2036
NC Duration:	2014 – 2036

Program Description:
In 2009, the Company began an AMI Demonstration throughout Virginia in order to fully understand the impacts of AMI. This program involves lowering the voltage on the distribution circuits by systematically decreasing the load tap changing transformers and the circuit voltage regulators by an average of 5% during off-peak load conditions, while maintaining the minimum voltage levels for customers at the end of the circuit. The objective of this program is to conserve energy by reducing voltage for residential, commercial and industrial customers served within the allowable band of 114 to 126 volts at the customer meter (for normal 120-volt service) during off-peak hours. The program is enabled through the deployment of AMI, which provides 15-minute voltage information from the meter for all customers.

Commercial Re-Commissioning Program

Target Class:	Non-residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2013 – 2036
NC Duration:	2015 – 2036

Program Description:
In this Program, qualifying customers are provided an incentive to optimize the energy performance of their existing building and systems by identifying and implementing operational and maintenance improvements. These improvements include, but are not limited to, monitoring, troubleshooting, and adjusting the building's current system to optimize energy performance.

Commercial Solar Window Film Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2013 – 2036
NC Duration:	2015 – 2036

Program Description:
This Program provides an incentive to participants who have a contractor install low-emissivity window film to existing windows.

Commercial Data Center /Computer Room Program

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2013 – 2036
NC Duration: 2015 – 2036

Program Description:
This Program will support owners and operators of stand-alone data centers and computer rooms within a facility in identifying and implementing site-specific cost-effective retrofit and new construction energy efficiency opportunities through measures not addressed by other offerings. All retrofit projects will first require a comprehensive audit conducted by a qualified data center professional. Calculated incentives will be paid based on measures implemented or equipment installed.

Commercial Custom Incentive Program

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2013 – 2036
NC Duration: 2015 – 2036

Program Description:
This Program will support non-residential customers in identifying and implementing site-specific and unique cost-effective retrofit and new construction energy efficiency opportunities through measures not addressed by other offerings. Calculated incentives will be paid based on measures implemented or equipment installed.

Residential Cool Roof Program

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2013 – 2036
NC Duration: 2015 – 2036

Program Description:
This Program provides an incentive to customers who have a professional contractor install a cool, light-reflecting, roof on residential structures.

5.5.3 FUTURE DSM PROGRAMS' COST-EFFECTIVENESS RESULTS

The Company performs individual cost/benefit tests on each future DSM program. These results were used to determine if a program should be included as a future DSM program in this 2011 Plan. The Company believes this evaluation is consistent with the guidance provided by the SCC in Case No. PUE-2009-00081. Figure 5.5.3.1 provides the future DSM programs' individual cost/benefit results and projected cumulative demand and energy reductions by 2026.

Figure 5.5.3.1 FUTURE DSM INDIVIDUAL COST-EFFECTIVENESS RESULTS

Program	Participant	Utility	TRC	RIM	2026 MW Reduction	2026 GWh Savings
Voltage Conservation Program	N/A	5.02	5.02	5.02	0	2,569
Commercial Re-Commissioning Program	2.84	5.74	3.05	1.15	59	298
Commercial Solar Window Film Program	3.34	7.49	3.97	1.22	51	222
Commercial Data Center/Computer Room Program	2.13	5.57	2.14	0.92	2	31
Commercial Custom Incentive Program	2.52	3.18	2.83	1.08	31	108
Residential Cool Roof Program	N/A	1.98	1.98	1.14	6	5

The Company also performed a portfolio evaluation to ensure that each DSM program passed the cost/benefit tests as a portfolio of programs. When evaluating DSM programs as a portfolio, each program must compete for avoided cost benefits potentially resulting in lower test scores than when evaluated individually. It is important to consider the portfolio results since all resources available to meet or reduce load are considered together. It is also important to examine the portfolio run, which includes incremental common costs. Common costs are expenses that cannot be directly tied to any individual program, but are incurred based on program start-up and general implementation costs for the collective DSM Program offerings. The common costs are included in the portfolio run to ensure the addition of these expenses do not alter the overall cost-effectiveness of the portfolio.

Figure 5.5.3.2 provides the future DSM portfolios' cost/benefit results and projected demand and energy reductions.

Figure 5.5.3.2 FUTURE DSM PORTFOLIO COST-EFFECTIVENESS RESULTS

Program	Participant	Utility	TRC	RIM	2026 MW Reduction	2026 GWh Savings
Voltage Conservation Program	N/A	5.02	5.02	5.02	0	2,569
Commercial Re-Commissioning Program	2.84	5.63	2.99	1.13	59	298
Commercial Solar Window Film Program	3.34	7.47	3.96	1.22	51	222
Commercial Data Center/Computer Room Program	2.13	5.39	2.07	0.89	2	31
Commercial Custom Incentive Program	2.52	3.01	2.68	1.03	31	108
Residential Cool Roof Program	N/A	1.81	1.81	1.04	6	5
Portfolio Results	**2.88**	**5.02**	**4.27**	**2.55**	**149**	**3,233**

5.5.4 REJECTED DSM PROGRAMS

The Company has evaluated a wide variety of DSM programs for both the residential and non-residential sectors. During the planning process, the Company internally rejects programs that do not meet the Company's planning criteria. Rejected programs may be reevaluated for inclusion in future DSM portfolios, if there are changes in program or resource planning assumptions that indicate those programs may meet then current DSM selection criteria.

A list of rejected programs from prior IRP cycles is shown in Figure 5.5.4.1. A short description of each of the rejected programs, including an explanation for each program's rejection, can be viewed in the Company's 2010 Plan, provided at www.Dom.com.

Figure 5.5.4.1 REJECTED DSM PROGRAMS

Commercial HVAC Tune-Up Program
Curtailment Service Program
Energy Management System Program
ENERGY STAR® New Homes Program
Geo-Thermal Heat Pump Program
Home Energy Comparison Program
Home Performance with ENERGY STAR® Program
In-Home Energy Display Program
Premium Efficiency Motors Program
Programmable Thermostat Program
Residential Refrigerator Turn-In Program
Residential Solar Water Heating Program
Residential Water Heater Cycling Program

In addition to the rejected programs listed in Figure 5.5.4.1, the Company evaluated the Residential Comprehensive Energy Audit Program and the Residential Radiant Barrier Program during this IRP planning cycle. A description of the programs and explanation for rejection of each is listed below.

Residential Comprehensive Energy Audit Program

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2012 – 2036
NC Duration: 2014 – 2036

Program Description:
In this Program, energy professionals provide comprehensive energy audits to qualified homeowners. This Program also provides incentives for qualifying energy efficiency projects.

Reason for Program Rejection:
The Comprehensive Energy Audit Program was rejected for two reasons. First, the Program's cost/benefit scores did not pass the Company's criteria as set forth in Section 5.5.1. The Program's test scores are provided in Figure 5.5.5.1. Second, the Company determined not to pursue simultaneously managing two residential audit programs. As part of its September 1, 2011 DSM application filed with the SCC, the Company proposed a residential audit Program (Residential Home Energy Check-Up).

Residential Radiant Barrier Program

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2013 – 2036
NC Duration: 2015 – 2036

Program Description:
This program provides an incentive to residential customers who have a professional contractor install radiant energy reflecting barriers in their attic space.

Reason for Program Rejection:
The Residential Radiant Barrier Program was determined not to be market ready at this time, and therefore not rejected from a cost/benefit perspective. However, the Company will continue to monitor this program for possible inclusion in a future Plan.

5.5.5 REJECTED DSM PROGRAMS' COST-EFFECTIVENESS RESULTS

At this time, the Company has recently evaluated and rejected two DSM programs, the Comprehensive Energy Audit Program and the Residential Radiant Barrier Program for the reasons described in Section 5.5.4. The cost-effectiveness results for the Residential Comprehensive Energy Audit Program are provided in Figure 5.5.5.1.

Figure 5.5.5.1 REJECTED PROGRAMS' COST-EFFECTIVENESS RESULTS[1]

Program	Participant	Utility	TRC	RIM	2026 MW Reduction	2026 GWh Savings
Residential Comprehensive Energy Audit Program	1.87	1.95	1.30	0.66	2	11

Note: 1) Residential Radiant Barrier Program not evaluated for cost/benefit.

5.5.6 DSM TRC TEST ANALYSIS

During the SRP meetings, stakeholders identified concerns regarding the screening process the Company used for DSM programs. Some stakeholders remarked that screening DSM programs based on RIM criteria could remove DSM programs that would have a beneficial impact on the Company's Plan. Specifically, their concern was that some of these programs may provide other benefits to the utility system primarily through reduced utility costs. Through the SRP, the Company agreed to examine the matter and developed a TRC screening criteria to evaluate the relative cost impact as compared to the Base Plan.

In the DSM TRC Test Analysis, the Company identified previously screened programs that were rejected based on their cost/benefit test scores. The Company included programs evaluated individually in Strategist against the current expansion plan with a TRC test score of 1.0 or greater. This led to the inclusion of the Commercial HVAC Tune-Up Program, the Curtailment Service Program, and the Home Energy Comparison Program. After completing the Strategist run, it was found that these three programs would add a combined 115 MW and 42 GWh of capacity and energy savings, respectively. The programs would cause a 0.26% increase in net benefits to the Utility test, but a 2.68% decrease in net benefits to the RIM test. Figure 5.5.6.1 below shows the percent change in net benefits between the portfolio of DSM resources in this Plan and the addition of these three resources to that Plan. Figure 5.5.6.2 below shows the individual cost/benefit results for the programs considered for inclusion in this analysis.

Figure 5.5.6.1 PORTFOLIO NET BENEFITS PERCENT CHANGE

	Participant	Utility	TRC	RIM
Net Benefits (% Change)	20.09%	0.26%	2.07%	-2.68%

The DSM TRC Test Analysis illustrates that the addition of the three programs to the portfolio of DSM programs decreases total system utility costs (as shown by the 0.26% increase in net benefits to the Utility test), while increasing rate impacts to non-participants (as shown by the 2.68% decrease in net benefits to the RIM test as compared to the 2011 Plan). In Case No. PUE-2009-00081, the SCC indicated that it would give greatest weight to the RIM test as the primary indicator of whether a DSM program should be approved, followed closely by the TRC test and rounded out by consideration of the Participant and Utility Cost tests. Based on the Company's interpretation of the SCC's guidance, the results of this analysis indicate that the three additional programs should not be included in the proposed portfolio of DSM programs at this time due to their impact on rates in general.

Figure 5.5.6.2 DSM TRC TEST ANALYSIS INDIVIDUAL COST-EFFECTIVENESS RESULTS[1]

Program	Participant	Utility	TRC	RIM	2026 MW Reduction	2026 GWh Savings
Commercial HVAC Tune-Up Program	***1.34***	***1.12***	***1.01***	***0.75***	***20***	***35***
Curtailment Service Program	***3.56***	***1.18***	***1.93***	***1.14***	***94***	***5***
Energy Management System Program	1.42	1.23	0.96	0.66	17	83
ENERGY STAR® New Homes Program	1.25	2.31	0.85	0.63	5	41
Geo-Thermal Heat Pump Program	0.91	0.70	0.67	0.44	0	0
Home Energy Comparison Program	***N/A***	***1.44***	***1.44***	***0.54***	***0***	***2***
Home Performance with ENERGY STAR® Program	1.42	0.97	0.74	0.53	6	22
In-Home Energy Display Program	1.87	0.40	0.40	0.28	0	0
Premium Efficiency Motors Program	1.08	0.60	0.48	0.43	0	0
Programmable Thermostat Program	2.72	0.00	0.00	0.00	-17	12
Residential Refrigerator Turn-In Program	N/A	0.82	0.99	0.46	3	16
Residential Solar Water Heating Program	1.56	0.39	0.64	0.27	3	23
Residential Water Heater Cycling Program	N/A	0.18	0.44	0.18	33	0

Note: 1) Italicized, bolded Programs chosen for inclusion in analysis.

5.5.7 NEW CONSUMER EDUCATION PROGRAMS

Future promotion of DSM programs will be through methods that raise program awareness and attention such as mass marketing and targeted advertising in Virginia and North Carolina. The Company plans to educate customers on how to better manage their energy usage. The Company also plans to educate customers about the potential monetary savings, environmental benefits, and the technologies used as part of the Company's DSM programs.

5.5.8 ASSESSMENT OF OVERALL DEMAND-SIDE OPTIONS

Figure 5.5.8.1 represents approximately 4,420 GWh in energy savings from the DSM programs at a system-level by 2026.

Figure 5.5.8.1 DSM ENERGY REDUCTIONS

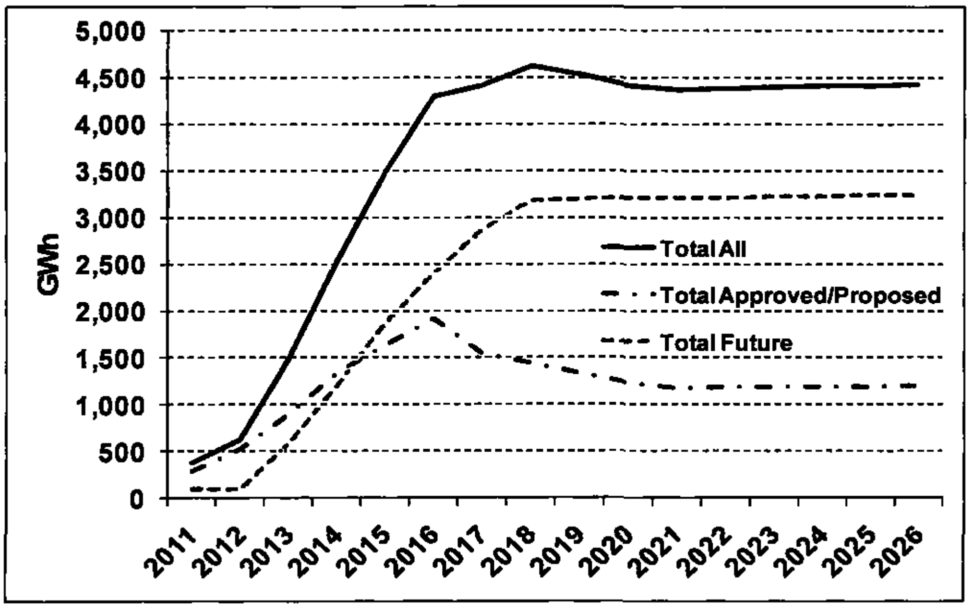
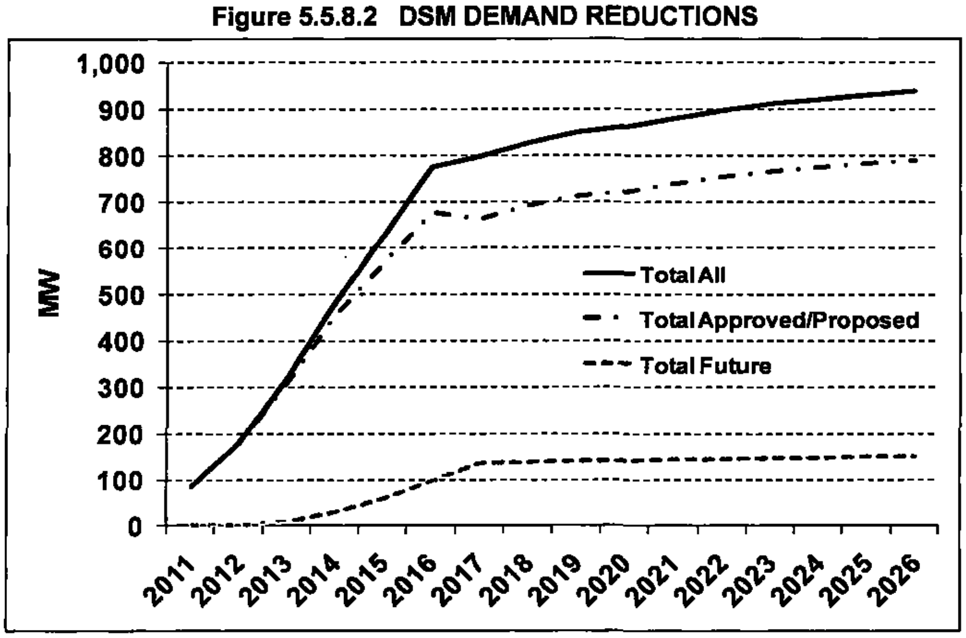


Figure 5.5.8.2 represents a system coincidental demand reduction of approximately 940 MW by 2026 from the DSM programs at a system-level.

Figure 5.5.8.2 DSM DEMAND REDUCTIONS



Additionally, the Company has provided load duration curves for the years 2012, 2016, and 2026 in Figures 5.5.8.3, 5.5.8.4, and 5.5.8.5.

Figure 5.5.8.3 LOAD DURATION CURVE 2012

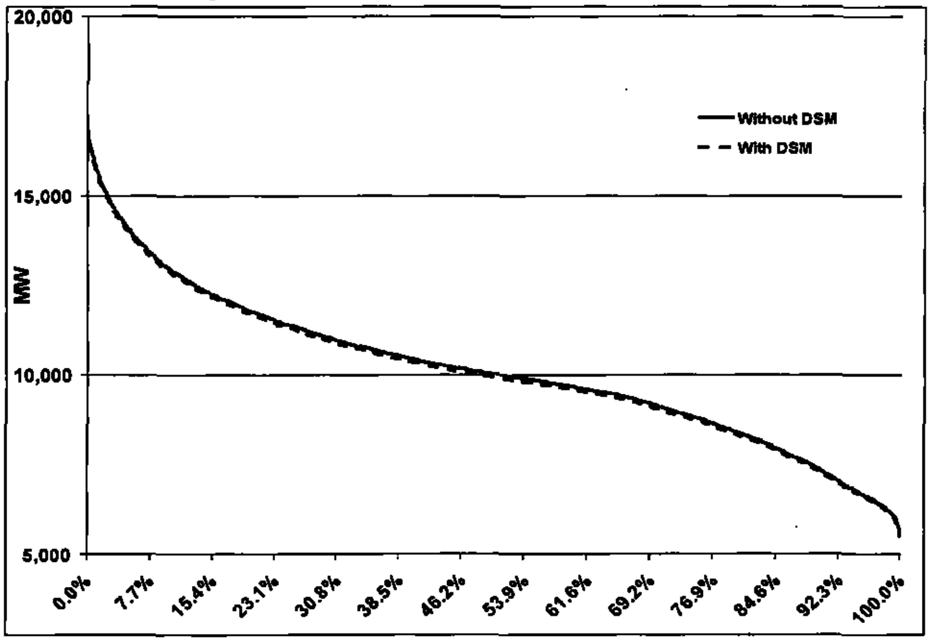


Figure 5.5.8.4 LOAD DURATION CURVE 2016

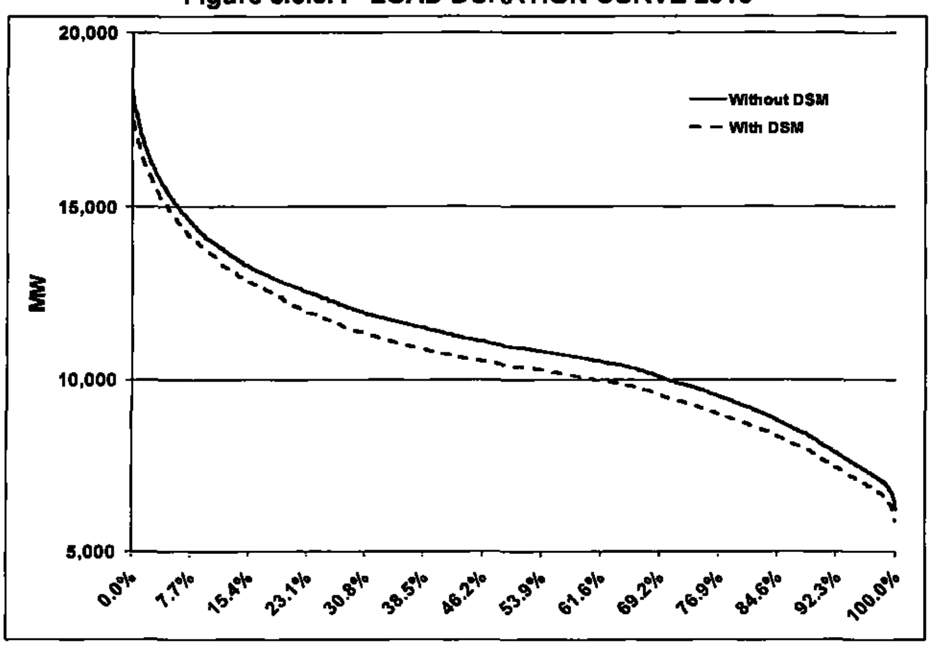
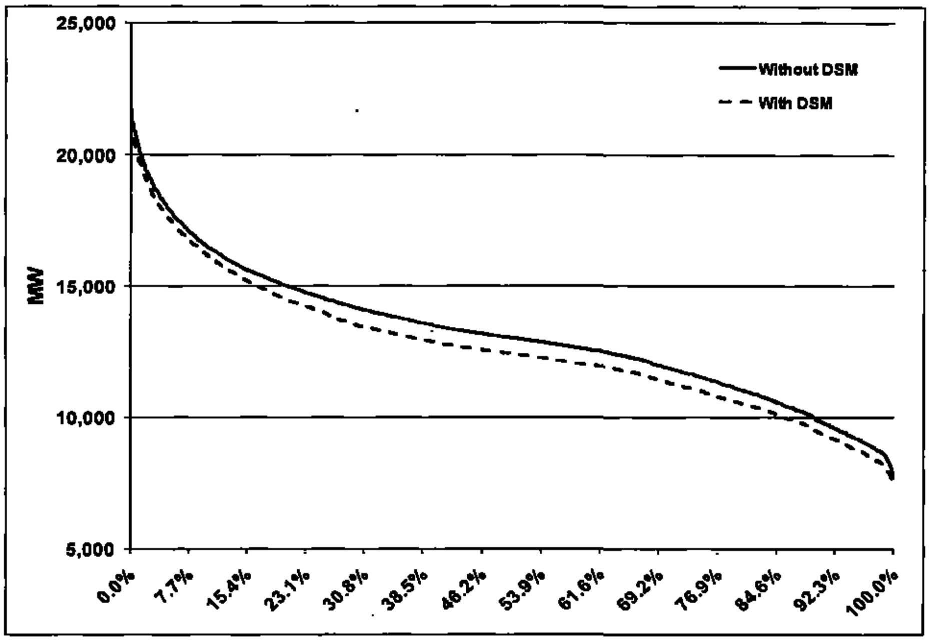


Figure 5.5.8.5 LOAD DURATION CURVE 2026



5.6 FUTURE TRANSMISSION PROJECTS

Appendix 5J provides a list of the Company's planned transmission interconnection projects for the Planning Period with associated enhancement costs. Extraordinarily Sensitive Appendix 5K provides a list of transmission lines that are planned to be constructed during the Planning Period.

Chapter 6 | Development of the Integrated Resource Plan

CHAPTER 6 – DEVELOPMENT OF THE INTEGRATED RESOURCE PLAN

6.1 IRP PROCESS

The IRP process identifies, evaluates, and selects a variety of new resources to meet customers' growing capacity and energy needs to augment existing resources. The Company's approach to IRP relies on integrating cost-effective DSM programs, supply-side resources, market purchases, and transmission options over the Study Period. This integration is intended to produce a long-term plan that focuses on the Company's commitment to provide reliable electric service at a reasonable cost while meeting all regulatory and environmental requirements. This analysis develops a forward-looking representation of the Company's system within the larger electricity market that simulates the dispatch of its electric generation units, market transactions, and demand-side programs in an economic and reliable manner over the Planning Period.

The IRP process begins with the development of a long-term annual peak and energy requirements forecast. Next, existing and approved supply- and demand-side resources are compared with expected load and reserve requirements. This comparison yields the Company's expected future capacity needs to maintain reliable service for its customers over the Planning Period. After the capacity need is identified, the Company evaluates the economics associated with various supply- and demand-side alternatives that complement existing resources to meet capacity and energy requirements in conjunction with regulatory and legislative requirements.

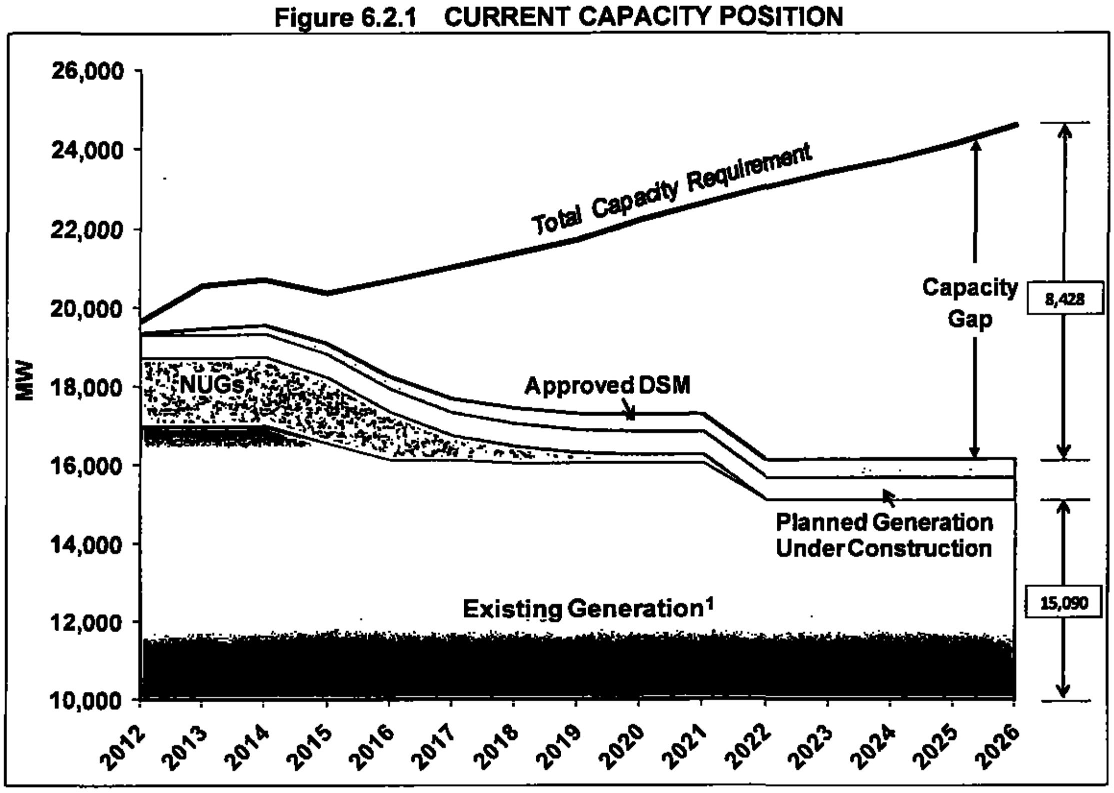
An initial screening analysis is conducted, as described in Chapter 5, to determine supply- and demand- side resources that could potentially fit into the Company's resource mix. The potential resources and their associated economics are inputs to the Company's planning model, Strategist, which helps determine the quantity, type, and timing of new resources selected to meet future energy and capacity requirements. The next step is to develop a range of alternative plans which represent plausible future paths considering the major drivers of future uncertainty. These alternative plans are designed to test alternative resource strategies that are available to the Company. These alternative plans are meant in part to display the relative costs of these resources to the Company's stakeholders. Finally, alternative plans are assessed using various sensitivities and scenarios to gauge the strength of each alternative plan as compared to other plans under a variety of conditions. The performance of each alternative plan leads to the determination of the Preferred Plan. This Preferred Plan best meets the energy and capacity needs of the Company's customers at the lowest reasonable cost. The Company utilizes Promod IV® to evaluate the impact of potential supply- and demand-side resources and transmission projects on both energy prices and the DOM Zone transmission system.

The Company developed its 2011 Plan in consultation with various internal planning and operational groups. The results of the analysis were verified and reviewed for accuracy and reasonableness. The resulting 2011 Plan is presented to the SCC and NCUC in this filing.

6.2 CAPACITY & ENERGY NEEDS

As discussed in Chapter 2 of this 2011 Plan, over the Planning Period the Company forecasted an average annual growth rate of 1.93% in peak demand and 1.89% in energy requirements. Chapter 3 discussed the Company's existing supply- and demand-side resources, NUG contracts, and generation resources under construction. Figure 6.2.1 shows the Company's supply-side resources compared to the total capacity requirement including peak load and reserve margin. The area marked as "capacity gap" shows additional capacity resources that will be needed over the Planning Period in order to meet the total capacity requirement. The Company plans to meet this capacity gap using a balanced combination of additional generating capacity, DSM programs, renewable generation, and market purchases, as determined by the economics of each available option within the IRP process.

Figure 6.2.1 CURRENT CAPACITY POSITION

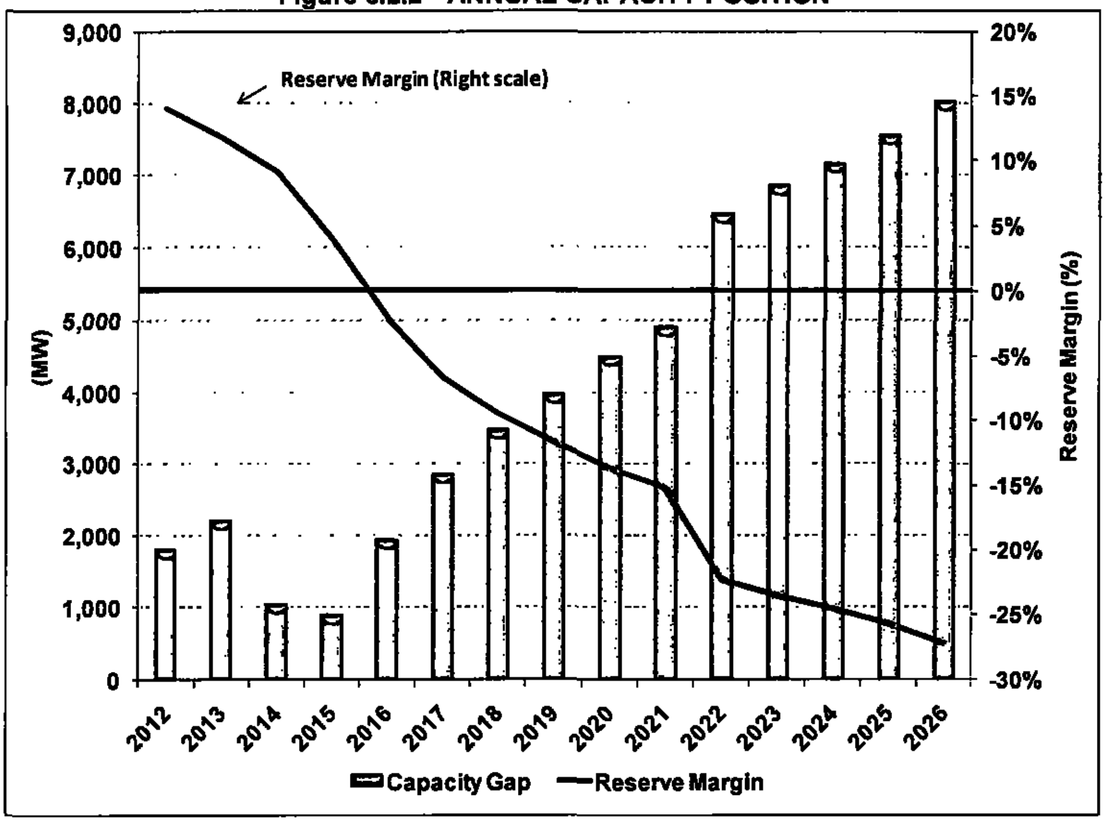


Note: 1) Accounts for unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

As indicated in Figure 6.2.1, the capacity gap is significant. The Planning Period capacity gap is expected to be approximately 8,400 MW. If this capacity deficit is not filled with additional resources, the reserve margin is expected to fall significantly over the Planning Period. In fact, without additional resources, the Company's reserve margin drops below 0% in 2016 resulting in insufficient capacity to meet projected load. Figure 6.2.2 shows the capacity gap and resulting

Company reserve margin over each year of the Planning Period, should no additional capacity be acquired. The Company expects that such a low reserve margin will negatively affect customer reliability and costs. The Company plans to follow a prudent strategy of filling this gap with a carefully chosen and diverse portfolio of resources to meet its customers' long-term needs at the lowest reasonable cost.

Figure 6.2.2 ANNUAL CAPACITY POSITION



Note: Figure includes rating changes to existing units in the Plan; however, purchased market capacity not included.

Figure 6.2.3 presents the projected baseload needs over the Planning Period. This exhibit displays the Company's baseload capacity need as defined by the 65th percentile of the Company's load duration curve for each year, net of any DSM that occurs in these baseload hours. This is compared to the current baseload capacity mix[15] of the Company's generation fleet. The Company's current baseload resources include nuclear, scrubbed coal/biomass, and non-scrubbed coal. The increasing capacity gap over the course of the 15-year Planning Period is in part attributed to draft and final environmental regulations under consideration by the EPA. These laws and regulations are expected to lower the Company's use of baseload coal in its

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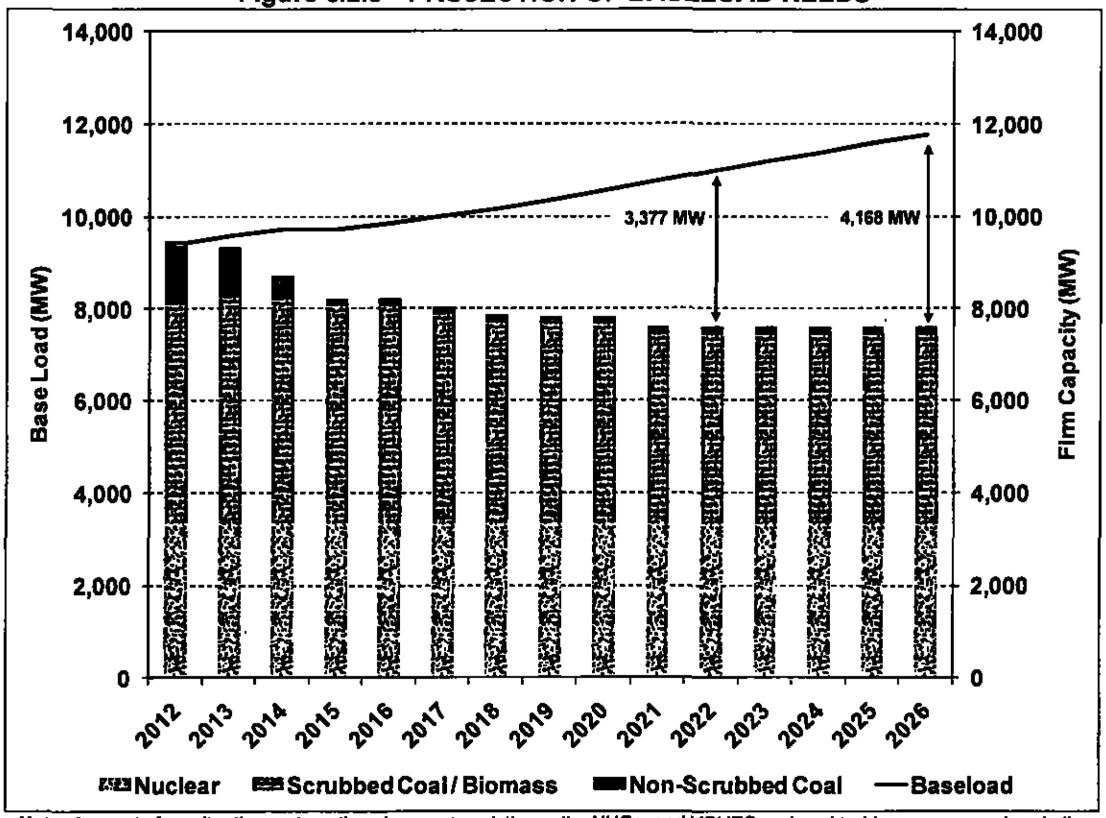
[15] While the Company fully expects intermittent renewable generation in baseload hours, the Company chose to include only firm, dispatchable resources in this assessment.

generating fleet. This capacity and energy gap will need to be replaced with additional supply- and demand-side resources and market purchases.

Figure 6.2.3 PROJECTION OF BASELOAD NEEDS



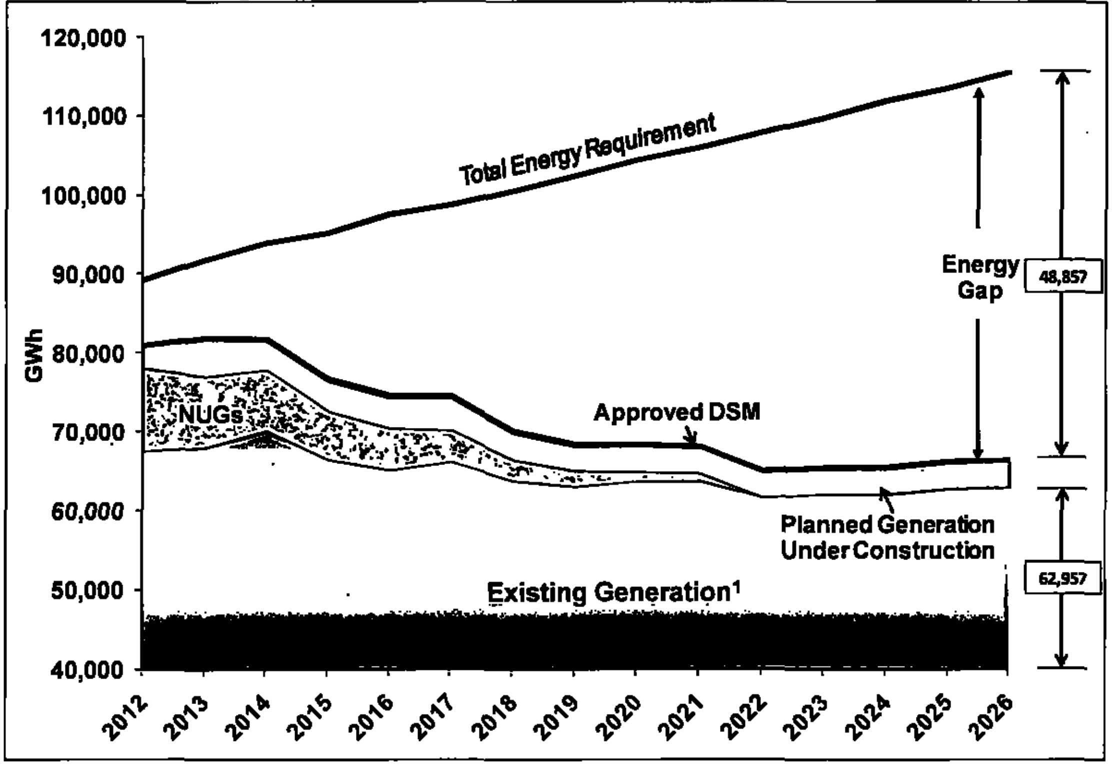
Note: Accounts for unit retirements, rating changes to existing units, NUGs, and VCHEC and coal-to-biomass conversions in the Plan.

The Company's PJM membership has given it access to a wide pool of generating resources for its energy and capacity needs. However, it is critical that adequate reserves are maintained not just in PJM as a whole, but specifically in the DOM Zone to ensure that the Company's load can be served reliably. Maintaining adequate reserves within the DOM Zone lowers congestion costs, ensures a higher level of reliability, and keeps capacity prices low within the region.

For modeling purposes, the Company assumed that NUG capacity will be available as a firm resource. These NUG units also provide energy to the Company according to their contractual arrangements. At the expiration of these NUG contracts, these units will no longer be modeled as a firm capacity resource. After the contract expiration, the NUG has the opportunity to continue operating its resources in the PJM market, providing energy and capacity at competitive prices. Although this is a reasonable planning assumption, parties are not prohibited from entering into another bilateral contract at an agreed upon price. Due to the fact that the price of a potential bilateral contract is not known at this time, the market price is the best proxy to use for planning purposes.

Figure 6.2.4 illustrates the amount of annual energy required by the Company after the dispatch of its existing resources. The figure shows that the Company's energy requirements increase significantly over time.

Figure 6.2.4 CURRENT COMPANY ENERGY POSITION



Note: 1) Accounts for unit retirements and rating changes to existing units in the Plan.

The Company's long-term energy and capacity requirements shown in this section are met through an optimal mix of new generation, DSM, and market resources using the IRP process.

6.3 MODELING PROCESSES & TECHNIQUES

The Company used a methodology that compares the costs of alternative plans to evaluate the types and timing of resources that were included in those plans. The first step in the process was to construct a representation of the Company's current resource base. Then, future assumptions including, but not limited to load, fuel prices, emissions costs, maintenance costs, and resource costs were used as inputs to the model. Simultaneously, supply-side resources underwent an initial screening analysis as discussed in Chapter 5. This analysis provided a set of future supply-side resources potentially available to the Company, along with their characteristics. Cost-effective and available resources that passed this screening analysis were input into the model to meet the Company's resource gap. The Company then determined a portfolio of supply-side resources that met the Company's capacity and energy resource requirements at the lowest reasonable cost over the Study Period.

As described in Chapter 5, potential DSM resources were also screened. For the initial screening of demand-side resource options, an expansion plan of only supply-side resources and approved DSM programs was developed. The proposed and future DSM programs that passed the Company's cost/benefit evaluation discussed in Section 5.5.1 were compared to this initial plan with the opportunity to modify the expansion plan based on their economics. After cost-effective demand-side resources were identified, they were included as a portfolio of programs that were given the opportunity to eliminate, defer, or alter the need for future supply-side resources and market purchases. Next, supply-side options as well as approved and *proposed demand-side resource options were re-optimized along with the future DSM portfolio* to arrive at a base plan. This process ensured that supply- and demand-side resources were treated equally while meeting peak demand and energy requirements.

The Company optimized its combination of market purchases, supply-side resources, and demand-side resources in order to meet the reserve margin target discussed in Chapter 4. Strategist ranked the set of possible resource plans by the total net present value ("NPV") utility costs over the Study Period. The minimization of the NPV utility costs was the ranking mechanism used by the Company. The NPV utility costs included the variable costs of all resources (including emissions and fuel), the costs of market purchases, and the fixed costs of future resources.

To assess an optimum resource strategy and the validity of the Company's 2011 Plan, the Company identified four alternative plans representing plausible future paths, as described in Section 6.4. All four alternative plans were then analyzed and tested against a set of scenarios and sensitivities designed to measure the relative cost performance of each plan under varying market, commodity, and regulatory conditions. This process stressed each alternative plan to find the set of resources that best achieved the Company's goal of providing reliable electric service at the lowest reasonable cost to customers. The alternative plan that performed best was then selected as the Preferred Plan.

6.4 ALTERNATIVE PLANS

The Company's alternative plan analysis is intended to serve two specific purposes. First, each alternative plan represents a plausible path of the Company's future resource additions. Second, the alternative plans are intended to clearly show and allow examination of possible resource additions that could occur for reasons outside the control of the Company. The Company's alternative plans are identified and discussed in this section.

Plan A: Base Plan

Base Plan includes a cost-effective mix of DSM programs, as well as biomass, nuclear, CT, and CC generation resources. Specifically, this plan includes approximately 4,000 MW of CC, 2,400 MW of CT, and a 1,450 MW nuclear unit. The plan includes the 4 MW Halifax County Solar facility with battery storage. The plan also contains DSM programs totaling approximately 940 MW. The Base Plan represents the plan with the lowest reasonable cost for the Company's customers as described in detail in Section 6.6.

The Base Plan includes the retrofits for Possum Point Unit 5 (779 MW) and Yorktown Unit 3 (804 MW) by 2015. In addition, the coal-fired Yorktown Unit 2 (156 MW) is in the Plan to be repowered by natural gas by the same year.

The Base Plan includes the retirement of Chesapeake Energy Center Units 1(111 MW) and 2 (111 MW) by 2015 and Units 3 (156 MW) and 4 (217 MW) by 2016. The Base Plan also includes the retirement of Yorktown Units 1 (159 MW) by 2015, 2 (156 MW) and 3 (804 MW) by 2022.

Plan B: NUG Extension Plan

The Company currently has eight NUG contracts which are expiring within the Planning Period. These contracts provide over 1,747 MW of capacity. This plan extends the current NUG contracts until the end of the Planning Period, except three NUGs totaling 316 MW that already notified the Company of their decision not to extend the current contracts. The NUG contracts are assumed to be renewed at market price for the following years. The purpose of this plan is to show the system cost with renewed NUG contracts at assumed energy and capacity prices.

Plan C: Retrofit Plan

Retrofit Plan is designed to explore the costs under the circumstance where generation unit retirements are not an option for the Company when attempting to comply with environmental regulatory requirements. Instead, the Company would need to retrofit those units affected by environmental regulation requirements in order to stay in compliance and continue operating.

The following list of generation retrofits, which are specific to this plan, are based on a current snapshot in time of the Company's cost projections and assumptions regarding environmental regulations. These retrofits are assumed necessary in order for the identified generation units to meet environmental regulation requirements and stay in service over the Planning Period. Chesapeake Energy Center Units 1 and 2 are assumed to require Selective Catalytic Reduction ("SCR") units, Dry Sorbent Injection Systems ("DSI"), and Cooling Towers. Chesapeake Energy Center Units 3 and 4 are assumed to require Dry Sorbent Injection Systems, and Cooling Towers. Yorktown Units 1 and 2 are assumed to require SCR units, DSI Systems, and Cooling Towers. Yorktown Unit 3 is assumed to require a SNCR unit and Cooling Towers. Possum Point Unit 5 is assumed to require a SNCR unit.

Plan D: Renewable Plan

Renewable Plan presents a way for the Company to test the feasibility and cost of meeting a hypothetical target of providing 20% of the Company's energy needs with renewable resources by 2020 ("20 by 20"). To meet this target with resources from its service territory, the Company would be required to develop a significant amount of renewable resources compared to all other plans. This plan includes a 30 MW (nameplate) Community Solar Power Program, 248 MW (nameplate) of incremental onshore wind, and up to 3,000 MW (nameplate) offshore wind. There is, however, a great deal of uncertainty as to the availability and amount of onshore wind within the Company's service territory. Additionally, the amount of offshore wind resources is extremely optimistic considering the permit and building process has not been determined at this time. For purposes of this alternative, online dates of the Company's offshore wind farms have been accelerated with the first facility projected to come online by 2019 to meet the hypothetical 2020 target. Due to the constraints and uncertainties of building up to 3,000 MW of offshore wind in such a short timeframe, additional renewable resources could be necessary to meet the 20 by 20 hypothetical target, at additional costs. This plan includes one less CC than the Base Plan; however, an additional CT was needed to meet the installed reserve margin requirement as these new renewable resources do not provide full capacity at the time of the Company's peak demand.

The addition of new renewable resources allows the Company to support the policies of Virginia and North Carolina. The Virginia legislature enacted a law that established a voluntary RPS program with a goal that increases by year and has stated that it is in the public interest for utilities to achieve the targets set forth in Virginia's RPS program. Additionally, the Virginia legislature has indicated that small renewable energy projects are in the public interest (Va. Code § 56-580.D). The North Carolina legislature has established a REPS (NCGS § 62-133.8) with mandatory renewable requirements that increase by year and include specific requirements for solar, swine waste, and poultry waste.

Figure 6.4.1 displays the resources by type (traditional, renewable or DSM) that are included in each alternative plan by year.

Figure 6.4.1 ALTERNATIVE PLANS

Year	Plan A Base Plan		Plan B NUG Extension Plan		Plan C Retrofit Plan		Plan D Renewable Plan	
	Traditional	Renewable/ DSM	Traditional	Renewable/ DSM	Traditional	Renewable/ DSM	Traditional	Renewable/ DSM
2012	VCHEC	App. DSM	VCHEC	App. DSM	VCHEC	App. DSM	VCHEC	App. DSM
2013		Pro./Fut. DSM		Pro./Fut. DSM		Pro./Fut. DSM		Pro./Fut. DSM/SLR
2014		Halifax		Halifax		Halifax		Halifax/SLR
2015	Warren		Warren		Warren		Warren	SLR
2016	CC						CC	WND
2017								WND
2018					CC		CT	WND / Bio
2019	CC		CC		CT		CT	Bio / OFF
2020	CT		CT		CT		CT	OFF
2021	CT		CT				CT	
2022	NA3		NA3		NA3		NA3	
2023	CT						CT	
2024	CT				CT		CT	
2025	CT		CC		CT		CT	
2026	CT		CT		CT		CT	

Key: App. DSM: Approved DSM Programs; Bio: Biomass; CC: Combined Cycle; CT: Combustion Turbine (2 units); Halifax: Halifax County Solar; NA3: North Anna 3; OFF: Offshore Wind; Pro./Fut.DSM: Proposed and Future DSM Programs; SLR: Community Solar Program; VCHEC: Virginia City Hybrid Energy Center; Warren: Warren County Power Station; WND: Onshore Wind
***Note:** DSM capacity continues to increase throughout the Planning Period.*

6.5 BASECASE, SCENARIOS, & SENSITIVITIES

The Company used a number of scenarios and sensitivities based upon its planning assumptions to evaluate these four alternative plans. The Company's operational environment is highly dynamic and can be significantly impacted by variations in commodity prices, construction costs, and environmental and regulatory requirements. Testing multiple expansion plans under different assumptions provided assurance that the selected plan would perform well under a multitude of possible futures. The Company examined one basecase, three scenarios, and 12 sensitivities as explained below.

<u>*Basecase (1)*</u>

The basecase used the expected or forecast "base" values including the load forecast (Chapter 2), existing system resources (Chapter 3), planning assumptions (Chapter 4), and new resources (Chapter 5).

<u>Scenarios:</u>

Scenarios provided an all-encompassing view of the variable future evolution of the markets and regulatory conditions. Several important assumptions were changed in a scenario which accounted for systemic changes in the view of the future. These changes included multiple variables that were interrelated, such as emission and cost variables, ensuring all assumptions were consistent. The Company examined the no carbon cost, high fuel cost and low fuel cost scenarios.

No Carbon Cost Scenario (2)

One of the biggest uncertainties for the electric utility industry is whether carbon legislation will be enacted and, if it occurs, what its structure will be and what the potential impacts on the fuel markets will be. The Company's basecase assumed that carbon legislation will be enacted by 2018 similar to many of the proposals considered by the United States Congress. However, until a specific law is passed, there is a great deal of uncertainty about the exact limits on emissions and the number of allowances that may be given to the electric power industry.

Due to the uncertainty surrounding potential future carbon legislation, the Company chose to examine a scenario where carbon legislation would not come into effect during the Planning Period. In this scenario, fuel and commodity processes were correlated appropriately to the effects of the modeled CO_2 market. The major assumptions that were adjusted in this scenario included: i) fossil fuel prices (coal, gas, and oil); ii) environmental allowance prices (SO_2, NO_X, Hg, and CO_2); and iii) market capacity and energy prices.

High and Low Fuel Cost Scenarios (3-4)

These scenarios were designed to test fuel price variations for all generation units in each alternative plan. This test was important because fuel costs are a significant portion of final customer rates. Volatility in rates is generally viewed as undesirable. Therefore, plans that reduce volatility may be preferred to other alternative plans. These scenarios consider adjustments to the following assumptions (with the changes in the fuel prices being the main driver): i) fossil fuel prices (coal, gas, and oil); ii) environmental allowance prices (SO_2, NO_X, Hg, and CO_2); and iii) market capacity and energy prices.

Sensitivities:

A sensitivity represents a change in a single or small subset of variables from the basecase assumptions. The sensitivities performed by the Company were designed to test the alternative plans under varying assumptions to better understand the inherent risks embedded in the Company's 2011 Plan. The Company performed the following 12 sensitivities:

High and Low Load Growth Sensitivities (5-6)

Future load growth was one of the key inputs used to develop the 2011 Plan. Demand growth is significantly impacted by regional economic growth and technological changes. As discussed in Chapter 2, the basecase average annual growth rate over the Planning Period was 1.89% for energy requirements and 1.93% for peak demand. The high and low load growth sensitivities assumed a plus and minus 0.5% change in these average annual growth rates. The high load growth sensitivity could result from an above average economic growth rate or expanded penetration of new technological devices at home and in the workplace. The low load growth sensitivity may come from lower than expected economic growth, additional energy conservation, or a decline in real disposable income.

High and Low Construction Costs Sensitivities (7-8)

The escalation of power plant construction costs could represent a significant risk for the Company's stakeholders. Recent trends indicate that the volatility of costs surrounding the construction of new facilities has increased above historical averages. This increase in construction costs represents a significant challenge to utilities, regulators, and customers across the United States as utilities focus on replacing aging infrastructure and adding new capacity to meet current regulatory requirements and future demand growth. The construction cost sensitivities analyzed the risk associated with potential future increases or decreases in the construction costs of traditional and renewable plants. The high and low construction cost sensitivities assumed an increase and decrease of costs by 25% in order to determine the economic impact of potential changes in the construction cost of planned units.

High and Low Transmission and Distribution Costs ("T&D") Sensitivities (9-10)

The Company assumed that a portion of the benefits from the Company's portfolio of DSM programs was from avoided T&D investments to meet incremental demand growth. The costs estimated for incremental T&D projects have increased in recent years in a similar fashion to generation construction projects. As a result, the high and low T&D cost sensitivities of the approved, proposed, and future DSM programs were tested by increasing and decreasing the T&D benefit of the DSM programs by 25%.

Alternative Energy Sensitivity (11)

The alternative energy sensitivity is a combination of potential future programs that could affect future energy consumption patterns. The programs include net metering and dynamic pricing rate schedules, as described below:

Net Metering:

In Virginia, net metering is currently available to customers on a first-come, first-serve basis in each electric distribution Company's service area. This occurs until the rated generating capacity owned and operated by eligible customer generators reaches 1% of each electric distribution Company's adjusted Virginia peak load forecast for the previous year. This sensitivity will allow the Company to determine the impact on load in the event that the 1% cap is reached in Virginia by 2026. In North Carolina, there is no aggregate capacity limit for net metering.

Dynamic Pricing Rate Schedules:

Dynamic pricing rate schedules are rates designed to price the sale of electricity to follow the changing costs of production. As AMI is deployed through the Company's service territory, additional customers will be eligible for dynamic rate options. The Company is currently offering dynamic rates as a part of a pilot program, which was approved by the SCC in April 2011.

EVs & PHEVs Sensitivity (12):

The Company's basecase assumes a certain level of EV and PHEV penetrations in its service territory. This sensitivity relies on the EPRI's PHEV study[16] for higher penetrations. The objective of the EV and PHEV sensitivity was to project the impact of higher plug-in EV penetration on the Company's grid and identify resources needed to meet this potential new technology's requirements.

No REC Sales Sensitivity (13)

The Company's basecase assumed that new renewable generation resources were able to sell RECs to others in order to reduce the cost to its customers. In this sensitivity, the Company assumed that it would not be able to sell RECs, therefore increasing the cost of renewable generation.

High REC Sales Sensitivity (14)

This sensitivity assumes that renewable generation resources will receive a REC that has twice the value of a basecase REC.

High and Low Cost Combination Sensitivities (15-16)

The high and low cost combination sensitivities included a grouping of two individual sensitivities meant to form a more extreme case. The high cost combination case included the high construction cost sensitivity and high fuel cost sensitivity while the low cost combination case included the low construction cost sensitivity and low fuel cost sensitivity.

6.6 INTEGRATED RESOURCE PLAN RANKING

The Company examined the four alternative plans using the basecase, three scenarios, and 12 sensitivities to rank the plans using the NPV utility costs over the Study Period. The Company determined its Preferred Plan because it produced the lowest average NPV utility cost, the number of least-cost rankings, across all scenarios and sensitivities evaluated and the evaluation of the basecase.

Figure 6.6.1 presents the results of the four alternative plans compared on an individual scenario or sensitivity basis. Each row of the figure constitutes a grouping of plans that were considered for that particular scenario or sensitivity. The lowest cost plan is shaded for each scenario or sensitivity in the respective row. The results are displayed as a percentage change in costs compared to the Base Plan with basecase assumptions (marked with a star). For example, Figure 6.6.1 illustrates that the NPV utility cost of Base Plan for the "No CO_2 scenario" is 12.69% less expensive than that of the basecase. However, the NPV utility cost of the Renewable Plan for the same scenario is 6.25% more expensive than that of the basecase in the Base Plan. The same results are also illustrated in a bar chart in Figure 6.6.2.

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[16] This study is available at http://www.epri.com.

Figure 6.6.1 indicates that the Base Plan (Plan A) is the Preferred Plan as it was the:

- Best ranked plan with the basecase assumptions,
- Top performing plan in all of the sensitivities and scenarios examined, and
- Plan with lowest relative average NPV utility costs.

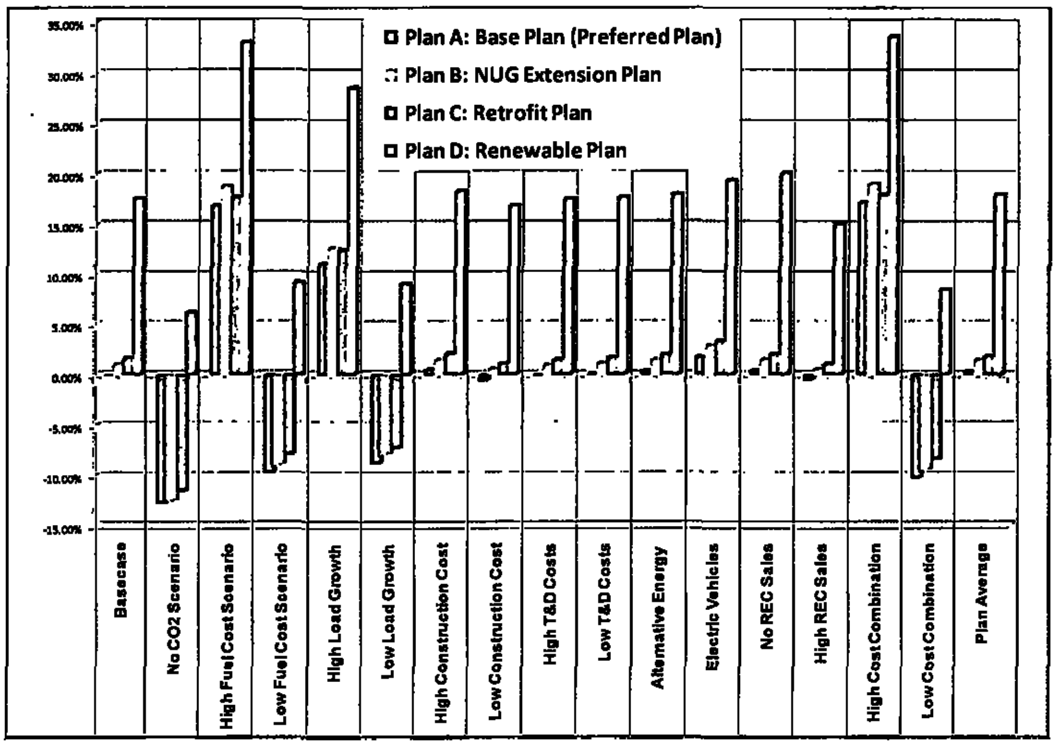
The Preferred Plan minimized changes to the Company's cost of providing service across the range of assumptions considered in its planning process.

Figure 6.6.1 PLAN COMPARISON UNDER SCENARIOS & SENSITIVITIES

	NPV Relative to the Cost of Base Case in Preferred Plan			
	Plan A: Base Plan (Preferred Plan)	Plan B: NUG Extension Plan	Plan C: Retrofit Plan	Plan D: Renewable Plan
Basecase	☆	1.12%	1.68%	17.68%
No CO2 Scenario	-12.69%	-12.51%	-11.58%	6.25%
High Fuel Cost Scenario	16.91%	18.94%	17.76%	33.13%
Low Fuel Cost Scenario	-9.73%	-8.96%	-7.93%	9.27%
High Load Growth	11.16%	12.78%	12.52%	28.63%
Low Load Growth	-8.84%	-7.89%	-7.30%	9.10%
High Construction Cost	0.57%	1.58%	2.18%	18.40%
Low Construction Cost	-0.57%	0.66%	1.18%	16.96%
High T&D Costs	-0.09%	1.03%	1.59%	17.59%
Low T&D Costs	0.09%	1.21%	1.77%	17.77%
Alternative Energy	0.43%	1.55%	2.10%	18.11%
Electric Vehicles	1.85%	2.97%	3.46%	19.47%
No REC Sales	0.48%	1.61%	2.16%	20.10%
High REC Sales	-0.52%	0.60%	1.16%	15.21%
High Cost Combination	17.32%	19.18%	18.05%	33.69%
Low Cost Combination	-10.30%	-9.42%	-8.43%	6.56%
Plan Average	0.38%	1.53%	1.90%	18.12%

Note: *The results are displayed as a percentage of costs compared to the Base Plan with basecase assumptions (marked with a star).*

Figure 6.6.2 PLAN COMPARISON UNDER SCENARIOS & SENSITIVITIES (Bar Chart)



The NUG Extension Plan was ranked as the second alternative plan when compared to the Preferred Plan, at an additional cost of 1.12%. It was the second ranked plan in 13 cases and the third ranked plan in three cases.

The Retrofit Plan was ranked as the third alternative plan when compared to the Preferred Plan, at an additional cost of 1.68%. It was ranked the second best plan in three cases, and the third best in 13 cases.

The Renewable Plan performed poorly under all cases and displayed a higher variance across the range of sensitivities and scenarios. The Renewable Plan was the worst performing alternative plan in all 16 cases. On average, this set of resources would cause the Company's average NPV utility costs to rise 17.68% over the Study Period compared to the Base Plan. The most salient risks of the Renewable Plan were clearly under conditions of low carbon costs, low fuel costs, lower load growth, and high construction costs. Although it provides some marginal benefits under the reverse conditions, no solar or offshore wind resources have entered mainstream service in conditions similar to the Company's service territory at this time. The Company plans to closely follow the development of these technologies for future consideration.

6.7 PREFERRED PLAN

The Preferred Plan displayed in Figure 6.7.1 contains a balanced mix of supply- and demand-side options to meet expected future resource needs in an efficient and cost-effective manner. The Preferred Plan advocates a balanced mix of baseload, intermediate, and peaking units as well as a diverse fuel mixture giving the Preferred Plan the flexibility to maintain reasonable costs and offer reliable service to its customers.

Figure 6.7.1 PREFERRED INTEGRATED RESOURCE PLAN

Year	Supply-side Resources				Demand-side Resources
	New	Retrofit	Repower	Retire	
2012	VCHEC				Approved DSM Proposed & Future DSM
2013			AV, HW, SH – Biomass		
2014	Halifax		BR3 – Gas BR4 – Gas		
2015	Warren	PP5 – SNCR YT3 – SNCR	YT2 – Gas/Oil	CEC 1-2 YT1	
2016	CC			CEC 3-4	
2017					
2018					
2019	CC				
2020	CT				
2021	CT				
2022	North Anna 3			YT 2-3	
2023	CT				
2024	CT				
2025	CT				
2026	CT				

Key: Retrofit: Additional environmental control reduction equipment; Repower: Convert fuel to biomass or natural gas; Retire: Remove a unit from service; AV: Altavista; BR: Bremo; CEC: Chesapeake Energy Center; CC: Combined Cycle; CT: Combustion Turbine (2 units); Halifax: Halifax County Solar; HW: Hopewell; PP: Possum Point Unit; SH: Southampton; SNCR: Selective Non-Catalytic Reduction; VCHEC: Virginia City Hybrid Energy Center; Warren: Warren County Power Station; YT: Yorktown Unit

Note: DSM capacity savings continue to increase throughout the Planning Period.

To meet growing demand, the Preferred Plan identifies a need for the following resources by the end of the Planning Period:

- *Existing Generation* – Uprates, derates, and retirements allow the Company to utilize existing generation capacity.
- *Planned Generation Under Construction* – One unit under construction, VCHEC, has a capacity of approximately 585 MW.
- *Planned Generation Under Development* – Two units under development, Warren County Power Station and North Anna 3, with a combined capacity of approximately 2,790 MW.
- *Planned Renewable Generation Under Development* – Halifax County Solar facility of 4 MW with battery storage;

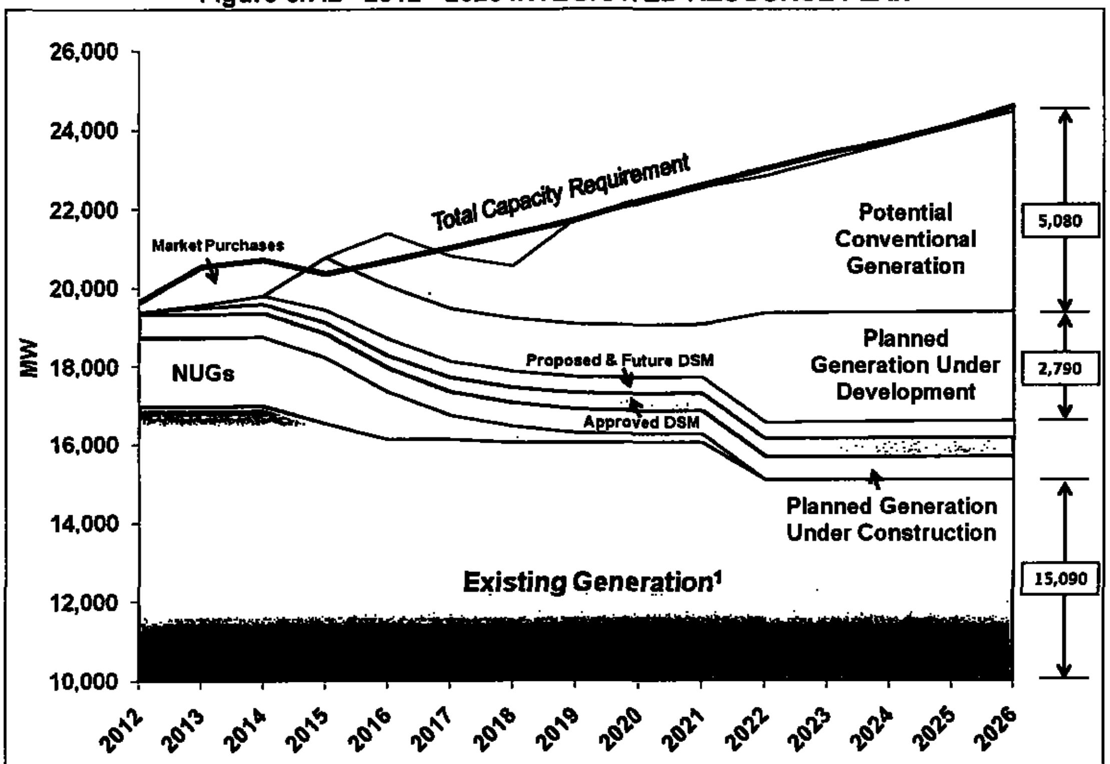
- *Demand-Side Resources* – Approved, proposed and future demand-side resources total approximately 940 MW.
- *Potential Conventional Generation Resources* – Additional 5,075 MW of newly constructed CC and CT resources including:
  - One CC in 2016 and 2019
  - CT in 2020, 2021, 2023, 2024, 2025, and 2026
- *Market Purchases* – Rely on the PJM energy and capacity resources whenever economical.
- *NUG capacity under contract*

On June 27, 2011 the Company filed an application with the SCC for approval to convert Altavista, Hopewell, and Southampton power stations to biomass fuel totaling 153 MW by the end of 2013. In addition, the Company currently plans to repower Bremo Power Station Units 3 and 4 totaling 227 MW by natural gas in 2014.

By the end of the Planning Period, the Company projects a need for more than 8,400 MW of new capacity. Additional details regarding the size and output of new generating units have been provided in Appendices 6A and 6B. Further, Extraordinarily Sensitive Appendix 6C provides details on existing, new, and DSM resources and the Company's capacity position relative to its reserve requirements. Confidential Appendix 6D provides the construction cost estimates associated with the Preferred Plan. Finally, Extraordinarily Sensitive Appendix 6E provides the Company's capacity position when the Preferred Plan is combined with existing resources.

The IRP process has indicated that the Preferred Plan contains an appropriate mix of supply-side resources, demand-side resources, and market purchases to provide its customers energy reliably at the lowest reasonable cost. Figure 6.7.2 illustrates the Company's resulting resource position at the end of the Planning Period.

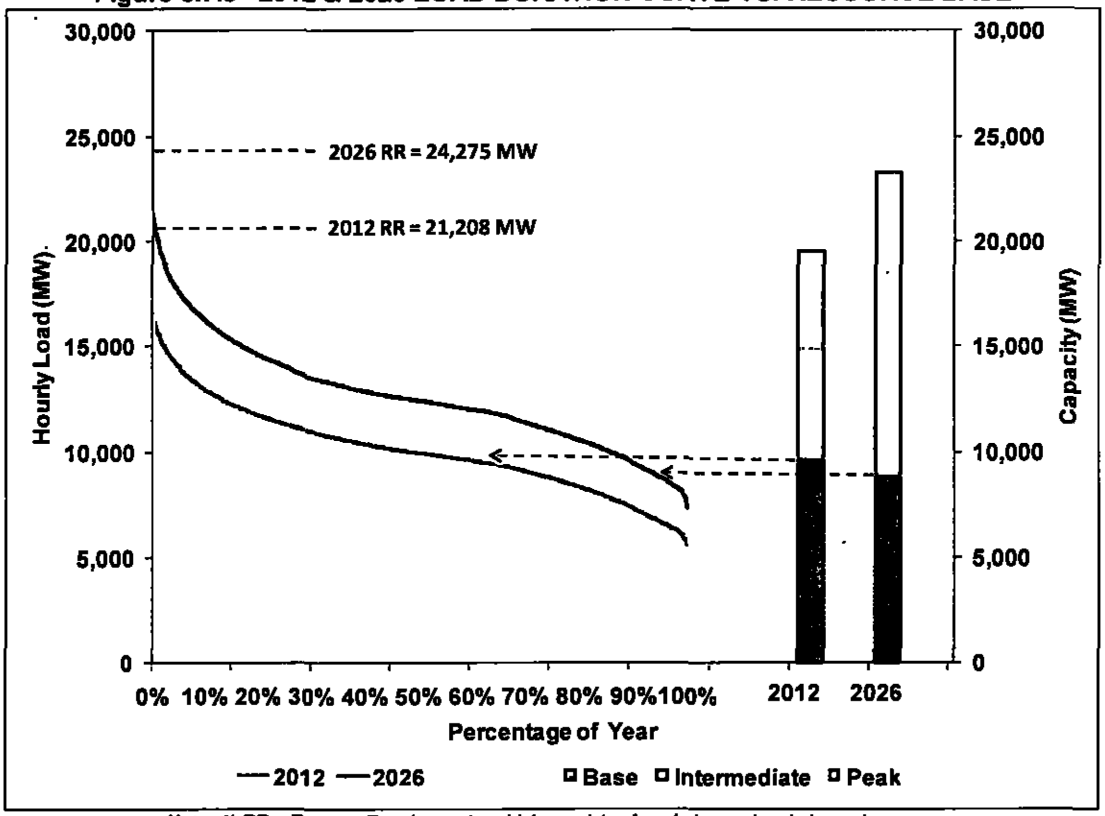
Figure 6.7.2 2012 - 2026 INTEGRATED RESOURCE PLAN



Note: 1) Accounts for unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Figure 6.7.3 displays the Company's load duration curve, net of DSM, against a resource stack of the Company's generation units defined by baseload, intermediate, and peak resources.

Figure 6.7.3 2012 & 2026 LOAD DURATION CURVE VS. RESOURCE BASE

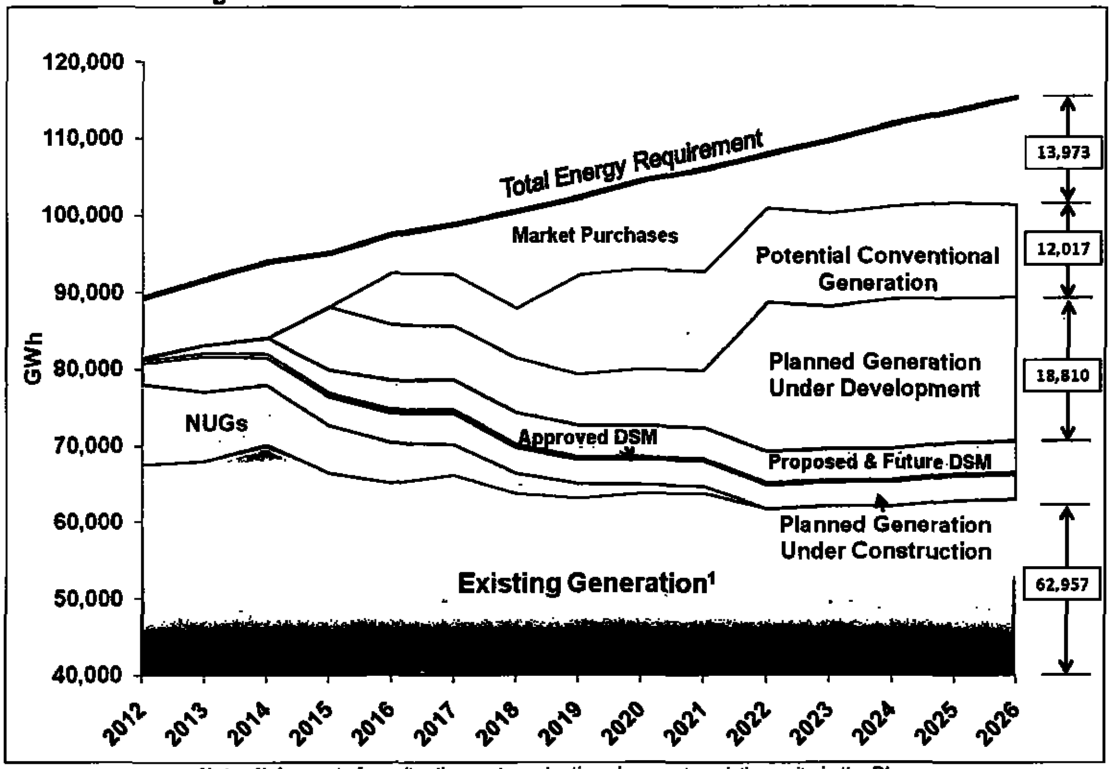


Note: 1) RR = Reserve Requirements, which consists of peak demand and planned reserve.

During the Planning Period, the Preferred Plan results in the addition of approximately 3,300 MW of intermediate capacity, 1,750 MW of peaking capacity, and approximately 880 MW of new DSM resources. The Plan also results in a reduction of 440 MW of baseload capacity. The Company considers this balance between resource types necessary to provide an appropriate trade-off between costs and risks for its customers. Maintaining a balanced portfolio of resources maximizes the value that customers receive from the Company's generating assets and DSM programs while reducing the Company's dependence on market capacity purchases.

The Company's market energy purchases are expected to grow as its customers' demand for electricity increases as illustrated in Figure 6.7.4. However, planned generation under development, potential conventional generation, potential renewable generation, and energy provided by approved, proposed, and future DSM programs are expected to stabilize the Company's market energy purchases.

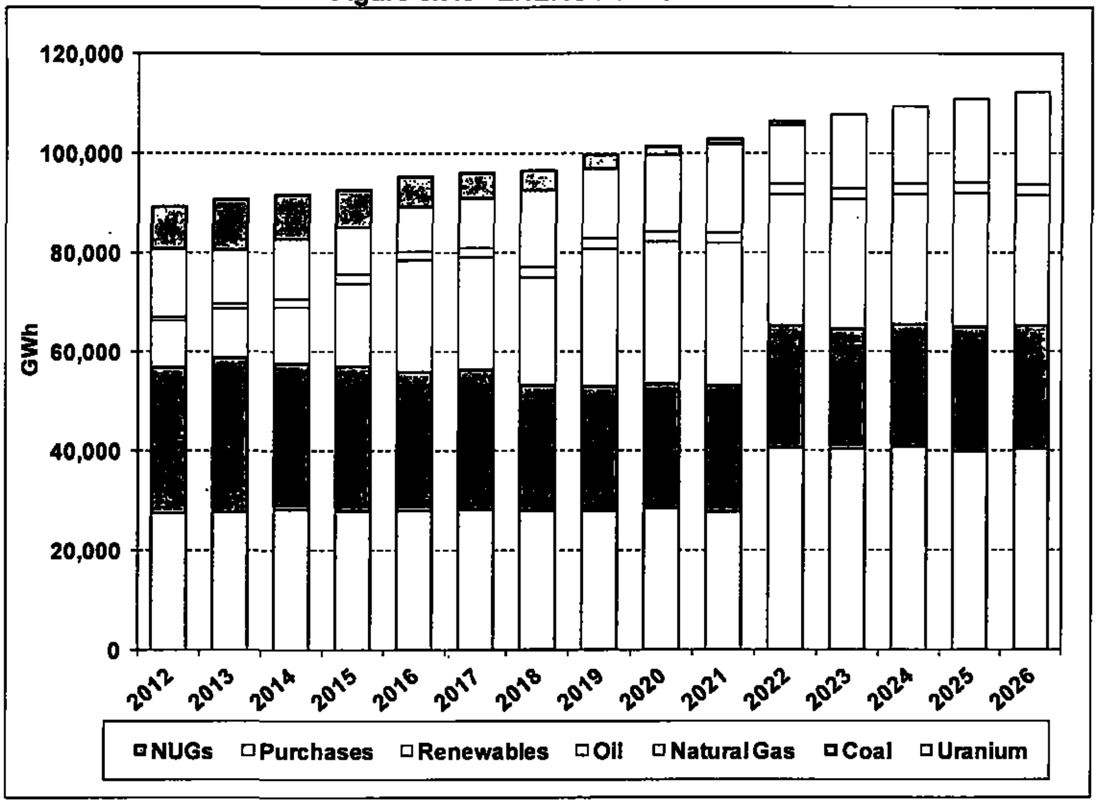
Figure 6.7.4 COMPANY'S PROJECTED ENERGY POSITION



Note: 1) Accounts for unit retirements and rating changes to existing units in the Plan.

In addition to maintaining the balance between baseload, intermediate, and peaking capacity, the Company has considered the fuel mix that would result from its 2011 Plan. As displayed in Figure 6.7.5, the Company's current fuel mix includes uranium, coal, oil, natural gas, renewables, purchased power, and NUGs. The Preferred Plan illustrates that the reliance on new natural gas units for energy is growing, while nuclear and coal are major sources of energy to meet the increasing energy requirements.

Figure 6.7.5 ENERGY BY SOURCE



Although the Company plans its capacity additions to meet peak demand and reserve requirements, new generation resources often require long development lead times and capacity additions larger than a single year's increase in load. Although the Company does not intend to build excess capacity, it may be difficult to meet the exact capacity requirements in any particular year which could create a shortage or overage of capacity compared to the target reserve margin in that year. Because of the uncertainties surrounding the impact of draft and final EPA regulations and the opportunities for developing new natural gas units in the upcoming years based on current market conditions, the Preferred Plan represents a certain amount of excess capacity for 2015 and 2016. The Company's participation in the RPM capacity market will assist in buying and selling capacity to align with the annual reserve target.

6.8 CONCLUSIONS

The Company's 2011 Plan provides a mix of supply- and demand-side resource options to meet expected customer demand growth while meeting reserve requirements at the lowest reasonable cost. The Preferred Plan provides a path for meeting the energy demands of the Company's customers while providing reliable electric service at the lowest reasonable cost. The 2011 Plan addresses a number of considerations including:

- Meeting capacity and energy needs at the lowest reasonable cost;
- Meeting draft and final environmental regulations during the Planning Period;

- Proposing DSM programs that reduce peak demand and energy requirements;
- Reducing reliance on imported capacity and decreasing market risk;
- Providing flexibility in regard to future resource selection and maintaining fuel diversity;
- Meeting commercial operation dates for resources; and
- Remaining cost-effective under a range of future market conditions.

In order to comply with the draft and final environmental regulations and depending on the specific situation for each generating unit, the analysis determined one of three options for each "at risk" unit: (1) retrofitting with additional environmental control reduction equipment, (2) fuel repowering to biomass or natural gas, or (3) retiring the unit.

Based on draft and final form of environmental regulations along with current market conditions, the 2011 Plan includes the following impacts to the existing generating resources in terms of retrofitting, repowering and retiring, which may be revised when the regulations are finalized:

1. Retrofit
   - 1,583 MW of heavy oil-fired generation with new SNCR controls by 2015
2. Repower
   - 153 MW of small coal-fired generation repowered from coal to biomass by the end of 2013
   - 383 MW of small coal-fired generation repowered from coal to natural gas and oil by 2015
3. Retire
   - 754 MW of small coal-fired generation retired by 2016
   - 960 MW of heavy oil-fired and natural gas-fired units retired by 2022

Over the next five years (2012-2016), the Company plans to add VCHEC and Warren County Power Station totaling approximately 1,920 MW. The Company also plans to reduce its near-term reliance on market purchases for energy and capacity with approximately 770 MW of additional DSM resources. The Company also plans to add Halifax County Solar facility of 4 MW with battery storage by 2015. The Company is planning to convert three of its coal-fired units to biomass, totaling approximately 153 MW. Additionally, the coal-fired Bremo Units 3 and 4, totaling 227 MW, are planned to be repowered by natural gas in 2014.

In the long-term (2017-2026), additional resources will be required to meet the growing demand. The Company plans to add 1,454 MW of baseload capacity, 1,337 MW of intermediate capacity, and 2,400 MW of peaking capacity. Specifically, North Anna 3 will primarily meet anticipated baseload growth. Further, DSM resources will account for approximately 170 MW of capacity.

Uncertainty surrounding environmental regulations, renewable energy requirements, fuel costs, construction costs, and load growth are major drivers that could significantly affect customers in the future. To address these issues, the 2011 Plan provides fuel diversity, renewable resources, DSM resources, and a balanced mix of baseload, intermediate, and peaking capacity. As these drivers evolve and regulatory uncertainty is reduced, the Company will address these changes in future integrated resource plans.

Chapter 7

Short-Term Action Plan

CHAPTER 7 – SHORT-TERM ACTION PLAN

The STAP provides the Company's strategic plan for the next five years (2012 – 2016) as well as a discussion of the specific short-term actions the Company is taking to meet the initiatives discussed in this 2011 Plan. A combination of developments on the market, technological, and regulatory fronts over the next five years will likely shape the future of the Company and the utility industry for many decades to come. The Company proactively is positioning itself in the short-term to address these evolving developments for the benefit of all stakeholders over the long-term. Major components of the Company's strategy for the next five years are expected to include:

- Continue working on projects to meet projected load growth such as:
  - Timely completion of infrastructure expansion projects including VCHEC and several new transmission lines in Virginia and North Carolina;
  - Seek approval for CPCNs for Warren County Power Station and amended CPCNs for Altavista, Hopewell and Southampton;
  - Enhance and upgrade the Company's existing transmission grid;
  - Construct additional generation while maintaining a balanced fuel mix;
  - Economically reduce reliance on power imports;
  - Continue to develop and implement a renewable strategy that supports the Virginia RPS goal and North Carolina REPS requirements; and
  - Continue to implement cost-effective DSM programs in Virginia and North Carolina;
- Enhance reliability and customer service.

A more detailed discussion of the current and planned activities over the next five years is provided in the following sections.

7.1 CURRENT ACTIONS (2011)

Demand-Side Management:

Virginia

Currently, the Company has five approved programs in Virginia and is collecting data, through the EM&V process, to validate the associated energy and demand savings. On September 1, 2011, the Company filed for approval of six additional DSM programs, which includes one bundle of residential programs.

North Carolina

On September 1, 2010, the Company filed for NCUC approval of the five programs approved in Virginia as well as the CDG Program. On February 22, 2011 the NCUC issued final orders approving five of the six proposed programs. The Company began implementing the Residential Lighting Program in May 2011 and the other programs in June 2011. Currently, the NCUC's proceeding regarding the CDG Program review is pending.

Advanced Metering Infrastructure:
The Company is currently demonstrating the effectiveness and benefits of installing AMI, or smart meters, on homes and businesses throughout Virginia. The AMI demonstrations test the effectiveness of AMI in achieving voltage conservation, remotely turning off and on electric service, power outage and restoration detection and reporting, remote daily meter readings, and offering dynamic rates.

1. In January 2009, the Company began installing 6,700 AMI meters on homes and businesses served by the Trabue substation distribution circuits in portions of Midlothian, Virginia.
2. Installations continued in the City of Charlottesville and Albemarle County, with 46,500 AMI meters installed by the end of 2009.
3. By December 2010, 32,000 AMI meter installations were completed in parts of the Company's Northern Virginia service territory. The AMI meters are installed in parts of the City of Alexandria, Arlington County, Fairfax County, and the City of Falls Church.
4. The Company's efforts to demonstrate meter technology continue with additional meter exchanges in 2011. The Company plans to install approximately 8,000 meters to evaluate additional technology in Blue Ridge, downtown Richmond, and Williamsburg by the end of 2011.
5. In April 2011, the SCC approved a dynamic rate pilot program, PUE-2009-00084. The pilot program offers residential and small commercial AMI customers an option to enroll in a dynamic rate where the price for electricity varies based on day classification, time of day and season.

Generation:

1. Altavista, Hopewell and Southampton (51 MW each) request for amended CPCNs filed in 2011.
2. Bear Garden (590 MW) came online in 2011.
3. Chesapeake CT Unit 2 was derated 64 MW in 2011.
4. Chesterfield Unit 5 uprated 1 MW effective 2011.
5. Chesterfield Unit 6 uprated 7 MW effective 2011.
6. Kitty Hawk Units 1 and 2 (31 MW) will be retired by the end of 2011.[17]
7. Mt.Storm Unit 2 uprated 31 MW effective 2011.
8. North Anna Unit 1 was derated 1 MW effective 2011.
9. North Anna Unit 2 was derated 26 MW effective 2011.
10. Surry Unit 2 uprated 40 MW effective 2011.
11. Warren County Power Station (1337 MW) CPCNs filed in 2011.

Transmission:
Virginia:

1. The Company filed a request (Case No. PUE-2011-00003) on January 18, 2011, that the SCC approve the rebuild of Mt.Storm – Doubs 500 kV Line and grant a CPCN.

[17] Kitty Hawk units 1 and 2 were put into cold reserve status on March 15, 2011, due to the age of the units.

2. The Company filed a request (Case No. PUE-2011-00011) on February 7, 2011, that the SCC approve the construction of Cannon Branch – Cloverhill 230 kV Line and grant a CPCN.
3. The Company filed a request (Case No. PUE-2011-00015) on February 18, 2011, that the SCC approve the Hollymead 230 kV Double Circuit project and grant a CPCN.
4. The Company filed a request (Case No. PUE-2011-00039) on April 29, 2011, that the SCC approve the construction of Dooms – Bremo 230 kV Rebuild project and grant a CPCN.
5. The Company filed a request (Case No. PUE-2011-00082) on July 20, 2011, that the SCC approve the construction Northwest – Lakeside 230 kV Line and grant a CPCN.

North Carolina:

1. The Company will be filing a request in 2012 with the NCUC to construct a Shawboro to Aydlett 230 kV line with a target service date of May 2015.
2. The Company will be rebuilding the Winfall – Elizabeth City 230 kV line with a target service date of May 2015.

Renewable Energy Resources:

Approximately 401 MW of qualifying renewable generation is currently in operation. The Company has existing contracts for approximately 25 MW of BTMG renewable capacity, as well as one contracted renewable NUG facility at Ogden-Martin Fairfax that will provide approximately 63 MW in 2011.

Virginia:

1. Virginia RPS Program – The Company plans to meet its 2011 target by applying renewable generation from existing qualified facilities, including NUGs, and purchasing cost-effective RECs (including optimization).
2. Virginia Annual Report – On November 1, 2011, the Company intends to submit its Annual Report to the SCC, as required, detailing its efforts towards the RPS plan.

North Carolina:

1. North Carolina REPS Compliance Report – The Company submitted its annual REPS Compliance Report on August 25, 2011.
2. North Carolina REPS Compliance Plan – The Company submitted its annual REPS Compliance Plan, which is filed as North Carolina IRP Addendum 2 to this 2011 Plan..

7.2 FUTURE ACTIONS (2012 – 2016)

DSM PROGRAMS

Figure 7.2.1 lists the projected demand and energy savings by 2016 from the approved, proposed, and future DSM programs.

Figure 7.2.1 DSM PROJECTED SAVINGS BY 2016

Program[1]	Projected MW Reduction	Projected GWh Savings	Status (VA/NC)
Air Conditioner Cycling Program	267	0	Approved
Commercial HVAC Upgrade Program	17	43	
Commercial Lighting Program	35	279	
Low Income Program	3	14	
Residential Lighting Program	19	215	
Commercial Distributed Generation Program[2]	58	0	Proposed / Pending Review
Commercial Energy Audit Program	12	69	Proposed / Future
Commercial Duct Testing & Sealing Program	15	67	
Commercial Refrigeration Program	107	638	
Residential Lighting Program (Phase II)	75	353	
Residential Bundle Program	70	222	
Residential Home Energy Check-Up Program	*2*	*9*	
Residential Duct Testing & Sealing Program	*7*	*11*	
Residential Heat Pump Tune-Up Program	*41*	*139*	
Residential Heat Pump Upgrade Program	*21*	*63*	
Voltage Conservation Program	0	1,958	Future / Future
Commercial Re-Commissioning Program	38	192	
Commercial Solar Window Film Program	33	143	
Commercial Data Center/Computer Room Program	1	21	
Commercial Custom Incentive Program	20	69	
Residential Cool Roof Program	3	3	
Totals	773	4,285	

Notes: 1) All programs will be implemented in Virginia and North Carolina by 2015 assuming Commission approval. 2) Currently, the NCUC's proceeding regarding the CDG Program review is pending.

GENERATION ADDITIONS:

Figure 7.2.2 lists the generation plants that are currently under construction and are expected to be operational by 2016. Figure 7.2.3 lists the generation plants that are currently under development and are expected to be operational by 2016.

Figure 7.2.2 GENERATION PLANTS UNDER CONSTRUCTION

Forecasted COD	Unit	Location	Primary Fuel	Unit Type	Capacity (Net MW)	
					Summer	Winter
2012	Virginia City Hybrid Energy Center	Wise County, VA	Coal/Biomass	Baseload	585	635

Figure 7.2.3 GENERATION PLANTS UNDER DEVELOPMENT

Forecasted COD	Unit	Location	Primary Fuel	Unit Type	Capacity (Net MW)	
					Summer	Winter
2015	Warren County Power Station	Warren County, VA	Natural Gas	Intermediate	1,337	1,437

GENERATION UPRATES/DERATES:

Figure 7.2.4 lists the Company's planned changes to existing generating units.

Figure 7.2.4 PLANNED CHANGES TO EXISTING GENERATION

Unit Name	Type	MW	Year Effective
Chesterfield 3	Derate	-3	2011
Chesterfield 4	Derate	-4	2011
North Anna 1	Uprate	18	2012
Mt. Storm 1	Uprate	30	2013
Possum Point 6	Uprate	34	2013
Altavista	Derate	-12	2013
Hopewell	Derate	-12	2013
Southampton	Derate	-12	2013

The Company plans to convert Altavista, Hopewell and Southampton to biomass and to *repower Bremo units 3 and 4 by natural gas.*

POTENTIAL GENERATION RETIREMENTS:

The Company currently anticipates that the units listed in Figure 7.2.5 will be considered for retirement by the end of 2016.

Figure 7.2.5 POTENTIAL GENERATION RETIREMENTS

Unit Name	MW Summer	Year Effective
Chesapeake 1	-111	2015
Chesapeake 2	-111	2015
Chesapeake 3	-156	2016
Chesapeake 4	-217	2016
Lowmoor GT1	-12	2015
Lowmoor GT2	-12	2015
Lowmoor GT3	-12	2015
Lowmoor GT4	-12	2015
Mount Storm GT1	-11	2015
Northern Neck GT1	-12	2016
Northern Neck GT2	-11	2016
Northern Neck GT3	-12	2016
Northern Neck GT4	-12	2016
Possum Point CT1	-12	2014
Possum Point CT2	-12	2014
Possum Point CT3	-12	2014
Possum Point CT4	-12	2014
Possum Point CT5	-12	2014
Possum Point CT6	-12	2014
Yorktown 1	-159	2015

Transmission:

Figure 7.2.6 lists the major transmission additions including line voltage and capacity, expected operation target dates, and its regulatory status.

Figure 7.2.6 PLANNED TRANSMISSION ADDITIONS

Line Terminal	Line Voltage (kV)	Line Capacity (MVA)	Target Date	SCC/NCUC Status
Hayes – Yorktown	230	1,047	May-12	Approved (VA)
Glebe – Radnor Heights – Ballston UG Line	230	500	May-12	Approved (VA)
Hopewell – Prince George	230	1,047	May-12	Approved (VA)
Reconductor Chucktuck – Newport News	230	583	May-12	Approval Not Required
Uprate 500 kV Line # 555 Dooms – Lexington	500	2,913	May-12	Approval Not Required
Landstown – Virginia Beach	230	797	Dec-12	Approved (VA)
Line 270 Burke – Sideburn 2nd Underground	230	600	May-13	Approval Not Required
Convert Line 49 Loudoun – New Road	230	1,047	May-13	Approved (VA)
Lakeside to Northwest 230kv Line*	230	1,047	May-13	Pending Approval (VA)
Cannon Branch to Liberty – New 230kV Line (Part 1 Cannon Branch-Cloverhill)*	230	1,047	Jun-13	Pending Approval (VA)
Dahlgren Substation 230kV Line (Loop Line #2076)*	230	608	May-14	Not Yet Filed (VA)
Convert Trowbridge – Winfall Line	230	900	May-14	Approval Not Required (NC)
Uprate Line #575 (Ladysmith – North Anna)	500	3,377	Jun-14	Approval Not Required (VA)
Brambleton – Waxpool – BECO*	230	1,047	May-14	Not Yet Filed (VA)
Chickahominy – Skiffs Creek 500 kV Line*	500	3,460	Nov-14	Not Yet Filed (VA)
Skiffes Creek – Whealton Line*	230	1,047	Nov-14	Not Yet Filed (VA)
2nd 230kV Line Harrisonburg to Endless Caverns*	230	1,047	May-15	Not Yet Filed (VA)
Line #222 Uprate from Northwest to Southwest	230	706	May-15	Approval Not Required (VA)
New 230kV Line North Anna to Oak Green*	230	1,047	May-15	Not Yet Filed (VA)
Uprate Line 2022 – Possum Point to Dumfries Substation	230	706	May-15	Approval Not Required (VA)
Cannon Branch to Liberty – New 230kV Line (Part 2 Cloverhill-Liberty)*	230	1,047	May-15	Not Yet Filed (VA)
Shawboro – Aydlett New Line*	230	1,047	May-15	Not Yet Filed (NC)
Rebuild Winfall – Elizabeth City Line	230	1,047	Jun-15	Approval Not Required (NC)
Rebuild Line #551 (Mt Storm – Doubs)	500	4,330	Jun-15	Pending Approval (VA) Approved (WV)
Rebuild Loudon – Brambleton	500	3,460	May-16	Not Yet Filed (VA)
Clark – Idylwood*	230	706	May-16	Not Yet Filed (VA)

* Planned transmission addition subject to change based on inclusion in future PJM RTEP and/or receipt of applicable regulatory approval(s)

RENEWABLE RESOURCES:

Virginia:

Figure 7.2.7 lists the Company's future renewable resources within the first five years of the Plan.

1. An additional 216 MW of renewable resources are planned to be online by 2015 (Figure 7.2.7). The Company plans to meet its Virginia RPS goals at a reasonable cost and in a prudent manner by
   a. Application of current renewable generating facilities including NUGs,
   b. Purchase of cost-effective RECs (including optimization), and
   c. Developing new renewable energy resources when and where feasible.

Figure 7.2.7 FUTURE RENEWABLE RESOURCES

Unit Name	MW	Year Effective
VCHEC	59	2012
Altavista	51	2013
Hopewell	51	2013
Southampton	51	2013
Halifax County Solar	4	2015
Total	**216**	

North Carolina:

1. The Company's strategy to meet the North Carolina REPS requirements is outlined in the Company's 2011 REPS Compliance Plan, filed as North Carolina IRP Addendum 1 to this 2011 Plan.
2. Solar requirements are intended to be met by purchasing unbundled solar RECs. The Company has procured the solar RECs necessary to comply with the North Carolina REPS solar requirements for 2011.
3. The Company continues to develop its plans to comply with swine and poultry waste requirements that begin in 2012. As part of this effort, the Company has entered into agreements with other electric suppliers to conduct and evaluate joint RFPs in compliance with the NCUC's guidelines and oversight. The Joint Buyer's Group received several proposals in response to a RFP. After careful analysis and evaluation the Buyer's Group developed a short list of the suppliers. Contract negotiations were then carried out with these RECs suppliers. The Company has signed five long-term contracts with the Swine Waste RECs suppliers to comply with Swine Waste Energy requirements. The Poultry Litter Buyers group is also negotiating with a Poultry Litter RECs supplier for a long-term contract. The Company is also looking for Poultry Litter RECs procurement opportunities from out of state Poultry Litter Facilities.
4. The Company intends to meet the general REPS requirements with a combination of:
   a. Energy efficiency programs,
   b. Purchase of cost-effective RECs, and
   c. Development of new renewable resources when and where feasible.

OTHER INITIATIVES:

As discussed in Section 5.4, the Company is currently considering other technologies and resources within the next five years including:

1. Community Solar Power Program and Tariff – In response to House Bill 1686, legislation passed by the General Assembly in 2011 that promoted solar distributed generation, the Company is planning to seek approval for a Community Solar Power Program in which solar PV DG would be strategically located in areas of the Company's service territory to study the impact and assess benefits to the distribution system. In addition, as part of the study and as an alternative to net metering, the Community Solar Power Program tariff would provide the opportunity for customers to sell solar generation output and renewable energy certificates to the Company. The size of the Company's combined solar distributed PV initiative (Company-owned installations and purchases under the new Community Solar Power Program Tariff) would not exceed 33 MW.
2. Dynamic Pricing Pilot Program - On September 30, 2010, the Company filed an application with the SCC (Case No. PUE-2010-00135) proposing to offer three experimental and voluntary dynamic pricing tariffs to prepare for a potential system-wide offering in the future. The filing was approved by the SCC's Order Establishing Pilot Program issued on April 8, 2011.
3. EV Pilot Program - On January 31, 2011, in SCC Case No. PUE-2011-00014, the Company filed a petition for a pilot program to offer experimental and voluntary EV rate options provide incentives to residential customers who purchase or lease EVs to charge them during off-peak periods. The SCC approved the pilot on July 11, 2011. The program will be open to up to 1,500 residential customers, with up to 750 in each of the two experimental rates. The Company plans to begin pilot enrollment October 3, 2011 and conclude the pilot November 30, 2014. If warranted by the results of the pilot program, the Company plans to request approval of a Virginia service territory EV peak-shaving program in the future.

Appendix

APPENDIX 2A – TOTAL SALES BY CUSTOMER CLASS (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2001	24,784	23,541	10,883	8,988	281	3,812	72,289
2002	27,064	24,296	10,832	9,296	286	3,519	75,294
2003	27,246	24,732	10,525	9,445	280	3,075	75,302
2004	28,249	25,878	10,843	9,798	284	2,167	77,220
2005	29,942	27,023	10,331	10,120	280	1,736	79,432
2006	28,544	27,078	10,168	10,040	282	1,801	77,912
2007	30,469	28,416	10,094	10,660	283	1,953	81,875
2008	29,646	28,484	9,779	10,529	282	1,926	80,646
2009	29,904	28,455	8,644	10,448	276	1,911	79,637
2010	32,547	29,233	8,512	10,670	281	1,926	83,169
2011	30,459	30,623	8,125	10,726	290	1,919	82,144
2012	31,048	33,041	8,463	11,079	295	1,946	85,873
2013	31,388	34,381	9,091	11,052	299	1,966	88,177
2014	31,857	35,882	8,981	11,262	304	1,992	90,277
2015	32,449	37,044	8,874	11,439	309	2,032	92,147
2016	33,117	38,132	9,114	11,411	314	2,131	94,217
2017	33,692	38,891	9,075	11,383	319	2,164	95,524
2018	34,413	39,758	9,073	11,355	324	2,207	97,130
2019	35,141	40,706	9,126	11,328	329	2,250	98,880
2020	35,927	41,867	9,229	11,300	333	2,297	100,953
2021	36,543	42,801	9,218	11,272	338	2,329	102,501
2022	37,243	43,862	9,248	11,245	342	2,369	104,309
2023	37,915	44,962	9,267	11,217	347	2,411	106,119
2024	38,766	46,156	9,297	11,190	351	2,460	108,220
2025	39,303	47,119	9,312	11,163	355	2,496	109,748
2026	39,988	48,239	9,333	11,136	359	2,539	111,594

***Note:** Historic (2001 – 2010), Projected (2011 – 2026)*

APPENDIX 2B – VIRGINIA SALES BY CUSTOMER CLASS (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2001	23,516	22,838	9,402	8,864	273	2,677	67,569
2002	25,673	23,559	9,239	9,165	278	2,337	70,251
2003	25,822	23,993	8,961	9,303	272	1,996	70,348
2004	26,771	25,109	9,051	9,652	275	2,126	72,984
2005	28,359	26,243	8,621	9,976	272	1,692	75,164
2006	27,067	26,303	8,404	9,903	274	1,754	73,705
2007	28,890	27,606	8,359	10,519	274	1,906	77,556
2008	28,100	27,679	8,064	10,391	273	1,877	76,384
2009	28,325	27,646	7,147	10,312	268	1,860	75,558
2010	30,831	28,408	6,872	10,529	273	1,877	78,791
2011	28,870	29,774	6,716	10,584	282	1,869	78,096
2012	29,427	32,145	7,000	10,932	286	1,895	81,687
2013	29,750	33,465	7,512	10,906	290	1,915	83,838
2014	30,193	34,926	7,422	11,113	295	1,939	85,888
2015	30,754	36,060	7,333	11,287	300	1,979	87,714
2016	31,359	37,134	7,521	11,258	305	2,076	89,652
2017	31,905	37,871	7,489	11,231	310	2,109	90,914
2018	32,590	38,713	7,487	11,203	314	2,151	92,459
2019	33,283	39,634	7,529	11,176	319	2,193	94,134
2020	34,031	40,762	7,613	11,149	324	2,238	96,117
2021	34,619	41,670	7,593	11,123	328	2,270	97,602
2022	35,284	42,701	7,606	11,096	332	2,309	99,328
2023	35,923	43,769	7,617	11,070	337	2,350	101,066
2024	36,732	44,929	7,633	11,044	341	2,398	103,076
2025	37,242	45,865	7,631	11,017	345	2,433	104,533
2026	37,891	46,953	7,639	10,991	349	2,475	106,298

***Note:** Historic (2001 – 2010), Projected (2011 – 2026)*

APPENDIX 2C – NORTH CAROLINA SALES BY CUSTOMER CLASS (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2001	1,268	703	1,482	124	8	1,135	4,720
2002	1,391	738	1,592	131	8	1,182	5,043
2003	1,424	739	1,564	141	8	1,078	4,955
2004	1,479	769	1,792	146	8	41	4,235
2005	1,583	780	1,709	143	8	44	4,268
2006	1,477	775	1,763	137	8	47	4,207
2007	1,579	810	1,735	140	8	47	4,319
2008	1,546	806	1,715	138	8	49	4,263
2009	1,579	809	1,497	136	8	51	4,079
2010	1,716	825	1,640	141	8	49	4,378
2011	1,589	849	1,409	142	8	51	4,048
2012	1,621	896	1,463	147	8	51	4,186
2013	1,638	916	1,579	146	9	52	4,339
2014	1,664	956	1,559	149	9	52	4,389
2015	1,695	984	1,541	151	9	53	4,433
2016	1,758	998	1,593	153	9	55	4,565
2017	1,787	1,020	1,586	152	9	55	4,610
2018	1,823	1,045	1,586	152	9	56	4,672
2019	1,858	1,072	1,597	151	10	57	4,746
2020	1,896	1,105	1,616	151	10	59	4,836
2021	1,924	1,131	1,625	150	10	59	4,899
2022	1,959	1,161	1,642	149	10	60	4,981
2023	1,992	1,193	1,650	147	10	61	5,054
2024	2,034	1,227	1,664	146	10	62	5,144
2025	2,061	1,254	1,681	145	10	63	5,215
2026	2,097	1,286	1,694	144	10	64	5,296

Note: Historic (2001 – 2010), Projected (2011 – 2026)

APPENDIX 2D – TOTAL CUSTOMER COUNT (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2001	1,890,918	206,571	775	26,479	1,945	5	2,126,693
2002	1,929,901	210,551	741	27,024	2,058	5	2,170,279
2003	1,964,320	213,461	709	27,673	2,136	5	2,208,304
2004	1,998,691	216,186	684	27,910	2,275	5	2,245,751
2005	2,036,041	219,837	655	28,233	2,426	5	2,287,197
2006	2,072,726	223,961	635	28,540	2,356	4	2,328,222
2007	2,102,751	227,829	620	28,770	2,347	3	2,362,319
2008	2,124,089	230,715	598	29,008	2,513	3	2,386,925
2009	2,139,604	232,148	581	29,073	2,687	3	2,404,097
2010	2,157,581	232,988	561	29,041	2,798	3	2,422,972
2011	2,172,320	233,931	540	29,119	2,953	3	2,438,866
2012	2,193,642	236,185	539	29,287	3,091	3	2,462,747
2013	2,226,963	239,149	539	29,477	3,232	3	2,499,363
2014	2,264,171	242,369	539	29,697	3,373	3	2,540,151
2015	2,300,671	245,542	539	29,963	3,513	3	2,580,231
2016	2,335,095	248,588	539	30,265	3,654	3	2,618,143
2017	2,368,380	251,565	539	30,581	3,794	3	2,654,862
2018	2,401,388	254,525	539	30,861	3,936	3	2,691,251
2019	2,433,997	257,460	539	31,071	4,076	3	2,727,146
2020	2,465,880	260,350	539	31,217	4,217	3	2,762,206
2021	2,496,752	263,178	539	31,333	4,358	3	2,796,163
2022	2,526,592	265,943	539	31,439	4,498	3	2,829,015
2023	2,555,470	268,647	539	31,541	4,639	3	2,860,839
2024	2,583,410	271,295	539	31,636	4,780	3	2,891,662
2025	2,610,864	273,913	539	31,723	4,921	3	2,921,962
2026	2,638,277	276,527	539	31,804	5,061	3	2,952,212

Note: *Historic (2001 – 2010), Projected (2011 – 2026)*

APPENDIX 2E – VIRGINIA CUSTOMER COUNT (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2001	1,797,885	192,121	687	24,672	1,607	4	2,016,975
2002	1,835,280	195,687	657	25,217	1,717	4	2,058,562
2003	1,868,436	198,240	630	25,778	1,777	4	2,094,866
2004	1,901,785	200,958	606	26,017	1,913	4	2,131,282
2005	1,937,806	204,457	585	26,343	2,062	4	2,171,256
2006	1,973,430	208,556	566	26,654	1,994	3	2,211,203
2007	2,002,884	212,369	554	26,896	1,971	2	2,244,675
2008	2,023,592	215,212	538	27,141	2,116	2	2,268,601
2009	2,038,843	216,663	522	27,206	2,290	2	2,285,525
2010	2,056,576	217,531	505	27,184	2,403	2	2,304,201
2011	2,069,203	218,075	483	27,223	2,506	2	2,317,492
2012	2,089,513	220,176	483	27,381	2,623	2	2,340,177
2013	2,121,252	222,939	483	27,558	2,742	2	2,374,976
2014	2,156,694	225,940	483	27,764	2,862	2	2,413,744
2015	2,191,462	228,899	483	28,013	2,981	2	2,451,839
2016	2,224,251	231,738	483	28,295	3,101	2	2,487,869
2017	2,255,956	234,513	483	28,590	3,220	2	2,522,764
2018	2,287,397	237,273	483	28,852	3,340	2	2,557,346
2019	2,318,458	240,009	483	29,048	3,459	2	2,591,459
2020	2,348,828	242,703	483	29,184	3,578	2	2,624,779
2021	2,378,235	245,339	483	29,293	3,698	2	2,657,050
2022	2,406,658	247,917	483	29,393	3,817	2	2,688,270
2023	2,434,165	250,438	483	29,488	3,936	2	2,718,512
2024	2,460,779	252,906	483	29,576	4,056	2	2,747,801
2025	2,486,930	255,346	483	29,658	4,176	2	2,776,594
2026	2,513,042	257,783	483	29,734	4,295	2	2,805,338

***Note:** Historic (2001 – 2010), Projected (2011 – 2026)*

APPENDIX 2F – NORTH CAROLINA CUSTOMER COUNT (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2001	93,033	14,449	88	1,808	338	1	109,718
2002	94,621	14,863	84	1,807	341	1	111,717
2003	95,884	15,221	79	1,895	359	1	113,438
2004	96,906	15,228	79	1,894	362	1	114,469
2005	98,235	15,380	70	1,890	364	1	115,941
2006	99,296	15,406	69	1,886	363	1	117,019
2007	99,867	15,460	66	1,874	376	1	117,644
2008	100,497	15,502	60	1,867	397	1	118,324
2009	100,761	15,485	59	1,867	398	1	118,572
2010	101,005	15,457	56	1,857	395	1	118,771
2011	103,117	15,857	56	1,896	447	1	121,374
2012	104,129	16,009	56	1,906	468	1	122,570
2013	105,711	16,210	56	1,919	490	1	124,387
2014	107,477	16,428	56	1,933	511	1	126,407
2015	109,210	16,644	56	1,951	532	1	128,393
2016	110,844	16,850	56	1,970	553	1	130,274
2017	112,424	17,052	56	1,991	575	1	132,098
2018	113,991	17,252	56	2,009	596	1	133,905
2019	115,539	17,451	56	2,023	617	1	135,687
2020	117,052	17,647	56	2,032	639	1	137,427
2021	118,518	17,839	56	2,040	660	1	139,113
2022	119,934	18,026	56	2,047	681	1	140,746
2023	121,305	18,209	56	2,053	703	1	142,328
2024	122,631	18,389	56	2,060	724	1	143,861
2025	123,934	18,567	56	2,065	745	1	145,368
2026	125,236	18,744	56	2,070	767	1	146,874

***Note:** Historic (2001 – 2010), Projected (2011 – 2026)*

APPENDIX 2G – SUMMER & WINTER PEAKS

Company Name: Virginia Electric and Power Company

Schedule 5

POWER SUPPLY DATA

	(ACTUAL)			(PROJECTED)																
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
II. Load (MW)																			
1. Summer																			
a. Adjusted Summer Peak(1)	16,908	16,067	16,933	17,302	17,920	18,390	18,610	18,036	18,238	18,546	18,878	19,197	19,640	20,020	20,374	20,726	21,007	21,360	21,794
b. Other Commitments(2)	150	150	150	597	921	943	658	-352	-448	-427	-417	-407	-395	-393	-397	-399	-402	-405	-407
c. Total System Summer Peak	16,758	15,917	16,783	16,705	16,999	17,447	17,952	18,388	18,686	18,973	19,295	19,604	20,035	20,413	20,771	21,125	21,409	21,765	22,201
d. Percent Increase in Total Summer Peak	-5.5%	-5.0%	5.4%	-0.5%	1.8%	2.6%	2.9%	2.4%	1.6%	1.5%	1.7%	1.6%	2.2%	1.9%	1.8%	1.7%	1.3%	1.7%	2.0%
2. Winter																			
a. Adjusted Winter Peak(1)	14,787	15,577	15,334	15,002	15,421	15,675	15,914	16,142	16,380	16,664	16,954	17,148	17,409	17,826	18,105	18,405	18,686	18,864	19,291
b. Other Commitments(2)	128	132	143	136	123	75	-10	-230	-294	-292	-287	-281	-274	-272	-275	-277	-279	-281	-283
c. Total System Winter Peak	14,659	15,445	15,191	14,866	15,298	15,600	15,924	16,372	16,674	16,956	17,241	17,429	17,684	18,098	18,380	18,681	18,965	19,145	19,574
d. Percent Increase in Total Winter Peak	-6.3%	5.4%	-1.6%	-2.1%	2.9%	2.0%	2.1%	2.8%	1.8%	1.7%	1.7%	1.1%	1.5%	2.3%	1.6%	1.6%	1.5%	0.9%	2.2%

(1) Peak after energy efficiency and demand-side programs, includes adjustments from Appendix 2H.
(2) Includes firm commitments for the receipt of specified blocks of power (i.e., unit power, limited term, diversity exchange, etc.).

APPENDIX 2H – PROJECTED SUMMER & WINTER PEAK LOAD & ENERGY FORECAST

Company Name: Virginia Electric and Power Company **Schedule 1**

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)[1]			(PROJECTED)															
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	16,758	15,917	16,783	16,705	16,999	17,447	17,952	18,366	18,688	18,973	19,295	19,604	20,035	20,413	20,771	21,125	21,409	21,765	22,201
1b. Additional Forecast																			
NCEMC	150	150	150	150	150	150	150	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[4]	-	-	-17	-30	-21	-101	-242	-352	-448	-427	-417	-407	-395	-393	-397	-399	-402	-405	-407
3. Demand Response[2][5]	-	-	-21	-55	-38	-144	-224	-274	-325	-371	-410	-442	-468	-488	-501	-511	-519	-525	-530
4. Demand Response-Existing[2][3]	-22	-18	-9	-7	-7	-7	-7	-7	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Peak Adjustment	-	-	-	447	782	894	750	-	-	-	-	-	-	-	-	-	-	-	-
6. Adjusted Load	16,908	16,067	16,933	17,302	17,920	18,390	18,610	18,038	18,238	18,546	18,876	19,197	19,640	20,020	20,374	20,726	21,007	21,360	21,784
7. % Increase in Adjusted Load (from previous year)	-5.5%	-5.0%	5.4%	2.2%	2.2%	2.6%	1.2%	-3.1%	1.1%	1.7%	1.8%	1.7%	2.3%	1.9%	1.8%	1.7%	1.4%	1.7%	2.0%
B. Winter																			
1a. Base Forecast	14,637	15,427	15,184	14,858	15,291	15,593	15,917	16,365	16,669	16,951	17,236	17,424	17,679	18,093	18,375	18,678	18,960	19,140	19,569
1b. Additional Forecast																			
NCEMC	150	150	150	143	145	146	147	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-	-	-14	-23	-15	-64	-150	-223	-269	-287	-282	-276	-269	-267	-270	-272	-274	-276	-278
3. Demand Response[2][5]	-	-	-12	-20	-	-19	-47	-50	-58	-66	-73	-78	-81	-84	-87	-91	-94	-95	-96
4. Demand Response-Existing[2][3]	-22	-18	-7	-7	-7	-7	-7	-7	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Adjusted Load	14,787	15,577	15,334	15,002	15,421	15,675	15,914	16,142	16,390	16,664	16,954	17,146	17,409	17,826	18,105	18,405	18,686	18,864	19,291
6. % Increase in Adjusted Load	-6.2%	5.3%	-1.6%	-2.2%	2.8%	1.6%	1.5%	1.4%	1.6%	1.7%	1.7%	1.1%	1.5%	2.4%	1.6%	1.7%	1.5%	1.0%	2.3%
2. Energy (GWh)																			
A. Base Forecast	83,547	82,501	86,663	84,766	88,583	90,994	93,165	95,097	97,449	98,605	100,468	102,280	104,422	106,027	107,902	109,779	111,955	113,537	115,447
B. Additional Forecast																			
NCEMC				619	645	658	676	-	-	-	-	-	-	-	-	-	-	-	-
ODECsupp[6]				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Conservation & Demand Response[4]	-	-	-265	-379	-623	-1,476	-2,516	-3,484	-4,285	-4,404	-4,614	-4,621	-4,414	-4,369	-4,383	-4,394	-4,402	-4,413	-4,423
D. Demand Response-Existing[2][3]	-3	-2	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
E. Adjusted Energy	83,547	82,501	86,663	85,006	88,605	90,176	91,324	91,613	93,164	94,401	95,854	97,759	100,008	101,658	103,519	105,385	107,553	109,124	111,024
F. % Increase in Adjusted Energy	-2.6%	-1.3%	5.0%	-1.9%	4.2%	1.8%	1.3%	0.3%	1.7%	1.3%	1.5%	2.0%	2.3%	1.6%	1.8%	1.8%	2.1%	1.5%	1.7%

(1) Actual metered data.

(2) Demand response programs are classified as capacity resources and are not included in adjusted load.

(3) Existing DSM programs are included in the load forecast.

(4) Values for 2010 and 2011 represent modeled energy; actual historical data based upon measured and verified EM&V results is not yet available

(5) Values in 2010 and 2011 represent modeled capacity; actual historical data based upon measured and verified EM&V results is not yet available. Projected values represent modeled DSM firm capacity.

(6) ODEC contract expired year end 2010.

APPENDIX 2I – REQUIRED RESERVE MARGIN

Company Name: Virginia Electric and Power Company **Schedule 6**

POWER SUPPLY DATA (continued)

	(ACTUAL)			(PROJECTED)															
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
I. Reserve Margin[1]																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[1]	1,312	1,964	3,397	3,218	3,425	3,407	2,121	1,984	2,006	2,040	2,077	2,112	2,161	2,202	2,241	2,280	2,311	2,350	2,398
b. Percent of Load	7.8%	12.2%	20.1%	18.6%	19.1%	18.5%	11.4%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	9.07%	8.97%	6.80%	6.85%	15.28%	17.33%	12.25%	8.96%	13.37%	12.69%	12.64%	12.11%	12.21%	12.66%	12.71%	12.34%
2. Winter Reserve Margin																			
a. MW[1]	N/A	N/A	N/A	8,059	8,373	8,041	7,807	8,897	9,380	7,229	6,637	6,719	6,855	6,881	6,920	7,064	7,226	7,489	7,503
b. Percent of Load	N/A	N/A	N/A	53.7%	54.3%	51.3%	49.1%	55.1%	57.3%	43.4%	39.1%	39.2%	39.4%	38.6%	38.2%	38.4%	38.7%	39.7%	38.9%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I. Reserve Margin[1][2][3]																			
(Excluding Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[1]	1,312	1,964	3,323	3,050	3,288	3,333	2,047	1,984	2,006	2,040	2,077	2,112	2,161	2,202	2,241	2,280	2,311	2,350	2,398
b. Percent of Load	7.8%	12.2%	19.6%	17.6%	18.3%	18.1%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	8.6%	8.2%	6.4%	6.5%	15.3%	17.3%	12.3%	9.0%	13.4%	12.7%	12.6%	12.1%	12.2%	12.7%	12.7%	12.3%
2. Winter Reserve Margin																			
a. MW[1]	N/A	N/A	N/A	7,919	8,233	7,964	7,730	8,897	9,380	7,229	6,637	6,719	6,855	6,881	6,920	7,064	7,226	7,489	7,503
b. Percent of Load	N/A	N/A	N/A	52.8%	53.4%	50.8%	48.8%	55.1%	57.3%	43.4%	39.1%	39.2%	39.4%	38.6%	38.2%	38.4%	38.7%	39.7%	38.9%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
III. Annual Loss-of-Load Hours[5]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) To be calculated based on Total Net Capability for summer and winter.
(2) The Company has two units in cold reserve.
(3) The Company and PJM forecasts a summer peak throughout the Planning Period.
(4) Does not include spot purchases of capacity.
(5) The Company follows PJM reserve requirements which are based on LOLE.

APPENDIX 3A – EXISTING GENERATION UNITS IN SERVICE

Company Name: Virginia Electric and Power Company **Schedule 14a**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.(1)	MW Summer	MW Winter
Altavista	Altavista, VA	Base	Coal	Feb-1992	-	63
Bath County Units 1-6	Warm Springs, VA	Intermediate	Hydro-Pumped Storage	Dec-1985	1,802	1,788
Bear Garden Combined Cycle	Buckingham County, Va	Intermediate	Natural Gas-CC	May-2011	590	613
Bellemeade Combined Cycle	Richmond, VA	Intermediate	Natural Gas-CC	Mar-1991	267	281
Bremo 3	Bremo Bluff, VA	Base	Coal	Jun-1950	71	74
Bremo 4	Bremo Bluff, VA	Base	Coal	Aug-1958	156	161
Chesapeake 1	Chesapeake, VA	Base	Coal	Jun-1953	111	111
Chesapeake 2	Chesapeake, VA	Base	Coal	Dec-1954	111	111
Chesapeake 3	Chesapeake, VA	Base	Coal	Jun-1959	156	162
Chesapeake 4	Chesapeake, VA	Base	Coal	May-1962	217	221
Chesapeake CT 1	Chesapeake, VA	Peak	Light Fuel Oil	Dec-1967	15	20
Chesapeake CT 2	Chesapeake, VA	Peak	Light Fuel Oil	Dec-1969	36	49
Chesterfield 3	Chester, VA	Base	Coal	Dec-1952	100	104
Chesterfield 4	Chester, VA	Base	Coal	Jun-1960	166	171
Chesterfield 5	Chester, VA	Base	Coal	Aug-1964	325	332
Chesterfield 6	Chester, VA	Base	Coal	Dec-1969	652	663
Chesterfield 7	Chester, VA	Intermediate	Natural Gas-CC	Jun-1990	197	226
Chesterfield 8	Chester, VA	Intermediate	Natural Gas-CC	May-1992	200	236
Clover 1	Clover, VA	Base	Coal	Oct-1995	215	218
Clover 2	Clover, VA	Base	Coal	Mar-1996	217	219
Cushaw Hydro Unit	Big Island, VA	Intermediate	Hydro-Conventional	Apr-2005	2	4
Darbytown 1	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84	98
Darbytown 2	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84	97
Darbytown 3	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84	95
Darbytown 4	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84	97
Elizabeth River 1	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	122
Elizabeth River 2	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	122
Elizabeth River 3	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	122
Gaston Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Feb-1963	220	220
Gordonsville 1	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109	135
Gordonsville 2	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109	135
Gravel Neck 1	Surry, VA	Peak	Light Fuel Oil	Aug-1970	28	38
Gravel Neck 3	Surry, VA	Peak	Natural Gas-Turbine	Oct-1989	84	98
Gravel Neck 4	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	84	97
Gravel Neck 5	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	84	98
Gravel Neck 6	Surry, VA	Peak	Natural Gas-Turbine	Nov-1989	84	97
Hopewell	Hopewell, VA	Base	Coal	Jul-1989	63	63
Kitty Hawk	Kitty Hawk, NC	Peak	Light Fuel Oil	Mar-1971	-	45
Ladysmith 1	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151	183
Ladysmith 2	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151	183
Ladysmith 3	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	161	183
Ladysmith 4	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	160	183
Ladysmith 5	Woodford, VA	Peak	Natural Gas-Turbine	Apr-2009	160	183

(1) Commercial Operation Date.

APPENDIX 3A Cont. – EXISTING GENERATION UNITS IN SERVICE

Company Name: Virginia Electric and Power Company **Schedule 14a**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.(1)	MW Summer	MW Winter
Lowmoor CT	Covington, VA	Peak	Light Fuel Oil	Jul-1971	48	65
Mecklenburg 1 (Company-owned)	Clarksville, VA	Base	Coal	Nov-1992	69	69
Mecklenburg 2 (Company-owned)	Clarksville, VA	Base	Coal	Nov-1992	69	69
Mount Storm 1	Mt. Storm, WV	Base	Coal	Sep-1965	524	539
Mount Storm 2	Mt. Storm, WV	Base	Coal	Jul-1966	555	570
Mount Storm 3	Mt. Storm, WV	Base	Coal	Dec-1973	512	529
Mount Storm CT	Mt. Storm, WV	Peak	Light Fuel Oil	Oct-1967	11	15
North Anna 1	Mineral, VA	Base	Nuclear	Jun-1978	813	821
North Anna 2	Mineral, VA	Base	Nuclear	Dec-1980	834	862
North Anna Hydro	Mineral, VA	Intermediate	Hydro-Conventional	Dec-1987	1	1
North Branch	Bayard, WV	Base	Coal	Jan-1992	-	77
Northern Neck CT	Warsaw, VA	Peak	Light Fuel Oil	Jul-1971	47	70
Possum Point 3	Dumfries, VA	Peak	Natural Gas	Jun-1955	96	100
Possum Point 4	Dumfries, VA	Peak	Natural Gas	Apr-1962	220	225
Possum Point 5	Dumfries, VA	Peak	Heavy Fuel Oil	Jun-1975	786	805
Possum Point 6	Dumfries, VA	Intermediate	Natural Gas-CC	Jul-2003	559	615
Possum Point CT	Dumfries, VA	Peak	Light Fuel Oil	May-1968	72	106
Remington 1	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	153	187
Remington 2	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	151	187
Remington 3	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152	187
Remington 4	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152	188
Roanoke Rapids Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Sep-1955	95	95
Panda Company-owned	Roanoke Rapids, NC	Intermediate	Natural Gas-CC	Dec-1990	165	186
Pittsylvania	Hurt, VA	Base	Renewable	Jun-1994	83	83
Southampton	Franklin, VA	Base	Coal	Mar-1992	63	63
Surry 1	Surry, VA	Base	Nuclear	Dec-1972	839	870
Surry 2	Surry, VA	Base	Nuclear	May-1973	839	813
Yorktown 1	Yorktown, VA	Base	Coal	Jul-1957	159	162
Yorktown 2	Yorktown, VA	Base	Coal	Jan-1959	164	165
Yorktown 3	Yorktown, VA	Peak	Heavy Fuel Oil	Dec-1974	818	820
Subtotal - Base					8,083	8,365
Subtotal - Intermediate					4,316	4,535
Subtotal - Peak					4,588	5,165
Total					16,987	18,065

(1) Commercial Operation Date.

APPENDIX 3B – OTHER GENERATION UNITS

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.[1]	MW Summer	MW Winter	Restart Date
Units in Cold Storage							
North Branch	Gormania, WV	Base	Coal	Jan-1992	74	77	Unknown
Altavista	Altavista, Va	Base	Coal	Feb-1992	63	63	05/2013

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Non-Utility Generation (NUG) Units							
Spruance Genco, LLC Facility 1	Richmond, VA	Base	Coal	115,500	Yes	8/1/1992	7/3/2017
Spruance Genco, LLC Facility 2	Richmond, VA	Base	Coal	85,000	Yes	8/1/1992	7/31/2017
Edgecombe Genco, LLC	Battleboro, NC	Base	Coal	115,500	Yes	10/15/1990	10/14/2015
Doswell Complex	Ashland, VA	Intermediate	Natural Gas	605,000	Yes	5/16/1992	5/5/2017
Hopewell Cogen	Hopewell, VA	Intermediate	Natural Gas	336,600	Yes	8/1/1990	7/30/2015
Ogden-Martin Fairfax	Lorton, VA	Base	MSW	63,000	Yes	5/5/1990	5/31/2015
Roanoke Valley II	Weldon, NC	Base	Coal	44,000	Yes	6/1/1995	5/31/2020
Roanoke Valley Project	*Weldon, NC*	*Base*	*Coal*	*165,000*	*Yes*	*5/29/1994*	*5/28/2019*
SEI Birchwood	King George, VA	Base	Coal	217,800	Yes	11/15/1996	11/14/2021
Behind-The-Meter (BTM) Generation Units[2]							
BTM Alexandria/Arlington - Covanta	VA	NUG	MSW	21,000	No	1/29/1988	1/28/2023
BTM Richmond Electric	VA	Must Take	Methane	2,900	No	8/27/1993	8/26/2013
BTM Brasfield Dam	VA	Must Take	Hydro	2,176	No	10/12/1993	10/11/2013
BTM Suffolk Landfill	VA	Must Take	Methane	3,000	No	11/4/1994	11/3/2014
BTM Columbia Mills	VA	Must Take	Hydro	147	No	2/7/1985	2/6/2015
BTM Schoolfield Dam	VA	Must Take	Hydro	2,500	No	12/1/1990	11/30/2015
BTM Lakeview (Swift Creek) Dam	VA	Must Take	Hydro	400	No	11/28/2008	Auto renew
BTM MeadWestvaco (formerly Westvaco)	VA	NUG	Coal/Biomass	70,000	No	11/3/1982	Auto renew
BTM Banister Dam	VA	Must Take	Hydro	1,765	No	9/28/2008	Auto renew
BTM 119 Goose Castle Terrace	NC	Must Take	Solar	3	No	3/18/2008	Auto renew
BTM 4113 Lindberg Ave	NC	Must Take	Solar	2	No	2/19/2008	Auto renew
BTM Coquina Beach	NC	Must Take	Wind	2	No	8/22/2008	Auto renew
BTM Ocean Trail	NC	Must Take	Wind	2	No	9/14/208	Auto renew
BTM Owens Road	NC	Must Take	Wind	2	No	5/16/2008	Auto renew
BTM 409 W Villa Dunes	NC	Must Take	Solar	4	No	2/24/2009	Auto renew
BTM 148 Turner Road	NC	Must Take	Solar	2	No	7/1/2009	Auto renew
BTM 3820 Virginia Dare Trail N	NC	Must Take	Solar	4	No	9/14/2009	Auto renew
BTM Weyerhaeuser/Domtar[3]	NC	NUG	Coal/Biomass	28,400	No	7/27/1991	Auto renew
BTM Chapman Dam	VA	Must Take	Hydro	300	No	10/17/1984	Auto renew
BTM I-95 Landfill	VA	Must Take	Methane	3,000	No	1/1/1992	5/31/2012
BTM I-95 Phase 2	VA	Must Take	Methane	3,000	No	2/10/1993	2/9/2013
BTM Smurfit-Stone Container[3]	VA	NUG	Coal/Biomass	48,400	No	3/21/1981	10/26/2011
BTM Rivanna	VA	Must Take	Hydro	100	No	4/21/1998	Auto renew
BTM Rapidan Mill	VA	Must Take	Hydro	100	No	6/15/2009	Auto renew
BTM River Farm Energy	VA	Must Take	Solar	8	No	1/30/2009	Auto renew
BTM Dairy Energy Inc.	VA	Must Take	Methane	400	No	8/2/2011	8/1/2016

(1) Commercial Operation Date.

(2) These units are provided for informational purposes, they are not part of the 2011 Plan.

(3) Agreement to provide excess energy only.

APPENDIX 3B Cont. – OTHER GENERATION UNITS

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned(4)							
	Ahoskie	Standby	Diesel	1250	No	N/A	N/A
	Tillery	Standby	Diesel	585	No	N/A	N/A
	Whitakers	Standby	Diesel	10000	No	N/A	N/A
	Columbia	Standby	Diesel	400	No	N/A	N/A
	Grandy	Standby	Diesel	400	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	500	No	N/A	N/A
	Moyock	Standby	Diesel	350	No	N/A	N/A
	Nags Head	Standby	Diesel	400	No	N/A	N/A
	Nags Head	Standby	Diesel	450	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	400	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	500	No	N/A	N/A
	Corolla	Standby	Diesel	700	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	700	No	N/A	N/A
	Rocky Mount	Standby	Diesel	700	No	N/A	N/A
	Roanoke Rapids	Standby	Coal	25000	No	N/A	N/A
	Manteo	Standby	Diesel	300	No	N/A	N/A
	Conway	Standby	Diesel	800	No	N/A	N/A
	Lewiston	Standby	Diesel	4000	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	1200	No	N/A	N/A
	Weldon	Standby	Diesel	750	No	N/A	N/A
	Tillery	Standby	Diesel	450	No	N/A	N/A
	Elizabeth City	Standby	Unknown	2000	No	N/A	N/A
	Greenville	Standby	Diesel	1800	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Northern VA	Standby	Diesel	1270	No	N/A	N/A
	Alexandria	Standby	Diesel	300	No	N/A	N/A
	Alexandria	Standby	Diesel	475	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 60	No	N/A	N/A
	Northern VA	Standby	Diesel	14000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Norfolk	Standby	Diesel	4000	No	N/A	N/A
	Richmond	Standby	Diesel	4470	No	N/A	N/A
	Arlington	Standby	Diesel	5650	No	N/A	N/A
	Richmond	Standby	Diesel	22850	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Hampton Roads	Standby	Diesel	3000	No	N/A	N/A
	Northern VA	Standby	Diesel	900	No	N/A	N/A
	Richmond	Standby	Diesel	20110	No	N/A	N/A
	Richmond	Standby	Diesel	3500	No	N/A	N/A
	Richmond	Standby	NG	10	No	N/A	N/A
	Richmond	Standby	LP	120	No	N/A	N/A
	Va Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesapeake	Standby	Diesel	500	No	N/A	N/A
	Chesapeake	Standby	Diesel	2500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	700	No	N/A	N/A
	Hopewell	Standby	Diesel	75	No	N/A	N/A
	Newport News	Standby	Unknown	1000	No	N/A	N/A
	Newport News	Standby	Unknown	4500	No	N/A	N/A
	Norfolk	Standby	Diesel	2000	No	N/A	N/A
	Norfolk	Standby	Diesel	9000	No	N/A	N/A
	Portsmouth	Standby	Diesel	2250	No	N/A	N/A

(4) These units are provided for informational purposes, they are not part of the 2011 Plan.

APPENDIX 3B Cont. – OTHER GENERATION UNITS

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[4]							
	Va Beach	Standby	Diesel	3500	No	N/A	N/A
	Va Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesterfield	Standby	Diesel	2000	No	N/A	N/A
	Central VA	Merchant	Coal	92000	No	N/A	N/A
	Central VA	Merchant	Coal	115000	No	N/A	N/A
	Williamsburg	Standby	Diesel	2800	No	N/A	N/A
	Richmond	Standby	Diesel	30000	No	N/A	N/A
	Charlottesville	Standby	Diesel	40000	No	N/A	N/A
	Arlington	Standby	Diesel	13042	No	N/A	N/A
	Arlington	Standby	Diesel/NG	7500	No	N/A	N/A
	Fauquier	Standby	Diesel	1885	No	N/A	N/A
	Hanover	Standby	Diesel	12709.5	No	N/A	N/A
	Hanover	Standby	NG	13759.5	No	N/A	N/A
	Hanover	Standby	LP	81.25	No	N/A	N/A
	Henrico	Standby	NG	1341	No	N/A	N/A
	Henrico	Standby	LP	126	No	N/A	N/A
	Henrico	Standby	Diesel	828	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Newport News	Standby	Diesel	1750'	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Chesapeake	Standby	Unknown	750	No	N/A	N/A
	Northern VA	Merchant	NG	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	138000	No	N/A	N/A
	Richmond	*Standby*	*Steam*	*20000*	*No*	*N/A*	*N/A*
	Herndon	Standby	Diesel	415	No	N/A	N/A
	Herndon	Standby	Diesel	50	No	N/A	N/A
	VA	Merchant	Hydro	2700	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Fairfax County	Standby	Diesel	20205	No	N/A	N/A
	Fairfax County	Standby	NG	2139	No	N/A	N/A
	Fairfax County	Standby	LP	292	No	N/A	N/A
	Fairfax County	Standby	Diesel	10	No	N/A	N/A
	Springfield	Standby	Diesel	6500	No	N/A	N/A
	Warrenton	Standby	Diesel	2 - 750	No	N/A	N/A
	Northern VA	Standby	Diesel	5350	No	N/A	N/A
	Richmond	Standby	Diesel	18400	No	N/A	N/A
	Norfolk	Standby	Diesel	350	No	N/A	N/A
	Charlottesville	Standby	Diesel	400	No	N/A	N/A
	Farmville	Standby	Diesel	350	No	N/A	N/A
	Mechanicsville	Standby	Diesel	350	No	N/A	N/A
	King George	Standby	Diesel	350	No	N/A	N/A
	Chatham	Standby	Diesel	350	No	N/A	N/A
	Hampton	Standby	Diesel	350	No	N/A	N/A
	Virginia Beach	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	400	No	N/A	N/A
	Powhatan	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Chesapeake	Standby	Diesel	400	No	N/A	N/A
	Newport News	Standby	Diesel	350	No	N/A	N/A
	Dinwiddie	Standby	Diesel	300	No	N/A	N/A
	Goochland	Standby	Diesel	350	No	N/A	N/A

(4) These units are provided for informational purposes, they are not part of the 2011 Plan.

APPENDIX 3B Cont. – OTHER GENERATION UNITS

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[(4)]							
	Portsmouth	Standby	Diesel	350	No	N/A	N/A
	Fredericksburg	Standby	Diesel	350	No	N/A	N/A
	Northern VA	Standby	Diesel	22690	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	15100	No	N/A	N/A
	Herndon	Standby	Diesel	1250	No	N/A	N/A
	Herndon	Standby	Diesel	500	No	N/A	N/A
	Henrico	Standby	Diesel	1000	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 910	No	N/A	N/A
	Alexandria	Standby	Diesel	1000	No	N/A	N/A
	Fairfax	Standby	Diesel	4 - 750	No	N/A	N/A
	Loudoun	Standby	Diesel	2100	No	N/A	N/A
	Loudoun	Standby	Diesel	710	No	N/A	N/A
	Mount Vernon	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Jarratt	Standby	Diesel	750	No	N/A	N/A
	Jarratt	Standby	Diesel	600	No	N/A	N/A
	Jarratt	Standby	Diesel	250	No	N/A	N/A
	Jarratt	Standby	Diesel	100	No	N/A	N/A
	Hopewell	Standby	Diesel	500	No	N/A	N/A
	Falls Church	Standby	Diesel	200	No	N/A	N/A
	Falls Church	Standby	Diesel	250	No	N/A	N/A
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Norfolk	Standby	NG	1050	No	N/A	N/A
	Richmond	Standby	Diesel	6400	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Elkton	Standby	Nat gas	6000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	#2 FO	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Vienna	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Norfolk	Standby	Diesel	1000	No	N/A	N/A
	Northern VA	Standby	Diesel	1000	No	N/A	N/A
	Norfolk	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	3000	No	N/A	N/A
	Newport News	Standby	Diesel	750	No	N/A	N/A
	Chesterfield	Standby	Coal	500	No	N/A	N/A
	Richmond	Standby	Diesel	1500	No	N/A	N/A
	Richmond	Standby	Diesel	1000	No	N/A	N/A
	Richmond	Standby	Diesel	1000	No	N/A	N/A
	Northern VA	Standby	Diesel	3000	No	N/A	N/A
	Richmond Metro	Standby	NG	6000	No	N/A	N/A
	Suffolk	Standby	Diesel	2000	No	N/A	N/A
	Northern VA	Standby	Diesel	6000	No	N/A	N/A
	Richmond	Standby	Diesel	500	No	N/A	N/A
	Hampton Roads	Standby	Diesel	4000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	12000	No	N/A	N/A
	West Point	Standby	Unknown	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	100	No	N/A	N/A
	Herndon	Standby	Diesel	18100	No	N/A	N/A

(4) These units are provided for informational purposes, they are not part of the 2011 Plan.

APPENDIX 3B Cont. – OTHER GENERATION UNITS

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[4]							
	VA	Merchant	RDF	60000	No	N/A	N/A
	Chesterfield	Standby	Diesel	750	No	N/A	N/A
	Henrico	Standby	Diesel	750	No	N/A	N/A
	Richmond	Standby	Diesel	5150	No	N/A	N/A
	Culpepper	Standby	Diesel	7000	No	N/A	N/A
	Richmond	Standby	Diesel	8000	No	N/A	N/A
	Northern VA	Standby	Diesel	2000	No	N/A	N/A
	Northern VA	Standby	Diesel	6000	No	N/A	N/A
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Northern VA	Standby	NG	50000	No	N/A	N/A
	Hampton Roads	Standby	Unknown	4000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Northern VA	Standby	Diesel	13000	No	N/A	N/A
	Southside VA	Standby	Water	227000	No	N/A	N/A
	Northern VA	Standby	Diesel	300	No	N/A	N/A
	Northern VA	Standby	Diesel	1000	No	N/A	N/A
	Richmond	Standby	Diesel	1500	No	N/A	N/A
	Richmond	Standby	Diesel	30	No	N/A	N/A
	New port News	Standby	Diesel	1000	No	N/A	N/A
	Hampton	Standby	Diesel	12000	No	N/A	N/A
	New port News	Standby	Natural gas	3000	No	N/A	N/A
	New port News	Standby	Diesel	2000	No	N/A	N/A
	Petersburg	Standby	Diesel	1750	No	N/A	N/A
	Various	Standby	Diesel	3000	No	N/A	N/A
	Various	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	2000	No	N/A	N/A
	Ashburn	Standby	Diesel	16000	No	N/A	N/A
	Northern VA	Standby	Diesel	6450	No	N/A	N/A
	Virginia Beach	Standby	Diesel	2000	No	N/A	N/A
	Ashburn	Standby	Diesel	12 - 2000	No	N/A	N/A
	Innsbrook-Richmond	Standby	Diesel	6050	No	N/A	N/A
	Northern VA	Standby	Diesel	150	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Virginia Beach	Standby	Diesel	1500	No	N/A	N/A

(4) These units are provided for informational purposes, they are not part of the 2011 Plan.

APPENDIX 3C – EQUIVALENT AVAILABILITY FACTOR (%)

Company Name: Virginia Electric and Power Company — Schedule 8

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

Unit Name	2008 (ACTUAL)	2009	2010	2011 (PROJECTED)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Altavista	98	95	94	-	-	98	96	98	96	96	98	96	98	98	96	98	96	98	98
Bath County Units 1-6	85	83	86	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bear Garden CC	-	-	-	96	96	98	98	96	96	98	96	96	98	98	96	98	96	98	98
Bellemeade CC	88	82	81	84	84	84	84	84	84	84	84	84	84	87	87	87	87	87	87
Bremo 3	85	87	87	93	93	93	90	89	90	89	89	89	90	89	89	89	90	89	90
Bremo 4	86	89	77	91	91	91	95	95	95	95	95	95	95	95	95	95	95	95	95
Chesapeake 1	83	82	86	88	88	88	88	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 2	95	88	86	88	87	87	87	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 3	80	88	76	80	80	90	90	90	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 4	81	84	76	80	80	90	90	90	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1	84	96	85	89	89	89	89	89	89	89	89	-	-	-	-	-	-	-	-
Chesapeake CT 2	83	90	96	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	84	89	88	87	87	87	87	87	87	87	87	87	87	90	90	90	90	90	90
Chesterfield 4	86	77	81	83	87	87	87	87	87	87	87	87	87	91	91	91	91	91	91
Chesterfield 5	80	92	78	91	91	91	91	91	91	91	91	91	91	92	92	92	92	92	92
Chesterfield 6	76	92	87	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
Chesterfield 7 CC	91	81	77	79	79	79	79	79	79	79	79	79	79	85	85	85	85	85	85
Chesterfield 8 CC	78	88	87	79	79	79	79	79	79	79	79	79	79	85	85	85	85	85	85
Clover 1	94	84	84	95	95	95	95	95	95	95	95	95	95	98	98	98	98	98	98
Clover 2	92	82	86	95	95	95	95	95	95	95	95	95	95	98	98	98	98	98	98
Spruance Genco ,LLC Facility 1	-	-	-	98	98	98	98	98	98	-	-	-	-	-	-	-	-	-	-
Spruance Genco, LLC Facility 2	-	-	-	94	94	94	94	94	94	-	-	-	-	-	-	-	-	-	-
Edgecombe Genco, LLC	-	-	-	94	94	94	94	94	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle 3x1 :2016	-	-	-	-	-	-	-	-	96	96	98	98	98	98	98	98	98	96	96
Combined Cycle 3x1 :2019	-	-	-	-	-	-	-	-	-	-	-	96	96	96	96	96	96	96	96
CT:2020	-	-	-	-	-	-	-	-	-	-	-	-	98	98	98	98	98	98	98
CT:2021	-	-	-	-	-	-	-	-	-	-	-	-	-	98	96	98	96	98	98
CT:2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	98	98	98	98
CT:2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	98	98	96
CT:2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	96	96
CT:2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	96
Cushaw Hydro Unit	73	62	42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 1	95	99	96	98	96	98	98	96	96	98	96	98	96	98	98	98	98	96	98
Darbytown 2	78	100	86	98	98	96	98	96	96	98	96	98	96	98	98	98	98	98	98
Darbytown 3	82	78	88	98	98	98	98	98	96	98	96	98	98	98	98	98	98	98	98
Darbytown 4	93	99	79	98	98	96	98	96	94	98	95	98	96	98	96	98	96	98	98
Doswell Complex	-	-	-	94	94	94	94	94	94	94	-	-	-	-	-	-	-	-	-
Elizabeth River 1	87	98	93	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Elizabeth River 2	87	98	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Elizabeth River 3	87	88	82	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Gaston Hydro	84	89	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1 CC	97	68	89	88	88	88	88	88	88	88	88	88	88	87	87	87	87	87	87
Gordonsville 2 CC	88	94	71	89	89	89	89	89	89	89	89	89	89	90	90	90	90	90	90
Gravel Neck 1	85	86	87	99	99	99	99	99	99	99	99	-	-	-	-	-	-	-	-
Gravel Neck 3	83	97	89	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gravel Neck 4	85	97	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gravel Neck 5	87	88	79	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gravel Neck 6	87	85	88	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Halifax Solar	-	-	-	-	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50
Battery Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

APPENDIX 3C Cont. – EQUIVALENT AVAILABILITY FACTOR (%)

Company Name: Virginia Electric and Power Company **Schedule 8**

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

Unit Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	(ACTUAL)				(PROJECTED)														
Hopewell	89	97	91	89	89	88	98	96	98	96	98	98	98	98	98	98	98	98	98
Hopewell Cogen	-	-	-	95	95	95	95	95	-	-	-	-	-	-	-	-	-	-	-
Kitty Hawk	99	93	91	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	92	96	97	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Ladysmith 2	91	99	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Ladysmith 3	93	91	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Ladysmith 4	94	99	96	96	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Ladysmith 5	-	98	99	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Lowmoor CT	99	99	99	99	99	99	99	99	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	96	84	84	83	83	83	83	83	83	83	83	83	83	85	85	95	95	95	95
Mecklenburg 2	96	91	84	83	83	83	83	83	83	83	83	83	83	85	85	95	95	95	95
Mount Storm 1	91	54	88	90	90	90	90	90	90	90	90	90	90	92	92	92	92	92	92
Mount Storm 2	95	88	87	80	80	80	80	80	80	80	80	80	80	83	83	93	93	93	93
Mount Storm 3	68	91	91	91	92	92	92	92	92	92	92	92	92	93	93	93	93	93	93
Mount Storm CT	93	78	88	99	99	99	99	99	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	99	91	84	96	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
North Anna 2	81	99	79	96	96	98	98	96	96	96	96	96	98	98	98	98	98	96	96
North Anna 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88	88	98	99	99
North Anna Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Branch	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT	99	98	93	99	99	99	99	99	99	-	-	-	-	-	-	-	-	-	-
Ogden-Martin Fairfax	-	-	-	88	88	88	88	88	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania 1	91	80	89	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
Possum Point 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	91	91	83	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
Possum Point 4	83	85	43	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Possum Point 5	80	66	78	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Possum Point 6 CC	82	86	86	88	88	88	88	88	88	88	88	88	88	94	94	94	94	94	94
Possum Point CT	96	99	96	99	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	89	98	95	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Remington 2	88	95	97	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Remington 3	90	95	97	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Remington 4	92	98	89	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Roanoke Rapids Hydro	100	98	97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley II	-	-	-	98	98	98	98	98	98	98	98	98	96	-	-	-	-	-	-
Roanoke Valley Project	-	-	-	97	97	97	97	97	97	97	97	97	-	-	-	-	-	-	-
Rosemary CC	86	73	80	79	79	79	79	79	79	79	79	79	79	80	80	80	80	80	80
SEI Birchwood	-	-	-	92	92	92	92	92	92	92	92	92	92	97	-	-	-	-	-
Southampton	93	88	89	90	90	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Surry 1	87	93	87	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Surry 2	93	90	98	96	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Virginia City	-	-	-	-	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Warren 3x1	-	-	-	-	-	-	-	96	96	96	96	96	96	96	96	96	96	96	96
Yorktown 1	89	71	64	88	88	88	89	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	94	86	78	92	91	91	91	91	91	91	91	91	91	91	-	-	-	-	-
Yorktown 3	82	77	68	86	85	85	85	85	85	85	85	85	85	85	-	-	-	-	-

APPENDIX 3D – NET CAPACITY FACTOR

Company Name: Virginia Electric and Power Company — Schedule 9

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

Unit Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	(ACTUAL)				(PROJECTED)														
Altavista	33.5	23.5	37.4	-	-	27.1	92.1	92.0	92.3	92.1	91.9	92.0	92.3	92.1	91.8	90.5	91.3	90.8	91.9
Bath County Units 1-6	11.5	13.9	16.4	18.0	16.0	18.8	15.8	14.6	13.0	15.5	18.4	15.2	15.9	17.5	12.1	14.2	14.7	18.1	18.0
Bear Garden CC	-	-	-	38.4	57.9	58.3	61.9	41.3	49.2	50.1	43.8	47.7	48.1	47.1	44.4	43.6	43.5	45.1	43.7
Bellemeade CC	19.6	20.1	32.1	28.2	16.6	24.8	28.5	22.4	18.8	20.2	18.0	18.3	18.8	19.7	17.6	17.1	18.5	18.1	16.9
Bremo 3	50.6	28.1	37.1	23.4	23.8	18.0	8.8	7.0	7.7	7.8	7.0	6.1	6.9	8.8	6.2	6.4	6.4	6.8	6.2
Bremo 4	64.3	54.6	55.2	59.0	51.0	41.7	17.8	13.2	14.3	14.3	12.6	11.4	11.8	11.8	10.1	10.0	8.8	10.2	9.4
Chesapeake 1	55.5	49.1	62.4	27.5	30.5	29.6	28.4	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 2	59.1	54.1	64.7	28.7	32.1	31.9	28.5	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 3	75.0	70.4	66.0	43.8	46.1	47.7	41.0	55.1	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 4	71.4	72.8	66.0	37.8	41.9	39.2	42.1	50.0	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1	0.1	0.1	0.1	0.00	0.01	0.01	0.01	0.01	0.02	0.01	-	-	-	-	-	-	-	-	-
Chesapeake CT 2	-	0.1	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	58.3	40.6	38.0	28.5	25.3	19.6	28.5	39.8	45.9	54.0	20.3	28.8	24.8	25.5	23.8	22.0	23.2	24.2	22.9
Chesterfield 4	67.8	58.3	60.4	37.3	36.8	38.6	48.7	61.6	64.1	60.6	43.3	41.2	38.7	40.1	38.4	34.9	33.8	35.3	34.3
Chesterfield 5	77.9	85.0	73.4	78.2	77.7	88.8	81.5	77.0	84.4	85.7	78.8	78.8	78.2	78.0	77.9	74.6	73.8	78.5	75.7
Chesterfield 6	67.1	63.2	61.9	78.6	74.6	73.9	73.6	80.4	81.2	76.0	75.0	75.0	74.2	73.6	72.4	72.4	72.6	72.9	72.6
Chesterfield 7 CC	45.2	67.7	50.8	43.8	41.6	43.5	43.6	38.6	33.0	29.1	31.7	26.7	30.2	30.7	29.7	27.8	28.8	28.7	28.9
Chesterfield 8 CC	40.1	78.0	72.3	44.4	43.4	38.2	48.6	33.9	31.3	34.8	30.7	32.1	30.6	34.2	30.1	30.8	29.5	32.0	29.5
Clover 1	77.3	75.2	61.8	91.9	79.5	91.0	90.6	67.6	91.5	91.7	80.7	88.4	88.4	66.1	88.8	88.7	83.5	88.9	90.2
Clover 2	75.8	72.3	82.1	87.0	93.2	91.2	79.1	91.0	91.6	82.9	91.5	88.6	84.1	92.8	88.8	83.7	88.9	90.8	84.9
Spruance Genco ,LLC Facility 1	-	-	-	77.4	70.6	68.4	51.7	50.2	53.5	37.3	-	-	-	-	-	-	-	-	-
Spruance Genco, LLC Facility 2	-	-	-	73.2	77.7	64.5	67.4	58.5	58.2	42.0	-	-	-	-	-	-	-	-	-
Edgecombe Genco, LLC	-	-	-	82.6	80.5	80.2	50.6	38.6	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle 3x1 :2016	-	-	-	-	-	-	-	-	52.7	53.1	51.0	49.5	49.6	48.9	48.8	48.1	48.8	47.2	45.5
Combined Cycle 3x1 :2019	-	-	-	-	-	-	-	-	-	-	-	53.8	52.8	52.1	49.3	48.5	48.5	48.8	48.3
CT:2020	-	-	-	-	-	-	-	-	-	-	-	-	0.9	1.0	0.6	0.5	0.3	0.3	0.3
CT:2021	-	-	-	-	-	-	-	-	-	-	-	-	-	0.8	1.2	1.0	0.6	0.5	0.4
CT:2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	1.2	0.8	0.6
CT:2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	1.4	1.0
CT:2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.4	1.5
CT:2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5
Cushaw Hydro Unit	70.3	69.7	67.8	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7
Darbytown 1	3.4	3.2	6.4	1.2	1.1	1.2	1.3	0.7	0.8	0.8	0.8	0.6	0.5	0.3	0.2	0.2	0.1	0.2	0.2
Darbytown 2	3.9	2.5	6.2	1.0	0.8	1.0	1.1	0.8	0.8	0.7	0.8	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.2
Darbytown 3	3.5	2.1	6.2	0.9	0.6	0.9	1.0	0.5	0.7	0.8	0.5	0.4	0.4	0.2	0.1	0.1	0.1	0.1	0.2
Darbytown 4	3.2	1.8	5.8	0.7	0.7	0.8	0.8	0.5	0.6	0.5	0.4	0.4	0.3	0.2	0.1	0.1	0.1	0.1	0.1
Doswell Complex	-	-	-	39.7	87.3	61.0	51.0	34.8	34.8	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	3.1	3.1	8.0	10.2	8.3	8.5	10.3	8.0	9.2	8.8	7.8	6.8	7.4	7.0	8.7	6.7	6.5	6.8	6.3
Elizabeth River 2	3.1	3.1	8.8	9.4	8.5	6.7	9.5	7.2	8.3	7.9	6.8	6.1	6.7	6.3	6.0	6.1	5.9	6.3	5.7
Elizabeth River 3	3.1	3.1	8.3	8.6	7.7	7.9	8.7	6.4	7.6	7.1	6.1	5.4	6.0	6.7	6.3	5.9	5.4	5.7	5.2
Gaston Hydro	8.2	16.3	7.0	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3
Gordonsville 1 CC	19.6	24.6	38.6	16.3	15.1	12.7	16.2	14.4	14.9	15.6	14.5	12.6	13.4	12.9	11.2	10.9	11.1	11.9	10.8
Gordonsville 2 CC	16.3	34.0	28.3	16.0	14.3	14.7	18.2	15.6	16.6	17.8	16.2	14.8	14.5	15.1	12.6	13.2	12.1	13.6	12.2
Gravel Neck 1	0.1	-	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-
Gravel Neck 3	2.2	3.5	4.6	0.6	0.6	0.6	0.7	0.4	0.5	0.5	0.4	0.3	0.3	0.2	0.1	0.1	0.1	0.1	0.1
Gravel Neck 4	1.4	1.3	5.7	0.5	0.5	0.5	0.6	0.3	0.4	0.4	0.3	0.3	0.3	0.2	0.1	0.1	0.1	0.1	0.1
Gravel Neck 5	2.2	3.3	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Gravel Neck 6	1.6	1.5	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Halifax Solar	-	-	-	-	-	-	-	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1
Battery Storage	-	-	-	-	-	-	-	3.3	3.4	3.3	3.4	3.4	3.3	3.6	3.5	3.5	3.5	3.5	3.6

APPENDIX 3D Cont. – NET CAPACITY FACTOR

Company Name: Virginia Electric and Power Company | Schedule 9

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

Unit Name	(ACTUAL) 2008	2009	2010	2011	(PROJECTED) 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hopewell	45.8	18.9	38.6	14.6	13.1	41.4	90.6	90.7	91.6	91.6	88.9	88.5	90.0	90.6	88.9	87.0	87.5	88.5	88.9
Hopewell Cogen	-	-	-	33.3	33.2	27.5	24.0	14.3	-	-	-	-	-	-	-	-	-	-	-
Kitty Hawk	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	5.8	4.6	13.3	3.9	3.3	3.3	3.7	2.3	2.8	2.7	2.1	2.0	2.5	2.3	2.1	2.3	2.5	2.7	2.4
Ladysmith 2	5.7	4.2	12.0	4.1	3.6	3.6	3.9	2.8	3.1	2.8	2.3	2.0	2.6	2.4	2.2	2.4	2.5	2.8	2.6
Ladysmith 3	6.8	5.9	14.3	7.1	6.3	6.5	6.9	4.8	5.4	6.3	4.8	3.9	4.6	4.3	4.0	4.1	4.1	4.5	4.1
Ladysmith 4	6.7	4.2	13.6	8.1	5.4	5.8	9.8	4.0	4.6	4.4	3.7	3.2	3.9	3.6	3.3	3.5	3.6	3.8	3.5
Ladysmith 5	-	8.2	11.0	5.2	4.6	4.6	5.0	3.3	4.0	3.6	3.0	2.6	3.3	3.0	2.7	3.0	3.1	3.4	3.1
Lowmoor CT	0.1	-	-	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	44.6	32.1	41.0	26.5	24.7	24.3	31.1	33.1	39.2	61.0	25.6	24.7	22.6	26.4	24.8	23.1	25.5	25.6	25.3
Mecklenburg 2	42.5	33.4	39.4	25.5	23.6	21.9	29.9	32.3	37.6	49.1	24.8	23.2	20.9	25.3	23.7	21.8	23.1	23.5	23.6
Mount Storm 1	88.6	61.1	74.1	83.6	82.1	73.4	79.5	82.7	76.3	83.7	79.3	72.4	78.3	80.2	73.1	77.4	77.4	74.6	78.7
Mount Storm 2	81.5	61.7	72.1	81.7	82.1	80.5	78.4	82.2	82.4	78.4	78.7	78.0	74.6	81.3	78.3	78.2	78.9	79.5	78.3
Mount Storm 3	82.5	80.4	81.7	80.8	71.0	77.0	82.0	82.1	82.7	83.6	71.1	77.4	76.8	74.9	76.9	76.6	72.7	78.3	76.6
Mount Storm CT	0.1	0.1	0.1	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	89.4	91.8	84.3	87.5	88.8	88.8	86.1	90.7	89.0	86.1	90.7	90.9	96.3	88.8	90.9	98.1	91.0	90.8	98.1
North Anna 2	89.8	89.5	79.7	88.9	90.7	88.6	90.2	98.4	91.3	91.2	86.4	88.9	91.4	98.4	91.0	89.1	96.7	91.0	89.1
North Anna 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	96.5	90.0	96.7	91.1	90.8
North Anna Hydro	-	-	-	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1
North Branch	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT	0.1	0.6	0.3	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
Ogden-Martin Fairfax	-	-	-	67.8	91.0	72.9	64.3	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania 1	67.0	59.1	58.8	53.8	68.2	42.2	43.7	47.5	52.1	64.4	77.7	78.0	78.1	80.5	78.0	77.3	77.6	78.6	78.7
Possum Point 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	6.6	5.8	12.4	54.1	11.0	10.6	12.8	12.1	12.4	12.4	10.5	9.2	9.7	9.4	8.1	8.2	8.0	8.4	7.7
Possum Point 4	8.0	5.0	11.0	53.9	12.4	12.0	12.0	11.5	13.0	14.0	13.3	11.7	12.0	11.8	10.3	10.4	10.0	10.7	9.8
Possum Point 5	4.9	3.2	5.7	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Possum Point 6 CC	42.8	62.1	63.8	55.7	45.2	51.7	60.8	42.7	41.1	44.1	41.4	40.1	40.4	42.7	39.4	38.6	38.6	40.1	38.5
Possum Point CT	-	-	-	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	5.0	5.9	8.3	2.9	2.5	2.7	2.9	1.6	2.1	1.8	1.5	1.4	1.6	1.7	1.5	1.7	1.9	2.2	2.1
Remington 2	8.0	4.4	8.9	1.4	1.2	1.4	1.5	0.8	1.1	1.0	0.8	0.7	1.0	1.0	0.8	1.0	1.2	1.4	1.4
Remington 3	3.7	3.3	6.9	2.3	2.0	2.2	2.3	1.3	1.7	1.5	1.2	1.1	1.5	1.4	1.2	1.4	1.6	1.9	1.8
Remington 4	3.8	5.9	8.4	1.8	1.6	1.7	1.9	1.0	1.4	1.2	0.9	0.8	1.2	1.2	1.0	1.1	1.3	1.5	1.8
Roanoke Rapids Hydro	20.3	38.8	40.2	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9
Roanoke Valley II	-	-	-	82.7	80.1	88.6	88.8	85.7	88.1	88.8	88.8	88.7	-	-	-	-	-	-	-
Roanoke Valley Project	-	-	-	80.4	86.3	88.4	88.3	86.4	88.7	88.4	88.3	-	-	-	-	-	-	-	-
Rosemary CC	12.8	10.0	8.3	11.1	11.7	11.1	12.3	12.3	12.6	13.8	11.5	11.4	11.5	11.6	10.0	10.2	9.8	10.4	9.8
SEI Birchwood	-	-	-	31.0	40.8	24.4	18.6	28.9	24.8	30.2	32.5	34.4	53.9	49.5	-	-	-	-	-
Southampton	49.4	21.2	31.7	18.3	18.4	68.1	81.4	81.2	82.2	82.1	81.0	81.6	81.1	81.8	81.3	88.4	88.0	88.8	90.6
Surry 1	87.4	93.8	87.7	98.3	89.8	88.8	90.3	89.0	91.1	98.3	89.0	90.8	96.6	91.1	88.7	98.3	91.3	88.7	88.3
Surry 2	81.3	90.9	88.8	87.2	89.4	96.1	89.9	90.7	96.4	88.9	90.7	98.1	91.2	88.8	98.1	90.9	91.0	98.1	90.9
Virginia City	-	-	-	-	60.5	83.7	84.9	88.0	88.5	72.7	60.0	55.4	58.4	58.5	57.1	56.1	57.9	58.9	58.6
Warren 3x1	-	-	-	-	-	-	-	65.4	59.5	58.1	58.9	53.3	59.2	60.0	54.1	53.6	54.1	54.8	54.5
Yorktown 1	65.1	65.7	49.8	45.5	43.4	38.9	27.4	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	68.7	65.5	59.8	54.0	51.2	50.4	37.5	9.9	7.2	10.8	8.3	7.9	9.3	8.6	-	-	-	-	-
Yorktown 3	4.9	3.2	4.5	0.3	0.3	0.4	0.8	0.4	0.5	0.6	0.5	0.4	0.4	0.2	-	-	-	-	-

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 3E – HEAT RATES

Company Name: Virginia Electric and Power Company — Schedule 10a

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh) (At Maximum)

Unit Name	(ACTUAL) 2008	2009	2010	(PROJECTED) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Altavista	12.09	12.98	12.49	[redacted]															
Bath County Units 1-6	-	-	-																
Bear Garden CC	-	-	-																
Bellemeade CC	8.15	8.95	9.00																
Bremo 3	12.00	12.05	12.55																
Bremo 4	10.35	10.32	10.49																
Chesapeake 1	10.65	10.55	10.48																
Chesapeake 2	10.60	10.49	10.50																
Chesapeake 3	10.14	10.08	10.31																
Chesapeake 4	10.17	10.12	10.40																
Chesapeake CT 1	18.83	17.02	18.70																
Chesapeake CT 2	19.47	18.78	19.88																
Chesterfield 3	11.50	11.58	11.79																
Chesterfield 4	10.08	10.25	10.81																
Chesterfield 5	10.14	10.14	10.10																
Chesterfield 6	8.83	8.83	10.01																
Chesterfield 7 CC	7.52	7.32	7.33																
Chesterfield 8 CC	7.92	7.81	7.59																
Clover 1	9.95	9.88	9.88																
Clover 2	9.88	9.88	9.91																
Spruance Genco ,LLC Facility 1	-	-	-																
Spruance Genco, LLC Facility 2	-	-	-																
Edgecombe Genco, LLC	-	-	-																
Combined Cycle 3x1 :2016	-	-	-																
Combined Cycle 3x1 :2019	-	-	-																
CT:2020	-	-	-																
CT:2021	-	-	-																
CT:2023	-	-	-																
CT:2024	-	-	-																
CT:2025	-	-	-																
CT:2026	-	-	-																
Cushaw Hydro Unit	-	-	-																
Darbytown 1	12.04	12.88	12.80																
Darbytown 2	12.52	12.59	12.70																
Darbytown 3	12.80	12.81	12.70																
Darbytown 4	12.04	12.57	12.80																
Doswell Complex	-	-	-																
Elizabeth River 1	12.10	12.09	12.20																
Elizabeth River 2	12.10	12.09	12.30																
Elizabeth River 3	12.10	12.09	12.10																
Gaston Hydro	-	-	-																
Gordonsville 1 CC	8.48	8.61	8.28																
Gordonsville 2 CC	8.45	8.52	8.16																
Gravel Neck 1	18.33	18.92	19.08																
Gravel Neck 3	12.76	12.66	12.80																
Gravel Neck 4	12.75	12.72	13.20																
Gravel Neck 5	13.43	13.03	13.20																
Gravel Neck 6	12.32	12.86	13.00																
Halifax Solar	-	-	-																
Battery Storage	-	-	-																

EXTRAORDINARILY SENSITIVE
INFORMATION REDACTED

APPENDIX 3E Cont. – HEAT RATES

Company Name: Virginia Electric and Power Company

Schedule 10a

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh) (At Maximum)

Unit Name	(ACTUAL) 2008	2009	2010	(PROJECTED) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hopewell	12.77	12.42	11.85	[redacted]															
Hopewell Cogen	-	-	-																
Kitty Hawk	14.29	18.90	19.41																
Ladysmith 1	10.26	10.68	10.90																
Ladysmith 2	10.76	10.46	10.80																
Ladysmith 3	11.13	10.51	10.50																
Ladysmith 4	11.10	10.46	10.50																
Ladysmith 5	-	10.88	10.45																
Lowmoor CT	17.09	17.80	18.88																
Mecklenburg 1	11.79	11.67	11.59																
Mecklenburg 2	11.89	11.87	11.88																
Mount Storm 1	10.11	10.02	10.07																
Mount Storm 2	10.14	9.90	9.99																
Mount Storm 3	10.08	10.15	10.23																
Mount Storm CT	14.30	18.98	16.87																
North Anna 1	10.82	10.78	10.80																
North Anna 2	10.61	10.81	10.08																
North Anna 3	-	-	-																
North Anna Hydro	-	-	-																
North Branch	13.28	13.78	-																
Northern Neck CT	17.13	18.95	18.51																
Ogden-Martin Fairfax	-	-	-																
Pittsylvania 1	15.48	16.09	15.83																
Possum Point 1	-	-	-																
Possum Point 2	-	-	-																
Possum Point 3	11.48	11.48	11.48																
Possum Point 4	11.20	11.02	11.06																
Possum Point 5	12.35	10.86	11.03																
Possum Point 6 CC	7.34	7.13	7.16																
Possum Point CT	18.92	18.23	18.80																
Remington 1	10.82	10.83	10.80																
Remington 2	10.70	10.81	10.70																
Remington 3	10.70	10.71	10.80																
Remington 4	11.07	10.07	10.70																
Roanoke Rapids Hydro	-	-	-																
Roanoke Valley II	-	-	-																
Roanoke Valley Project	-	-	-																
Rosemary CC	9.50	9.55	8.71																
SEI Birchwood	-	-	-																
Southampton	12.48	12.21	11.76																
Surry 1	10.76	10.77	10.00																
Surry 2	10.74	10.74	10.00																
Virginia City	-	-	-																
Warren 3x1	-	-	-																
Yorktown 1	10.26	10.62	10.50																
Yorktown 2	10.06	10.01	9.90																
Yorktown 3	10.58	10.83	11.11																

EXTRAORDINARILY SENSITIVE
INFORMATION REDACTED

APPENDIX 3E Cont. – HEAT RATES

Company Name: Virginia Electric and Power Company — Schedule 10b

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh) (At Minimum)

	(ACTUAL)			(PROJECTED)															
Unit Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Altavista	-	-	-	[redacted]															
Bath County Units 1-6	-	-	-																
Bear Garden CC	-	-	-																
Bellemeade CC	-	-	-																
Bremo 3	-	-	-																
Bremo 4	-	-	-																
Chesapeake 1	-	-	-																
Chesapeake 2	-	-	-																
Chesapeake 3	-	-	-																
Chesapeake 4	-	-	-																
Chesapeake CT 1	-	-	-																
Chesapeake CT 2	-	-	-																
Chesterfield 3	-	-	-																
Chesterfield 4	-	-	-																
Chesterfield 5	-	-	-																
Chesterfield 6	-	-	-																
Chesterfield 7 CC	-	-	-																
Chesterfield 8 CC	-	-	-																
Clover 1	-	-	-																
Clover 2	-	-	-																
Spruance Genco, LLC Facility 1	-	-	-																
Spruance Genco, LLC Facility 2	-	-	-																
Edgecombe Genco, LLC	-	-	-																
Combined Cycle 3x1 :2016	-	-	-																
Combined Cycle 3x1 :2019	-	-	-																
CT:2020	-	-	-																
CT:2021	-	-	-																
CT:2023	-	-	-																
CT:2024	-	-	-																
CT:2025	-	-	-																
CT:2026	-	-	-																
Cushaw Hydro Unit	-	-	-																
Darbytown 1	-	-	-																
Darbytown 2	-	-	-																
Darbytown 3	-	-	-																
Darbytown 4	-	-	-																
Doswell Complex	-	-	-																
Elizabeth River 1	-	-	-																
Elizabeth River 2	-	-	-																
Elizabeth River 3	-	-	-																
Gaston Hydro	-	-	-																
Gordonsville 1 CC	-	-	-																
Gordonsville 2 CC	-	-	-																
Gravel Neck 1	-	-	-																
Gravel Neck 3	-	-	-																
Gravel Neck 4	-	-	-																
Gravel Neck 5	-	-	-																
Gravel Neck 6	-	-	-																
Halifax Solar	-	-	-																
Battery Storage	-	-	-																

APPENDIX 3E Cont. – HEAT RATES

Company Name: Virginia Electric and Power Company — Schedule 10b

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh) (At Minimum)

Unit Name	(ACTUAL) 2008	2009	2010	(PROJECTED) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hopewell	-	-	-	[redacted]															
Hopewell Cogen	-	-	-																
Kitty Hawk	-	-	-																
Ladysmith 1	-	-	-																
Ladysmith 2	-	-	-																
Ladysmith 3	-	-	-																
Ladysmith 4	-	-	-																
Ladysmith 5	-	-	-																
Lowmoor CT	-	-	-																
Mecklenburg 1	-	-	-																
Mecklenburg 2	-	-	-																
Mount Storm 1	-	-	-																
Mount Storm 2	-	-	-																
Mount Storm 3	-	-	-																
Mount Storm CT	-	-	-																
North Anna 1	-	-	-																
North Anna 2	-	-	-																
North Anna 3	-	-	-																
North Anna Hydro	-	-	-																
North Branch	-	-	-																
Northern Neck CT	-	-	-																
Ogden-Martin Fairfax	-	-	-																
Pittsylvania 1	-	-	-																
Possum Point 1	-	-	-																
Possum Point 2	-	-	-																
Possum Point 3	-	-	-																
Possum Point 4	-	-	-																
Possum Point 5	-	-	-																
Possum Point 6 CC	-	-	-																
Possum Point CT	-	-	-																
Remington 1	-	-	-																
Remington 2	-	-	-																
Remington 3	-	-	-																
Remington 4	-	-	-																
Roanoke Rapids Hydro	-	-	-																
Roanoke Valley II	-	-	-																
Roanoke Valley Project	-	-	-																
Rosemary CC	-	-	-																
SEI Birchwood	-	-	-																
Southampton	-	-	-																
Surry 1	-	-	-																
Surry 2	-	-	-																
Virginia City	-	-	-																
Warren 3x1	-	-	-																
Yorktown 1	-	-	-																
Yorktown 2	-	-	-																
Yorktown 3	-	-	-																

APPENDIX 3F – EXISTING CAPACITY

Company Name: Virginia Electric and Power Company

CAPACITY DATA

Schedule 7

	(ACTUAL)				(PROJECTED)														
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
I. Installed Capacity (MW)[(1)]																			
a. Nuclear	3,194	3,194	3,280	3,325	3,343	3,343	3,343	3,343	3,343	3,343	3,343	3,343	3,343	3,343	4,796	4,796	4,796	4,796	4,796
b. Coal	4,774	4,774	4,781	4,675	5,254	5,180	4,902	4,357	3,984	3,981	3,975	3,970	3,964	3,958	3,955	3,955	3,955	3,955	3,955
c. Heavy Fuel Oil	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,589	1,583	1,583	1,583	1,583	1,583	1,583	779	779	779	779	779
d. Light Fuel Oil	352	352	352	257	257	257	185	126	79	79	0	0	0	0	0	0	0	0	0
e. Natural Gas-Boiler	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316
f. Natural Gas-Combined Cycle	1,584	1,584	1,606	2,196	2,196	2,230	2,452	3,850	5,287	5,287	5,287	6,624	6,624	6,624	6,468	6,468	6,468	6,468	6,468
g. Natural Gas-Turbine	2,231	2,415	2,415	2,411	2,411	2,411	2,411	2,411	2,411	2,411	2,411	2,411	2,811	3,211	3,211	3,611	4,011	4,411	4,811
h. Hydro-Conventional	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318
i. Pumped Storage	1,754	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802	1,802
j. Renewable	83	83	83	83	83	112	265	271	271	274	280	286	292	298	301	301	301	301	301
k. Total Company Installed	16,210	16,442	16,557	16,987	17,584	17,573	17,598	18,483	19,394	19,394	19,315	20,652	21,052	21,452	21,945	22,345	22,745	23,145	23,545
l. Other (NUG)	1,749	1,861	1,749	1,747	1,747	1,747	1,747	1,684	1,232	627	427	262	218	218	0	0	0	0	0
n. Total	18,070	18,303	18,306	18,735	19,331	19,320	19,345	20,167	20,626	20,021	19,742	20,914	21,270	21,670	21,945	22,345	22,745	23,145	23,545
II. Installed Capacity Mix (%)[(2)]																			
a. Nuclear	17.7%	17.5%	17.9%	17.7%	17.3%	17.3%	17.3%	16.6%	16.2%	16.7%	16.9%	16.0%	15.7%	15.4%	21.9%	21.5%	21.1%	20.7%	20.4%
b. Coal	26.4%	26.1%	26.1%	25.0%	27.2%	26.8%	25.3%	21.6%	19.3%	19.9%	20.1%	19.0%	18.6%	18.3%	18.0%	17.7%	17.4%	17.1%	16.8%
c. Heavy Fuel Oil	8.9%	8.8%	8.8%	8.6%	8.3%	8.3%	8.3%	7.9%	7.7%	7.9%	8.0%	7.6%	7.4%	7.3%	3.6%	3.5%	3.4%	3.4%	3.3%
d. Light Fuel Oil	1.9%	1.9%	1.9%	1.4%	1.3%	1.3%	1.0%	0.6%	0.4%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
e. Natural Gas-Boiler	1.7%	1.7%	1.7%	1.7%	1.6%	1.6%	1.6%	1.6%	1.5%	1.6%	1.6%	1.5%	1.5%	1.5%	1.4%	1.4%	1.4%	1.4%	1.3%
f. Natural Gas-Combined Cycle	8.8%	8.7%	8.8%	11.7%	11.4%	11.5%	12.7%	19.6%	25.6%	26.4%	26.8%	31.7%	31.1%	30.6%	29.5%	28.9%	28.4%	27.9%	27.5%
g. Natural Gas-Turbine	12.3%	13.2%	13.2%	12.9%	12.5%	12.5%	12.5%	12.0%	11.7%	12.0%	12.2%	11.5%	13.2%	14.8%	14.6%	16.2%	17.6%	19.1%	20.4%
h. Hydro-Conventional	1.8%	1.7%	1.7%	1.7%	1.6%	1.6%	1.6%	1.6%	1.5%	1.6%	1.6%	1.5%	1.5%	1.5%	1.4%	1.4%	1.4%	1.4%	1.4%
i. Pumped Storage	9.7%	9.8%	9.8%	9.6%	9.3%	9.3%	9.3%	8.9%	8.7%	9.0%	9.1%	8.6%	8.5%	8.3%	8.2%	8.1%	7.9%	7.8%	7.7%
j. Renewable	0.5%	0.5%	0.5%	0.4%	0.4%	0.6%	1.4%	1.3%	1.3%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.3%	1.3%	1.3%	1.3%
k. Total Company Installed	89.7%	89.8%	90.4%	90.7%	91.0%	91.0%	91.0%	91.6%	94.0%	96.9%	97.8%	98.7%	99.0%	99.0%	100.0%	100.0%	100.0%	100.0%	100.0%
l. Other (NUG)	9.7%	10.2%	9.6%	9.3%	9.0%	9.0%	9.0%	8.4%	6.0%	3.1%	2.2%	1.3%	1.0%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%
n. Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

(1) Net dependable installed capability during peak season.

(2) Each item in Section I as a percent of line n (Total).

APPENDIX 3G – ACTUAL ENERGY GENERATION BY TYPE (GWh)

Company Name: Virginia Electric and Power Company **Schedule 2**

GENERATION

	(ACTUAL)			(PROJECTED)															
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
I. System Output (GWh)																			
a. Nuclear	26,232	26,449	25,092	27,984	27,555	27,769	28,297	27,871	27,954	28,296	27,871	27,877	28,534	27,704	40,547	40,121	40,820	39,848	40,241
b. Coal	28,775	27,644	27,097	27,613	29,345	31,037	29,288	29,353	27,840	27,993	25,436	25,144	25,022	25,498	24,855	24,577	24,743	25,173	24,990
c. Heavy Fuel Oil	466	440	707	28	29	32	54	37	45	54	39	37	35	19	8	7	4	4	5
d. Light Fuel Oil	68	196	199	0.2	0.3	0.3	0.4	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
e. Natural Gas-Boiler	205	144	317	1,536	341	329	359	333	364	385	354	312	322	315	273	278	266	284	261
f. Natural Gas-Combined Cycle	4,640	6,511	6,709	8,091	8,269	8,707	10,082	15,641	21,569	21,606	20,791	26,862	27,678	27,729	25,673	25,366	25,313	25,996	25,284
g. Natural Gas-Turbine	556	669	1,701	903	801	838	898	607	725	680	572	501	631	625	573	626	673	770	758
h. Hydro-Conventional	336	1,049	1,192	576	576	576	576	576	576	576	576	576	576	576	576	576	576	576	576
i. Hydro-Pumped Storage	1,712	2,453	2,911	2,511	2,615	2,489	2,481	2,284	2,029	2,428	3,032	2,386	2,483	2,735	1,890	2,228	2,304	2,516	2,816
j. Renewable(1)	486	430	413	391	636	869	1,725	1,766	1,830	1,971	2,042	2,069	2,112	2,143	2,108	2,070	2,090	2,109	2,120
k. Total Generation	63,478	65,985	66,338	69,633	70,367	72,667	73,760	78,467	82,932	83,989	80,713	85,764	87,395	87,344	96,504	95,848	96,789	97,276	97,051
l. Purchased Power	24,495	20,965	25,579	19,259	22,413	21,349	21,127	17,215	15,074	15,157	19,477	16,882	17,120	18,939	12,627	14,743	15,642	16,748	18,777
m. Total Payback Energy(2)	-	-	-	4	9	14	20	25	30	34	37	40	41	42	43	41	39	36	32
n. Less Pumping Energy	-2,150	-3,062	-3,631	-3,154	-3,536	-3,126	-3,116	-2,671	-2,550	-3,052	-3,811	-3,000	-3,121	-3,437	-2,376	-2,801	-2,896	-3,162	-3,539
o. Less Other Sales(3)	-24	-126	-571	-732	-640	-714	-443	-1,193	-2,285	-1,686	-519	-1,882	-1,380	-1,181	-3,230	-2,399	-1,976	-1,732	-1,258
p. Total System Firm Energy Req.	85,798	83,762	87,715	85,006	88,605	90,176	91,326	91,619	93,171	94,408	95,861	97,765	100,014	101,664	103,525	105,391	107,559	109,131	111,030
II. Energy Supplied by Competitive																			
Service Providers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) Include current estimates for renewable energy generation by VCHEC in 2012, when it is commissioned.

(2) Payback Energy is accounted for in Total Generation.

(3) Include all sales or delivery transactions with other electric utilities, i.e., firm or economy sales, etc.

APPENDIX 3H – ACTUAL ENERGY GENERATION BY TYPE (%)

Company Name: Virginia Electric and Power Company **Schedule 3**

GENERATION

	(ACTUAL)			(PROJECTED)														
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
III. System Output Mix (%)																			
a. Nuclear	31.4%	31.6%	28.6%	32.9%	31.1%	30.8%	31.0%	30.4%	30.0%	30.0%	29.1%	28.5%	28.5%	27.3%	39.2%	38.1%	38.0%	36.5%	36.2%
b. Coal	34.4%	33.0%	30.9%	32.5%	33.1%	34.4%	32.1%	32.0%	29.9%	29.7%	26.5%	25.7%	25.0%	25.1%	24.0%	23.3%	23.0%	23.1%	22.5%
c. Heavy Fuel Oil	0.6%	0.5%	0.8%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
d. Light Fuel Oil	0.1%	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
e. Natural Gas-Boiler	0.2%	0.2%	0.4%	1.8%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.3%	0.2%
f. Natural Gas-Combined Cycle	5.6%	7.8%	7.6%	9.5%	9.3%	9.7%	11.0%	17.1%	23.2%	22.9%	21.7%	27.5%	27.7%	27.3%	24.8%	24.1%	23.5%	23.8%	22.8%
g. Natural Gas-Turbine	0.7%	0.8%	1.9%	1.1%	0.9%	0.9%	1.0%	0.7%	0.8%	0.7%	0.6%	0.5%	0.6%	0.6%	0.6%	0.6%	0.6%	0.7%	0.7%
h. Hydro-Conventional	0.4%	1.3%	1.4%	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%
i. Hydro-Pumped Storage	-0.5%	2.9%	3.3%	3.0%	3.2%	2.8%	2.7%	2.5%	2.2%	2.6%	3.2%	2.4%	2.5%	2.7%	1.8%	2.1%	2.1%	2.3%	2.5%
j. Renewable Resources	0.6%	0.5%	0.5%	0.5%	0.7%	1.0%	1.9%	1.9%	2.0%	2.1%	2.1%	2.1%	2.1%	2.1%	2.0%	2.0%	1.9%	1.9%	1.9%
k. Total Generation	73.3%	78.8%	75.6%	81.9%	79.4%	80.6%	80.8%	85.6%	89.0%	89.0%	84.2%	87.7%	87.4%	85.9%	93.2%	90.9%	90.0%	89.1%	87.4%
l. Purchased Power	29.3%	25.0%	29.2%	22.7%	25.3%	23.7%	23.1%	18.8%	16.2%	16.1%	20.3%	17.3%	17.1%	18.6%	12.2%	14.0%	14.5%	15.3%	16.9%
m. Direct Load Control (DLC)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
n. Less Pumping Energy	-2.6%	-3.7%	-4.1%	-3.7%	-4.0%	-3.5%	-3.4%	-3.1%	-2.7%	-3.2%	-4.0%	-3.1%	-3.1%	-3.4%	-2.3%	-2.7%	-2.7%	-2.9%	-3.2%
o. Less Other Sales[1]	0.0%	-0.2%	-0.7%	-0.9%	-0.7%	-0.8%	-0.5%	-1.3%	-2.5%	-1.8%	-0.5%	-1.9%	-1.4%	-1.2%	-3.1%	-2.3%	-1.8%	-1.6%	-1.1%
p. Total System Output	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
IV. System Load Factor	58.4%	58.6%	58.4%	58.1%	58.4%	56.0%	56.0%	58.0%	58.3%	58.1%	58.0%	58.1%	58.1%	58.0%	58.0%	58.0%	58.4%	58.3%	58.2%

(1) Economy energy.

APPENDIX 3I – PLANNED CHANGES TO EXISTING GENERATION UNITS

Company Name: Virginia Electric and Power Company

Schedule 13a

UNIT PERFORMANCE DATA(1)

Unit Size (MW) Uprate and Derate

Unit Name	(ACTUAL) 2008	2009	2010	2011	(PROJECTED) 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Altavista	-	-	-	-	-	-12	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County Units 1-6	48	48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bear Garden CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bellemeade CC	13	-	22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 2	-	-	-	-44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	-	-	-	-	-3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	-	-	-	-	-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	-5	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	-13	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 8 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco ,LLC Facility 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spruance Genco, LLC Facility 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Edgecombe Genco, LLC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle 3x1 :2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle 3x1 :2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT:2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT:2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT:2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT:2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT:2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT:2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cushaw Hydro Unit	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 1	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 2	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 3	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 4	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Doswell Complex	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 2	16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 3	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gaston Hydro	-5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 2 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 4	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 5	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Peak net dependable capability as of this filing. Incremental uprates shown as positive (+) and decremental derates shown as negative (-).

APPENDIX 3I Cont. – PLANNED CHANGES TO EXISTING GENERATION UNITS

Company Name: Virginia Electric and Power Company — Schedule 13a

UNIT PERFORMANCE DATA[1]

Unit Size (MW) Uprate and Derate

Unit Name	(ACTUAL)				(PROJECTED)														
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Gravel Neck 6	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Halifax Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell	-	-	-	-	-	-12	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell Cogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kitty Hawk	-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 3	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 4	9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lowmoor CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	-1	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 2	-	-	-	31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm CT		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	-	-	18	-1	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 2	-	-	81	-28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Branch	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ogden-Martin Fairfax	-	-	-	-23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 4	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	-	-	-	-	-	-	-	-7	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6 CC	27	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 2	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 3	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 4	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Rapids Hydro	-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley II	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley Project	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SEI Birchwood	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southampton	-	-	-	-	-	-12	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	-	-	40	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 2	-	-	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Virginia City	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Warren 3x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	-	-	-	-	-	-	-	-8	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	-	-	-	-	-	-	-	-8	-	-	-	-	-	-	-	-	-	-	-

(1) Peak net dependable capability as of this filing. Incremental uprates shown as positive (+) and decremental derates shown as negative (-).

APPENDIX 3I Cont. – PLANNED CHANGES TO EXISTING GENERATION UNITS

Company Name: Virginia Electric and Power Company **Schedule 13b**

UNIT PERFORMANCE DATA[1]

Planned Changes to Existing Generation Units

Station / Unit Name	Uprate/Derate Description	Expected Removal Date	Expected Return Date	Base Rating	Revised Rating	MW
Altavista	Fuel Switch	2010	2013	63	51	-12
Bremo 3	Fuel Switch	N/A	2014	71	71	-
Bremo 4	Fuel Switch	N/A	2014	156	156	-
Chesapeake CT 2	Partial Retirement	2012	N/A	100	36	-64
Chesterfield 3	Scrubber Installation	2011	2011	100	97	-3
Chesterfield 4	Scrubber Installation	2011	2011	166	162	-4
Hopewell	Fuel Switch	N/A	2013	63	51	-12
Mount Storm 1	Turbine Rotor	2013	2013	524	554	30
North Anna 1	Turbine Uprate	2012	2012	813	831	18
Possum Point 5	SNCR	N/A	2015	786	779	-7
Possum Point 6	Chiller	2013	2013	559	593	34
Southampton	Fuel Switch	N/A	2013	63	51	-12
Yorktown 2	Fuel Switch	N/A	2015	164	156	-8
Yorktown 3	SNCR	N/A	2015	818	810	-8

(1) Peak net dependable capability as of this filing. Incremental uprates shown as positive (+) and decremental derates shown as negative (-).

APPENDIX 3J – POTENTIAL UNIT RETIREMENTS

Company Name: Virginia Electric and Power Company **Schedule 19**

UNIT PERFORMANCE DATA

Potential Unit Retirements[1]

Unit Name	Location	Unit Type	Primary Fuel Type	Projected Retirement Year	MW Summer	MW Winter
Chesapeake CT 2	Chesapeake, VA	CombustionTurbine	Light Fuel Oil	2011	64	99
Chesapeake GT7					16	
Chesapeake GT8					16	
Chesapeake GT9					16	
Chesapeake GT10					16	
Kitty Hawk	Kitty Hawk, NC	CombustionTurbine	Light Fuel Oil	2011	31	45
Kitty Hawk GT1					15	
Kitty Hawk GT2					16	
Possum Point CT	Dumfries, VA	CombustionTurbine	Light Fuel Oil	2014	72	106
Possum Point GT1					12	
Possum Point GT2					12	
Possum Point GT3					12	
Possum Point GT4					12	
Possum Point GT5					12	
Possum Point GT6					12	
Yorktown 1	Yorktown, VA		Coal	2015	159	162
Chesapeake Energy Center	Chesapeake, VA		Coal	2015	222	222
Chesapeake 1					111	
Chesapeake 2					111	
Lowmoor CT	Covington, VA	CombustionTurbine	Light Fuel Oil	2015	48	65
Low moor GT1					12	
Low moor GT2					12	
Low moor GT3					12	
Low moor GT4					12	
Mount Storm CT	Mt. Storm, WV	CombustionTurbine	Light Fuel Oil	2015	11	15
Mt. Storm GT1					11	
Chesapeake Energy Center	Chesapeake, VA		Coal	2016	373	383
Chesapeake 3					156	
Chesapeake 4					217	
Northern Neck CT	Warsaw, VA	CombustionTurbine	Light Fuel Oil	2016	47	70
Northern Neck GT1					12	
Northern Neck GT2					11	
Northern Neck GT3					12	
Northern Neck GT4					12	
Chesapeake CT 1	Chesapeake, VA	CombustionTurbine	Light Fuel Oil	2018	15	20
Chesapeake GT1					15	
Chesapeake CT 2	Chesapeake, VA	CombustionTurbine	Light Fuel Oil	2018	36	49
Chesapeake GT2					12	
Chesapeake GT4					12	
Chesapeake GT6					12	
Gravel Neck 1	Surry, VA	CombustionTurbine	Light Fuel Oil	2018	28	38
Gravel Neck GT1					12	
Gravel Neck GT2					16	
Yorktown 2	Yorktown, VA		Natural Gas	2022	164	165
Yorktown 3	Yorktown, VA		Heavy Fuel Oil	2022	818	820

(1) Reflects retirement assumptions used for planning purposes, not firm Company commitments.

APPENDIX 3K – PLANNED GENERATION UNDER CONSTRUCTION

Company Name: Virginia Electric and Power Company **Schedule 15a**

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[1]	MW Summer	MW Nameplate
Under Construction						
Virginia City Hybrid Energy Center	Wise County, VA	Baseload	Coal	Apr-2012	585	635

(1) Commercial Operation Date

APPENDIX 3L – WHOLESALE POWER SALES CONTRACTS

Company Name: Virginia Electric and Power Company

Schedule 20

WHOLESALE POWER SALES CONTRACTS

Entity	Contract Length	Contract Type	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
			(Actual)							(Projected)											
Old Dominion Electric Coop	12/31/2009	Non-Firm Partial Requirements[2]	930	600																	-
North Carolina Electric Membership Coop	12/31/2014	Non-Firm Partial Requirements	150	150	150	150	150	150	150												-
Craig-Botetourt Electric Coop	12-Month Termination Notice	Full Requirements[1]	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7
Town of Windsor, North Carolina	12-Month Termination Notice	Full Requirements[1]	9	9	9	10	10	11	11	11	11	11	11	12	12	12	12	12	13	13	13
Virginia Municipal Electric Association	5/31/2031 with annual renewal	Full Requirements[1][3]	252	253	321	331	333	337	342	348	355	362	369	376	383	390	396	404	411	419	426

(1) Full requirements contracts do not have a specific contracted capacity amount. MWs are included in the Company's load forecast.

(2) ODEC contract expired year end 2010.

(3) VMEA contract reflects values as of July 5, 2011.

APPENDIX 3M – APPROVED PROGRAMS NON-COINCIDENTAL PEAK SAVINGS
(kW) (System-Level)

Programs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Air Conditioner Cycling Program	35,263	76,877	125,309	176,082	224,116	266,778	304,335	336,920	364,399	386,506	403,508	413,172	420,476	425,418	429,938	434,454
Commercial HVAC Upgrade Program	3,787	8,256	13,445	18,883	19,130	19,367	19,596	19,829	20,057	20,281	20,501	20,716	20,926	21,132	21,336	21,539
Commercial Lighting Program	10,738	23,241	37,811	53,086	53,780	54,446	55,096	55,743	56,385	57,016	57,634	58,239	58,830	59,408	59,981	60,552
Low Income Program	796	1,744	3,659	5,145	5,228	5,306	5,382	5,457	5,531	5,603	5,673	5,741	5,807	5,870	5,933	5,995
Residential Lighting Program	68,048	68,048	68,048	68,048	68,048	68,048	68,048	51,150	36,703	18,868	0	0	0	0	0	0

APPENDIX 3N – APPROVED PROGRAMS COINCIDENTAL PEAK SAVINGS
(kW) (System-Level)

Programs.	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Air Conditioner Cycling Program	35,263	76,877	125,309	176,082	224,116	266,778	304,335	336,920	364,399	386,506	403,508	413,172	420,476	425,418	429,939	434,454
Commercial HVAC Upgrade Program	3,389	7,388	12,031	16,898	17,119	17,330	17,538	17,743	17,948	18,149	18,345	18,538	18,726	18,910	19,092	19,274
Commercial Lighting Program	6,897	14,927	24,284	34,095	34,541	34,968	35,386	35,802	36,213	36,619	37,016	37,404	37,784	38,155	38,523	38,890
Low Income Program	421	921	1,834	2,578	2,620	2,659	2,697	2,735	2,772	2,808	2,843	2,877	2,910	2,942	2,973	3,004
Residential Lighting Program	18,836	18,836	18,836	18,836	18,836	18,836	18,836	14,158	10,159	5,222	0	0	0	0	0	0
Totals	64,805	118,948	182,294	248,489	297,231	340,572	378,791	407,357	431,491	449,304	461,713	471,991	479,895	485,426	490,528	495,622

APPENDIX 3O – APPROVED PROGRAMS ENERGY SAVINGS
(MWh) (System-Level)

Programs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Air Conditioner Cycling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade Program	8,403	18,318	29,832	41,899	42,446	42,972	43,485	43,996	44,502	45,000	45,488	45,965	46,432	46,889	47,340	47,791
Commercial Lighting Program	54,946	118,920	193,471	271,633	275,183	278,588	281,918	285,228	288,509	291,741	294,904	297,997	301,020	303,982	306,909	309,832
Low Income Program	2,285	5,006	9,884	13,899	14,123	14,334	14,539	14,741	14,941	15,137	15,327	15,510	15,687	15,858	16,027	16,195
Residential Lighting Program	215,251	215,251	215,251	215,251	215,251	215,251	215,251	161,797	116,098	50,677	0	0	0	0	0	0
Totals	280,885	357,495	448,438	542,682	547,003	551,146	555,193	505,762	464,051	411,555	355,719	359,472	363,139	366,729	370,277	373,819

APPENDIX 3P – APPROVED PROGRAMS PENETRATIONS
(System-Level)

Programs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Air Conditioner Cycling Program	35,226	76,796	125,177	175,897	223,860	266,488	304,015	336,565	364,015	386,089	403,083	412,737	420,033	424,971	429,467	433,996
Commercial HVAC Upgrade Program [1]	289	630	1,026	1,441	1,460	1,478	1,496	1,513	1,531	1,548	1,564	1,581	1,597	1,613	1,628	1,644
Commercial Lighting Program [1]	213	461	750	1,053	1,067	1,080	1,093	1,106	1,118	1,131	1,143	1,155	1,167	1,178	1,190	1,201
Low Income Program	5,526	12,109	19,766	27,795	28,243	28,666	29,074	29,479	29,860	30,271	30,650	31,016	31,371	31,714	32,051	32,386
Residential Lighting Program [2]	7,681,964	7,681,964	7,681,964	7,681,964	7,681,964	7,681,964	7,681,964	5,774,277	4,143,359	2,129,759	0	0	0	0	0	0

(1) Program penetrations have been adjusted for exempt customers.
(2) Number of bulbs.

APPENDIX 3Q – PROPOSED PROGRAM NON-COINCIDENTAL PEAK SAVINGS (kW) (System-Level)

Programs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Commercial Energy Audit Program	0	627	3,055	6,630	10,803	15,198	15,450	15,632	15,812	15,989	16,162	16,332	16,497	16,659	16,820	16,980
Commercial Duct Testing & Sealing Program	0	982	3,606	7,813	12,738	17,908	18,204	18,418	18,630	18,838	19,043	19,242	19,438	19,629	19,818	20,006
Commercial Refrigeration Program	0	15,986	46,287	80,890	106,007	123,122	48,536	35,810	22,660	9,114	8,227	7,244	5,724	3,690	2,263	707
Commercial Distributed Generation Program	20,021	26,344	37,935	47,418	49,526	57,956	66,386	72,708	77,977	81,138	84,299	87,460	90,622	93,783	94,689	95,595
Residential Lighting Program (Phase II)	0	17,583	35,333	54,574	73,997	93,627	95,837	98,045	99,376	100,678	101,939	103,157	104,336	105,477	106,598	107,717
Residential Bundle Program	0	5,121	19,084	41,694	68,304	96,330	98,987	100,394	101,757	103,090	104,361	105,628	106,835	108,003	109,151	110,297
Residential Home Energy Check-Up Program	*0*	*109*	*399*	*867*	*1,417*	*1,999*	*2,053*	*2,108*	*2,137*	*2,165*	*2,192*	*2,218*	*2,244*	*2,268*	*2,292*	*2,316*
Residential Duct Testing & Sealing Program	*0*	*385*	*1,437*	*3,138*	*5,142*	*7,251*	*7,451*	*7,555*	*7,657*	*7,758*	*7,855*	*7,949*	*8,040*	*8,128*	*8,214*	*8,300*
Residential Heat Pump Tune-Up Program	*0*	*2,823*	*10,524*	*22,994*	*37,671*	*53,128*	*54,593*	*55,354*	*56,106*	*56,841*	*57,552*	*58,240*	*58,906*	*59,550*	*60,183*	*60,815*
Residential Heat Pump Upgrade Program	*0*	*1,804*	*6,725*	*14,694*	*24,075*	*33,953*	*34,890*	*35,376*	*35,857*	*36,326*	*36,781*	*37,221*	*37,646*	*38,058*	*38,462*	*38,866*

APPENDIX 3R – PROPOSED PROGRAM COINCIDENTAL PEAK SAVINGS (kW) (System-Level)

Programs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Commercial Energy Audit Program	0	660	2,440	5,296	8,629	12,140	12,341	12,486	12,630	12,771	12,910	13,046	13,178	13,307	13,435	13,563
Commercial Duct Testing & Sealing Program	0	810	2,975	6,445	10,508	14,772	15,017	15,193	15,368	15,540	15,708	15,873	16,034	16,192	16,348	16,503
Commercial Refrigeration Program	0	13,674	40,154	70,201	91,998	106,844	41,761	30,751	19,567	7,653	6,923	6,102	4,839	3,136	1,907	624
Commercial Distributed Generation Program	20,021	26,344	37,935	47,418	49,626	57,956	66,386	72,708	77,977	81,138	84,299	87,460	90,622	93,783	94,689	95,595
Residential Lighting Program (Phase II)	0	14,084	28,301	43,713	59,270	74,994	76,764	78,532	79,589	80,641	81,651	82,627	83,571	84,485	85,383	86,279
Residential Bundle Program	0	3,714	13,839	30,233	49,530	69,852	71,779	72,801	73,789	74,756	75,692	76,597	77,472	78,319	79,151	79,982
Residential Home Energy Check-Up Program	*0*	*89*	*327*	*709*	*1,159*	*1,636*	*1,680*	*1,725*	*1,749*	*1,772*	*1,794*	*1,815*	*1,836*	*1,856*	*1,876*	*1,895*
Residential Duct Testing & Sealing Program	*0*	*347*	*1,292*	*2,822*	*4,623*	*6,520*	*6,700*	*6,793*	*6,885*	*6,975*	*7,063*	*7,147*	*7,229*	*7,308*	*7,386*	*7,463*
Residential Heat Pump Tune-Up Program	*0*	*2,157*	*8,040*	*17,567*	*28,780*	*40,588*	*41,708*	*42,289*	*42,864*	*43,425*	*43,969*	*44,494*	*45,003*	*45,495*	*45,978*	*46,461*
Residential Heat Pump Upgrade Program	*0*	*1,122*	*4,181*	*9,135*	*14,967*	*21,108*	*21,691*	*21,993*	*22,292*	*22,584*	*22,867*	*23,140*	*23,404*	*23,660*	*23,912*	*24,163*
Totals	20,021	59,286	125,644	203,306	269,461	336,558	284,047	282,472	278,930	272,500	277,184	281,704	285,715	289,222	290,913	292,546

APPENDIX 3S – PROPOSED PROGRAM ENERGY SAVINGS
(MWh) (System-Level)

Programs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Commercial Energy Audit Program	0	3,739	13,818	29,987	48,861	68,738	69,879	70,700	71,513	72,314	73,098	73,864	74,614	75,348	76,073	76,708
Commercial Duct Testing & Sealing Program	0	3,654	13,386	29,001	47,284	66,622	67,572	68,366	69,152	70,084	70,685	71,426	72,151	73,024	73,562	74,263
Commercial Refrigeration Program	0	82,736	239,547	418,922	549,139	637,970	252,288	186,213	119,298	47,931	43,194	38,021	30,039	19,368	11,915	4,077
Commercial Distributed Generation Program	91	4	177	232	19	14	351	2,437	163	427	237	61	56	49	40	42
Residential Lighting Program (Phase II)	0	66,365	133,361	205,983	279,294	353,387	361,727	370,060	375,085	379,899	384,756	389,355	393,805	398,110	402,341	406,566
Residential Bundle Program	0	11,823	44,040	96,204	157,598	222,265	228,394	231,703	234,849	237,928	240,904	243,784	246,570	249,266	251,915	254,560
Residential Home Energy Check-Up Program	*0*	*517*	*1,893*	*4,113*	*6,722*	*9,485*	*9,742*	*10,004*	*10,140*	*10,273*	*10,401*	*10,526*	*10,646*	*10,762*	*10,877*	*10,991*
Residential Duct Testing & Sealing Program	*0*	*560*	*2,086*	*4,557*	*7,467*	*10,530*	*10,820*	*10,971*	*11,120*	*11,265*	*11,406*	*11,543*	*11,675*	*11,802*	*11,928*	*12,053*
Residential Heat Pump Tune-Up Program	*0*	*7,378*	*27,502*	*60,091*	*98,448*	*138,841*	*142,671*	*144,660*	*146,624*	*148,545*	*150,404*	*152,202*	*153,941*	*155,625*	*157,278*	*158,930*
Residential Heat Pump Upgrade Program	*0*	*3,369*	*12,559*	*27,443*	*44,962*	*63,410*	*65,160*	*66,069*	*66,966*	*67,843*	*68,692*	*69,513*	*70,308*	*71,077*	*71,832*	*72,586*
Totals	91	168,321	444,330	780,329	1,082,195	1,348,996	980,212	929,478	870,061	808,680	812,875	816,511	817,236	815,166	815,847	816,305

APPENDIX 3T – PROPOSED PROGRAM PENETRATIONS
(System-Level)

Programs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Commercial Energy Audit Program(1)	0	145	535	1,161	1,881	2,660	2,705	2,736	2,768	2,799	2,829	2,859	2,886	2,916	2,944	2,972
Commercial Duct Testing & Sealing Program(1)	0	117	430	932	1,520	2,136	2,172	2,197	2,222	2,247	2,272	2,296	2,319	2,342	2,364	2,387
Commercial Refrigeration Program(2)	0	3,564	10,696	19,440	26,693	32,523	18,148	15,688	13,211	10,313	9,469	8,131	6,388	4,219	3,147	1,822
Commercial Distributed Generation Program(3)(4)	19	25	36	45	47	55	63	69	74	77	80	83	86	89	90	91
Residential Lighting Program (Phase II)(5)	0	2,462,928	4,949,249	7,644,357	10,365,066	13,114,764	13,424,295	13,733,536	13,920,029	14,102,371	14,276,928	14,449,582	14,614,736	14,774,523	14,931,531	15,088,310
Residential Bundle Program	0	16,468	61,352	134,025	219,558	309,847	318,185	322,767	327,150	331,435	335,585	339,595	343,477	347,232	350,922	354,607
Residential Home Energy Check-Up Program	*0*	*602*	*2,207*	*4,795*	*7,838*	*11,058*	*11,358*	*11,664*	*11,822*	*11,977*	*12,127*	*12,272*	*12,412*	*12,548*	*12,681*	*12,814*
Residential Duct Testing & Sealing Program	*0*	*1,267*	*4,723*	*10,318*	*16,905*	*23,840*	*24,496*	*24,838*	*25,175*	*25,505*	*25,824*	*26,133*	*26,432*	*26,721*	*27,005*	*27,288*
Residential Heat Pump Tune-Up Program	*0*	*10,203*	*38,033*	*83,103*	*136,148*	*192,009*	*197,306*	*200,056*	*202,773*	*205,429*	*208,001*	*210,487*	*212,893*	*215,220*	*217,507*	*219,791*
Residential Heat Pump Upgrade Program	*0*	*4,396*	*18,388*	*35,809*	*58,668*	*82,740*	*85,024*	*86,209*	*87,380*	*88,524*	*89,633*	*90,704*	*91,741*	*92,744*	*93,729*	*94,713*

(1) Program penetrations have been adjusted for exempt customers.
(2) Penetrations represent measures.
(3) Number of 1,000 kW participants.
(4) Values reflect the continuation of the DG/Load Curtailment Pilot for Large Non-Residential customers.
(5) Number of bulbs.

APPENDIX 3U – GENERATION INTERCONNECTION PROJECTS UNDER CONSTRUCTION

N/A

APPENDIX 3V – LIST OF TRANSMISSION LINES UNDER CONSTRUCTION

Line Terminal	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Garrisonville Underground Cable	230	722	Dec-11	VA
Remington CT – Gainesville	230	1,047	Apr-12	VA
Hayes – Yorktown	230	1,047	May-12	VA
Glebe – Radnor Heights – Ballston UG Line	230	500	May-12	VA
Landstown – Virginia Beach	230	847	Dec-12	VA
Convert Line 49 Loudoun – New Road	230	1,047	May-13	VA
Rebuild Line #551 (Mt Storm - Doubs)	500	4,330	Jun-15	VA/WV

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 4A – DELIVERED FUEL DATA

Company Name: Virginia Electric and Power Company **Schedule 18**

FUEL DATA[1]

		(ACTUAL)									(PROJECTED)								
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
I. Delivered Fuel Price ($/mmBtu)																			
a. Nuclear	0.51	0.55	0.60	[redacted]															
b. Coal	2.44	2.71	3.05																
c. Heavy Fuel Oil	11.39	9.42	11.49																
d. Light Fuel Oil[2]	17.84	10.56	15.48																
e. Natural Gas	10.30	5.32	6.44																
f. Renewable[3]	2.88	1.92	2.13																
II. Primary Fuel Expenses (cents/KWh)																			
a. Nuclear	0.61	0.56	0.60																
b. Coal	2.50	3.03	3.22																
c. Heavy Fuel Oil	17.64	7.70	8.93																
d. Light Fuel Oil[2]	18.27	14.15	16.24																
e. Natural Gas	9.53	4.41	4.72																
f. Renewable[3]	2.88	3.13	3.43																
g. NUG	4.60	3.75	3.74																
i. Economy Energy Purchases	8.27	4.12	5.06																
j. Purchases ($KW-Year)																			
Energy and Capacity Charges	41.33	38.75	63.62																

(1) Fuel data delivered fuel prices and fuel expenses reflect average delivered costs.
(2) Light fuel oil is used for reliability only at dual-fuel facilities.
(3) Per definition of § 56-576 of the Code of Virginia.

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 5A – TABULAR RESULTS OF BUSBAR

	Capacity Factor (%)										
$/kW-Year	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
CT	[redacted]										
CC 3x1	[redacted]										
CC 2x1	[redacted]										
Nuclear	[redacted]										
Concentrating Solar Power	[redacted]										
Solar PV	[redacted]										
Onshore Wind	[redacted]										
Offshore Wind	[redacted]										
Biomass	[redacted]										
IGCC CCS	[redacted]										
PC CCS	[redacted]										
Hydro Power	[redacted]										

CONFIDENTIAL AND EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 5B – BUSBAR ASSUMPTIONS

Nominal $	Heat Rate	Variable O&M	Fixed O&M	Service Life	Overnight Costs	Year 1 ECC
	MMBtu/MWh	$/MWh	$/kW-Year	Years	$/kW	%
CT	[redacted]					
CC 3x1	[redacted]					
CC 2x1	[redacted]					
Nuclear	[redacted]					
Concentrating Solar Power	[redacted]					
Solar PV	[redacted]					
Onshore Wind	[redacted]					
Offshore Wind	[redacted]					
Biomass	[redacted]					
IGCC CCS	[redacted]					
PC CCS	[redacted]					
Hydro Power	[redacted]					

APPENDIX 5C – PLANNED GENERATION UNDER DEVELOPMENT

Company Name: Virginia Electric and Power Company **Schedule 15c**

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.(1)	MW Summer	MW Nameplate
Under Development						
Halifax County Solar	Halifax, VA	Baseload	Solar	N/A	1.5	4
Battery Storage	Halifax,VA	Baseload	Storage	N/A	4.5	4.5
Warren County Power Station	Warren County, VA	Intermediate	Natural Gas-CC	N/A	1,337	1,437
North Anna 3	Mineral, VA	Baseload	Nuclear	N/A	1,453	1,500

(1) Commercial Operation Date

APPENDIX 5D – STANDARD DSM TEST DESCRIPTIONS

<u>Participant Test</u>

The Participant test is the measure of the quantifiable benefits and costs to program participants due to enrollment in a program. This test indicates whether the program or measure is economically attractive to the customer enrolled in the program. Benefits include the participant's retail bill savings over time plus any incentives offered by the utility, while costs include only the participant's costs. A result of 1.0 or higher indicates that a program is beneficial for the participant.

<u>Utility Cost Test</u>

The Utility Cost test compares the cost to the utility to implement a program to the cost that is expected to be avoided as a result of the program implementation. The Utility Cost test measures the net costs and benefits of a DSM program as a resource option, based on the costs and benefits incurred by the utility including incentive costs and excluding any net costs incurred by the participant. The Utility Cost test ignores participant costs, meaning that a measure could pass the Utility Cost test, but may not be cost-effective from a more comprehensive perspective. A result of 1.0 or higher indicates that a program is beneficial for the utility.

<u>Total Resource Cost Test</u>

The TRC test compares the total costs and benefits to the utility and participants, relative to the costs to the utility and participants. It can also be viewed as a combination of the Participant and Utility Cost tests, measuring the impacts to the utility and all program participants as if they were treated as one group. Additionally, this test considers customer incentives as a pass-through benefit to customers and, therefore, does not include customer incentives. If a program passes the TRC test, then it is a viable program absent any equity issues associated with non-participants. A result of 1.0 or higher indicates that a program is beneficial for both participants and the utility.

<u>Ratepayer Impact Measure Test</u>

The RIM test considers equity issues related to programs. This test determines the impact the DSM program will have on non-participants and measures what happens to customer bills or rates due to changes in utility revenues and operating costs attributed to the program. A score on the RIM test of greater than 1.0 indicates the program is beneficial for both participants and non-participants, because it should have the effect of lowering bills or rates even for customers not participating in the program. Conversely, a score on the RIM test of less than 1.0 indicates the program is not as beneficial because the costs to implement the program exceed the benefits shared by all customers, including non-participants.

<u>Societal Test</u>

The Societal test is structurally similar to the TRC test but it goes beyond the TRC test in that it attempts to quantify the change in total resource costs to society as a whole rather than to only the utility and its customers. The Company does not currently use the Societal test to determine the benefits of DSM programs. However, as societal costs and benefits are factored into state and federal requirements (e.g. CO_2 legislation), the Company will consider these factors, as appropriate, in the program assessment process.

APPENDIX 5E – DSM PROGRAMS ENERGY SAVINGS (MWh)
(System-Level)

Company Name: Virginia Electric & Power Company

Schedule 12

Energy Efficiency/Energy Efficiency-Demand Response/Peak Shaving/Demand Side Management (MWh)

Program Type (1)	Program Name	Date (2)	Life/ Duration (3)	Size MW (4)	(ACTUAL - MWh) 2008	2009	2010	2011	(PROJECTED - MWh) 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Peak Shaving	Air Conditioner Cycling Program (5)	2010	2026	414	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal				414	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency - Demand Response	Commercial Distributed Generation Program (7)	2010 (7)	2026	96	0	0	157	81	4	177	232	19	14	351	2,417	165	427	237	61	58	49	40	43
	Standby Generation & Curtailable Service (Pricing Tariffs) (5)	1987	2026	5	1,640	2,160	1,080	840	840	840	840	600	600	600	600	600	600	600	600	600	600	600	600
Sub total				101	1,640	2,160	1,237	921	844	1,017	1,072	619	614	951	3,017	765	1,027	837	661	658	649	640	643
Energy Efficiency	Commercial HVAC Upgrade Program (6)	2010	2026	19	0	0	2,297	8,403	19,518	29,032	41,199	42,446	42,972	43,489	43,996	44,503	45,000	45,480	45,965	46,432	46,889	47,340	47,791
	Commercial Lighting Program (6)	2010	2026	90	0	0	14,962	54,946	118,920	191,471	271,633	275,183	278,580	281,910	285,278	288,500	291,741	294,904	297,807	301,030	303,982	306,909	309,832
	Low Income Program (6)	2010	2026	3	0	0	585	2,285	5,086	9,884	13,899	14,123	14,334	14,539	14,741	14,943	15,137	15,327	15,516	15,687	15,858	16,027	16,185
	Residential Lighting Program (6)	2010 (8)	2026	0	0	0	155,575	215,251	215,251	215,251	215,251	215,251	215,251	215,251	161,791	116,090	59,677	0	0	0	0	0	0
	Commercial Energy Audit Program (6)	2012	2026	14	0	0	0	0	5,539	13,016	29,987	48,841	68,796	69,839	70,580	71,313	72,114	73,094	73,861	74,614	75,340	76,079	76,794
	Commercial Duct Testing & Sealing Program (6)	2012	2026	17	0	0	0	0	5,656	13,146	30,004	47,381	66,622	67,572	68,366	69,152	70,001	70,685	71,426	72,151	72,854	73,562	74,261
	Commercial Refrigeration Program (6)	2012	2026	1	0	0	0	0	82,736	239,547	418,872	540,139	637,970	252,388	186,213	119,398	47,951	41,194	36,051	30,039	19,368	11,913	4,017
	Residential Lighting Program (Phase II) (6)	2012	2026	88	0	0	0	0	66,365	133,361	205,905	279,294	353,387	361,727	370,060	375,886	379,999	384,756	388,355	393,305	398,110	402,341	406,565
	Residential Bundle Program (9)	2012	2026	68	0	0	0	0	11,923	64,840	96,304	157,590	222,365	228,304	231,780	234,640	237,936	240,906	243,704	246,570	249,386	251,915	254,560
	Residential Home Energy Check-Up Program (6)	*2012*	*2026*	*2*	0	0	0	0	*317*	*1,893*	*4,113*	*6,732*	*9,485*	*9,742*	*10,004*	*10,140*	*10,275*	*10,401*	*10,526*	*10,646*	*10,762*	*10,877*	*10,991*
	Residential Duct Testing & Sealing Program (6)	*2012*	*2026*	*7*	0	0	0	0	*500*	*2,080*	*4,337*	*7,467*	*10,550*	*10,670*	*10,971*	*11,120*	*11,261*	*11,406*	*11,543*	*11,673*	*11,802*	*11,924*	*12,033*
	Residential Heat Pump Tune-Up Program (6)	*2012*	*2026*	*40*	0	0	0	0	[illegible]	*27,302*	*60,091*	*94,646*	*138,841*	*142,871*	*144,660*	*146,624*	*148,545*	*150,404*	*152,302*	*153,941*	*155,635*	*157,256*	*158,930*
	Residential Heat Pump Upgrade Program (6)	*2012*	*2026*	*14*	0	0	0	0	*3,869*	*12,559*	*27,448*	*44,063*	*62,410*	*65,180*	*66,069*	*66,966*	*67,841*	*68,692*	*69,513*	*70,308*	*71,077*	*71,813*	*72,586*
	Voltage Conservation Program (6)	2011	2026	0	0	0	91,254	97,642	97,642	549,603	1,090,857	1,593,556	1,957,572	2,367,815	2,560,985	2,560,985	2,560,985	2,560,985	2,560,985	2,560,985	2,560,985	2,560,985	2,560,985
	Commercial Re-Commissioning Program (6)	2013	2026	6	0	0	0	0	0	14,854	54,244	117,731	191,540	209,691	274,031	277,173	280,276	283,314	286,286	289,190	292,034	294,847	297,656
	Commercial Solar Window Film Program (6)	2013	2026	51	0	0	0	0	0	10,972	40,595	85,645	142,869	201,053	204,002	206,560	209,263	211,558	213,779	215,955	219,081	220,196	222,287
	Commercial Data Center/Computer Room Program (6)	2013	2026	2	0	0	0	0	0	2,570	7,314	12,853	20,563	28,275	28,607	28,937	29,282	29,560	29,881	30,191	30,492	30,786	31,080
	Commercial Custom Incentive Program (6)	2013	2026	91	0	0	0	0	0	5,340	18,431	43,245	69,000	97,844	98,861	100,378	101,739	102,700	103,825	104,925	106,186	107,067	108,132
	Residential Cool Roof Program (6)	2013	2026	30	0	0	0	0	0	210	843	1,832	2,995	4,236	4,339	4,454	4,513	4,589	4,634	4,677	4,728	4,775	4,820
Subtotal				407	0	0	264,672	370,827	623,454	1,476,860	2,516,360	3,484,842	4,284,714	4,405,172	4,611,410	4,530,837	4,413,096	4,369,063	4,383,511	4,394,342	4,403,358	4,412,732	4,433,880
Total Demand Side Management				941	1,640	2,160	265,909	371,488	624,298	1,477,877	2,517,432	3,485,460	4,285,328	4,406,124	4,614,456	4,531,600	4,414,083	4,369,899	4,384,172	4,394,999	4,404,007	4,413,372	4,433,523

(1) The Program types have been categorized by the Virginia definitions of peak shaving, energy efficiency, and demand response.
(2) Implementation date.
(3) State expected life of facility or duration of purchase contract. The Company used Program life (Years).
(4) Attributable capability and describe in the notes when such reductions are available, i.e.: at peak, all hours, on-peak hours, etc. The MWs reflected as of 2026.
(5) Reductions available during on-peak hours.
(6) Reductions available during all hours.
(7) This Program was an outgrowth of the Company's current Distributed Generation/Load Curtailment Pilot for Large Non-Residential customers.
(8) This Program was an extension of the Company's current CFL price reduction program that began in October 2007.
(9) Residential Bundle Program is comprised of the Residential Home Energy Check-Up Program, Residential Duct Testing & Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program.

APPENDIX 5F – FUTURE PROGRAMS NON-COINCIDENTAL PEAK SAVINGS (kW) (System-Level)

Programs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Voltage Conservation Program	19,081	18,423	107,401	209,263	311,211	369,350	443,171	502,020	502,020	484,709	502,020	502,020	502,020	484,709	502,020	502,020
Commercial Re-Commissioning Program	0	0	4,074	14,876	32,288	52,537	73,962	75,150	76,014	76,865	77,698	78,513	79,310	80,090	80,861	81,632
Commercial Solar Window Film Program	0	0	3,301	12,153	26,369	42,989	60,489	61,376	62,266	62,965	63,649	64,317	64,971	65,612	66,245	66,877
Commercial Data Center/Computer Room Program	0	0	621	1,864	3,106	4,970	6,834	6,914	6,994	7,072	7,149	7,224	7,298	7,370	7,441	7,512
Commercial Custom Incentive Program	0	0	1,961	7,271	15,809	25,776	36,315	36,920	37,563	38,002	38,432	38,853	39,264	39,667	40,066	40,464
Residential Cool Roof Program	0	0	467	1,713	3,722	6,086	8,586	8,816	9,050	9,169	9,283	9,394	9,502	9,606	9,708	9,810

APPENDIX 5G – FUTURE PROGRAMS COINCIDENTAL PEAK SAVINGS (kW) (System-Level)

Programs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Voltage Conservation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Re-Commissioning Program	0	0	2,949	10,770	23,375	38,034	53,545	54,405	55,031	55,647	56,250	56,840	57,417	57,981	58,540	59,097
Commercial Solar Window Film Program	0	0	2,533	9,324	20,231	32,963	46,409	47,089	47,772	48,308	48,833	49,346	49,848	50,339	50,825	51,310
Commercial Data Center/Computer Room Program	0	0	171	513	855	1,368	1,880	1,903	1,924	1,946	1,967	1,988	2,008	2,028	2,047	2,067
Commercial Custom Incentive Program	0	0	1,510	5,801	12,177	19,854	27,971	28,438	28,933	29,271	29,602	29,926	30,243	30,554	30,861	31,167
Residential Cool Roof Program	0	0	267	979	2,127	3,478	4,906	5,038	5,172	5,240	5,305	5,369	5,430	5,489	5,548	5,606
Totals	0	0	7,430	27,186	58,764	95,716	134,712	136,872	138,832	140,412	141,957	143,469	144,946	146,391	147,820	149,248

APPENDIX 5H – FUTURE PROGRAMS ENERGY SAVINGS
(MWh) (System-Level)

Programs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Voltage Conservation Program	97,642	97,642	549,603	1,070,857	1,592,556	1,967,572	2,267,835	2,568,985	2,568,985	2,568,985	2,568,985	2,568,985	2,568,985	2,568,985	2,568,985	2,568,985
Commercial Re-Commissioning Program	0	0	14,854	54,244	117,731	191,568	269,691	274,021	277,173	280,276	283,314	286,286	289,190	292,034	294,847	297,656
Commercial Solar Window Film Program	0	0	10,972	40,385	87,645	142,889	201,053	204,002	206,960	209,283	211,556	213,779	215,953	218,081	220,166	222,267
Commercial Data Center/Computer Room Program	0	0	2,570	7,711	12,852	20,563	28,275	28,607	28,937	29,262	29,580	29,891	30,195	30,492	30,786	31,080
Commercial Custom Incentive Program	0	0	5,240	19,431	42,245	69,000	97,044	98,661	100,378	101,728	102,701	103,825	104,925	106,186	107,067	108,132
Residential Cool Roof Program	0	0	230	843	1,832	2,995	4,226	4,339	4,454	4,513	4,569	4,624	4,677	4,728	4,778	4,828
Totals	97,642	97,642	583,469	1,193,481	1,854,862	2,384,587	2,868,124	3,178,615	3,186,888	3,194,047	3,200,705	3,207,390	3,213,924	3,220,505	3,226,849	3,232,969

APPENDIX 5I – FUTURE PROGRAMS PENETRATIONS
(System-Level)

Programs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Voltage Conservation Program (1)	107,000	107,000	602,278	1,173,491	1,745,191	2,145,191	2,485,191	2,815,204	2,815,204	2,815,204	2,815,204	2,815,204	2,815,204	2,815,204	2,815,204	2,815,204
Commercial Re-Commissioning Program (2)	0	0	53	192	416	680	957	972	983	994	1,005	1,016	1,026	1,036	1,046	1,056
Commercial Solar Window Film Program (2)	0	0	866,920	3,191,659	6,825,022	11,269,918	15,885,809	16,118,578	16,352,313	16,535,863	16,715,470	16,891,112	17,062,844	17,230,996	17,397,276	17,563,314
Commercial Data Center/Computer Room Program	0	0	2	6	10	16	22	22	23	23	23	23	23	24	24	24
Commercial Custom Incentive Program	0	0	48	178	387	631	889	904	920	930	941	951	961	971	981	991
Residential Cool Roof Program	0	0	744	2,728	5,927	9,691	13,672	14,040	14,412	14,601	14,763	14,960	15,131	15,296	15,459	15,621

(1) Values in 2011 and 2012 reflect the AMI demonstration.
(2) Program penetrations have been adjusted for exempt customers.

APPENDIX 5J – PLANNED GENERATION INTERCONNECTION PROJECTS

Line Terminal	PJM Queue	Line Voltage (kV)	Line Capacity (MVA)	Interconnection Cost (Million $)	Target Date	Location
North Anna – Ladysmith*	Q-65	500	3,464	48	Apr-18	VA

*Subject to change based on receipt of applicable regulatory approval(s)

APPENDIX 5K – LIST OF PLANNED TRANSMISSION LINES

Line Terminal	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Garrisonville Underground Cable	230	1,047	Dec-11	VA
Remington CT – Gainesville	230	1,047	Apr-12	VA
Hayes – Yorktown	230	1,047	May-12	VA
Glebe – Radnor Heights – Ballston UG Line	230	500	May-12	VA
Reconductor Chucktuck – Newport News	230	583	May-12	VA
Hopewell – Prince George	230	1,047	May-12	VA
Uprate 500 kV Line # 555 Dooms-Lexington	500	2,913	May-12	VA
Landstown – Virginia Beach	230	797	Dec-12	VA
Line 270 Burke – Sideburn 2nd Underground	230	600	May-13	VA
Convert Line 49 Loudoun – New Road	230	1,047	May-13	VA
Lakeside to Northwest 230kv Line*	230	1,047	May-13	VA
Cannon Branch to Liberty – New 230kV Line (Part 1 Cannon Branch-Cloverhill)*	230	1,047	Jun-13	VA
Dahlgren Substation 230kV Line (Loop Line #2076)*	230	608	May-14	VA
Convert Trowbridge – Winfall Line	230	900	May-14	NC
Uprate Line #575 (Ladysmith – North Anna)	500	3,377	Jun-14	VA
Brambleton – Waxpool – BECO*	230	1,047	May-14	VA
Chickahominy – Skiffs Creek 500 kV Line *	500	3,460	Nov-14	VA
Skiffes Creek – Whealton Line *	230	1,047	Nov-14	VA
2nd 230kV Line Harrisonburg to Endless	230	1,047	May-15	VA
Line #222 Uprate from Northwest to Southwest	230	706	May-15	VA
New 230kV Line North Anna to Oak Green*	230	1,047	May-15	VA
Uprate Line 2022 – Possum Point to Dumfries Substation	230	706	May-15	VA
Cannon Branch to Liberty – New 230kV Line (Part 2 Cloverhill-Liberty)*	230	1,047	May-15	VA
Shawboro – Aydlett New Line*	230	1,047	May-15	NC
Rebuild Winfall – Elizabeth City Line	230	1,047	Jun-15	NC
Rebuild Line #551 (Mt Storm – Doubs)	500	4,330	Jun-15	VA/WV
Clark – Idylwood*	230	706	May-16	VA
Rebuild Loudon – Brambleton	500	3,460	May-16	VA
North Anna – Ladysmith 500 kV Line*	500	3,460	Apr-18	VA
Convert Line 145 and Line 183 Ox – Independent Hill – Bristers*	230	1,047	May-18	VA
Midlothian – Chesterfield*	230	1,047	May-18	VA
Bristers – Garrisonville*	230	1,047	Jun-18	VA
[redacted]				

* Planned transmission lines subject to change based on inclusion in future PJM RTEP and/or receipt of applicable regulatory approval(s)

APPENDIX 6A – RENEWABLE RESOURCES

Company Name: Virginia Electric and Power Company

RENEWABLE RESOURCE GENERATION (GWh)

Schedule 11

Resource Type[1]	Unit Name	C.O.D.[2]	Build/Purchase/ Convert[3]	Life/Duration[4]	Size MW[5]	(ACTUAL) 2008	2009	2010	2011	(PROJECTED) 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hydro																								
	Cushaw Hydro Unit	Apr-05	Build	60	2	13	12	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	Gaston Hydro	Feb-63	Build	60	220	157	313	267	276	276	276	276	276	276	276	276	276	276	276	276	276	276	276	276
	North Anna Hydro	Dec-87	Build	60	1	1	1.1	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Roanoke Rapids Hydro	Sep-55	Build	60	95	166	319	275	282	282	282	282	282	282	282	282	282	282	282	282	282	282	282	282
Sub-total					318	337	645	560	576	576	576	576	576	576	576	576	576	576	576	576	576	576	576	576
Solar																								
	Halifax Solar	-	Build	25	4	-	-	-	-	-	-	2	6	6	6	6	6	6	6	6	6	6	6	6
	Battery Storage	-	Build	25	4.5	-	-	-	-	-	-	0	1	1	1	1	1	1	1	1	1	1	1	1
Sub-total					9	-	-	-	-	-	-	2	8	8	8	8	8	8	8	8	8	8	8	8
Biomass[6]	Unit Name																							
	Pittsylvania	Jun-94	Build	60	83	488	430	492	391	490	307	318	345	379	458	565	575	575	585	567	562	564	571	573
	Virginia City[7]	Apr-12	Build	60	59	-	-	-	-	140	233	181	188	209	303	264	283	325	325	318	312	322	328	326
	Altavista	Feb-92	Convert	30	51	-	-	-	-	-	121	411	411	412	411	411	411	412	411	410	404	408	406	411
	Southampton	Mar-92	Convert	30	51	-	-	-	-	-	71	408	408	412	411	407	409	407	409	408	395	396	401	408
	Hopewell	Jul-92	Convert	30	51	-	-	-	-	-	157	405	405	408	409	402	404	402	405	397	389	391	395	397
	Ogden-Martin Fairfax	-	Purchase	-	63	569	595	650	374	502	403	300	122	-	-	-	-	-	-	-	-	-	-	-
Sub-total					358	1,077	1,026	1,142	785	1,138	1,292	2,023	1,881	1,822	2,003	2,056	2,082	2,121	2,135	2,100	2,062	2,083	2,101	2,112
Total Renewables					684	1,413	1,670	1,702	1,341	1,714	1,868	2,601	2,465	2,406	2,587	2,652	2,676	2,705	2,719	2,684	2,646	2,667	2,686	2,696

(1) Per definition of § 56-576 of the Va. Code.
(2) Commercial Operation Date.
(3) Company built, purchased or converted.
(4) Expected life of facility or duration of purchase contract.
(5) Net Summer Capacity.
(6) Excludes contracted 25 MW BTMG biomass capacity.
(7) Dual fired coal & biomass.

APPENDIX 6B – POTENTIAL SUPPLY-SIDE RESOURCES

Company Name: Virginia Electric and Power Company **Schedule 15b**

UNIT PERFORMANCE DATA

Potential Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[1]	MW Summer	MW Nameplate
Combined Cycle 3x1 :2016	N/A	Intermediate	Natural Gas-CC	N/A	1,337	1,437
Combined Cycle 3x1 :2019	N/A	Intermediate	Natural Gas-CC	N/A	1,337	1,437
CT:2020	N/A	Peak	Natural Gas-Turbine	N/A	400	440
CT:2021	N/A	Peak	Natural Gas-Turbine	N/A	400	440
CT:2023	N/A	Peak	Natural Gas-Turbine	N/A	400	440
CT:2024	N/A	Peak	Natural Gas-Turbine	N/A	400	440
CT:2025	N/A	Peak	Natural Gas-Turbine	N/A	400	440
CT:2026	N/A	Peak	Natural Gas-Turbine	N/A	400	440

(1) Commercial Operation Date.

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 6C – SUMMER CAPACITY POSITION

Company Name: Virginia Electric and Power Company — Schedule 16

UTILITY CAPACITY POSITION (MW)

	(ACTUAL)				(PROJECTED)														
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Existing Capacity																			
Conventional	14,005	14,239	14,354	14,764	14,788	14,785	14,657	14,160	13,773	13,773	13,694	13,694	13,694	13,694	12,734	12,734	12,734	12,734	12,734
Renewable	2,165	2,203	2,203	2,203	2,203	2,203	2,356	2,356	2,356	2,356	2,356	2,356	2,356	2,356	2,356	2,356	2,356	2,356	2,356
Total Existing Capacity	16,210	16,442	16,557	16,967	16,990	16,988	17,013	16,565	16,129	16,129	16,050	16,050	16,050	16,050	15,090	15,090	15,090	15,090	15,090
Planned Under Construction																			
Conventional	-	-	-	0	556	556	556	556	556	553	547	541	535	529	527	527	527	527	527
Renewable	-	-	-	0	29	29	29	29	29	32	38	44	50	56	59	59	59	59	59
Total Planned Construction Capacity	-	-	-	0	585	585	585	585	585	585	585	585	585	585	586	586	586	585	586
Planned Under Development																			
Conventional	-	-	-	0	0	0	0	1,337	1,337	1,337	1,337	1,337	1,337	1,337	2,790	2,790	2,790	2,790	2,790
Renewable	-	-	-	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Development Capacity	-	-	-	0	0	0	0	1,337	1,337	1,337	1,337	1,337	1,337	1,337	2,790	2,790	2,790	2,790	2,790
Potential (Expected) New Capacity																			
Conventional	-	-	-	0	0	0	0	0	1,337	1,337	1,337	2,674	3,074	3,474	3,474	3,874	4,274	4,674	5,074
Renewable	-	-	-	0	0	0	0	6	6	6	6	6	6	6	6	6	6	6	6
Total Potential New Capacity	-	-	-	0	0	0	0	6	1,343	1,343	1,343	2,680	3,080	3,480	3,480	3,880	4,280	4,680	5,080
Other (NUG)	1,749	1,749	1,749	1,747	1,747	1,747	1,747	1,684	1,232	627	427	262	218	218	-	-	-	-	-
Unforced Availability				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Generation Capacity	17,959	18,191	18,306	18,735	19,331	19,320	19,345	20,167	20,626	20,021	19,742	20,914	21,270	21,670	21,845	22,345	22,745	23,145	23,545
Existing DSM Reductions																			
Demand Response	22	18	9	7	7	7	7	7	5	5	5	5	5	5	5	5	5	5	5
Conservation/Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing DSM Reductions(1)	22	18	9	7	7	7	7	7	5	5	5	5	5	5	5	5	5	5	5
Approved DSM Reductions																			
Demand Response(4)	-	-	9	35	38	125	176	224	267	304	337	364	387	404	413	420	425	430	434
Conservation/Efficiency(2)(4)	-	-	17	30	21	57	72	73	74	74	70	67	63	58	59	59	60	61	61
Total Approved DSM Reductions	-	-	26	65	59	182	248	297	341	378	407	431	449	462	472	480	485	491	495
Proposed & Future DSM Reductions																			
Demand Response(4)	-	-	12	20	0	19	47	50	58	66	73	78	81	84	87	91	94	95	96
Conservation/Efficiency(2)	-	-	-	0	0	44	169	276	374	352	347	340	332	335	338	340	342	344	346
Total Proposed & Future DSM Reductions	-	-	12	20	0	63	217	326	432	418	419	418	413	419	425	431	436	439	442
Total Demand-Side Reductions(1)	0	0	37	85	59	245	465	625	773	796	827	849	862	881	897	911	921	929	937
Net Generation & Demand-side	18,070	18,191	18,306	18,735	18,391	19,565	19,811	20,783	21,399	20,818	20,569	21,763	22,132	22,551	22,842	23,256	23,666	24074	24 483
Capacity Sale(3)	[redacted]							-500	-750	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200
Capacity Purchase(3)								78	43	384	1,003	153	294	205	370	349	284	240	316
Capacity Adjustment(3)								0	0	0	0	0	0	0	0	0	0	0	0
Capacity Requirement or PJM Capacity Obligation	[redacted]							20,020	20,244	20,586	20,895	21,309	21,801	22,222	22,618	23,006	23,310	23,710	24,181
Net Utility Capacity Position	[redacted]							-421	-707	184	803	-47	64	65	170	149	54	40	116

(1) Existing DSM programs are included in the load forecast.

(2) Efficiency programs are not part of the Company's calculation of capacity.

(3) Capacity Sale, Purchase, and Adjustments are used for modeling purposes.

(4) Values in 2010 and 2011 represent modeled capacity; actual historical data based upon measured and verified EM&V results is not yet available. Projected values represent modeled DSM firm capacity.

CONFIDENTIAL INFORMATION REDACTED

APPENDIX 6D – CONSTRUCTION FORECAST

Company Name: Virginia Electric and Power Company — Schedule 17

CONSTRUCTION COST FORECAST (Thousand Dollars)

(PROJECTED)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
I. New Traditional Generating Facilities																
a. Construction Expenditure (Not AFUDC)	[redacted]															
b. AFUDC[1]																
c. Annual Total																
d. Cumulative Total																
II. New Renewable Generating Facilities																
a. Construction Expenditure (Not AFUDC)																
b. AFUDC[1]																
c. Annual Total																
d. Cumulative Total																
III. Other Facilities																
a. Transmission																
b. Distribution																
c. Energy Conservation & DR																
d. Other																
e. AFUDC																
f. Annual Total																
g. Cumulative Total																
IV. Total Construction Expenditures																
a. Annual																
b. Cumulative																
V. % of Funds for Total Construction Provided from External Financing																

(1) Does not include Construction Work in Progress.

EXTRAORDINARILY SENSITIVE INFORMATION REDACTED

APPENDIX 6E – CAPACITY POSITION

Company Name: Virginia Electric and Power Company — Schedule 4

POWER SUPPLY DATA

	(ACTUAL)								(PROJECTED)										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
I. Capability (MW)																			
1. Summer																			
a. Installed Net Dependable Capacity(1)	16,210	16,442	16,557	16,987	17,584	17,573	17,598	18,483	19,394	19,384	19,315	20,852	21,052	21,452	21,845	22,345	22,745	23,145	23,545
b. Positive Interchange Commitments(2)	1,749	1,861	1,749	1,747	1,747	1,747	1,747	1,684	1,232	627	427	262	218	218	-	-	-	-	-
c. Capability in Cold Reserve/ Reserve Shutdown Status(1)	0	0	74	168	137	74	74	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response - Existing	22	18	9	7	7	7	7	7	5	5	5	5	5	5	5	5	5	5	5
e. Demand Response - Approved(5)	-	-	9	35	36	125	176	224	267	304	337	384	387	404	413	420	425	430	434
f. Demand Response - Proposed(5)	-	-	12	20	-	19	47	50	58	66	73	78	81	84	87	91	94	95	96
g. Capacity Sale(3)	[redacted]							-500	-750	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200
h. Capacity Purchase(3)	[redacted]							79	43	394	1,003	153	264	285	370	349	254	240	316
i. Capacity Adjustment(3)	[redacted]							-	-	-	-	-	-	-	-	-	-	-	-
j. Total Net Summer Capability(4)	[redacted]							20,020	20,244	20,586	20,955	21,309	21,801	22,222	22,816	23,006	23,318	23,710	24,191
2. Winter																			
a. Installed Net Dependable Capacity(1)	-	-	-	20,981	21,713	21,680	21,656	23,113	24,341	23,181	23,084	23,521	23,961	24,401	24,938	25,378	25,818	26,258	26,698
b. Positive Interchange Commitments(2)	-	-	-	1,940	1,940	1,840	1,940	1,877	1,361	635	434	267	222	222	-	-	-	-	-
c. Capability in Cold Reserve/ Reserve Shutdown Status(1)	0	0	77	140	140	77	77	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response(5)	-	-	12	20	-	19	47	50	58	66	73	78	81	84	87	91	94	95	96
e. Demand Response-Existing(6)	22	18	7	7	7	7	7	7	5	5	5	5	5	5	5	5	5	5	5
f. Total Net Winter Capability(4)	-	-	-	22,920	23,653	23,639	23,644	25,040	25,760	23,892	23,591	23,866	24,264	24,708	25,026	25,469	25,912	26,353	26,794

(1) Net Seasonal Capability.
(2) Includes only firm commitments from Non-Utility Generation.
(3) Capacity Sale, Purchase, and Adjustments are used for modeling purposes.
(4) Does not include Cold Reserve Capacity and Behind-the-Meter Generation MWs.
(5) Values in 2010 and 2011 represent modeled capacity; actual historical data based upon measured and verified EM&V results is not yet available. Projected values represent modeled DSM firm capacity.
(6) Included in the winter capacity forecast

NC IRP ADDENDUM 1

DOMINION NORTH CAROLINA POWER
2011 REPS COMPLIANCE PLAN

Pursuant to North Carolina Utilities Commission ("NCUC") Rule R8-67 (b), Virginia Electric & Power Company d/b/a Dominion North Carolina Power ("Company") submits its Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Compliance Plan in accordance with N.C.G.S. § 62-133.8 (b), (c), (d), (e) and (f), and the aforementioned NCUC Rule R8-67(b). The REPS Compliance Plan covers the current (2011) and immediately subsequent two calendar years (2012-2013). This North Carolina REPS Compliance Plan is an addendum to the Company's 2011 Integrated Resource Plan ("IRP").

As indicated in the Company's REPS Compliance Report filed on August 25, 2011, the Company has met its 2010 REPS requirement.

1.1 RENEWABLE ENERGY REQUIREMENTS

An overview of North Carolina's REPS requirements and Virginia's Renewable Energy Portfolio Standard ("RPS") goals are provided in Chapter 4, Section 4.3 of the Company's 2011 Integrated Resource Plan ("2011 Plan") filed simultaneously with this addendum.

1.2 COMPLIANCE PLAN

In accordance with Rule R8-67 (b) (i), the Company describes its planned actions to comply with G.S. 62-133.8 (b), (c), (d), (e), and (f) for each year.

<u>The Company</u>

The Company plans to meet North Carolina's statu tory goals through the year 2021 and thereafter with a REPS Compliance Plan that includes the use of Renewable Energy Certificates ("RECs"), energy efficiency ("EE") and new company-generated renewable energy where economically feasible. North Carolina General Statute § 62-133.8(d) sets the initial compliance target for solar in years 2010 and 2011 as 0.02% of the previous year's baseline load, with overall REPS compliance beginning in 2012, along with swine waste and poultry waste set-asides. The Company began implementing the energy efficiency programs in North Carolina by introduction of the Residential Lighting Program in May 2011 and the other approved programs in June 2011. These programs will contribute to the overall REPS goals, subject to approval by the NCUC.

On September 22, 2009, the NCUC issued an order on the Company's motion for further clarification in Docket No. E-100, Sub 113 ruling that the Company is allowed to utilize out-of-state RECs to meet all of its REPs requirements per G.S. 62-133.8(b)(2)(e). Therefore, in accordance with such order, the Company plans to meet DNCP's obligations with a mix of purchased out-of-state RECs, in-state RECs, qualified energy efficiency programs, and qualified company-generated renewable energy where economically feasible. Figure 1.2.1 provides the summary for the 2011 to 2013 REPS Compliance Plan.

Figure 1.2.1 2011-2013 COMPANY'S REPS COMPLIANCE PLAN SUMMARY

	2011	2012	2013
Baseline Sales Forecast (MWh)	3,996,743	4,135,654	4,287,900
NC Total REPs Requirement %		3%	3%
Total REPS Target (MWh)[1]		119,903	124,070
NC Total Solar Target %	0.02%	0.07%	0.07%
Total Solar Target (MWh)[1]	866	2,798	2,895
NC Total Swine Target %		0.07%	0.07%
Total Swine Target (MWh)[1]		2,798	2,895
NC Total Poultry Target %[1,2] Total Poultry Target (MWh)		3.02% of 170,000 MWh 5,137	3.07% of 700,000 MWh 21,490
General REPS Requirement (net of Solar, Swine and Poultry) (MWh)		109,170	96,790
Energy Efficiency (MWh)[3]	[redacted]	[redacted]	[redacted]
Company-Generated Renewables (MWh)			28,939

Notes: (1) 2011 target is based on actual 2010 retail sales of 4,329,303 MWh. 2012-2013 targets are based on baseline retail sales forecasts. The total target is the product of the previous year's baseline load and the current year target percentage. (2)Calculation may not equal due to rounding. (3) Per the statute, the energy savings from EE programs in 2011 can be retained and applied to the 2012 target.

The Town of Windsor

The Company is also responsible for meeting REPs requirements for the Town of Windsor, a wholesale customer of the Company, as outlined in Figure 1.2.2

Figure 1.2.2 2011-2013 TOWN OF WINDSOR REPS COMPLIANCE PLAN SUMMARY

	2011	2012	2013
Baseline Sales Forecast (MWh)	[redacted]	[redacted]	[redacted]
NC Total REPs Requirement %		3%	3%
Total REPS Target (MWh)[1]		[redacted]	[redacted]
NC Total Solar Target %	0.02%	0.07%	0.07%
Total Solar Target (MWh)[1]	[redacted]	[redacted]	[redacted]
NC Total Swine Target %		0.07%	0.07%
Total Swine Target (MWh)[1]		[redacted]	[redacted]
NC Total Poultry Target %[2] Total Poultry Target (MWh)[1]		0.04% of 170,000 MWh [redacted]	0.04% of 700,000 [redacted]

General REPS Requirement (net of Solar, Swine and Poultry) (MWh)		[redacted]	[redacted]

Notes: (1) 2011 target is based on actual 2010 retail sales of [redacted] MWh reported by the Town of Windsor. 2012-2013 targets are based on forecasts from the Town of Windsor. The total target is a product of the previous year's baseline retail sales and the current year target percentage.

Solar RECs

The Company's strategy for DNCP's compliance with solar requirements is to buy unbundled out-of-state RECs to minimize the compliance cost to the ratepayers. The Company has purchased or entered into contracts to purchase solar RECs for DNCP's compliance with G.S. 62-133.8 (b) and (d) through 2013. Specifically, the Company has entered into contracts for the purchase of Solar RECs for the term of six (6) years with Integrys Energy Sevices Inc (d/b/a Solar Star California). This contract will provide enough Solar RECs to satisfy DNCP's compliance for the years 2012 thru 2014 and approximately 35% of the requirements for 2015 through 2017.

The Company is currently negotiating a contract with a facility located in NC that will satisfy the Town of Windsor's compliance requirements for 2011 and 2012. As per the guidance and advice received from Public Staff, the Company intends to purchase 75% of the Solar Carve-out REPS requirements for the Town of Windsor from solar facilities located inside the state.

Swine and Poultry RECs

Under the oversight of the Commission, a group of electric suppliers subject to North Carolina statutes, including the Company, issued joint requests for proposals ("RFPs") for swine waste and poultry litter energy that meet the current set-aside requirements. Several proposals from Swine and Poultry waste RECs suppliers were received and evaluated. Negotiations were finalized with five (5) swine waste RECs suppliers and the Company has signed long term contracts with all five of these suppliers. The joint buyers' group is also negotiating with a poultry litter RECs supplier for a long term contract.

General REPS Requirements Net of Solar, Swine and Poultry

The Company plans to comply with the general REPS requirements, which begin in 2012, using a combination of the approved options to include obtaining qualifying RECs, applying EE programs, and using company-generated new renewable energy that qualify under North Carolina law. The Company's 2011 IRP, of which this Plan is filed as an addendum, includes in the Preferred Plan, beginning in 2013, company-generated new renewable energy from biomass fuel co-firing at the Company's Virginia City Hybrid Energy Center (VCHEC) expected to go on-line in 2012 as well as biomass fuel conversions at the Altavista, Hopewell and Southhampton power stations (pending approval).

1.3 REC CONTRACTS

In accordance with Rule R8-67 (b) (ii), the Company provides a list of executed contracts to purchase renewable energy certificates.

As mentioned in the previous section, the Company has purchased Solar RECS and entered into long-term Swine Waste and Solar REC contracts to comply with G.S. 62-133.8 (b) and (d) and (e). Figures 1.3.1 and 1.3.3 provide summaries of the contracts.

Figure 1.3.1 2011-2013 Solar REC Purchase Contract Summary[1]

	Total Volume	Volume / Year	Term	Price / MWh	Total Expense
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]					
Total Volume	[redacted]			Total Expense	[redacted]

Notes: Contracts are confidential. (1) The Company plans to retain any surplus RECs from 2010 and 2011 and use for future compliance. (2) Contracts for Town of Windsor compliance.

Figure 1.3.2 COMPANY'S SOLAR REC COMPLIANCE BY YEAR

Type of REC	2011	2012	2013
Solar			
Target (MWh)	[redacted]	[redacted]	[redacted]
Less Banked RECs	[redacted]	[redacted]	[redacted]
Town of Windsor[2]	[redacted]	[redacted]	[redacted]
Net Target	[redacted]	[redacted]	[redacted]
Purchased RECs	[redacted]	[redacted]	[redacted]
Net Solar REC Position	[redacted]	[redacted]	[redacted]

Notes: (1) 1,313 RECs banked in 2010. (2) Town of Windsor's 25% allowable out of state requirement is added to the Company's requirement for execution efficiency. Town of Windsor's remaining 75% in state solar requirement is satisfied separately. Therefore, it is not included in Figure 1.3.2.

Figure 1.3.3 2011-2013 Swine Waste REC Purchase Contract Summary

	Total Volume	Volume / Year[1]	Term	Price / MWh[2]	Total Expense
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Volume	[redacted]			**Total Expense**	[redacted]

Notes: Contracts are confidential. (1) Reduced volumes in first year of contract. Volume / Year shows first full calendar year production. (2) Price escalates approximately 2.5% per year. Prices given are for initial year. (3) Assumes 50% of RECs are produced with swine waste (contract requires at least 50% production from swine waste).

Figure 1.3.4 COMPANY'S SWINE REC COMPLIANCE BY YEAR

Type of REC	2012	2013
Swine		
Target (MWh)	[redacted]	[redacted]
Less Banked RECs	[redacted]	[redacted]
Town of Windsor	[redacted]	[redacted]
Net Target	[redacted]	[redacted]
Purchased RECs	[redacted]	[redacted]
Net Swine REC Position	[redacted]	[redacted]

Notes: (1) Expected delivery in 2011 from contracts listed in Figure 1.3.2. (2) Company is actively attempting to purchase Swine Waste RECs from out of state suppliers to comply.

Based on the Company's assessment of the current status of the signed contracts (shown in Figure 1.3.3), it is highly unlikely that the Swine Waste Compliance Requirements will be satisfied for the 2012 compliance year.

1.4 ENERGY EFFICIENCY PROGRAMS

In accordance with Rule R8-67 (b) (iii), the Company provides a list of planned or implemented energy efficiency measures, including a brief description of the measure and projected impacts.

The Company will apply its energy efficiency programs approved by the NCUC to meet the NC REPS requirements as permitted by law. Figure 1.4.1 lists the potential energy efficiency programs and gives a projection of the resulting energy savings from each program.

Figure 1.4.1 NORTH CAROLINA ENERGY EFFICIENCY PROGRAMS ENERGY SAVINGS (MWh)

	2011[1]	2012	2013
Commercial HVAC Upgrade Program	[redacted]	[redacted]	[redacted]
Commercial Lighting Program	[redacted]	[redacted]	[redacted]
Low Income Program	[redacted]	[redacted]	[redacted]
Residential Lighting Program	[redacted]	[redacted]	[redacted]
Energy Efficiency Total	[redacted]	[redacted]	[redacted]

Note: (1) Per the statute, the energy savings from energy efficiency programs in 2011 can be retained and applied to the 2012 target. (2) Total does not equal due to rounding.

A brief description of these energy efficiency programs can be found in Section 3.2.6 of the IRP of which this report is an addendum. The Company also intends to seek approval of additional programs with the NCUC in the future.

1.5 RETAIL SALES & CUSTOMER ACCOUNTS

In accordance with Rule R8-67 (b) (iv), the Company states the projected Company's North Carolina retail sales and year-end number of customer accounts by customer class for each year.

The Company

Figure 1.5.1 summarizes the Company's North Carolina retail sales and Figure 1.5.2 summarizes the year-end number of customer accounts by customer class for each year of the REPS Compliance Plan.

Figure 1.5.1 COMPANY'S NORTH CAROLINA RETAIL SALES[1]

Year	Residential Sales (MWh)	Commercial Sales (MWh)[2]	Industrial Sales (MWh)	Total Sales (MWh)
2011 (projected)	1,588,607	999,488	1,408,648	3,996,743
2012 (projected)	1,621,287	1,051,317	1,463,050	4,135,654
2013 (projected)	1,638,102	1,071,132	1,578,666	4,287,900

Notes: (1) Excludes the Town of Windsor's wholesale customer load. (2) Includes the Public Authority and Street and Traffic Lighting load.

Figure 1.5.2 COMPANY'S NORTH CAROLINA CUSTOMER ACCOUNTS[1]

Year	Residential Customers	Commercial Customers[2]	Industrial Customers	Total Customers
2011 (projected)	103,200	18,202	57	121,459
2012 (projected)	104,541	18,412	57	123,010
2013 (projected)	106,256	18,660	57	124,973

Notes: (1) Customer account totals are year-end forecasts. These differ slightly from Appendix 2F in the 2011 IRP which are average yearly amounts. (2) Includes the Public Authority and Street and Traffic Lighting accounts.

Town of Windsor

Figure 1.5.3 summarizes the Town of Windsor's retail sales and Figure 1.5.4 summarizes the year-end number of customer accounts by customer class for each year of the REPS Compliance Plan.

Figure 1.5.3 TOWN OF WINDSOR'S RETAIL SALES[1]

Year	Residential Sales (MWh)	Commercial Sales (MWh)	Industrial Sales (MWh)	Total Sales (MWh)
2011 (projected)	[redacted]	[redacted]	[redacted]	[redacted]
2012 (projected)				
2013 (projected)				

Note: (1) *Sales are year-end forecasts provided by the Town of Windsor.*

Figure 1.5.4 TOWN OF WINDSOR'S CUSTOMER ACCOUNTS[1]

Year	Residential Customers	Commercial Customers[2]	Industrial Customers	Total Customers
2011 (projected)	[redacted]	[redacted]	[redacted]	[redacted]
2012 (projected)	[redacted]	[redacted]	[redacted]	[redacted]
2013 (projected)	[redacted]	[redacted]	[redacted]	[redacted]

Notes: (1) Customer account totals are year-end forecasts provided by Town of Windsor.

1.6 AVOIDED COST RATES

In accordance with Rule R8-67 (b) (v), the Company provides the following statement regarding the current and projected avoided cost rates for each year.

Figure 1.6.1 identifies the projected avoided energy and capacity cost from the Biennial Determination of Avoided Costs Rates for Electric Utility Purchases from Qualifying Facilities – 2010 proceeding E-100, SUB 127 before the North Carolina Utilities Commission. Avoided energy and capacity cost as used in the 2011 IRP are given below in Figure 1.6.2.

Figure 1.6.1 PROJECTED AVOIDED ENERGY AND CAPACITY COST (from E-100 sub 127)

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Capacity Price ($/kW-Year)
2011	50.09	38.46	49.93
2012	52.31	40.09	20.23
2013	54.84	41.19	8.41

Figure 1.6.2 PROJECTED AVOIDED ENERGY AND CAPACITY COST (from NC 2011 IRP)

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Capacity Price ($/kW-Year)
2011	58.13	42.76	49.93
2012	59.52	45.05	20.23
2013	57.20	43.34	8.41

1.7 TOTAL & PROJECTED COSTS

In accordance with Rule R8-67 (b) (vi), the Company provides the projected total and incremental costs anticipated to implement the REPS Compliance plan for each year.

The Company

The Company's total and incremental costs for the plan year 2011 are expected to consist of the cost to purchase unbundled out-of-state solar RECs. The projected costs for 2012 and 2013 are expected to consist of the sum of the costs required to comply with solar, swine, poultry and other general renewable requirements. Outside legal costs, joint RFP consulting engineer's fees and NC RETS system development costs and ongoing user fees could also be incurred. Figure 1.7.1 outlines the Company's Compliance Cost Summary for RECs procurement from 2011 to 2013.

Figure 1.7.1 COMPANY'S COMPLIANCE COST SUMMARY

Type of REC	2011	2012	2013
Solar			
Target (MWh)	[redacted]	[redacted]	[redacted]
REC Cost ($/MWh)[1]	[redacted]	[redacted]	[redacted]
Projected Cost	[redacted]	[redacted]	[redacted]
Swine			
Target (MWh)	[redacted]	[redacted]	[redacted]
REC Cost ($/MWh)[2]		[redacted]	[redacted]
Projected Cost		[redacted]	[redacted]
Poultry			
Target (MWh)	[redacted]	[redacted]	[redacted]
REC Cost ($/MWh)[2]		[redacted]	[redacted]

Projected Cost		[redacted]	[redacted]
General REPs			
Target (MWh)	[redacted]	[redacted]	[redacted]
Less Energy Efficiency[3]		[redacted]	[redacted]
Less Company-Generated Renewable			[redacted]
Net Target		[redacted]	[redacted]
REC Cost ($/MWh)[2]		[redacted]	[redacted]
Projected Cost		[redacted]	[redacted]
Projected Administrative Cost[4]	[redacted]	[redacted]	[redacted]
TOTAL PROJECTED COMPLIANCE COST	[redacted]	[redacted]	[redacted]

Notes: (1) Solar REC costs for 2011-2013 are from contracts listed in Figure 1.3.1. (2) 2012/2013 projected REC costs are based on market estimates, signed contracts and/or ongoing negotiations. (3) Energy efficiency for 2012 is the sum of 2011 and 2012. (4) Administrative costs include, but are not limited to: NC-RETs fees, broker fees, and miscellaneous expenses.

The Town of Windsor

The Town of Windsor's total and incremental costs for the plan year 2011 are expected to consist of the purchase of qualified solar RECs. The projected costs for 2012 and 2013 are expected to consist of the sum of the costs required to comply with solar, swine, poultry and other general renewable requirements. Figure 1.7.2 outlines the Town of Windsor's Compliance Cost Summary from 2011 to 2013.

Figure 1.7.2 TOWN OF WINDSOR'S COMPLIANCE COST SUMMARY

Type of REC	2011	2012	2013
Solar			
Target (MWh)	[redacted]	[redacted]	[redacted]
REC Cost ($/MWh)[1,2]	[redacted]	[redacted]	[redacted]
Projected Cost	[redacted]	[redacted]	[redacted]
Swine			
Target (MWh)	[redacted]	[redacted]	[redacted]
REC Cost ($/MWh)[2]		[redacted]	[redacted]
Projected Cost		[redacted]	[redacted]
Poultry			
Target (MWh)	[redacted]	[redacted]	[redacted]
REC Cost ($/MWh)[2]		[redacted]	[redacted]
Projected Cost		[redacted]	[redacted]
General REPs			
Target (MWh)	[redacted]	[redacted]	[redacted]
REC Cost ($/MWh)[2]		[redacted]	[redacted]

Projected Cost		[redacted]	[redacted]
TOTAL PROJECTED COMPLIANCE COST	[redacted]	[redacted]	[redacted]

Notes: (1) Solar REC costs for 2011 are weighted averages from contracts listed in Figure 1.3.1. (2) 2012/2013 projected REC costs are based on market estimates, signed contracts and/or ongoing negotiations.

1.8 ANNUAL COST CAPS

In accordance with Rule R8-67 (b) (vii), the Company provides the following comparison of projected costs to the annual cost caps contained in G.S. 62-133.8 (h) (4).

Figure 1.8.1 provides a comparison of the Company's projected costs to the annual cost caps for each year of the REPS Compliance Plan. Compliance costs are allocated to the Customer Classes based on the percentage of each of the Customer Class Cost Caps to the Total Cost Cap.

Figure 1.8.1 COMPANY'S COMPARISON TO ANNUAL CAPS

Compliance Year 2011	**Residential Customers**	**Commercial Customers**	**Industrial Customers**	**Total Customers**
Projected Year-End Annual Customers	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap per Customer	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap, Total	[redacted]	[redacted]	[redacted]	[redacted]
Projected Cost of Compliance[1]	[redacted]	[redacted]	[redacted]	[redacted]

Compliance Year 2012	**Residential Customers**	**Commercial Customers**	**Industrial Customers**	**Total Customers**
Projected Year-End Annual Customers	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap per Customer[2]	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap, Total	[redacted]	[redacted]	[redacted]	[redacted]
Projected Cost of Compliance[1]	[redacted]	[redacted]	[redacted]	[redacted]

Compliance Year 2013	**Residential Customers**	**Commercial Customers**	**Industrial Customers**	**Total Customers**
Projected Year-End Annual Customers	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap per Customer	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap, Total	[redacted]	[redacted]	[redacted]	[redacted]
Projected Cost of Compliance[1]	[redacted]	[redacted]	[redacted]	[redacted]

Notes: (1) Projected costs were allocated to the customer classes based on customer percentage of total cost cap. (2) Annual cost cap per customer increases in 2012 per 62-133.8 (h) (4).

Figure 1.8.2 provides a comparison of the Town of Windsor's projected costs to the annual cost caps for each year of the REPS Compliance Plan.

Figure 1.8.2 TOWN OF WINDSOR'S COMPARISON TO ANNUAL CAPS
Confidential information indicated by italics.

Compliance Year 2011	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Projected Year-End Annual Customers	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap per Customer	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap, Total	[redacted]	[redacted]	[redacted]	[redacted]
Projected Cost of Compliance[1]				[redacted]

Compliance Year 2012	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Projected Year-End Annual Customers	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap per Customer[2]	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap, Total	[redacted]	[redacted]	[redacted]	[redacted]
Projected Cost of Compliance[1]				[redacted]

Compliance Year 2013	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Projected Year-End Annual Customers	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap per Customer	[redacted]	[redacted]	[redacted]	[redacted]
Annual Cost Cap, Total	[redacted]	[redacted]	[redacted]	[redacted]
Projected Cost of Compliance[1]				[redacted]

Notes: (1) The Town of Windsor is to determine the allocation among the different customer classes. (2) Annual cost cap per customer increases in 2012 per 62-133.8 (h) (4).

1.9 REPS RIDER

In accordance with Rule R8-67 (b) (viii), the Company provides an estimate of the amount of the REPS rider and the impact on the cost of fuel and fuel-related costs rider necessary to fully recover the projected costs.

The Company did not file a REPS Rider in 2010 and is not filing a REPS Rider in 2011. As described in the Company's REPS Compliance Report filed on August 26, 2011, the Company expects to spend in total under $60,000 for 2010 and 2011 REPS compliance for DNCP and Town of Windsor. Due to the relatively small cost of compliance so far, the Company does not consider it to be cost-effective to seek recovery of these costs at this time. The Company recognizes that any recovery of these costs will need to be approved by the Commission.

1.10 REGISTRATION INFORMATION

In accordance with Rule R8-67 (b) (ix), the Company provides the following statement in response to the requirement that, to the extent not already filed with the Commission, the electric power supplier shall, on or before September 1 of each year, file a renewable energy facility registration statement pursuant to Rule R8-66 for any facility it owns and upon which it is relying as a source of power or RECs in its REPS compliance plan..

The Company will confirm that the facilities generating solar, swine, poultry and/or other renewable RECs, used by the Company for its REPS Compliance Plan have registered and filed the appropriate information with the NCUC pursuant to Rule R8-66.

NC IRP ADDENDUM 2

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	SURRY	SUFFOLK (531)	500.00	500.00	STEEL	37.27		1
2	DOOMS	CUNNINGHAM (534)	500.00	500.00	STEEL	32.66		1
3	OX	BRISTERS (539)	500.00	500.00	STEEL	22.89		1
4	FLUVANA PWR STA	CUNNINGHAM (542)	500.00	500.00	STEEL	0.28		1
5	PLEASANT VIEW	DOUBS (543)	500.00	500.00	STEEL	3.00		1
6	BRISTERS	MORRISVILLE (545)	500.00	500.00	STEEL	7.91		1
7	LEXINGTON	BATH (547)	500.00	500.00	STEEL	34.70		1
8	BATH	VALLEY (548)	500.00	500.00	LATTICE	51.82		1
9	VALLEY	DOOMS (549)	500.00	500.00	STEEL	17.72		1
10	MT. STORM	VALLEY (550)	500.00	500.00	STEEL	64.39		1
11	MT. STORM	DOUBS (551)	500.00	500.00	STEEL	96.40		1
12	BRISTERS	LADYSMITH (552)	500.00	500.00	STEEL	35.41		1
13		(552)	500.00	500.00	STEEL		1.20	
14	CUNNINGHAM	ELMONT (553)	500.00	500.00	STEEL	51.03		1
15	DOOMS	LEXINGTON (555)	500.00	500.00	STEEL	39.04		1
16	CLOVER	CARSON (556)	500.00	500.00	STEEL	76.72		1
17	ELMONT	CHICKAHOMINY (557)	500.00	500.00	STEEL	27.73		1
18	LOUDOUN	PLEASANT VIEW (558)	500.00	500.00	STEEL	13.01		1
19	LOUDOUN	CLIFTON (559)	500.00	500.00	STEEL	12.08		1
20	POSSUM POINT	BURCHES-PEPCO (560)	500.00	500.00	H.FRAME	0.19		1
21	CLIFTON	OX (561)	500.00	500.00	STEEL	7.05		1
22	CARSON	SEPTA (562)	500.00	500.00	STEEL	38.47		1
23	CARSON	MIDLOTHIAN (563)	500.00	500.00	STEEL	37.41		1
24	CUNNINGHAM	FLUVANA PWR STA (564)	500.00	500.00	STEEL	0.26		1
25	SUFFOLK	YADKIN (565)	500.00	500.00	STEEL	4.80		1
26		(565)	500.00	500.00	ALUM TOWER	8.66		
27	LEXINGTON	CLOVERDALE-APCO (566)	500.00	500.00	STEEL	7.09		1
28	CHICKAHOMINY	SURRY (567)	500.00	500.00	STEEL	44.44		1
29	POSSUM POINT	LADYSMITH (568)	500.00	500.00	STEEL	47.56		1
30	LOUDOUN	MORRISVILLE (569)	500.00	500.00	STEEL	22.36		1
31		(569)	500.00	500.00	STEEL	1.26		
32		(569)	500.00	500.00	STEEL	8.16		
33	CARSON	WAKE (570)	500.00	500.00	STEEL	56.40		1
34	OX	POSSUM POINT (571)	500.00	500.00	H.FRAME	12.86		1
35	NORTH ANNA	MORRISVILLE (573)	500.00	500.00	STEEL	32.91		1
36					TOTAL	5,308.05	860.32	425

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	ELMONT	LADYSMITH (574)	500.00	500.00	STEEL	26.19		1
2	NORTH ANNA	LADYSMITH (575)	500.00	500.00	STEEL	13.59		1
3		(575)	500.00	500.00	H.FRAME	0.94		
4	MIDLOTHIAN	NORTH ANNA (576)	500.00	500.00	STEEL	41.30		1
5	SEPTA	SURRY (578)	500.00	500.00	STEEL	11.46		1
6	FENTRESS	SEPTA (579)	500.00	500.00	LATTICE	46.86		1
7	MORRISVILLE	MEADOWBROOK (580)	500.00	500.00	STEEL	47.54		1
8								
9	SUBTOTAL-500KV		500.00	500.00		1,141.84	1.20	37
10								
11	PENDER	BULL RUN (200)	230.00	230.00	STEEL	0.63		1
12		(200)	230.00	230.00	H.FRAME	2.87		
13		(200)	230.00	230.00	STEEL POLE	3.99		
14	BRAMBLETON	PLEASANT VIEW (201)	230.00	230.00	STEEL	7.97		1
15	IDYLWOOD	CLARK (202)	230.00	230.00	STEEL	4.03		1
16	PLEASANT VIEW	DICKERSON (203)	230.00	230.00	STEEL	3.03		1
17	GUM SPRINGS	JEFFERSON ST (204)	230.00	230.00	STEEL	6.67		1
18		(204)	230.00	230.00	WOOD POLE	4.12		
19	CHESTERFIELD	LOCKS (205)	230.00	230.00	STEEL	2.81		1
20		(205)	230.00	230.00	STEEL	9.42		
21	BRADDOCK	IDYLWOOD (207)	230.00	230.00	STEEL		4.68	1
22	CHESTERFIELD	SOUTHWEST (208)	230.00	230.00	STEEL	10.61		1
23		(208)	230.00	230.00	STEEL	3.78		
24	WALLER	YORKTOWN (209)	230.00	230.00	WOOD	14.13		1
25		(209)	230.00	230.00	STEEL	4.57		
26	HAYFIELD	VAN DORN (210)	230.00	230.00	STEEL		2.90	1
27	CHESTERFIELD	HOPEWELL (211)	230.00	230.00	STEEL	11.17		1
28	HOPEWELL	SURRY (212)	230.00	230.00	H.FRAME	0.27		1
29		(212)	230.00	230.00	STEEL	42.70		
30	CAROLINA	THELMA (213)	230.00	230.00	STEEL	10.07		1
31	SURRY	WINCHESTER (214)	230.00	230.00	STEEL	13.90		1
32		(214)	230.00	230.00	STEEL		23.71	
33	POSSUM POINT	HAYFIELD (215)	230.00	230.00	STEEL	12.44		1
34		(215)	230.00	230.00	STEEL	7.62		
35		(215)	230.00	230.00	STEEL POLE	0.48	0.48	
36					TOTAL	5,308.05	860.32	425

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TRANSMISSION LINE STATISTICS

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	LAKESIDE	ELMONT (216)	230.00	230.00	H.FRAME	5.74		1
2	LAKESIDE	CHESTERFIELD (217)	230.00	230.00	H.FRAME	20.87		1
3		(217)	230.00	230.00	STEEL		0.63	
4	EVERETTS	GREENVILLE (CP&L) (218)	230.00	230.00	H.FRAME	20.32		1
5		(218)	230.00	230.00	STEEL	1.33		
6	MIDLOTHIAN	SOUTHWEST (219)	230.00	230.00	STEEL POLE	13.77		1
7		(219)	230.00	230.00	STEEL		7.52	
8	OX	GUM SPRINGS (220)	230.00	230.00	STEEL		9.68	1
9		(220)	230.00	230.00	WOOD POLE		4.53	
10	NORTHWEST	ELMONT (221)	230.00	230.00	STEEL	5.93		1
11	NORTHWEST	SOUTHWEST (222)	230.00	230.00	STEEL	10.25		1
12	SURRY	YADKIN (223)	230.00	230.00	STEEL	44.10		1
13	NORTHERN NECK	LANEXA (224)	230.00	230.00	STEEL	41.27		1
14	LAKEVIEW	THELMA (225)	230.00	230.00	STEEL	8.69		1
15	SURRY	CHURCHLAND (226)	230.00	230.00	STEEL		37.63	1
16		(226)	230.00	230.00	STEEL POLE		0.11	
17	BEAUMEADE	BRAMBLETON (227)	230.00	230.00	STEEL	5.19		1
18		(227)	230.00	230.00	STEEL	0.18		
19		(227)	230.00	230.00	STEEL		7.88	
20	CHESTERFIELD	HOPEWELL (228)	230.00	230.00	STEEL		10.97	1
21	EVERETTS	EDGECOMBE (229)	230.00	230.00	STEEL POLE	0.28		1
22		(229)	230.00	230.00	H.FRAME	42.04		
23		(229)	230.00	230.00	STEEL	2.53		
24	YADKIN	LANDSTOWN (231)	230.00	230.00	STEEL	13.16		1
25		(231)	230.00	230.00	STEEL	2.92		
26	GASTON	THELMA (232)	230.00	230.00	STEEL	0.17		1
27	CHARLOTTSVILLE	DOOMS (233)	230.00	230.00	STEEL POLE		22.46	1
28	WINCHESTER	WHEALTON (234)	230.00	230.00	STEEL	0.22		1
29	FARMVILLE	CLOVER (235)	230.00	230.00	STEEL	4.31		1
30		(235)	230.00	230.00	H.FRAME	47.51		
31		(235)	230.00	230.00	H.FRAME	3.64		
32	SOUTHWEST	PLAZA (236)	230.00	230.00	STEEL POLE	3.30		1
33		(236)	230.00	230.00	STEEL POLE	0.74		
34	POSSUM POINT	BRADDOCK (237)	230.00	230.00	STEEL		13.55	
35		(237)	230.00	230.00	STEEL		7.64	
36					TOTAL	5,308.05	860.32	425

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1		(237)	230.00	230.00	STEEL POLE	0.53		
2	CARSON	CLUBHOUSE (238)	230.00	230.00	STEEL	1.02		1
3		(238)	230.00	230.00	H.FRAME	27.53		
4	LAKEVIEW	HORNERTOWN (239)	230.00	230.00	WOOD	2.51		1
5		(239)	230.00	230.00	STEEL		1.73	
6	HOPEWELL	SURRY (240)	230.00	230.00	STEEL		42.97	1
7	JEFFERSON ST.	HAYFIELD (241)	230.00	230.00	STEEL	6.21		1
8	MIDLOTHIAN	TRABUE TAP PT (242)	230.00	230.00	STEEL		3.09	1
9	OX	VAN DORN (243)	230.00	230.00	STEEL	9.68		1
10		(243)	230.00	230.00	STEEL POLE	2.64		
11	BULL RUN	BURKE (244)	230.00	230.00	STEEL POLE	8.87		1
12	GREEN RUN	GREENWICH (245)	230.00	230.00	CON/STEEL	3.99	1.12	1
13	SUFFOLK	EARLEYS (246)	230.00	230.00	H.FRAME	41.29		1
14		(246)	230.00	230.00	STEEL	3.10		
15		NUCOR (246)	230.00	230.00	STEEL POLE	5.38		
16	SUFFOLK	WINFALL (247)	230.00	230.00	H.FRAME	35.28		1
17	GLEBE	OX (248)	230.00	230.00	STEEL POLE	4.93		1
18		(248)	230.00	230.00	STEEL POLE	1.37	8.12	
19		(248)	230.00	230.00	UG-HPOF	3.12		
20		(248)	230.00	230.00	STEEL POLE	0.74		
21	LOCKS	CARSON (249)	230.00	230.00	H.FRAME	7.07		1
22		(249)	230.00	230.00	STEEL		3.64	
23	ARLINGTON	GLEBE (250)	230.00	230.00	STEEL POLE		2.50	1
24	ARLINGTON	IDYLWOOD (251)	230.00	230.00	CONCRETE	0.05		1
25		(251)	230.00	230.00	STEEL POLE		7.70	
26	AQUIA HARBOR	POSSUM POINT (252)	230.00	230.00	STEEL	0.54	11.31	1
27	VALLEY	HARRISONBURG (253)	230.00	230.00	STEEL	10.62		1
28	CLUBHOUSE	LAKEVIEW (254)	230.00	230.00	H. FRAME	18.00		1
29	SOUTH ANNA PWR STA	NORTH ANNA (255)	230.00	230.00	H. FRAME	26.96		1
30		(255)	230.00	230.00	STEEL	3.13		
31		(255)	230.00	230.00	H. FRAME	0.63		
32	FOUR RIVERS	LADYSMITH CT (256)	230.00	230.00	H. FRAME	27.27		1
33	CHURCHLAND	SEWELLS POINT (257)	230.00	230.00	STEEL POLE	5.22		1
34		(257)	230.00	230.00	SUBMARINE	1.59		
35	ARLINGTON	GLEBE (258)	230.00	230.00	STEEL POLE	2.49		1
36					TOTAL	5,308.05	860.32	425

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	BASIN	CHESTERFIELD (259)	230.00	230.00	WOOD POLE	0.17		1
2		(259)	230.00	230.00	STEEL	3.85	3.83	
3		(259)	230.00	230.00	STEEL POLE	4.55		
4	GROTTOES	HARRISONBURG (260)	230.00	230.00	H. FRAME	10.63		1
5	NEWPORT NEWS	SHELLBANK (261)	230.00	230.00	STEEL POLE	4.86		1
6	YADKIN	GREENWICH (262)	230.00	230.00	STEEL	10.62		1
7		(262)	230.00	230.00	H. FRAME	0.10		
8		(262)	230.00	230.00	STEEL	2.83		
9	CHUCKATUK	NEWPORT NEWS (263)	230.00	230.00	WOOD POLE	0.22		1
10		(263)	230.00	230.00	STEEL	0.09	15.24	
11	HUNTER	RESTON (264)	230.00	230.00	STEEL	2.67		1
12	CLIFTON	SULLY (265)	230.00	230.00	STEEL		2.68	1
13		(265)	230.00	230.00	STEEL		4.87	
14		(265)	230.00	230.00	STEEL POLE		5.25	
15		(265)	230.00	230.00	STEEL POLE		1.16	
16	CLIFTON	GLEN CARLYN (266)	230.00	230.00	STEEL	7.01		1
17		(266)	230.00	230.00	STEEL POLE	5.15		
18		(266)	230.00	230.00	STEEL POLE	12.44		
19	CHURCHLAND	YADKIN (267)	230.00	230.00	STEEL	9.01	2.29	1
20		(267)	230.00	230.00	STEEL POLE		0.11	
21	COGENTRIX	HOPEWELL (268)	230.00	230.00	STEEL	1.00		1
22	SHAWBORO	FENTRESS (269)	230.00	230.00	STEEL	4.33		1
23		(269)	230.00	230.00	H. FRAME	21.00		
24	BURKE	RAVENSWORTH (270)	230.00	230.00	STEEL	2.98		1
25		(270)	230.00	230.00	U.G.=HPOF	2.18		
26	FENTRESS	LANDSTOWN (271)	230.00	230.00	STEEL	8.80		1
27		(271)	230.00	230.00	CONCRETE	0.17		
28	DOOMS	GROTTOES (272)	230.00	230.00	STEEL	11.53		1
29	GLEN CARLYN	ARLINGTON (273)	230.00	230.00	STEEL		2.44	1
30	BEAUMEADE	PLEASANT VIEW (274)	230.00	230.00	STEEL		0.16	1
31		(274)	230.00	230.00	STEEL POLE		0.18	
32		(274)	230.00	230.00	STEEL		5.06	
33	GLEBE	CRYSTAL (275)	230.00	230.00	U.G.=HPOF	1.23		1
34	GLEBE	CRYSTAL (276)	230.00	230.00	U.G.=HPOF	1.20		1
35	GLEN CARLYN	CLARENDON (277)	230.00	230.00	U.G.=HPOF	1.95		1
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	GLEN CARLYN	CLARENDON (278)	230.00	230.00	U.G.=HPOF	1.95		1
2	FENTRESS	REEVES AVENUE (279)	230.00	230.00	STEEL POLE	12.36		1
3	MARSH RUN CT	REMINGTON (280)	230.00	230.00	STEEL		1.24	1
4	BRADDOCK	RAVENSWORTH (281)	230.00	230.00	STEEL		2.06	1
5	SPRUANCE	MIDLOTHIAN (282)	230.00	230.00	STEEL	18.47		1
6		(282)	230.00	230.00	STEEL POLE		3.12	
7	ELMONT	NORTHEAST (283)	230.00	230.00	STEEL	5.22		1
8		(283)	230.00	230.00	H. FRAME	7.97		
9	BASIN	NORTHEAST (284)	230.00	230.00	STEEL	6.27		1
10		(284)	230.00	230.00	H. FRAME	2.26		
11	WALLER	YORKTOWN (285)	230.00	230.00	STEEL POLE	13.53		
12		(285)	230.00	230.00	STEEL	6.43		
13	DARBYTOWN	WHITE OAK (286)	230.00	230.00	STEEL	10.43		1
14		(286)	230.00	230.00	STEEL POLE	3.51		
15	CHESTERFIELD	CHICKAHOMINY (287)	230.00	230.00	H. FRAME		13.95	1
16		(287)	230.00	230.00	STEEL		0.63	
17	PENINSULA	YORKTOWN (288)	230.00	230.00	WOOD POLE		3.21	1
18		(288)	230.00	230.00	STEEL		8.00	
19	SUFFOLK	CHUCKATUCK (289)	230.00	230.00	H. FRAME	0.13		1
20		(289)	230.00	230.00	STEEL	9.85	4.31	
21		(289)	230.00	230.00	3-POLE	0.33		
22	SURRY	CHUCKATUCK (290)	230.00	230.00	STEEL		23.57	1
23		(290)	230.00	230.00	CONCRETE		0.11	
24	DOOMS	CHARLOTTSVILLE (291)	230.00	230.00	STEEL POLE		22.52	1
25	WHEALTON	YORKTOWN (292)	230.00	230.00	STEEL	10.55		1
26		(292)	230.00	230.00	H. FRAME	3.80		
27	VALLEY	DOOMS (293)	230.00	230.00	H. FRAME	17.73		1
28		(293)	230.00	230.00	STEEL		14.87	
29		(293)	230.00	230.00	STEEL POLE		1.37	
30	ANNANDALE	BRADDOCK (294)	230.00	230.00	U.G.=HPOF	3.58		1
31	LOUDOUN	BULL RUN (295)	230.00	230.00	STEEL		8.61	1
32	HALIFAX	PERSON-CP&L (296)	230.00	230.00	H. FRAME	20.41		1
33	ANNANDALE	BRADDOCK (297)	230.00	230.00	U.G.=HPOF	3.56		1
34	BREMO	FARMVILLE (298)	230.00	230.00	H. FRAME	15.48		1
35		(298)	230.00	230.00	H.FRAME	12.79		
36					TOTAL	5,308.05	860.32	425

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	REMINGTON CT	MARSH RUN CT (299)	230.00	230.00	STEEL	1.15		1
2		(299)	230.00	230.00	STEEL POLE	0.56		
3	OCCOQUAN	POSSUM POINT (2001)	230.00	230.00	WOOD POLE	0.17		1
4		(2001)	230.00	230.00	STEEL		4.44	
5		(2001)	230.00	230.00	STEEL		8.00	
6	CARSON	POE (2002)	230.00	230.00	WD 3 POLE	0.18		1
7		(2002)	230.00	230.00	STEEL	1.16	4.57	
8		(2002)	230.00	230.00	H.FRAME	6.78		
9	CHESTERFIELD	POE (2003)	230.00	230.00	WOOD POLE	0.24		1
10		(2003)	230.00	230.00	STEEL	7.00		
11		(2003)	230.00	230.00	STEEL		3.13	
12		(2003)	230.00	230.00	STEEL		9.02	
13	PENINSULA	SHELLBANK (2004)	230.00	230.00	STEEL	0.37		1
14		(2004)	230.00	230.00	STEEL POLE	5.92		
15	CLARK	HUNTER (2005)	230.00	230.00	STEEL	2.57		1
16	CHURCHLAND	LAKE KINGMAN (2006)	230.00	230.00	CON/STEEL	1.47		1
17	THALIA	LYNNHAVEN (2007)	230.00	230.00	CON/STEEL	3.37		1
18	LOUDOUN	DULLES (2008)	230.00	230.00	STEEL	4.53		1
19		(2008)	230.00	230.00	STEEL POLE	5.25		
20		(2008)	230.00	230.00	STEEL POLE		3.26	
21		(2008)	230.00	230.00	STEEL POLE	0.21		
22	MIDLOTHIAN	SHORT PUMP (2009)	230.00	230.00	H. FRAME	24.84		1
23	RESTON	TYSONS (2010)	230.00	230.00	STEEL POLE	0.42		1
24		(2010)	230.00	230.00	CONCRETE	4.63		
25		(2010)	230.00	230.00	WOOD POLE	2.78		
26	CLIFTON	CANNON BRANCH (2011)	230.00	230.00	STEEL POLE	7.46		1
27	ROANOLE VALLEY NUG	EARLEYS (2012)	230.00	230.00	STEEL	3.50		1
28		(2012)	230.00	230.00	H. FRAME		26.56	
29		(2012)	230.00	230.00	H. FRAME		2.09	
30		(2012)	230.00	230.00	H. FRAME		5.68	
31	OCCOQUAN	OX (2013)	230.00	230.00	STEEL POLE		1.45	1
32	EARLEYS	EVERETTS (2014)	230.00	230.00	H. FRAME	32.36	0.26	1
33	RESTON	DULLES (2015)	230.00	230.00	STEEL	1.42		1
34		(2015)	230.00	230.00	STEEL	3.64		
35		(2015)	230.00	230.00	CONC	0.14		
36					TOTAL	5,308.05	860.32	425

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	LANEXA	HARMONY VILLAGE (2016)	230.00	230.00	STEEL	5.19		1
2		(2016)	230.00	230.00	H. FRAME	25.84		
3	HARRISONBURG	ENDLESS CAVERNS (2017)	230.00	230.00	CONC	19.76		1
4	GREENWICH	E. RIVER NUG (2018)	230.00	230.00	STEEL		11.13	1
5	THALIA	GREENWICH (2019)	230.00	230.00	STEEL POLE	2.63		1
6	ELIZABETH CITY	WINFALL (2020)	230.00	230.00	H. FRAME	15.28		1
7	ELIZABETH CITY	SHAWBORO (2021)	230.00	230.00	H. FRAME	10.26		1
8	RAVENSWORTH	POSSUM POINT (2022)	230.00	230.00	STEEL	13.63		1
9		(2022)	230.00	230.00	STEEL POLE		0.53	
10		(2022)	230.00	230.00	STEEL POLE	5.65		
11	GLEBE	JEFFERSON STREET (2023)	230.00	230.00	STEEL POLE		0.83	1
12		(2023)	230.00	230.00	UG-HPOF		3.10	
13	CHICKAHOMINY	LANEXA (2024)	230.00	230.00	STEEL	14.26		1
14	GREEN RUN	LYNNHAVEN (2025)	230.00	230.00	STEEL	5.28		1
15		(2025)	230.00	230.00	CONCRETE	1.85		
16	LANDSTOWN	LYNNHAVEN (2026)	230.00	230.00	STEEL		5.94	1
17	MIDLOTHIAN	BREMO (2027)	230.00	230.00	WOOD/ST	29.28	5.98	1
18	CHARLOTTSVILLE	BREMO (2028)	230.00	230.00	STEEL	25.53		1
19	CIA	SWINKS MILL (2029)	230.00	230.00	STEEL POLE	3.78		1
20	LOUDOUN	GAINSVILLE (2030)	230.00	230.00	H. FRAME	0.19		1
21		(2030)	230.00	230.00	STEEL		7.56	
22	FOUR RIVERS	ELMONT (2032)	230.00	230.00	H. FRAME	8.93		1
23	CLARK	STERLING PARK (2033)	230.00	230.00	STEEL	2.47		1
24		(2033)	230.00	230.00	STEEL	2.63		
25		(2033)	230.00	230.00	STEEL POLE	1.59		
26		(2033)	230.00	230.00	STEEL	3.75		
27	EARLEYS	TROWBRIDGE (2034)	230.00	230.00	H. FRAME	28.50		1
28		(2034)	230.00	230.00	STEEL	6.72		
29	IDYLWOOD	CIA (2035)	230.00	230.00	CONCRETE	6.41		1
30	GLEBE	PENTAGON (2036)	230.00	230.00	U.G. HPFF	2.37		1
31	GLEBE	PENTAGON (2037)	230.00	230.00	U.G. HPFF	2.37		1
32	GREENWICH	REEVES AVENUE (2038)	230.00	230.00	STEEL POLE	1.83	3.92	1
33	MORRISVILLE	MARSH RUN CT (2039)	230.00	230.00	STEEL	3.92		1
34	MORRISVILLE	MARSH RUN CT (2040)	230.00	230.00	STEEL		3.92	1
35	HOPEWELL	HCF NUG (2041)	230.00	230.00	H.FRAME	0.03		1
36					TOTAL	5,308.05	860.32	425

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	OCCOQUAN	OGDEN MARTIN (2042)	230.00	230.00	WOOD/ST	2.95	0.36	1
2	DISCOVERY	RESTON (2043)	230.00	230.00	STEEL POLE	1.82		1
3		(2043)	230.00	230.00	STEEL		3.62	
4		(2043)	230.00	230.00	STEEL		1.46	
5	BEAR ISLAND	FOUR RIVERS (2044)	230.00	230.00	WOOD POLE	0.05		1
6	LOUDOUN	BRAMBLETON (2045)	230.00	230.00	ST TOWER	5.08		1
7	HOPEWELL	POLYESTER PWR STA	230.00	230.00	STEEL POLE	0.72		1
8	SURRY	GRAVEL NECK (2047)	230.00	230.00	CONCRETE	0.31		1
9	SURRY	GRAVEL NECK (2048)	230.00	230.00	CONCRETE	0.44		1
10	CHESTERFIELD	ALLIED (2049)	230.00	230.00	STEEL	2.89		1
11		(2049)	230.00	230.00	STEEL POLE	1.67		
12		(2049)	230.00	230.00	H. FRAME	5.35		
13	ALLIED	CHICKAHOMINY (2050)	230.00	230.00	STEEL	5.98		1
14		(2050)	230.00	230.00	H. FRAME	6.58		
15		(2050)	230.00	230.00	STEEL POLE	2.47		
16	CLIFTON	PENDER (2051)	230.00	230.00	STEEL POLE		6.78	1
17		(2051)	230.00	230.00	STEEL	2.88		
18	LEXINGTON	CLIFTON FORGE (2052)	230.00	230.00	STEEL	33.42		1
19	NORTHEAST	DARBYTOWN (2053)	230.00	230.00	STEEL POLE	3.67		1
20	CHARLOTTESVILLE	GORDONSVILLE (2054)	230.00	230.00	H. FRAME	8.41		1
21		(2054)	230.00	230.00	WOOD POLE	15.92		
22	BASIN	BELLEMEADE (2055)	230.00	230.00	STEEL	0.52	0.04	1
23	HORNERTOWN	ROCKY MT. CP&L (2056)	230.00	230.00	H. FRAME	26.47		1
24		(2056)	230.00	230.00	STEEL	2.68		
25		(2056)	230.00	230.00	STEEL		4.16	
26	HORNERTOWN	ROSEMARY (2057)	230.00	230.00	STEEL POLE	0.51		1
27	EDGECOMB	ROCKY MT. CP&L (2058)	230.00	230.00	STEEL	4.81		1
28	CAROLINA	ROCKY VALLEY NUG (2060)	230.00	230.00	STEEL	2.00		1
29		(2060)	230.00	230.00	H. FRAME	2.10		
30	FOUR RIVERS	FOUR RIVERS NUG (2061)	230.00	230.00	STEEL POLE	0.17		1
31	RESTON	DRANESVILLE (2062)	230.00	230.00	STEEL POLE	1.56		1
32		(2062)	230.00	230.00	CONCRETE	1.41		
33	CLIFTON	RAVENSWORTH (2063)	230.00	230.00	STEEL	7.13		1
34	SHAWBORO	KITTY HAWK (2064)	230.00	230.00	ST. H-FRAME	30.08		1
35		(2064)	230.00	230.00	CONC. POLE	2.87		
36					TOTAL	5,308.05	860.32	425

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1		(2064)	230.00	230.00	WOOD POLE	3.96		
2	BASIN	SPRUANCE (2065)	230.00	230.00	STEEL POLE	3.19	0.47	1
3	MIDLOTHIAN	WINTERPOCK (2066)	230.00	230.00	STEEL POLE	2.83	2.74	1
4		(2066)	230.00	230.00	STEEL	2.91		
5		(2066)	230.00	230.00	STEEL		7.72	
6		(2066)	230.00	230.00	STEEL		1.44	
7	FOUR RIVERS	FOUR RIVERS NUG (2067)	230.00	230.00	WOOD POLE	0.06		1
8	CLOVER	HALIFAX (2068)	230.00	230.00	H. FRAME	3.65		1
9		(2068)	230.00	230.00	H. FRAME	12.93		
10		(2068)	230.00	230.00	CON. H.	0.21		
11	YADKIN	ELIZABETH RIVER (2070)	230.00	230.00	STEEL POLE	2.56	0.72	1
12	ELIZABETH RIVER	E. RIVER PWR STA (2071)	230.00	230.00	STEEL POLE	0.08		1
13	LYNNHAVEN	VIRGINIA BEACH (2072)	230.00	230.00	CONCRETE	4.43		1
14	SHAWBORO	KITTY HAWK (2073)	230.00	230.00	ST. H-FRAME		30.08	1
15		(2073)	230.00	230.00	CONC. POLE		2.87	
16		(2073)	230.00	230.00	WOOD POLE	3.92		
17		AYDLETT	230.00	230.00	WD H-FRAME	1.63		
18	GORDONSVILLE	SOUTH ANNA (2074)	230.00	230.00	H. FRAME	0.63		1
19		(2074)	230.00	230.00	H. FRAME	0.19		
20		(2074)	230.00	230.00	STEEL POLE	0.21		
21	ELMONT	OLD CHURCH (2075)	230.00	230.00		15.91		1
22	BIRCHWOOD	NORTHERN NECK (2076)	230.00	230.00	H. FRAME	41.17		1
23		(2076)	230.00	230.00	H. FRAME	3.05		
24	REMINGTON	REMINGTON CT (2077)	230.00	230.00	ST. POLE	0.54		1
25	POSSUM POINT 500	POSSUM POINT 230 (2078)	230.00	230.00	H.FRAME	0.81		1
26	BEAUMEADE	DRANESVILLE (2079)	230.00	230.00	STEEL POLE	1.51	0.70	1
27		(2079)	230.00	230.00	STEEL	2.12		
28		(2079)	230.00	230.00	CONC POLE	0.04		
29		(2079)	230.00	230.00	STEEL		3.67	
30		(2079)	230.00	230.00	STEEL POLE		1.70	
31	BEAUMEADE	STERLING PARK (2081)	230.00	230.00	STEEL	0.72		1
32		(2081)	230.00	230.00	STEEL		2.24	
33		(2081)	230.00	230.00	CONC POLE		0.03	
34	SEWELLS POINT	NAVY NORTH (2082)	230.00	230.00	U.G. HPFF	2.02		1
35	BIRCHWOOD	FREDERCKSBURG (2083)	230.00	230.00	H. FRAME	12.18		1
36					TOTAL	5,308.05	860.32	425

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1		(2083)	230.00	230.00	H. FRAME		3.05	
2	LEXINGTON	LOWMOOR (2084)	230.00	230.00	STEEL	37.37		1
3	LANDSTOWN	WEST LANDING (2085)	230.00	230.00	STEEL POLE	7.90		1
4	REMINGTON CT	WARRENTON (2086)	230.00	230.00	CONC. POLE	11.20		1
5		(2086)	230.00	230.00	STEEL POLE		0.61	
6	FENTRESS	SHAWBORO (2087)	230.00	230.00	STEEL		4.33	1
7		(2087)	230.00	230.00	STEEL POLE	21.04		
8	GORDONSVILLE	LOUISA CT (2088)	230.00	230.00	H. FRAME	0.58		1
9		(2088)	230.00	230.00	STEEL POLE		0.21	
10	LADYSMITH	LADYSMITH CT (2089)	230.00	230.00	STEEL	3.94		1
11	LADYSMITH CT	FREDERICKSBURG (2090)	230.00	230.00	STEEL		5.20	1
12		(2090)	230.00	230.00	H. FRAME	12.09		
13	WHITE OAK	CHICKAHOMINY (2091)	230.00	230.00	STEEL	3.62		1
14		(2091)	230.00	230.00	STEEL POLE	3.51		
15	SEWELLS POINT	NAVY NORTH (2093)	230.00	230.00	U.G. HPFF	2.01		1
16	BRAMBLETON	LOUDOUN (2094)	230.00	230.00	ST TOWER		5.09	1
17	BEAUMEADE	GREENWAY (2095)	230.00	230.00	STEEL		0.57	1
18		(2095)	230.00	230.00	STEEL POLE	10.48		
19	CLARENDON	BALLSTON (2096)	230.00	230.00	U.G. XLPE	0.42		1
20	OX	IDYLWOOD (2097)	230.00	230.00	STEEL	7.83		1
21		(2097)	230.00	230.00	STEEL	4.47		
22		(2097)	230.00	230.00	STEEL	0.15		
23	PLEASANT VIEW	HAMILTON (2098)	230.00	230.00	STEEL POLE	9.94		1
24		(2098)	230.00	230.00	U.G. XLPE	2.16		
25	CHURCHLAND	SEWELLS POINT (2099)	230.00	230.00	STEEL POLE		5.25	1
26		(2099)	230.00	230.00	SUBMARINE	1.58		
27	GAINESVILLE	BRISTERS (2101)	230.00	230.00	STEEL		14.48	1
28		(2101)	230.00	230.00	STEEL		1.90	
29	CHICKAHOMINY	WALLER (2102)	230.00	230.00	H. FRAME	14.12		1
30		(2102)	230.00	230.00	STEEL POLE	3.83		
31		(2102)	230.00	230.00	STEEL	10.74		
32	SHORT PUMP	ELMONT (2103)	230.00	230.00	H. FRAME	9.66		1
33	FREDERICKSBURG	AQUIA HARBOR (2104)	230.00	230.00	H. FRAME	12.63		1
34		(2104)	230.00	230.00	STEEL POLE	0.78		
35		(2104)	230.00	230.00	WOOD	0.02		
36					TOTAL	5,308.05	860.32	425

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	BREMO	BEAR GARDEN (2106)	230.00	230.00	STEEL POLE	1.39		1
2	SULLY	DISCOVERY (2107)	230.00	230.00	STEEL POLE	1.16		1
3		(2107)	230.00	230.00	STEEL POLE	1.64		
4	SWINKS MILL	TYSONS (2108)	230.00	230.00	STEEL POLE	2.80		1
5	HARRISONBURG	VALLEY (2109)	230.00	230.00	STEEL		10.23	1
6		(2109)	230.00	230.00	STEEL POLE	0.26	0.09	
7	BREMO	BEAR GARDEN (2111)	230.00	230.00	STEEL POLE		1.34	1
8	LANEXA	WALLER (2113)	230.00	230.00	WOOD	14.48		1
9	BEAUMEADE	NIVO (2116)	230.00	230.00	U.G. XLPE	0.68		1
10	AQUIA HARBOR	GARRISONVILLE (2120)	230.00	230.00	U.G. XLPE	5.80		1
11	BEAUMEADE	NIVO (2130)	230.00	230.00	U.G. XLPE	0.72		1
12								
13	SUBTOTAL - 230		230.00	230.00		1,954.11	621.91	203
14								
15	BREMO	SCOTTSVILLE APCO (8)	138.00	138.00	STEEL	7.30		1
16	FUDGE HOLLOW	APCO INTERCONNECT (14)	138.00	138.00	STEEL	14.94		1
17	EASTMILL	WESTVACO (109)	138.00	138.00	STEEL POLE		0.89	1
18	LOWMOOR	FUDGE HOLLOW (112)	138.00	138.00	STEEL	4.64	0.65	1
19		(112)	138.00	138.00	STEEL POLE	2.14		
20	CLIFTON FORGE	LOWMOOR (133)	138.00	138.00	STEEL	5.05		1
21	EDINBURG	STRASBURG PT. ED. (152)	138.00	135.00	WOOD POLE	16.54		1
22	WESTVACO	FUDGE HOLLOW (155)	138.00	138.00	STEEL POLE	0.57		1
23		(155)	138.00	138.00	WOOD POLE		1.35	
24	LOWMOOR	EASTMILL (161)	138.00	138.00	WOOD POLE	6.41		1
25		(161)	138.00	138.00	STEEL POLE		3.43	
26								
27	SUBTOTAL - 138KV		138.00			57.59	6.32	8
28								
29	*VARIOUS*	*VARIOUS*	*115.00*		*H. FRAME*			
30			115.00		WOOD POLES	2,047.94	230.89	161
31			115.00		STEEL			
32								
33	SUBTOTAL - 115KV		115.00			2,047.94	230.89	161
34								
35	VARIOUS	VARIOUS	69.00	69.00	H. FRAME	87.33		6
36					TOTAL	5,308.05	860.32	425

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1			69.00	69.00	WOOD POLES			
2			69.00	69.00	UG CABLE	19.24		10
3								
4	SUBTOTAL - 69KV		69.00	69.00		106.57		16
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	5,308.05	860.32	425

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
ACAR 2500								1
AAAC 2049.5								2
ACAR 2500								3
AAAC 2049.5								4
AAAC 2049.5								5
ACAR 2500								6
ACAR 2500								7
ACAR 2500								8
AAAC 2049.5								9
AAAC 2049.5								10
AAAC 2049.5								11
AAAC 2049.5								12
AAAC 2049.5								13
AAAC 2049.5								14
AAAC 2049.5								15
ACSR 1351.5								16
AAAC 2049.5								17
AAAC 2049.5								18
ACAR 2500								19
ACAR 1534								20
ACAR 2500								21
ACAR 2500								22
ACAR 2500								23
AAAC 2049.5								24
ACAR 2500								25
ACAR 2500								26
AAAC 2049.5								27
ACAR 2500								28
ACAR 2500								29
ACSR 1351								30
AAAC 2049.5								31
ACAR 2500								32
ACAR 2500								33
ACAR 1534								34
ACAR 2500								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
AAAC 2049.5								1
ACAR 2500								2
SDC 2500								3
ACAR 2500								4
ACAR 2500								5
ACAR 2500								6
ACAR 2500								7
	102,034,483	432,155,185	534,189,668	3,696,228	2,883,117	41,914	6,621,259	8
	102,034,483	432,155,185	534,189,668	3,696,228	2,883,117	41,914	6,621,259	9
								10
ACSR 1033.5								11
ACAR 2500								12
ACAR 2500								13
ACAR 1109								14
ACAR 1192.5								15
ALUM 1177								16
ACAR 1033.5								17
ACAR 1109								18
ACAR 1109								19
ACSR 1033.5								20
ACSR 2500								21
ACSR 1033.5								22
ACAR 1109								23
ACSR1033.5								24
ACAR 721								25
ACAR 1109								26
ACAR 1109								27
ACAR 2500								28
ACAR 721								29
ACSR 1033.5								30
ACAR 1534								31
ACAR 721								32
ACAR 721								33
ACAR 2500								34
ACSR 636								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
ACAR 2500								1
ACAR 795								2
ACAR 795								3
ACAR 1109								4
ACAR 1109								5
ACAR 721								6
ACAR 721								7
ACSR 1033.5								8
ACAR 1109								9
ACAR 721								10
ACSR 1033.5								11
ACAR 721								12
ACAR 1109								13
ACSR 1033.5								14
ACAR 721								15
ACAR 2500								16
SSAC 1192.5								17
ACSR 1590								18
ACSR 1033.5								19
ACAR 1109								20
ACAR 1534								21
ACSR 1033.5								22
ACSR 1033.5								23
AAAC 1177								24
ACSR 1033.5								25
ACSR 795								26
ACAR 545.6								27
ACAR 1534								28
ACSR 545.6								29
ACSR 545.6								30
ACSR 636								31
ACAR 2500								32
ACAR 721								33
ACSR 1033.5								34
SSAC 1033.5								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
ACAR 721								1
ACAR 721								2
ACAR 721								3
ACSR 1033.5								4
ACSR 1033.5								5
ACAR 721								6
ACAR 1033.5								7
ACAR 721								8
ACSR 1033.5								9
ACAR 1109								10
ACAR 1534								11
SSAC 1590								12
ACAR 545								13
ACAR 545								14
ACSR 636								15
ACAR 1109								16
ACAR 2500								17
ACAR 2500								18
CU 2500								19
ACSR 636								20
ACSR 795								21
ACSR 795								22
ACAR 2500								23
AAAC 1600								24
AAAC 1600								25
ACAR 721								26
ACAR 721								27
ACSR 795								28
ACAR 545.6								29
ACAR 545.6								30
ACAR 1534								31
ACSR 795								32
ACAR 721								33
COPPER 1250								34
ACAR 2500								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

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TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
ACAR 2500								1
ACSR 1033								2
ACAR 2500								3
ACAR 1109								4
ACAR 1109								5
ACSR 1033								6
ACSR 1033								7
ACAR 721								8
ACAR 1534								9
ACAR 1534								10
ACSR 1192								11
ACSR 1033.5								12
ACSR 1033.5								13
ACSR 1590								14
ACAR 1534								15
ACSR 1033.5								16
AAAC 1600								17
ACAR 2500								18
ACAR 721								19
ACAR 2500								20
ACAR 1109								21
ACAR 545								22
ACAR 545								23
ACAR 1534								24
COPPER 1750								25
ACAR 721								26
ACAR 2500								27
ACAR 721								28
ACAR 1600								29
SSAC 1192.5								30
ACSR 1590								31
ACSR 1192.50								32
COPPER 1750								33
COPPER 1750								34
COPPER 1750								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

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10. *Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.*

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
COPPER 1750								1
ACAR 721								2
ACSS 795								3
ACAR 2500								4
ACAR 721								5
ACAR 2500								6
ACAR 721								7
ACAR 721								8
ACAR 721								9
ACAR 721								10
ACAR 721								11
ACAR 721								12
ACAR 721								13
								14
ACSR 1033.5								15
ACSR 1033.5								16
ACAR 721								17
ACAR 721								18
ACAR 2500								19
ACAR 721								20
ACAR 721								21
ACAR 721								22
ACAR 721								23
ACAR 545.6								24
ACSR 1033.5								25
ACAR 721								26
ACAR 545.6								27
ACAR 545.60								28
ACAR 545.6								29
COPPER 250								30
ACSR 1033								31
ACAR 545.6								32
COPPER 250								33
ACAR 545.6								34
ACAR 545.6								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
ACAR 545.6								1
ACSR 636								2
ACAR 2500								3
ACAR 721								4
ACSR 636								5
ACAR 721								6
ACAR 721								7
ACAR 721								8
ACAR 2500								9
ACAR 721								10
ACAR 1109								11
ACSR 1033.5								12
ACAR 721								13
ACAR 721								14
ACSR 1192.5								15
ACAR 1534								16
ACAR 2500								17
SSAC 1033.5								18
ACSR 1590								19
ACSR 1590								20
ACSR 1590								21
ACSR 636								22
SSAC 1033.5								23
SSAC 1033.5								24
SSAC 1033.5								25
ACSR 1590								26
ACAR 545.6								27
ACAR 545.6								28
ACAR 1534								29
AAC 1590								30
ACAR 2500								31
ACAR 545.6								32
SSAC 1192.5								33
SSAC 1033.5								34
SSAC 1033.5								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
SSAC 1033.5								1
SSAC 1033.5								2
								3
ACAR 1534								4
SSAC 1590								5
ACAR 1109								6
ACAR 545.6								7
ACSR 1033.5								8
ACAR 721								9
ACAR 2500								10
ACAR 2500								11
CU 2500								12
ACAR 721								13
ACAR 721								14
ACAR 2500								15
ACAR 721								16
SSAC 1033.5								17
ACAR 721								18
ACSS 1033.5								19
ACAR 1109								20
ACSR 636								21
ACSR 795								22
SSAC 1033.5								23
SSAC 1033.5								24
SSAC 1033.5								25
SSAC 1192.5								26
ACAR 545								27
ACAR 545								28
SSAC 1033.5								29
COPPER 1750								30
COPPER 1750								31
ACAR 2500								32
ACAR 545.6								33
SSAC 795								34
ACAR 1534								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
ACAR 1534								1
ACSR 1590								2
SSAC 1033.5								3
SSAC 1192.5								4
ACSR 795								5
ACCR 1033-T13								6
ACAR 1534								7
ACSR 1033.5								8
ACSR 1033.5								9
ACSR 636								10
ACSR 636								11
ACSR 636								12
ACSR 636								13
ACSR 636								14
ACSR 636								15
ACAR 2500								16
ACSR 1033.5								17
ACSR 1033								18
ACAR 721								19
ACAR 254.6								20
ACSR 477								21
ACAR 1534								22
ACSR 1033.5								23
ACSR 1033.5								24
ACAR 1109								25
ACAR 1534								26
ACAR 1109								27
ACAR 545.6								28
ACAR 1534								29
ACSR 1590								30
SSAC 1192.5								31
SSAC 1033.5								32
ACSR 1272								33
ACAR 545.6								34
ACSR/SD 795								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

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ACAR 721								1
ACAR 2500								2
ACSR 636								3
ACSR 636								4
ACSR 636								5
ACAR 721								6
ACSR 1590								7
ACSR 636								8
ACSR 477								9
ACSR 545.6								10
ACSR 1534								11
ACSR 1590								12
ACAR 2500								13
ACAR 545.6								14
ACSR/SD 795								15
ACSR 1033.5								16
ACSR 477								17
ACSR 1590								18
ACSR 477								19
ACSR 477								20
								21
ACAR 545.6								22
ACAR 1534								23
ACSR 636								24
ACSR 636								25
ACSR 2-636								26
ACSR 1192.5								27
SSAC 1033.5								28
SSAC 1192.5								29
SSAC 1192.5								30
ACSR 1192.5								31
SSAC 1192.5								32
SSAC 1033.5								33
CU 2500								34
ACAR 545.6								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

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TRANSMISSION LINE STATISTICS (Continued)

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ACAR 1534								1
ACSR 477								2
ACSR 636								3
ACAR 1109								4
ACAR 1109								5
ACAR 545.6								6
ACSR 636								7
ACSR 477								8
ACSR 477								9
ACSR 636								10
ACSR 795								11
ACSR 795								12
ACAR 721								13
ACSR 636								14
CU 2500								15
ACSS/TW 1233.6								16
ACSR 636								17
ACSR 636								18
CU 1500								19
ACSS 1033.5								20
ACSR 795								21
ACSR 636								22
ACSR 636								23
CU 3500								24
ACAR 721								25
COPPER 1250								26
ACSR 636								27
ACSR 636								28
ACSR 1033.5								29
ACAR 721								30
ACAR 721								31
ACAR 1109								32
ACAR 721								33
ACAR 721								34
ACAR 1109								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

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TRANSMISSION LINE STATISTICS (Continued)

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ACSR 636								1
ACAR 1534								2
ACSR 1590								3
ACSS 1033.5								4
ACAR 721								5
ACSR 636								6
ACSR 636								7
ACSR 1033.5								8
CU 3500								9
CU 3500								10
CU 3500								11
	113,470,232	617,464,784	730,935,016	8,330,030	6,497,556	94,460	14,922,046	12
	113,470,232	617,464,784	730,935,016	8,330,030	6,497,556	94,460	14,922,046	13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
	10,302,340	27,559,211	37,861,551	206,665	161,202	2,343	370,210	26
	10,302,340	27,559,211	37,861,551	206,665	161,202	2,343	370,210	27
								28
VARIOUS								29
								30
								31
	77,205,893	300,184,260	377,390,153	7,369,012	5,747,946	83,563	13,200,521	32
	77,205,893	300,184,260	377,390,153	7,369,012	5,747,946	83,563	13,200,521	33
								34
								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

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TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
								2
	1,030,080	8,508,754	9,538,834	344,613	268,804	3,908	617,325	3
	1,030,080	8,508,754	9,538,834	344,613	268,804	3,908	617,325	4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
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								33
								34
								35
	304,043,028	1,385,872,194	1,689,915,222	19,946,548	15,558,625	226,188	35,731,361	36

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TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	KITTY HAWK	COLINGTON (52)	7.40	SC POLE	12.00	1	1
2	CLARENDON	ROSSLYN (122)	2.64	U.G. XLPE		1	1
3	BALLSTON	ROSSLYN (143)	2.33	U.G. XLPE		1	1
4	TAP POINT	EPG (215)	0.48	DC POLE	8.00	2	2
5	LADYSMITH CT	tap point (256) (2090)	5.20	STEEL TOWER	7.00	2	2
6	GREENWAY	BRAMBLETON (2095)	7.90	DC POLE	10.00	1	1
7	PLEASANT VIEW	HAMILTON (2098)	9.94	SC POLE	8.00	1	1
8	DRY MILL	BREEZY KNOLL (2098)	2.16	U.G. XLPE		1	2
9	BREMO	BEAR GARDEN (2106) (2111)	1.39	DC POLE	7.00	2	2
10	HARRISONBURG	VALLEY (2109)	7.93	STEEL TOWER	6.00	2	2
11	BEAUMEADE	NIVO (2116)	0.68	U.G. XLPE		1	1
12	AQUIA HARBOR	GARRISONVILLE (2120)	5.80	U.G. XLPE		1	1
13	BEAUMEADE	NIVO (2130)	0.72	U.G. XLPE		1	1
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
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41							
42							
43							
44	TOTAL		54.57		58.00	17	18

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TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1177	AAAC	Vert 10'	115		7,078,297	947,561		8,025,858	1
2500	CU	Segmental	69		275,202	16,917,013	103,401	17,295,616	2
2500	CU	Segmental	69		311,499	16,880,715	103,401	17,295,615	3
636	ACSR	Vert 18.5'	230		2,003,344	439,172		2,442,516	4
795	ACSR	Vert 19.5'	230		5,085,642	3,863,409		8,949,051	5
636	ACSR	Vert 18.5'	230	32,993,653	19,389,131	2,981,043		55,363,827	6
636	ACSR	Vert 18.5'	230	5,476,081	29,357,987	3,647,416	15,098	38,496,582	7
3500	CU	Segmental	230	5,476,081	998,155	22,787,820	15,098	29,277,154	8
636	ACSR	Vert 18.5'	230	10,479	3,088,878	443,134		3,542,491	9
721	ACAR	Vert 19.5'	230		1,216,435	1,849,088	47,851	3,113,374	10
3500	CU	Segmental	230	191,635	46,874	2,498,878		2,737,387	11
3500	CU	Segmental	230	382,855	7,807,801	73,929,786	17,635	82,138,077	12
3500	CU	Segmental	230	191,635	46,874	2,498,978		2,737,487	13
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				44,722,419	76,706,119	149,684,013	302,484	271,415,035	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	ACCA	D	115.00	34.50	
2	ACCA	D	115.00	13.20	
3	AHOSKIE	D	115.00	34.50	
4	AIRLINE	D	34.50	4.16	
5	ALEXANDERS CORNER	D	34.50	13.20	
6	ALEXANDERS CORNER	D	115.00	13.20	
7	ALEXANDRIA PLANT	D	34.50	4.16	
8	ALLEGHANY	D	46.00	12.50	
9	ALTAVISTA	T	138.00	115.00	12.50
10	ALTAVISTA	T	138.00	69.00	12.50
11	ANNANDALE	D	34.50	12.50	
12	ANNANDALE	D	230.00	34.50	
13	AQUIA	D	230.00	34.50	
14	ARLINGTON	D	34.50	13.20	
15	ARLINGTON	D	230.00	34.50	
16	ARNOLDS CORNER	D	230.00	34.50	
17	ASHBURN	D	230.00	34.50	
18	ASHTON	D	13.20	4.16	
19	ATLANTIC	D	34.50	13.20	
20	AYDLETT	D	230.00	34.50	13.20
21	BAILEYS X-ROADS	D	34.50	12.50	
22	BAINS STORE	D	115.00	34.50	13.20
23	BALLSTON	T	230.00	69.00	
24	BALLSTON	D	230.00	34.50	
25	BANISTER	D	138.00	34.50	
26	BARRACKS ROAD	D	230.00	34.50	
27	BASIN	D	115.00	13.20	
28	BASIN	T	230.00	115.00	13.20
29	BASIN	D	230.00	34.50	
30	BATTLEBORO	D	115.00	34.50	2.40
31	BATTLEFIELD	D	34.50	13.20	
32	BAYSIDE	D	34.50	13.20	
33	BAYSIDE	D	115.00	34.50	13.20
34	BAYSIDE	D	115.00	13.20	
35	BEARSKIN	T	138.00	69.00	7.92
36	BEAUMEADE	D	230.00	34.50	
37	BECO	D	230.00	34.50	
38	BELLE HAVEN	D	34.50	12.50	
39	BELLWOOD	D	115.00	13.20	
40	BELT LINE	D	34.50	4.16	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BELVOIR	D	230.00	34.50	
2	BENNS CHURCH	D	34.50	12.50	
3	BERKLEY	D	115.00	11.00	
4	BETHEL CAROLINA	D	115.00	12.50	
5	BEVERLY HILLS	D	34.50	4.16	
6	BLOXOMS CORNER	D	115.00	23.00	
7	BOLLINGBROOK	D	34.50	4.16	
8	BOWERS HILL	D	230.00	34.50	
9	BOYKINS	D	115.00	34.50	
10	BRADDOCK	D	34.50	12.50	
11	BRADDOCK	D	230.00	34.50	
12	BREMO	D	115.00	34.50	13.20
13	BREMO	T	138.00	115.00	13.20
14	BREMO	T	230.00	115.00	13.20
15	BRIARFIELD	D	23.00	6.00	
16	BRISTERS	T	500.00	230.00	
17	BRISTERS	T	230.00	115.00	13.20
18	BRODNAX	D	115.00	12.50	
19	BRUNSWICK	T	115.00	69.00	13.20
20	BUCHANAN	D	46.00	12.50	
21	BUCKINGHAM	D	34.50	12.50	
22	BUCKINGHAM	D	230.00	34.50	
23	BUCKROE	D	23.00	6.00	
24	BUENA VISTA	D	115.00	12.50	
25	BULL RUN	T	230.00	115.00	13.20
26	BURKE	D	230.00	34.50	
27	BURTON	D	115.00	34.50	13.20
28	CALLAO	D	34.50	12.50	
29	CAMPOSTELLO	D	11.00	4.16	
30	CANNON BRANCH	D	115.00	34.50	
31	CANNON BRANCH	T	230.00	115.00	13.20
32	CAROLINA	D	115.00	13.20	
33	CAROLINA	T	230.00	115.00	13.20
34	CARROLL	D	34.50	13.20	
35	CARSON	T	500.00	230.00	34.50
36	CARSON	T	500.00	230.00	
37	CARTERSVILLE	D	115.00	34.50	
38	CARVER	D	115.00	34.50	
39	CARVER	D	115.00	13.20	
40	CASHIE	D	230.00	34.50	

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS

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2. *Substations which serve only one industrial or street railway customer should not be listed below.*
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CASH'S CORNER	T	230.00	115.00	
2	CENTRAL	D	115.00	12.50	
3	CENTRALIA	D	115.00	13.20	
4	CENTREVILLE	D	230.00	34.50	
5	CHANCELLOR	D	115.00	34.50	
6	CHANCELLOR	T	500.00	115.00	
7	CHARLES CITY RD	D	230.00	34.50	
8	CHARLOTTESVILLE	D	34.50	12.50	
9	CHARLOTTESVILLE	D	230.00	34.50	
10	CHASE CITY	T	115.00	69.00	13.20
11	CHASE CITY	D	115.00	12.50	
12	CHATHAM	D	69.00	12.50	
13	CHERRYDALE	D	34.50	12.50	
14	CHESTERBROOK	D	34.50	13.20	
15	CHESTERFIELD 230	T	230.00	115.00	13.20
16	CHICKAHOMINY	T	500.00	230.00	34.50
17	CHICKAHOMINY	D	230.00	13.20	
18	CHOWAN	D	115.00	34.50	
19	CHURCHLAND	D	115.00	13.20	
20	CHURCHLAND	T	230.00	115.00	13.20
21	CHURCHLAND	D	230.00	34.50	
22	CIA	D	230.00	34.50	
23	CITY HALL	D	34.50	11.00	
24	CLARENDON	D	230.00	34.50	
25	CLARENDON	T	230.00	69.00	
26	CLARK	D	230.00	34.50	
27	CLARKSVILLE	D	115.00	13.20	
28	CLARKSVILLE	D	69.00	13.20	2.40
29	CLIFTON	T	500.00	230.00	
30	CLIFTON FORGE	D	138.00	46.00	13.20
31	CLIFTON FORGE	D	138.00	12.50	
32	CLIFTON FORGE	T	230.00	138.00	13.20
33	CLOVER	T	500.00	230.00	
34	CLUBHOUSE	T	230.00	115.00	13.20
35	COLINGTON	D	115.00	34.50	
36	COLONIAL HEIGHTS	D	13.20	4.16	
37	COLONY	D	115.00	34.50	
38	COLONY	D	115.00	13.20	
39	COLUMBIA	D	34.50	12.50	
40	COLUMBIA FURNACE	D	34.50	23.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	COOKS CORNER	D	34.50	12.50	
2	COPELAND PARK	D	115.00	23.00	
3	CORRECTIONAL	D	230.00	34.50	
4	COTTAGE PARK	D	34.50	13.20	
5	COVINGTON	D	46.00	12.50	
6	COVINGTON	D	138.00	46.00	12.50
7	CRADOCK	D	115.00	34.50	
8	CRAIGSVILLE	D	115.00	23.00	
9	CRANES CORNER	D	230.00	34.50	
10	CRESWELL	D	34.50	12.50	
11	CRESWELL	D	115.00	34.50	
12	CREWE	D	115.00	12.50	
13	CRITTENDEN	D	230.00	34.50	
14	CROMWELL ROAD	D	34.50	4.16	
15	CROZET	D	230.00	34.50	
16	CRYSTAL	D	230.00	34.50	
17	CULPEPER	D	115.00	34.50	
18	CULPEPER REA	D	34.50	12.50	
19	CUSHAW	D	12.50	2.40	
20	DAVIS CORNER	D	115.00	34.50	13.20
21	DAVIS CORNER	D	115.00	13.20	
22	DAYTON	D	230.00	34.50	
23	DEEP CREEK	D	115.00	13.20	
24	DELTAVLLE	D	34.50	12.50	
25	DENBIGH	D	230.00	34.50	
26	DIAMOND SPRINGS	D	34.50	13.20	
27	DINWIDDIE	D	34.50	13.20	
28	DISPUTANTA	D	115.00	13.20	
29	DOMINION	D	115.00	34.50	
30	DOOMS 115	D	115.00	23.00	
31	DOOMS 500	T	230.00	115.00	13.20
32	DOOMS 500	T	500.00	230.00	
33	DOOMS 500	T	500.00	230.00	34.50
34	DOZIER	D	34.50	13.20	
35	DOZIER	D	115.00	13.20	
36	DRANESVILLE	D	230.00	34.50	
37	DRY RUN	D	46.00	12.50	
38	DRYBURG	D	115.00	12.50	
39	DULLES	D	230.00	34.50	
40	DUMFRIES	D	230.00	34.50	

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SUBSTATIONS

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1	DUNNSVILLE	D	230.00	34.50	
2	DUPONT	D	115.00	13.20	
3	DWYER	D	34.50	4.16	
4	EAGLE ROCK	D	46.00	12.50	
5	EARLEYS	D	115.00	34.50	
6	EARLEYS	T	230.00	115.00	13.20
7	EAST END	D	23.00	6.00	
8	EAST OCEAN VIEW	D	34.50	13.20	
9	EDENTON	D	115.00	12.50	
10	EDGEWATER	D	34.50	4.16	
11	EDINBURG	D	115.00	34.50	
12	EDINBURG	T	138.00	115.00	13.20
13	ELEVENTH STREET	D	34.50	4.16	
14	ELIZABETH CITY	D	230.00	34.50	
15	ELKO	D	230.00	34.50	
16	ELM	D	34.50	12.50	
17	ELMONT	T	230.00	115.00	13.20
18	ELMONT	D	230.00	34.50	
19	ELMONT	T	500.00	230.00	
20	ELMONT	T	500.00	230.00	34.50
21	EMPORIA	D	115.00	12.50	
22	ENDLESS CAVERNS	D	115.00	34.50	
23	ENDLESS CAVERNS	T	230.00	115.00	13.20
24	ENGLESIDE	D	34.50	12.50	
25	ENON	D	34.50	13.20	
26	ENON	D	230.00	34.50	
27	EVERETTS	T	230.00	115.00	13.20
28	EVERETTS	D	230.00	34.50	
29	FAIRFAX	D	34.50	12.50	
30	FAIRFIELD	D	115.00	23.00	
31	FALLS CHURCH	D	34.50	12.50	
32	FALLS CHURCH	D	230.00	34.50	
33	FARMVILLE	D	115.00	12.50	
34	FARMVILLE	T	230.00	115.00	13.20
35	FARMVILLE	D	230.00	34.50	
36	FENTRESS	D	230.00	34.50	13.20
37	FENTRESS	T	500.00	230.00	
38	FISHERSVILLE	D	115.00	23.00	
39	FLAGGY RUN	D	34.50	13.20	
40	FORT HUNT	D	34.50	12.50	

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1	FORT LEE	D	115.00	13.20	
2	FORT MYER	D	34.50	12.50	
3	FORT PICKETT	D	115.00	12.50	
4	FOX HALL	D	34.50	4.16	
5	FRANCONIA	D	230.00	34.50	
6	FRANKLIN	D	115.00	13.20	
7	FREDERICKSBURG	D	115.00	34.50	
8	FREDERICKSBURG	D	115.00	13.20	
9	FREDERICKSBURG	T	230.00	115.00	13.20
10	FREDERICKSBURG	D	230.00	34.50	
11	GAINESVILLE	T	230.00	115.00	13.20
12	GAINESVILLE	D	230.00	34.50	
13	GALLOWS ROAD	D	230.00	34.50	
14	GARRISONVILLE	D	230.00	34.50	
15	GARYSVILLE	D	34.50	13.20	
16	GATESVILLE	D	34.50	12.50	
17	GLASGOW	D	115.00	46.00	13.20
18	GLASGOW	D	115.00	12.50	
19	GLEBE	D	230.00	34.50	
20	GLEN CARLYN	D	230.00	34.50	
21	GLOUCESTER	D	34.50	12.50	
22	GOLDMINE DP	D	34.50	13.20	
23	GORDONSVILLE	D	115.00	34.50	
24	GORDONSVILLE	T	230.00	115.00	13.20
25	GOSHEN	D	115.00	46.00	4.16
26	GOSHEN	D	115.00	23.00	
27	GOWRIE PARK	D	34.50	4.16	
28	GRAFTON	D	115.00	34.50	
29	GRASSFIELD	D	115.00	34.50	13.20
30	GREAT BRIDGE	D	115.00	34.50	13.20
31	GREEN HILL	D	34.50	4.16	
32	GREEN RUN	D	230.00	34.50	13.20
33	GREENWAY	D	230.00	34.50	
34	GREENWICH	T	230.00	115.00	13.20
35	GREENWICH	D	230.00	34.50	13.20
36	GRETNA	D	69.00	12.50	
37	GROTTOES	D	23.00	13.20	
38	GROTTOES	D	115.00	23.00	
39	GROTTOES	D	115.00	12.50	
40	GROTTOES	T	230.00	115.00	13.20

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1	GROVE AVENUE	D	34.50	13.20	
2	GROVE AVENUE	D	34.50	4.16	
3	GROVELAND	D	34.50	13.20	
4	GUM SPRINGS	D	230.00	34.50	
5	HALIFAX	T	230.00	115.00	13.20
6	HAMILTON	D	230.00	34.50	
7	HAMPTON	D	23.00	6.00	
8	HANOVER	D	115.00	13.20	
9	HANOVER	D	230.00	34.50	
10	HARBOUR VIEW	D	230.00	34.50	
11	HARMONY VILLAGE	D	115.00	34.50	
12	HARMONY VILLAGE	T	230.00	115.00	13.20
13	HARMONY VILLAGE	D	230.00	34.50	
14	HARRISONBURG	D	115.00	34.50	
15	HARRISONBURG	T	230.00	115.00	13.20
16	HARRISONBURG	T	230.00	69.00	13.20
17	HARROWGATE	D	115.00	13.20	
18	HARROWGATE	D	230.00	34.50	
19	HARVELL	D	115.00	13.20	
20	HAYES	D	115.00	34.50	
21	HAYFIELD	D	230.00	34.50	
22	HERNDON PARK	D	230.00	34.50	
23	HERTFORD	D	34.50	13.20	
24	HICKORY	D	115.00	34.50	13.20
25	HICKORY	D	115.00	13.20	
26	HICKORY	T	230.00	115.00	13.20
27	HILLWOOD	D	34.50	13.20	
28	HILTON	D	34.50	6.00	
29	HODGES FERRY	D	115.00	34.50	
30	HODGES FERRY	D	115.00	13.20	
31	HOLLAND	D	115.00	13.20	
32	HOLLIN HALL	D	34.50	13.20	
33	HOLLYMEADE	D	230.00	34.50	
34	HOPEWELL	D	34.50	13.20	
35	HOPEWELL	D	230.00	34.50	13.20
36	HORNERTOWN	D	115.00	34.50	
37	HORNERTOWN	D	115.00	13.20	
38	HORNERTOWN	D	230.00	34.50	
39	HORSEPEN	D	34.50	4.16	
40	HULL ST	D	230.00	34.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HUNTER	D	230.00	34.50	
2	IDYLWOOD	D	34.50	13.20	
3	IDYLWOOD	D	230.00	34.50	
4	IGLOO	D	34.50	12.50	
5	ILDA	D	34.50	13.20	
6	INDUSTRIAL PARK	D	115.00	34.50	13.20
7	INDUSTRIAL PARK	D	115.00	13.20	
8	IRONBRIDGE	D	230.00	34.50	
9	IVOR	D	115.00	13.20	
10	IVY	D	23.00	6.00	
11	JACKSON RIVER	D	46.00	12.50	
12	JARRATT	D	115.00	13.20	
13	JEFFERSON STREET	D	230.00	34.50	
14	JETERSVILLE	D	115.00	34.50	
15	KEENE MILL	D	230.00	34.50	
16	KELFORD	D	115.00	34.50	
17	KENBRIDGE	D	115.00	12.50	
18	KINDERTON	D	115.00	12.50	
19	KING GEORGE	D	34.50	13.20	
20	KINGS FORK	D	115.00	34.50	
21	KINGS FORK	D	115.00	13.20	
22	KINGS FORK	D	230.00	34.50	
23	KINGS MILL	D	115.00	34.50	
24	KINGS MILL	D	230.00	34.50	
25	KITTY HAWK	D	34.50	13.20	
26	KITTY HAWK	D	115.00	34.50	13.20
27	KITTY HAWK	T	230.00	115.00	13.20
28	KITTY HAWK	D	230.00	34.50	13.20
29	LABURNUM	D	34.50	4.16	
30	LADYSMITH	T	500.00	230.00	
31	LAFAYETTE	D	34.50	4.16	
32	LAKE GASTON	D	115.00	34.50	
33	LAKELAND	D	34.50	4.16	
34	LAKERIDGE	D	230.00	34.50	
35	LAKESIDE	D	115.00	13.20	
36	LAKESIDE	T	230.00	115.00	13.20
37	LAKESIDE	D	230.00	34.50	
38	LAKESIDE	D	230.00	13.20	
39	LANCASTER	D	115.00	34.50	
40	LANCASTER	D	115.00	13.20	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LANDSTOWN	T	230.00	115.00	13.20
2	LANDSTOWN	D	230.00	34.50	13.20
3	LANEXA	D	115.00	13.20	
4	LANEXA	T	230.00	115.00	13.20
5	LAUREL AVE	D	34.50	4.16	
6	LAWRENCEVILLE	D	115.00	34.50	
7	LAWRENCEVILLE	D	115.00	12.50	
8	LEBANON	D	115.00	34.50	
9	LEBANON	D	115.00	13.20	
10	LEE D.P.	D	34.50	13.20	
11	LEESBURG	D	34.50	13.20	
12	LEMON	D	34.50	13.20	
13	LENOX	D	34.50	4.16	
14	LEXINGTON	T	230.00	115.00	13.20
15	LEXINGTON	T	500.00	230.00	
16	LIGHTFOOT	D	230.00	34.50	
17	LILLEY	D	34.50	12.50	
18	LIVINGSTON HEIGHT	D	34.50	13.20	
19	LOCKS	D	115.00	34.50	
20	LOCKS	D	115.00	13.20	
21	LOCKS	T	230.00	115.00	13.20
22	LONDON BRIDGE	D	115.00	34.50	13.20
23	LONG CREEK	D	115.00	34.50	13.20
24	LOUDOUN	T	230.00	115.00	13.20
25	LOUDOUN	T	500.00	230.00	
26	LOUISA	D	230.00	34.50	
27	LOVETTSVILLE	D	138.00	34.50	
28	LOW MOOR	T	230.00	138.00	13.20
29	LYNNHAVEN	D	34.50	13.20	
30	LYNNHAVEN	D	230.00	34.50	13.20
31	MADISON ST	D	13.20	4.16	
32	MAGRUDER	D	115.00	34.50	
33	MAGRUDER	D	115.00	13.20	
34	MANCHESTER	D	115.00	13.20	
35	MANTEO	D	34.50	13.20	
36	MARGARETTSVILLE	D	115.00	13.20	
37	MASSANUTTEN	D	34.50	12.50	
38	MATHEWS	D	34.50	13.20	
39	MCKENNEY	D	34.50	13.20	
40	MCLAUGHLIN	D	34.50	4.16	

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	MCLAUGHLIN	D	115.00	34.50	13.20
2	MCLEAN	D	34.50	13.20	
3	MECHANICSVILLE	D	34.50	13.20	
4	MERCK 5	D	115.00	34.50	
5	MERCURY	D	115.00	23.00	
6	MERRIFIELD	D	34.50	13.20	
7	MERRY POINT	D	34.50	13.20	
8	METCALF	D	115.00	12.50	
9	MIDDLEBURG	D	115.00	34.50	
10	MIDDLETON D.P.	D	34.50	13.20	
11	MIDLOTHIAN 34.5	D	230.00	34.50	
12	MIDLOTHIAN 500	T	500.00	230.00	34.50
13	MINE ROAD	D	230.00	34.50	
14	MONTROSS	D	34.50	13.20	
15	MORRISVILLE	T	500.00	230.00	
16	MOUNT EAGLE	D	230.00	34.50	
17	MOUNT LAUREL	D	115.00	12.50	
18	MOUNTAIN ROAD	D	230.00	34.50	
19	MT JACKSON	D	115.00	34.50	
20	MT STORM (N.BRANCH)	T	500.00	115.00	13.20
21	MURPHY	D	115.00	34.50	
22	MYRTLE	D	115.00	34.50	
23	NAGS HEAD	D	115.00	34.50	
24	NASH	D	230.00	34.50	13.20
25	NEW MARKET	D	34.50	12.50	
26	NEWPORT NEWS #2	D	23.00	6.00	
27	NEWPORT NEWS #2	D	230.00	23.00	
28	NORTH ANNA 500/22	T	500.00	230.00	
29	NORTH POLE	D	230.00	34.50	
30	NORTH VA. BEACH	D	34.50	13.20	
31	NORTHEAST	D	115.00	13.20	
32	NORTHEAST	T	230.00	115.00	13.20
33	NORTHEAST	D	230.00	34.50	
34	NORTHERN NECK	D	115.00	34.50	
35	NORTHERN NECK	T	230.00	115.00	13.20
36	NORTHWEST	D	115.00	13.20	
37	NORTHWEST	T	230.00	115.00	13.20
38	NORTHWEST	D	230.00	34.50	
39	NORVIEW	D	34.50	4.16	
40	OAK GROVE	D	230.00	34.50	

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SUBSTATIONS

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	OAK RIDGE	D	115.00	13.20	
2	OAKWOOD	D	115.00	34.50	13.20
3	OAKWOOD	D	115.00	13.20	
4	OCCOQUAN	D	230.00	34.50	
5	OCEAN VIEW	D	34.50	4.16	
6	OFFICE HALL D.P.	D	34.50	13.20	
7	OKISKO	D	34.50	12.50	
8	OLD CHURCH	D	230.00	34.50	
9	ORANGE	D	115.00	34.50	
10	ORANGE	D	115.00	12.50	
11	OTTER RIVER	D	115.00	12.50	
12	OX	T	500.00	230.00	
13	PAGAN	D	34.50	13.20	
14	PAMPLIN	D	34.50	23.00	
15	PAMPLIN	D	115.00	34.50	
16	PANTEGO	D	115.00	34.50	
17	PARMELE	D	115.00	12.50	
18	PEARSONS	D	230.00	34.50	
19	PENDER	D	230.00	34.50	
20	PENDLETON	D	115.00	34.50	13.20
21	PENINSULA	D	34.50	13.20	
22	PENINSULA	D	115.00	34.50	
23	PENINSULA	T	230.00	115.00	13.20
24	PENINSULA	D	230.00	34.50	
25	PENTAGON	T	230.00	69.00	
26	PERTH	D	115.00	34.50	
27	PHOEBUS	D	23.00	6.00	
28	PICKETT STREET	D	34.50	13.20	
29	PIMMIT	D	34.50	13.20	
30	PINE ST	D	34.50	11.00	
31	PLAZA	D	115.00	13.20	
32	PLAZA	T	230.00	115.00	13.20
33	PLAZA	D	230.00	34.50	
34	PLEASANT VIEW	D	230.00	34.50	
35	PLEASANT VIEW 500	T	500.00	230.00	
36	PLYMOUTH	D	115.00	34.50	
37	POE	D	34.50	13.20	
38	POE	T	230.00	115.00	13.20
39	POE	D	230.00	34.50	
40	POINT HARBOR	D	230.00	34.50	13.20

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	POOLESVILLE	D	230.00	34.50	
2	POPLAR CHAPEL	D	115.00	34.50	
3	PORT NORFOLK	D	34.50	4.16	
4	PORTSMOUTH	T	230.00	115.00	13.20
5	POSSUM POINT 230	T	230.00	115.00	13.20
6	POSSUM POINT 500	T	500.00	230.00	
7	POTOMAC	D	34.50	4.16	
8	POWHATAN	D	230.00	34.50	
9	PRENTIS PARK	D	34.50	4.16	
10	PRINCE GEORGE	D	34.50	13.20	
11	PRINCESS ANNE	D	115.00	34.50	13.20
12	PROVIDENCE FORGE	D	115.00	34.50	
13	PUNGO RIVER	D	34.50	13.20	
14	PURCELLVILLE	D	34.50	13.20	
15	Q ST	D	34.50	13.20	
16	QUANTICO	D	115.00	13.20	
17	RAVENSWORTH	D	230.00	34.50	
18	REEDY CREEK	D	115.00	34.50	
19	REEVES AVE	D	115.00	34.50	13.20
20	REEVES AVE	T	230.00	115.00	13.20
21	REMINGTON	D	115.00	34.50	
22	REMINGTON	T	230.00	115.00	13.20
23	REMINGTON CT	T	230.00	115.00	13.20
24	RESERVOIR	D	34.50	4.16	
25	RESTON	D	230.00	34.50	
26	RIDERS CREEK	D	115.00	34.50	
27	RIVER ROAD	D	115.00	13.20	
28	RIVER ROAD	D	230.00	34.50	
29	ROBERSONVILLE	D	12.50	4.16	
30	ROBERSONVILLE	D	115.00	12.50	
31	ROCKBRIDGE	D	46.00	12.50	
32	ROCKBRIDGE	D	115.00	13.20	
33	ROSEMONT	D	34.50	13.20	
34	ROSSLYN	D	69.00	13.20	
35	SANDBRIDGE	D	34.50	13.20	
36	SAPONY	D	115.00	34.50	
37	SAPONY	D	230.00	34.50	
38	SCOTLAND NECK	D	115.00	13.20	
39	SEABOARD	D	115.00	13.20	
40	SEAFORD	D	115.00	34.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SEWELLS POINT	T	230.00	115.00	13.20
2	SEWELLS POINT	D	230.00	34.50	13.20
3	SHACKLEFORD	D	115.00	34.50	
4	SHEA #1	D	34.50	13.20	
5	SHEA #1	D	34.50	4.16	
6	SHEA #2	D	115.00	34.50	13.20
7	SHELLBANK	D	115.00	23.00	
8	SHELLBANK	D	115.00	13.20	
9	SHELLBANK	T	230.00	115.00	13.20
10	SHERWOOD	D	115.00	34.50	
11	SHIRLEY DUKE	D	34.50	13.20	
12	SHOCKOE	D	115.00	34.50	
13	SHOCKOE	D	115.00	13.20	
14	SHORT PUMP	D	230.00	34.50	
15	SIDEBURN	D	230.00	34.50	
16	SINAI	D	115.00	12.50	
17	SISISKY	D	115.00	13.20	
18	SLIGO	D	230.00	34.50	13.20
19	SMITHFIELD	D	230.00	34.50	
20	SOMERSET	D	115.00	34.50	
21	SOUTH BOSTON	D	115.00	12.50	
22	SOUTH CREEK	D	34.50	12.50	
23	SOUTH CREEK	D	115.00	34.50	
24	SOUTH HILL	D	115.00	13.20	
25	SOUTH NORFOLK	D	34.50	13.20	
26	SOUTH NORFOLK	D	230.00	34.50	13.20
27	SOUTH WASHINGTON	D	34.50	4.16	
28	SOUTHWEST	D	230.00	34.50	
29	SPRINGFIELD	D	34.50	13.20	
30	ST ANDREW	D	13.20	4.16	
31	ST JOHNS	D	115.00	13.20	
32	ST JOHNS	T	230.00	115.00	13.20
33	STAFFORD	D	230.00	34.50	
34	STATE FARM	D	34.50	13.20	
35	STAUNTON	D	12.50	4.16	
36	STAUNTON	D	23.00	12.50	
37	STAUNTON	D	115.00	23.00	
38	STAUNTON	D	115.00	12.50	
39	STERLING PARK	D	230.00	34.50	
40	STONY CREEK	D	34.50	13.20	

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1	STRATFORD HILLS	D	115.00	13.20	
2	STUART GARDENS	D	23.00	6.00	
3	STUARTS DRAFT	D	115.00	23.00	
4	STUMPY LAKE	D	230.00	34.50	13.20
5	SUFFOLK	D	115.00	13.20	
6	SUFFOLK	D	115.00	34.50	
7	SUFFOLK	T	230.00	115.00	13.20
8	SUFFOLK	D	230.00	34.50	
9	SUFFOLK	T	500.00	230.00	
10	SULLY	D	230.00	34.50	
11	SUNBURY	D	230.00	34.50	
12	SWINKS MILL	D	230.00	34.50	
13	TABB	D	230.00	34.50	
14	TAPPAHANNOCK	D	34.50	4.16	
15	TAR RIVER	D	115.00	12.50	
16	TARBORO	D	115.00	13.20	
17	TARBORO	T	230.00	115.00	13.20
18	TARBORO	T	230.00	115.00	
19	TAUSSIG	D	115.00	34.50	13.20
20	TAUSSIG	D	115.00	13.20	
21	TEMPLE AVE.	D	115.00	34.50	
22	THALIA	D	34.50	13.20	
23	THALIA	D	230.00	34.50	13.20
24	THIRD STREET	D	23.00	12.50	
25	THIRD STREET	D	23.00	4.16	
26	THOLE ST	D	115.00	34.50	13.20
27	THOMPSONS CORNER	D	115.00	34.50	13.20
28	THOMPSONS CORNER	D	115.00	13.20	
29	THRASHER	D	230.00	34.50	13.20
30	TIMBERVILLE	D	115.00	12.50	
31	TITUSTOWN	D	34.50	4.16	
32	TOANO	D	115.00	34.50	
33	TRABUE	D	230.00	34.50	
34	TRAP	D	34.50	13.20	
35	TREGO	D	12.50	2.40	
36	TREGO	D	115.00	2.40	
37	TROWBRIDGE	T	230.00	115.00	13.20
38	TUNIS	D	115.00	34.50	
39	TURNER	D	115.00	34.50	
40	TURNER	D	230.00	34.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TWELFTH ST.	D	115.00	34.50	
2	TWELFTH ST.	D	115.00	13.20	
3	TWITTYS CREEK	D	34.50	12.50	
4	TWITTYS CREEK	D	115.00	34.50	
5	TYLER	D	115.00	13.20	
6	TYLER	D	230.00	34.50	
7	TYSONS	D	230.00	34.50	
8	UNIONVILLE DP	D	115.00	12.50	
9	VALLEY	T	500.00	230.00	
10	VAN DORN	D	230.00	34.50	
11	VERONA	D	115.00	23.00	
12	VICTORIA	D	115.00	12.50	
13	VIENNA	D	34.50	13.20	
14	VIRGINIA BEACH	D	115.00	34.50	13.20
15	VIRGINIA BEACH	D	115.00	13.20	
16	VIRGINIA BEACH	T	230.00	115.00	13.20
17	VIRGINIA HILLS	D	34.50	13.20	
18	VIRGINIA HILLS	D	230.00	34.50	
19	WAKEFIELD	D	13.20	4.16	
20	WAKEFIELD	D	115.00	34.50	
21	WAKEFIELD	D	115.00	13.20	
22	WALLER	D	230.00	34.50	
23	WALNEY	D	230.00	34.50	
24	WALNUT HILL	D	13.20	4.16	
25	WALTHALL	D	115.00	34.50	
26	WAN	D	115.00	34.50	
27	WAR	D	69.00	13.20	
28	WARRENTON	D	230.00	34.50	
29	WARSAW	D	34.50	13.20	
30	WARWICK	D	115.00	13.20	
31	WARWICK	D	230.00	34.50	
32	WATKINS CORNER	D	115.00	34.50	
33	WAVERLY	D	115.00	13.20	
34	WAYNE HILLS	D	23.00	12.50	
35	WAYNESBORO	D	115.00	23.00	
36	WELCO	D	115.00	34.50	
37	WELCO	D	115.00	12.50	
38	WESCOTT	D	34.50	13.20	
39	WEST LANDING	D	230.00	34.50	13.20
40	WEST STAUNTON	D	230.00	23.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. *Substations which serve only one industrial or street railway customer should not be listed below.*
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WESTHAVEN	D	34.50	4.16	
2	WESTMINSTER	D	34.50	13.20	
3	WESTMORELAND	D	230.00	34.50	
4	WESTPOINT	D	115.00	34.50	
5	WEYERS CAVE	D	115.00	34.50	
6	WHEALTON	T	230.00	115.00	13.20
7	WHITAKERS	D	115.00	34.50	13.20
8	WHITEHALL DP	D	34.50	23.00	
9	WHITESHOP	D	34.50	13.20	
10	WHITESTONE	D	115.00	12.50	
11	WILLIAMSBURG	D	34.50	13.20	
12	WILLOUGHBY	D	34.50	13.20	
13	WILLSTON	D	34.50	13.20	
14	WINCHESTER	D	34.50	13.20	
15	WINCHESTER	D	230.00	34.50	
16	WINFALL	D	115.00	34.50	
17	WINFALL	T	230.00	115.00	13.20
18	WINTERPOCK	D	230.00	34.50	
19	WOODBRIDGE	D	230.00	34.50	
20	WOODLAND	D	115.00	34.50	
21	WOODSTOCK	D	34.50	12.50	
22	WYTHE	D	23.00	6.00	
23	YADKIN	T	230.00	115.00	13.20
24	YADKIN	D	230.00	34.50	
25	YADKIN	T	500.00	230.00	34.50
26	YADKIN	T	500.00	230.00	
27	YORKTOWN	T	230.00	115.00	13.20
28	Total Transmssn & Distribution		91225.20	25136.96	1620.98
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
195	3					1
80	2					2
22	1					3
7	1					4
22	1					5
20	1					6
13	2					7
11	1					8
224	2					9
53	3	1				10
20	1					11
90	2					12
34	1					13
42	2					14
327	4					15
95	2					16
150	2					17
3	3					18
40	2					19
100	2					20
40	2					21
50	1					22
168	1					23
84	1					24
45	2					25
150	2					26
22	1					27
448	2					28
168	2					29
40	2					30
13	1					31
20	1					32
56	1					33
22	1					34
60	1	1				35
234	3					36
75	1					37
14	1					38
20	1					39
6	1					40

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
168	2					1
13	1					2
87	2					3
22	1					4
10	4					5
100	2					6
5	1					7
75	1					8
13	1					9
22	1					10
168	2					11
22	1					12
192	4	1				13
224	1					14
8	3					15
840	3	1				16
224	1					17
13	1					18
52	2					19
7	6	1				20
11	1					21
34	1	1				22
9	1					23
45	2					24
336	4					25
159	2					26
56	1					27
6	1					28
3	3					29
22	1					30
100	1					31
100	3					32
224	1					33
14	1					34
840	3	1				35
840	3					36
13	1					37
50	1					38
120	3					39
34	1					40

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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30	3	1				1
22	1					2
35	2					3
50	1					4
106	2					5
269	3	1				6
67	2					7
13	1					8
150	2					9
37	1					10
14	1					11
11	3					12
14	1					13
14	1					14
224	1					15
840	3	1				16
22	1					17
22	1					18
22	1					19
224	1					20
150	2					21
129	2					22
64	2					23
159	2					24
168	1					25
234	3					26
22	1					27
6	3					28
1680	6	1				29
20	1					30
22	1					31
250	1					32
840	3	2				33
168	1					34
56	3	1				35
5	1					36
168	2					37
22	1					38
5	1					39
15	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3	1					1
45	2					2
34	1					3
24	2					4
25	2					5
90	2					6
67	2					7
6	3	1				8
120	2					9
5	1					10
22	1					11
14	1					12
50	1					13
5	1					14
67	1					15
598	4					16
85	2					17
22	1					18
5	1					19
95	2					20
42	2					21
100	2					22
45	2					23
6	1					24
90	2					25
14	1					26
4	1					27
6	1					28
22	1					29
96	2					30
673	3					31
840	3					32
840	3	1				33
10	1					34
42	2					35
159	2					36
11	1					37
2	1					38
159	2					39
125	2					40

Name of Respondent VIRGINIA ELECTRIC AND POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
50	1					1
20	1					2
4	1					3
4	3	1				4
45	2					5
168	1					6
5	3					7
24	2					8
62	2					9
6	1					10
100	2					11
112	1					12
5	1					13
159	2					14
34	1					15
22	2					16
336	2					17
95	2					18
840	3	1				19
840	3					20
22	1					21
45	2					22
448	2					23
42	2					24
22	1					25
50	1					26
224	1					27
100	2					28
45	2					29
10	1					30
42	2					31
168	2					32
45	2					33
336	2					34
25	1					35
75	1					36
1680	6					37
45	2					38
13	1					39
40	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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45	2					1
9	1					2
20	1					3
5	1					4
168	2					5
45	2					6
75	1					7
42	2					8
168	1					9
84	1					10
393	4	1				11
118	2					12
159	2					13
84	1					14
8	1					15
5	1					16
22	1					17
22	1					18
159	2					19
234	3					20
7	2					21
11	1					22
22	1					23
448	2					24
30	3	1				25
13	1					26
5	1					27
50	1					28
34	1					29
67	2					30
5	1					31
196	2					32
234	3					33
448	2					34
50	1					35
9	3	1				36
9	1					37
13	1					38
22	1					39
224	1					40

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SUBSTATIONS (Continued)

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14	1					1
8	1					2
9	1					3
159	2					4
448	2					5
84	1					6
6	3					7
20	1					8
50	1					9
34	1					10
22	1					11
168	3	1				12
56	1					13
56	2					14
224	1					15
224	6	1				16
45	2					17
45	1					18
74	2					19
45	2					20
159	2					21
75	1					22
14	1					23
50	1					24
22	1					25
112	1					26
28	2					27
9	3					28
50	1					29
20	1					30
4	1					31
22	1					32
45	1					33
80	2					34
392	5					35
22	1					36
42	2					37
45	1					38
6	1					39
134	3					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
150	2					1
14	1					2
336	2					3
11	1					4
9	1					5
124	2					6
45	2					7
140	3					8
6	1					9
5	3					10
8	3					11
6	1					12
318	4					13
22	1					14
196	4					15
22	1					16
14	1					17
20	1					18
7	1					19
40	1					20
14	1					21
25	1					22
56	1					23
50	1					24
13	1					25
112	2					26
336	2	1				27
75	1					28
5	3					29
840	3	1				30
6	1					31
22	1					32
5	1					33
90	2					34
22	1					35
336	2					36
159	2					37
56	1					38
42	2					39
22	1					40

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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448	2					1
125	2					2
14	1					3
336	2					4
9	2					5
20	1					6
13	1					7
22	1					8
22	1					9
7	1					10
33	2					11
13	1					12
5	1					13
336	2					14
672	6	1				15
150	2					16
14	1					17
22	1					18
56	1					19
42	2					20
336	2					21
56	1					22
45	2					23
336	2					24
1680	6	2				25
45	1					26
106	4	1				27
250	1	1				28
42	2					29
131	2					30
7	6	1				31
45	2					32
22	1					33
106	2					34
7	1					35
3	3					36
9	1					37
11	1					38
4	1					39
19	2					40

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

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106	2					1
42	2					2
40	2					3
22	1					4
50	1					5
40	2					6
22	1					7
14	1					8
96	3					9
4	1					10
159	2					11
840	3					12
120	2					13
5	1					14
2220	6	1				15
50	1					16
22	1					17
125	2					18
22	1					19
100	3	1				20
45	2					21
22	1					22
113	6					23
50	1					24
4	1					25
5	3					26
224	2	1				27
672	6	1				28
50	1					29
22	2					30
42	2					31
224	1					32
224	2					33
45	2					34
168	3	1				35
22	1					36
168	1					37
252	3					38
5	1					39
50	1					40

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
45	2					1
168	3					2
42	2					3
150	2					4
9	2					5
6	1					6
5	1					7
50	1					8
22	1					9
22	1					10
45	2					11
1680	6	2				12
13	1					13
6	3	1				14
42	2					15
13	1					16
13	1					17
75	1					18
252	3					19
112	2					20
11	1					21
45	2					22
224	1					23
45	1					24
504	3					25
45	2					26
5	3					27
13	1					28
9	1					29
17	2					30
42	2					31
168	1					32
56	1					33
225	3					34
840	3	1				35
45	2					36
67	2					37
336	2					38
159	2					39
34	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
50	1					1
22	1					2
9	2					3
224	1					4
336	2					5
840	3	1				6
6	3					7
84	2					8
5	1					9
14	1					10
22	1					11
40	1					12
9	1					13
32	2					14
20	1					15
42	2					16
75	1					17
22	1					18
252	3					19
392	2					20
67	2					21
224	1					22
224	1					23
12	2					24
234	3					25
22	1					26
42	2					27
159	2					28
10	2					29
13	1					30
11	3	3				31
56	2					32
6	1					33
134	4					34
20	1					35
22	1					36
34	1					37
22	1					38
14	3	1				39
45	2					40

Name of Respondent VIRGINIA ELECTRIC AND POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
448	2					1
168	1					2
22	1					3
20	1					4
6	1					5
100	2					6
115	6					7
20	1					8
224	1					9
100	2					10
45	2					11
120	2					12
90	2					13
225	3					14
84	1					15
22	1					16
22	1					17
50	1					18
106	2					19
22	1					20
35	2					21
11	1					22
22	1					23
45	2					24
22	1					25
100	1					26
6	3					27
224	2					28
42	2					29
5	1					30
13	1					31
168	1					32
159	2					33
6	1					34
7	1					35
9	1					36
42	4					37
20	1					38
243	3					39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
45	2					1
5	3					2
47	2					3
159	2					4
40	3	1				5
22	1					6
448	2					7
75	1					8
840	3	1				9
150	2					10
25	1					11
120	2					12
129	2					13
3	1					14
22	1					15
20	1					16
112	1					17
112	1					18
56	1					19
22	1					20
22	1					21
40	2					22
224	2					23
9	1					24
4	3					25
50	1					26
140	2					27
42	2					28
224	3					29
20	1					30
5	1					31
56	2					32
120	2					33
6	1					34
3	3					35
6	1					36
336	2					37
56	2					38
45	1					39
45	1					40

Name of Respondent VIRGINIA ELECTRIC AND POWER COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
168	2					1
150	2					2
6	1					3
22	1					4
20	1					5
45	1					6
309	4					7
13	1					8
840	3	1				9
150	2					10
25	2					11
14	1					12
42	2					13
168	2					14
42	2					15
448	2					16
36	2					17
75	1					18
3	1					19
13	1					20
9	1					21
159	2					22
150	2					23
4	1					24
34	1					25
78	4	1				26
37	1					27
134	2					28
9	1					29
40	2					30
150	2					31
20	1					32
33	2					33
11	1					34
50	1					35
22	1					36
15	1					37
40	2					38
34	1					39
129	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
7	2					1
10	1					2
34	1					3
56	2					4
22	1					5
392	2					6
22	1					7
8	1					8
3	3					9
14	1					10
14	1					11
13	1					12
14	1					13
67	2					14
150	2					15
45	2					16
168	1					17
100	2					18
168	2					19
22	1					20
6	2					21
5	3					22
224	1					23
75	1					24
840	3	1				25
840	3	1				26
224	1					27
72711	1087	51				28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40