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September 15, 2009

OFFICIAL COPY

BY HAND

Ms. Renné Vance
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

Full Dist.

FILED
SEP 16 2009
Clerk's Office
N.C. Utilities Commission

Integrated Resource Plan
of Dominion North Carolina Power
Docket No. E-100, Sub 124

Dear Ms. Vance:

On September 1, 2009, Virginia Electric and Power Company d/b/a Dominion North Carolina Power ("DNCP" or "Company") filed with the Commission its updates to the Integrated Resource Plan for 2009 (the "2009 IRP"). This filing included Public and Confidential Versions of the 2009 IRP.

The Company has discovered that 6 pages in the Appendix (Appendix 3E—Heat Rates at pp. AP-22-27) of the Public version of the 2009 IRP should have been redacted and filed as confidential.

Enclosed are one (1) original unbound and one (1) bound copy of the new Public Version of the 2009 Plan with Appendix 3E redacted. In addition, enclosed are thirty (30) copies of the revised redacted pages AP-22-27 for the Public Version and thirty (30) copies of the revised confidential pages AP-22-27 for the Confidential Version. The revised redacted pages are also being sent to those who received the Public Version of the 2009 Plan with a request that they replace those pages and destroy the originals. The numbers and data in these replacement pages have not been changed.

Conf. Form 715
Finley Ericson
Kirby

Please date stamp the extra copy and return it to me via the courier.

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

Sincerely,

Bernard L. McNamee

Enclosures

cc: Robert W. Kaylor, Esq.
Service List

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N.C. Utilities Commission

Dominion®

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

Filed September 1, 2009

Revised 9/15/09

DOMINION VIRGINIA POWER'S AND DOMINION NORTH CAROLINA POWER'S 2009 REPORT OF ITS INTEGRATED RESOURCE PLAN

TABLE OF CONTENTS

List of Acronyms

The following is a list of acronyms used throughout the Integrated Resource Plan:

Acronym	Acronym Meaning
ACH	Air Changes per Hour
ADS	Air Distribution Systems
AMI	Advanced Metering Infrastructure
ATC	Available Transfer Capability
Bear	Bear Garden Combined Cycle Generating Station
Bio	Biomass
BTMG	Behind-the-Meter Generation
CC	Combined Cycle
CCS	Carbon Capture and Sequestration
CFA	Conditioned Floor Area
CFB	Circulating Fluidized Bed
CFL	Compact Florescent Light
CFM25	Cubic Feet per Minute @ 25 Pascals of Pressure
COL	Combined Construction Permit and Operating License
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical Peak Pricing
CPU	Central Processing Unit
CS	Curtailable Service
CT	Combustion Turbine
DG	Distributed Generation
DLC	Direct Load Control
DOM LSE	Dominion Load Serving Entity
DOM Zone	Dominion Zone within the PJM Interconnection, L.L.C. Regional Transmission Organization
DSM	Demand-Side Management
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GSP	Gross State Product
GWh	Gigawatt Hour
HSPF	Heating Seasonal Performance Factor
HVAC	Heating, Ventilating, and Air Conditioning
ICF	ICF International, Inc.
IGCC	Integrated-Gasification Combined Cycle
IRM	Installed Reserve Margin
IRP	Integrated Resource Planning
kV	Kilovolt(s)
kW	Kilowatt(s)
kWh	Kilowatt Hour(s)
LED	Light-Emitting Diode
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
M&V	Measurement and Verification
MW	Megawatt(s)
MWh	Megawatt Hour(s)

NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
NUG	Non-Utility Generation or Non-Utility Generator
ODEC	Old Dominion Electric Cooperative
O&M	Operation & Maintenance
OSW	Offshore Wind
PC	Pulverized Coal
PHEV	Plug-In Hybrid Electric Vehicle
PJM	PJM Interconnection, LLC
PRSG	Planned Reserve Sharing Group
PTC	Production Tax Credit
PV	Photovoltaic
RAA	Reliability Assurance Agreement
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	Virginia State Corporation Commission
SEER	Seasonal Energy Efficiency Ratio
SERC	Southeastern Reliability Conference
SG	Standby Generation
SRCC	Solar Rating and Certification Corporation
STAP	Short-Term Action Plan
T&D	Transmission and Distribution
TRC	Total Resource Cost
VACAR	Virginia-Carolinas Reliability Agreement
VCHEC	Virginia City Hybrid Energy Center
Warn	Warren County Combined Cycle Generating Station
WND	Wind

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 2009 Integrated Resource Plan ("2009 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 and Rule R8-60 of the North Carolina Utilities Commission's ("NCUC") Rules of Practice and Procedure. The 2009 Plan was prepared on a Load Serving Entity ("LSE") basis, specifically the Dominion LSE ("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 2009 Plan was developed to meet rising customer demand for electricity at the lowest reasonable cost and includes provisions to achieve policy goals from individual state legislatures by expanding the Company's electric generation capacity and increasing its Demand-Side Management ("DSM") programs.[1] The Appendices associated with this 2009 Plan only provide information and data associated with and applicable for the DOM LSE and do not include other data associated with other entities that are part of the Dominion Zone ("DOM Zone").

The 2009 Plan is a long-term planning document with 15-year forecasts of information addressing the 2010 to 2024 timeframe ("Planning Period") and should be viewed in this context. The 2009 Plan is based on the Company's current assumptions regarding load growth, commodity price projections, and DSM program penetrations, as well as many other regulatory and market developments throughout the Planning Period.

The 2009 Plan includes chapters on load forecasting, existing supply- and demand-side resources, plan requirements and constraints, and future supply- and demand-side resources. Additionally, the 2009 Plan includes a chapter entitled "Development of the Integrated Resource Plan" that outlines several alternative plans that were compared by weighing the costs and benefits of these plans using a variety of sensitivities and scenarios. The 2009 Plan also provides a Short-Term Action Plan ("STAP") which discusses the Company's specific actions currently being taken to implement the activities chosen to support the 2009 Plan over the next 5 years (2010 – 2014).

1.2 COMPANY DESCRIPTION

The Company, headquartered in Richmond, Virginia, currently serves approximately 2.4 million electric customers in Virginia and North Carolina. The Company's electric service area covers approximately 30,000 square miles in Virginia and North Carolina.

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[1] As used in this Plan, DSM includes energy efficiency (including demand response) and peak shaving programs.

The Company's regulated electric portfolio consists of 18,245 megawatts ("MW") of generation capacity, including 1,776 MW of non-utility generation ("NUG"), delivered over 6,000 miles of transmission lines in Virginia, North Carolina, and West Virginia, at voltages ranging from 69 kilovolts ("kV") to 500 kV. 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.

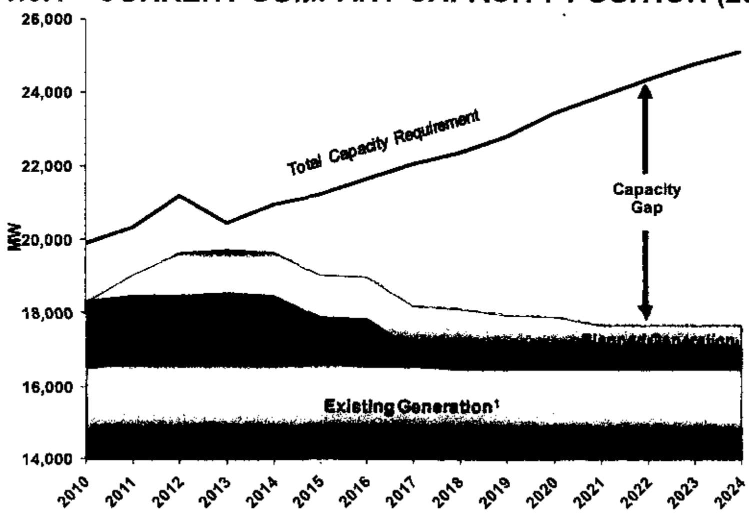
The Company has a diverse mix of generating resources consisting of Company-owned nuclear, fossil, hydro, pumped storage, and biomass facilities. Additionally, the Company purchases capacity and energy from NUGs and the PJM market. The Company's strategy to reduce dependence on volatile market purchases while maintaining a diverse mix of fuels and DSM programs is a fundamental focus of the 2009 Plan.

1.3 2009 INTEGRATED RESOURCE PLANNING PROCESS

The Company's objective in developing the 2009 Plan was to identify the mix of resources necessary to meet future energy needs in an efficient and reliable manner at the lowest reasonable cost.

The Company developed a comprehensive Integrated Resource Planning ("IRP") process that gave preference to those options that offer reasonable costs and contain an acceptable level of risk, maintain or increase the level of customer service, and provide reliable generation and infrastructure to meet customers' needs. The process included various planning groups within the Company who provided input and insight into evaluating all possible 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 when the Company developed a long-term load forecast, and then it identified the existing resource base. Collectively, these two elements helped determine new resource requirements as illustrated in Figure 1.3.1.

Figure 1.3.1 CURRENT COMPANY CAPACITY POSITION (2010 – 2024)



Note: 1) Includes rating changes to existing units.

Based on projected capacity needs, energy needs, and the resources available to meet them, the Company developed a set of five alternative plans. The Company used the Strategist model ("Strategist"), which is a computer modeling and resource optimization tool that systematically evaluated various combinations of supply- and demand-side options to analyze how the Company's resource requirements could be met. The alternative plans represent possible future paths considering the current regulatory and business environments. These paths were determined by the inclusion or exclusion of major resource types such as DSM, nuclear, or renewables. Figure 1.3.2 shows the timing and types of resources selected in each of the alternative plans.

Figure 1.3.2 ALTERNATIVE PLANS

Year	Base Plan			No Demand-Side Resources Plan		No Nuclear Expansion Plan			No Renewable Plan		Federal Renewable Plan		
	Traditional	Renewable	DSM	Traditional	Renewable	Traditional	Renewable	DSM	Traditional	DSM	Traditional	Renewable	DSM
2010			Pro.					Pro.		Pro.			Pro.
2011	Bear		Pro./Fut.	Bear		Bear		Pro./Fut.	Bear	Pro./Fut.	Bear		Pro./Fut.
2012	VCHEC			VCHEC		VCHEC			VCHEC		VCHEC		
2013													
2014				Warn							CT	WND	
2015	Warn			CC		Warn			Warn		Warn	WND 2OSW	
2016	2CT	Bio		2CT	Bio	2CT	Bio		2CT		CT	Bio 4WND 2OSW	
2017	CC	Bio 4WND		CC	Bio 4WND	CC	Bio 4WND		CC		CC	Bio 4WND 2OSW	
2018	NA3			CT NA3		CC			NA3		NA3		
2019	CT			CC		CC			CT		CT		
2020	CT			CT		2CT			CC		CT	2OSW	
2021	CC			CC		CC			CC		CC	2OSW	
2022	CC			CT		CC			CT		CT		
2023	CC			CC		CC			CC		CC		
2024	CC			CC		CC			CC		CC		

Key: Bear – Bear Garden; Bio – Biomass; CT – Combustion Turbine; CC – Combined Cycle; DSM – Demand-Side Management; Fut. – Future DSM Programs; NA3 – North Anna 3; OSW – Off-Shore Wind; Pro. – Proposed DSM Programs; VCHEC – Virginia City Hybrid Energy Center; Warn – Warren County CC.; WND – Wind (land)

***Note**: The Company intends to comply with the North Carolina REPS requirements, including the set-asides for energy derived from solar, poultry litter, and/or swine waste through the purchase of RECs and/or purchased energy, as applicable. Hence those resources do not appear in the above table. Moreover, the set aside requirements represent approximately 0.05% of system load by 2024 and will not materially alter the 2009 Plan.*

The Company assessed these alternative plans using various sensitivities and scenarios to understand how possible futures may impact the relative costs of the supply- and demand-side resources included in each alternative plan. In analyzing these alternative plans, the Company's process helped identify a single plan which, based on this assessment, provided the lowest reasonable cost plan most consistently given these potential future conditions. This single plan was then selected as the preferred Integrated Resource Plan ("Preferred Plan"). Each alternative plan was designed to test different resource strategies available to the Company over the Planning Period.

The alternative plans were compared on an individual scenario or sensitivity basis. These sensitivities and scenarios used in developing the analysis to determine the Preferred Plan are detailed in Figure 1.3.3. In Figure 1.3.3, each row constitutes a grouping of plans that were considered for a particular sensitivity or scenario. The results are displayed as a percentage based on a comparison of relative costs of the plans to the estimated costs of the lowest cost plan for each sensitivity or scenario. The best performing plan is labeled as 0.00% and is shaded for each sensitivity or scenario within Figure 1.3.3.

Figure 1.3.3 SCENARIOS & SENSITIVITIES

		% Above Minimum by Case	NPV Relative to the Lowest Cost Plan: Base Plan	No Demand-Side Resources Plan	No Nuclear Expansion Plan	No Renewable Plan	Federal Renewable Plan
Scenarios and Sensitivities	1	Base Case	[redacted]	2.80%	0.80%	0.21%	4.17%
	2	High CO2 Scenario	[redacted]	3.03%	1.90%	0.40%	1.69%
	3	Low CO2 Scenario	0.08%	2.81%	[redacted]	0.17%	5.79%
	4	High Fuel Costs	[redacted]	3.01%	1.87%	0.35%	2.05%
	5	Low Fuel Costs	0.75%	3.28%	[redacted]	0.76%	8.01%
	6	High Load Growth	[redacted]	2.64%	0.71%	0.20%	3.86%
	7	Low Load Growth	[redacted]	3.17%	0.58%	0.18%	4.89%
	8	High Construction Cost	0.36%	3.43%	[redacted]	0.42%	7.35%
	9	Low Construction Cost	[redacted]	2.53%	2.02%	0.37%	1.22%
	10	High T&D Costs	[redacted]	2.87%	0.80%	0.21%	4.17%
	11	Low T&D Costs	[redacted]	2.72%	0.80%	0.21%	4.17%
	12	Plug-in Hybrid Cars	[redacted]	2.78%	0.84%	0.22%	3.99%
	13	PTC Tax Credit	0.03%	2.82%	0.82%	[redacted]	7.16%
	14	Carbon Legislation	1.06%	3.80%	[redacted]	1.04%	9.14%
	15	REC Sales	[redacted]	2.79%	0.80%	0.03%	5.75%
	16	PTC & REC	0.21%	3.00%	1.01%	[redacted]	8.93%
	17	High Cost Combination	[redacted]	3.22%	0.86%	0.02%	6.93%
	18	Low Cost Combination	[redacted]	2.17%	0.70%	0.20%	3.71%
		Plan Average	[redacted]	**2.82%**	**0.73%**	**0.15%**	**4.93%**

1.4 2009 PREFERRED INTEGRATED RESOURCE PLAN

The Preferred Plan displayed in Figure 1.4.1 represents the single plan that performed most consistently throughout the aforementioned process and contains the preferred mix of supply- and demand-side options to meet expected future resource needs. Additionally, the Preferred Plan provides the lowest reasonable cost plan for the Company given considerations of these scenarios and sensitivities.

Figure 1.4.1 2009 PREFERRED INTEGRATED RESOURCE PLAN

Year	Planned Generation Under Construction	Planned Generation Under Development	Potential Generation Resources	Renewable Generation Resources	Demand-Side Resources
2010					Proposed DSM Programs
2011	Bear Garden				Proposed & Future DSM Programs
2012	Virginia City				↓
2013					
2014					
2015		Warren			
2016			2CT	Bio	
2017			CC	Bio + 4 Wind	
2018		North Anna 3			
2019			CT		
2020			CT		
2021			CC		
2022			CC		
2023			CC		
2024			CC		

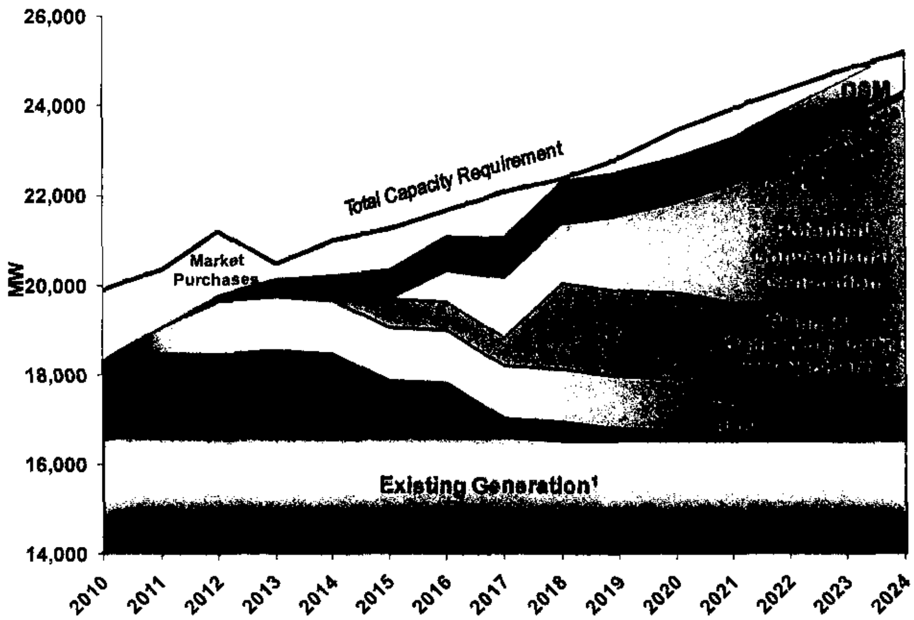
The Preferred Plan was reviewed and approved by the Company and subsequently represented in this filing with the SCC. While developing the Preferred Plan utilizing this IRP process, the Company continued to develop new generation projects and demand-side programs in response to growing capacity needs over the Planning Period.

In addition to existing generation, the 2009 Plan relies upon:

- Proposed and Future DSM programs reaching approximately 950 MW by 2024,
- Potential renewable resources of approximately 300 MW,
- Generation resources under construction of approximately 1,200 MW by 2024,
- Generation resources under development of approximately 1,900 MW by 2024,
- Additional conventional resources of approximately 4,500 MW that will continue to be studied as the resource need is established, and
- PJM market purchases and NUG capacity under contract.

To meet the projected electric customer demand and the reserve requirement in the Planning Period, the Company will need additional resources that total approximately 8,900 MW, consisting of a mix of supply-side resources totaling approximately 7,900 MW of capacity and nearly 950 MW of demand-side resources by 2024 as Figure 1.4.2 illustrates.

Figure 1.4.2 2009 INTEGRATED RESOURCE PLAN



Note: 1) Includes rating changes to existing units.

The 2009 Plan that the Company is presenting provides the ability to respond to many uncertainties brought on by changes in market conditions and customer demand. This 2009 Plan represents the Company's commitment to meeting future demand effectively through a balanced portfolio. This includes a combination of new traditional and renewable generation facilities as well as energy efficiency and peak shaving programs that provide a reliable supply of energy at the lowest reasonable cost to customers.

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 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 binary 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 binary variables to capture seasonal impacts
- *Industrial Sales equation*: Employment in manufacturing, Virginia GSP, electric prices, weather, billing days, and binary 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 binary variables to capture seasonal impacts
- *Street and Traffic Lighting Sales equation*: Number of customers and binary 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 binary 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 binary 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 2009 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 IHS Global Insight, Inc. ("Global Insight"). 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 1993 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. Historic and forecasted sales and customer count at the system level, as well as for Virginia and North Carolina individually, are given separately in Appendices 2A to 2F. Appendix 2G provides a summary of the summer and winter peaks used for modeling purposes.

Figure 2.2.1 SUMMARY OF ENERGY SALES & PEAK LOAD FORECAST

	2009	2024	Compound Annual Growth Rate (%) 2009-2024
DOM LSE			
TOTAL ENERGY SALES (GWh)	79,333	113,041	2.39%
Residential	29,851	38,408	1.69%
Commercial	27,739	47,999	3.72%
Industrial	9,306	10,741	0.96%
Resale	1,883	2,533	2.00%
Public Authorities	10,267	13,002	1.59%
Street and Traffic Lighting	287	358	1.48%
SEASONAL PEAK (MW)			
Summer	16,368	22,544	2.16%
Winter	14,288	18,992	1.92%
DOM ZONE			
SEASONAL PEAK (MW)			
Summer	18,727	25,618	2.11%
Winter	16,481	21,609	1.82%
ENERGY OUTPUT (GWh)	93,368	131,821	2.33%

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

Figure 2.2.2 GROWTH IN DOM ZONE PEAK LOAD

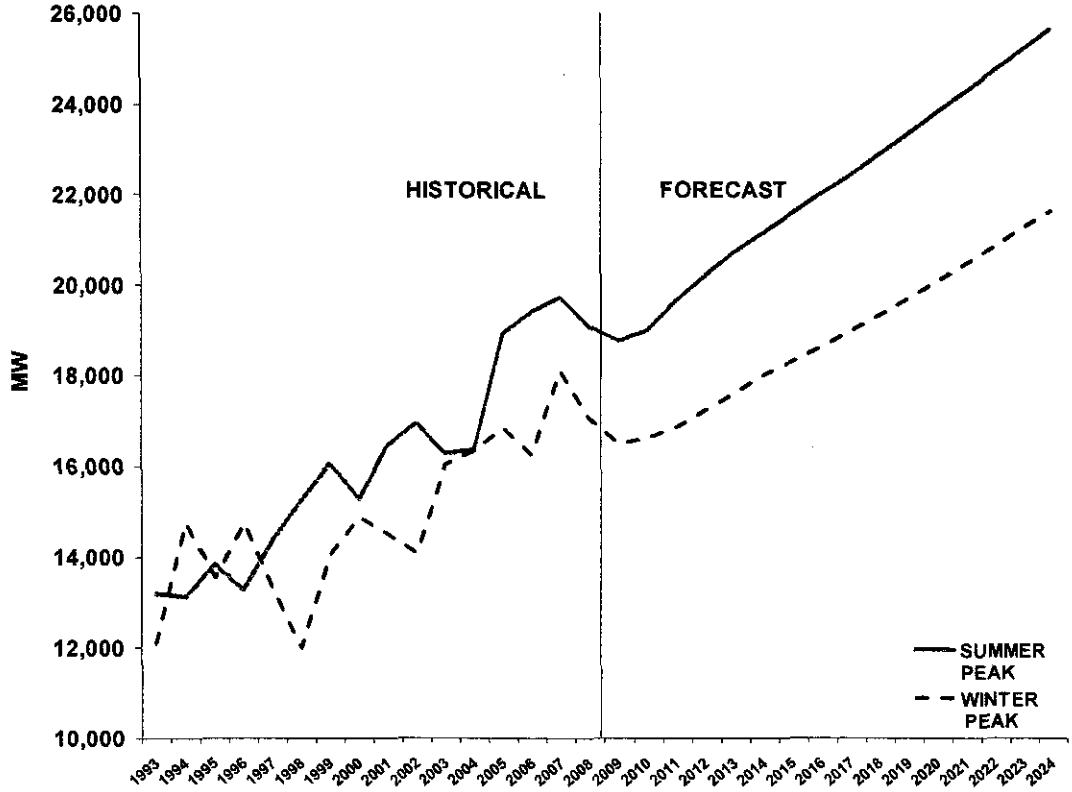


Figure 2.2.3 GROWTH IN DOM ZONE ANNUAL OUTPUT

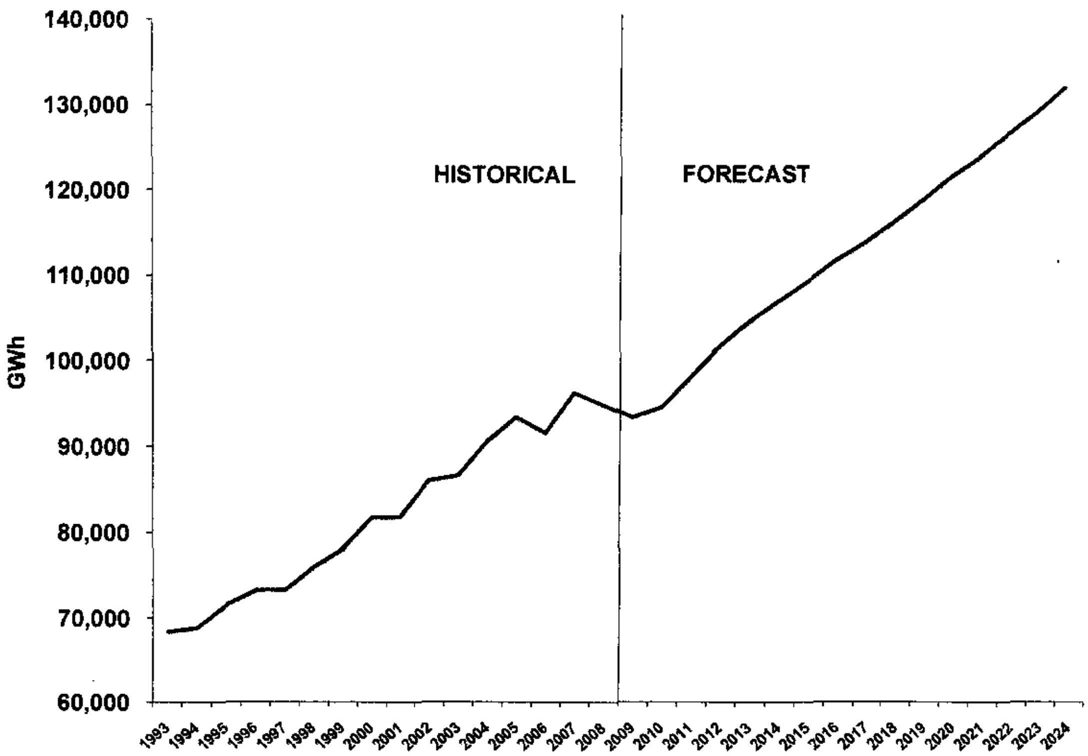


Figure 2.2.4 MAJOR ASSUMPTIONS FOR THE ENERGY SALES & PEAK DEMAND MODEL

	2009	2024	Compound Annual Growth Rate (%) 2009-2024
DEMOGRAPHIC:			
Customers (000)			
Residential	2,140	2,615	1.35%
Commercial	233	281	1.26%
Population (000)	7,849	8,963	0.89%
Housing - Total Starts	18,604	53,620	7.31%
ECONOMIC:			
Employment (000)			
Manufacturing	241	243	0.06%
Government	699	743	0.41%
Income ($)			
Per Capita Real disposable	31,340	42,001	1.97%
Price Index			
Consumer Price (1984=100)	211	294	2.24%
VA GSP	312	500	3.20%

The forecast of the Virginia economy drove the Company's energy sales and load forecasts. Though Virginia has been impacted by the current recession, the Commonwealth fared well compared to the nation in terms of job losses. As of June 2009, the seasonally adjusted unemployment rate in Virginia reached 7.2%, more than 2% 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 50% decline in housing starts in the state between 2005 and 2008. While recovery in housing is likely to be slow, Virginia is expected to show a 9% growth in housing starts in 2010, followed by a 16.6% increase in 2011. The unemployment rate should begin to level out in late 2009 and 2010 and start nudging down by 2011.

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 2% per year, on average. After suffering a decline in 2009, Virginia real GSP is projected to grow more than 3% per year, on average, over the next 15 years. During the same period, the Virginia population is expected to grow steadily at about 0.9% per year.

2.3 SUMMER & WINTER PEAK DEMAND & ANNUAL ENERGY

The 3-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 gives the required reserve margins for a 3-year actual and 15-year forecast.

2.4 ECONOMIC DEVELOPMENT RATES

The Company has one customer receiving service under an economic development rate in North Carolina with a peak load of 179 MW. There are no customers under an economic development rate in Virginia and there are no customers under a self-generation deferral rate.

Chapter 3

Existing & Proposed Resources

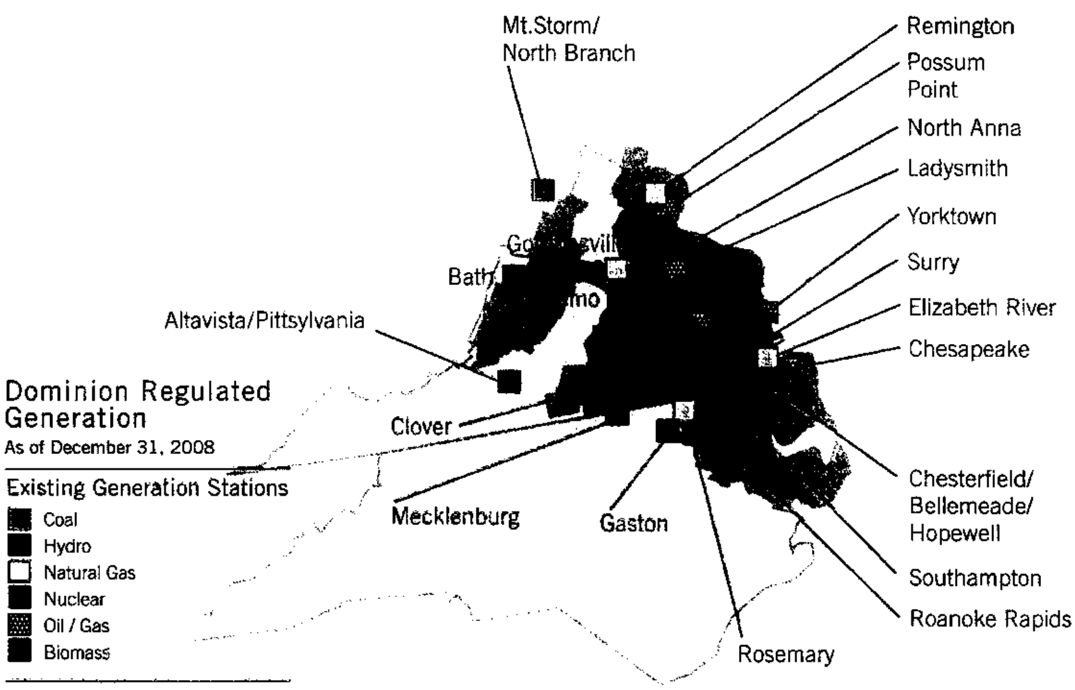
CHAPTER 3 – EXISTING & PROPOSED RESOURCES

OWNED GENERATION RESOURCES

3.1.1 EXISTING GENERATION

The Company's existing generating resources are located at multiple sites distributed geographically around its service territory as shown in Figure 3.1.1.1. This diverse fleet of 105 generation units includes 4 nuclear, 23 coal, 1 wood, 2 natural gas, 2 heavy oil, 7 combined cycle ("CC"), 46 combustion turbine ("CT"), 6 pumped storage, and 14 hydro units with a summer capacity exceeding 16,000 MW.[2] The Company's operational goal is to manage this fleet in a manner that provides reliable and cost-effective service under varying load conditions.

Figure 3.1.1.1 EXISTING GENERATION RESOURCES



The Company not only owns a variety of generation resources with different fuel types, but also has units with a wide age range of capacity. Figure 3.1.1.2 shows the demographics of the entire generation fleet. The largest share of the Company's total megawatts is generation units in the 30- to 40-year old range. Additionally, the next largest segment of generation resources is greater than 40 years old. In total, these generation resources provide more than half of the Company's megawatts. However, for the purpose of this 2009 Plan, it was assumed that no large unit retirements will occur during the Planning Period.

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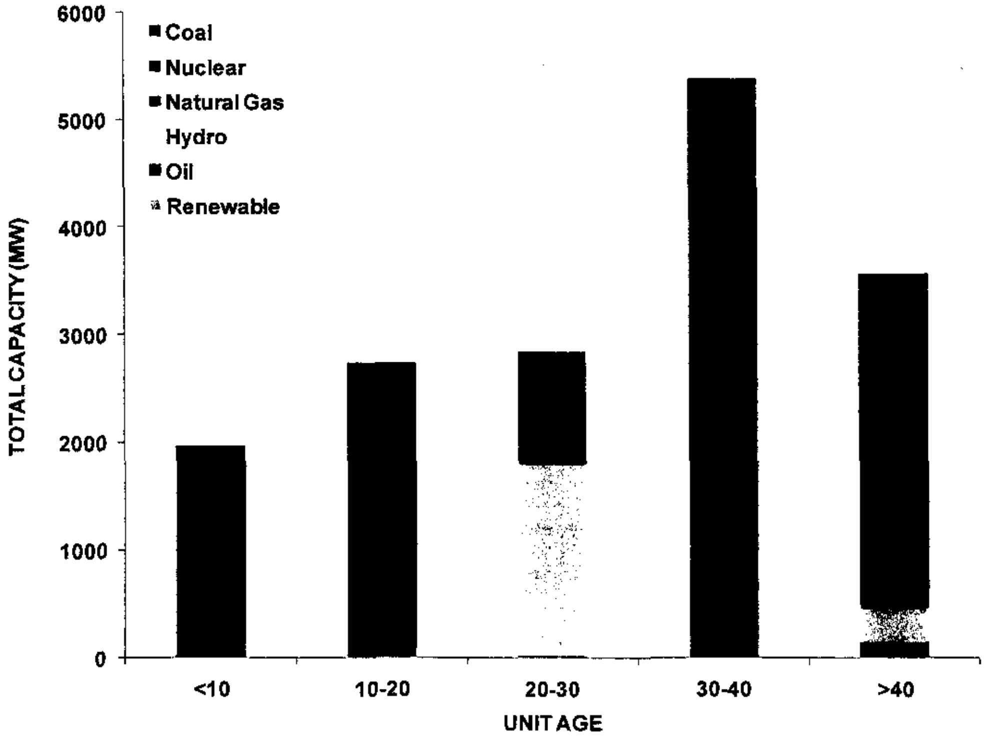
[2] All references to MW in this Chapter refer to summer capacity unless otherwise noted. Winter and nameplate capacities for Company owned generation units are listed in Appendix 3A attached to this filing.

Figure 3.1.1.2 GENERATION FLEET DEMOGRAPHICS



As shown in Figure 3.1.1.3, the Company's existing generation fleet is comprised of a balanced mix of over 16,000 MW of resources with varying operating characteristics and fueling requirements. The diversity of capacity and energy resources the Company uses to meet customer needs is an important aspect of resource planning.

Included in this mix of generation resources are over 400 MW of renewable generation that the Company owns and operates in Virginia and North Carolina. In Virginia, the Company owns and operates the wood-burning Pittsylvania power station (83 MW), which is one of the largest biomass facilities in the United States. Additionally, the Company's Altavista Power Station co-fires biomass with coal (6 MW of renewable). Hydro facilities include the Gaston Hydro Station (225 MW), Roanoke Rapids Hydro Station (99 MW), Cushaw (2 MW) and North Anna Hydro (1 MW). In 2009, these renewable resources provide over 400 gigawatt hours ("GWh") of generation.

In addition to the Company owned generation, the Company has contracted with several NUGs which supply over 1,770 MW of firm capacity and associated energy to meet the Company's load requirements. All of these contracts are expected to expire during the Planning Period. Once a NUG contract expires, the capacity available from such resource is not included as a firm resource for planning purposes. However, if the NUG continues to operate in the PJM market, its capacity and energy will be available to the Company through the competitive wholesale market or as a bilateral resource.

Figure 3.1.1.3 EXISTING CAPACITY RESOURCE MIX BY UNIT TYPE (2009)

[illegible]	Net Summer Capacity (MW)			
	[illegible]	Contracted	Total	%
Coal	4,772	743	5,515	30.2%
Natural Gas - Turbine	2,543	942	3,485	19.1%
Nuclear	3,195	-	3,195	17.5%
Hydro - Pumped Storage	1,802	-	1,802	9.9%
Heavy Fuel Oil	1,604	-	1,604	8.8%
Natural Gas - Combined Cycle	1,584	-	1,584	8.7%
Hydro - Conventional	327	-	327	1.8%
Natural Gas - Boiler	316	-	316	1.7%
Light Fuel Oil	237	-	237	1.3%
Renewable	89	92	181	1.0%
Total	16,469	1,776	18,245	100.0%

Due to differences in the operating and fuel costs of various types of units and PJM system conditions, the Company's generation mix is not equivalent to its capacity mix. The Company's generation fleet is economically dispatched by PJM within its larger footprint, ensuring that the 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 the resources within the DOM Zone from the lowest marginal cost units to the highest marginal cost units, while maintaining its mandated reliability standards. Figure 3.1.1.4 and Figure 3.1.1.5 give the Company's capacity and energy mix for 2009.

Figure 3.1.1.4 2009 CAPACITY MIX

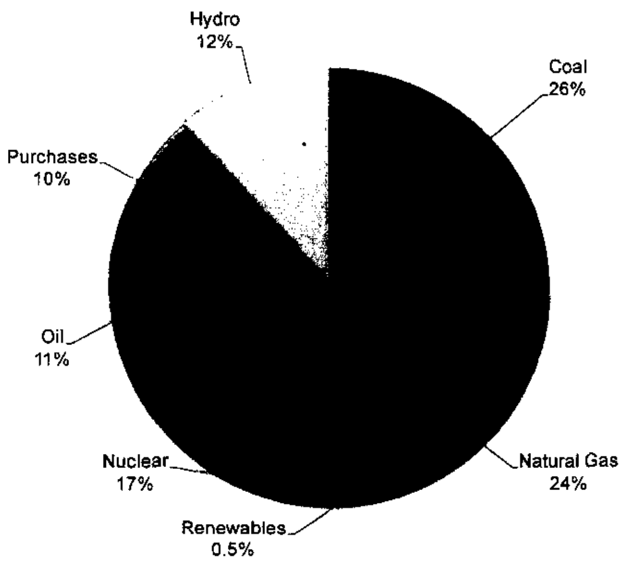
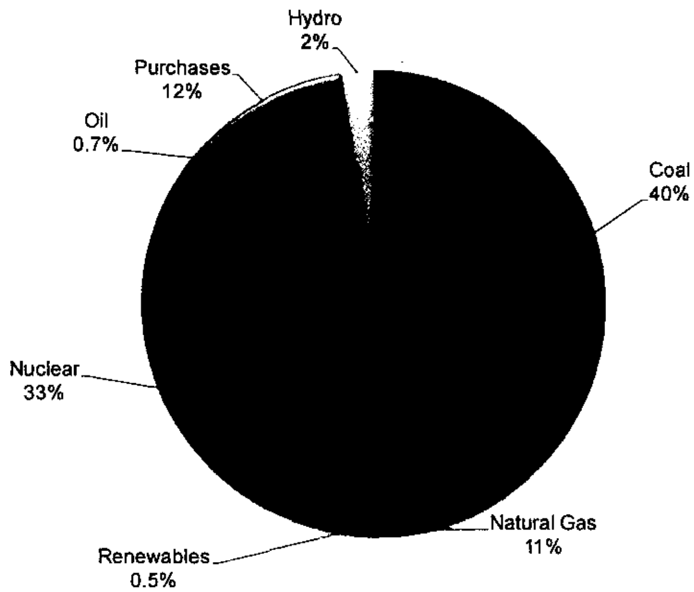


Figure 3.1.1.5 2009 ENERGY MIX



Appendices 3A, 3C, 3D, and 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 NUG units with which the Company does not have contractual relationships. This data is provided for information only and is not part of the Company's planning process.

3.1.2 PLANNED CHANGES TO EXISTING GENERATION

Efficiency, output, and environmental characteristics of plants are reviewed and improved upon as available through the Company's normal course of business. Many of the uprates and downrates discussed in this section occur during routine maintenance cycles or are associated with standard refurbishment. However, many plant ratings have been and will continue to be adjusted in accordance with PJM market rules and the final Consent Decree in October 2003 involving the Company, the U.S. Department of Justice, the U.S. Environmental Protection Agency, and five other states. The estimated capital expenditure at the time of the Decree was approximately $1.2 billion for environmental improvements to plants that will result in significant reductions in SO_2 and NO_x emissions by 2013. As additional uprates and downrates are identified, the Company will provide details of the associated analyses.

Over the past two years, the Company has increased its generating capacity by over 600 MW through the addition of new peaking units as well as uprates of existing units. 481 MW of new capacity resulted from the addition of 3 recently completed CT units at the existing Ladysmith Power Station in Caroline County, Virginia. Ladysmith Units 3 and 4, rated 161 and 160 MW respectively, began operations in June of 2008. Ladysmith Unit 5, a 160 MW unit, became operational in April 2009.

The Company continues to evaluate opportunities for existing unit uprates as a cost-effective means to increase generating capacity and improve system reliability. During the past two years, the Company's investment in its existing generation fleet has yielded capacity uprates of approximately 200 MW. Upgrades to the Darbytown, Elizabeth River, Remington, and Gravel Neck CT units added approximately 125 MW of peaking power to the fleet. Additionally, operating improvements at the Company's Bellemeade Power Station and Possum Point Unit 6 added approximately 30 MW of intermediate capacity. Additionally, the Company increased the capacity at its Bath County pumped storage facility by 48 MW.

Environmental emissions reduction is an important part of the Company's planning process and a key corporate focus. On May 7, 2008 the Company dedicated a new pollution control system at Chesterfield Unit 6. The installed scrubber is anticipated to provide a 95% reduction in sulfur dioxide emissions and a 90% reduction in mercury emissions. Additional scrubber installations are planned at five other coal units, which include the remaining Chesterfield station coal units and the two Yorktown station coal units.

Additional efforts to reduce emissions from the Company's existing generation fleet include plans to convert its coal-fired Bremo Power Station to gas, pending SCC approval. The station, which entered service in 1931, is the Company's oldest coal-fired power station in Virginia. The two coal units now in use were put into service in 1950 and 1958. The Company submitted this proposal as a part of its plans to build the Virginia City Hybrid Energy Center ("VCHEC") in Wise County, Virginia.

Bremo Units 3 and 4, with respective summer capacities of 71 and 156 MW, are planned to switch fuel in 2013 to 2014 timeframe. This conversion is expected to reduce the Company's emissions of SO_2, NO_x, and CO_2 while maintaining the same level of capacity at the Bremo site.

Appendix 3I provides a listing of uprates and downrates to the Company's existing generation. Outage dates are confidential and have been filed separately under seal in this docket.

3.1.3 POTENTIAL GENERATION RETIREMENTS

Although exact retirement dates are currently unknown, the Company anticipates that the units listed in Appendix 3J may retire within the Planning Period. The Appendix lists the retirement assumptions that are used for planning purposes but do not necessarily represent firm commitments by the Company. All the units referred to in Appendix 3J are older CTs with increasing risks of outage and failure. Prior to actual retirement the condition and economics of these units will be evaluated and the unit retirement dates may be revised.

3.1.4 PLANNED GENERATION RESOURCES

The Company has several planned generation projects currently in various stages of development and construction to meet its growing demand. The additions of these planned generating projects are needed to support the Company's load growth by providing baseload and intermediate capacity. Planned generation projects can be divided into two categories:

under construction and under development. These projects are summarized in Figure 3.1.4.1 and are detailed in the following sections.

Figure 3.1.4.1 PLANNED GENERATION ADDITIONS

Forecasted COD	Unit	Location	Primary Fuel	Unit Type[2]	Capacity (Net MW) Summer	Capacity (Net MW) Winter
Planned Generation Under Construction						
June 2011	Bear Garden	Buckingham County, VA	Natural Gas	I	590	613
2012	Virginia City Hybrid Energy Center	Wise County, VA	Coal/ Biomass	B	585	635
Planned Generation Under Development[1]						
2015[3]	Warren County Combined Cycle	Warren County, VA	Natural Gas	I	640	662
2018[3]	North Anna 3	Mineral, VA	Nuclear	B	1,273[4]	1,304[4]

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) Unit Type: B=Baseload; I=Intermediate. 3) Date as determined by this 2009 Plan. 4) Capacity reflects Company ownership only.

Planned Generation Under Construction:

There are two generation projects currently under construction, VCHEC and Bear Garden Power Station ("Bear Garden"). The two plants represent approximately 1,200 MW of capacity and both are expected to produce significant amounts of energy to serve the Company's customers. Project specifics and updates to construction are provided below.

Bear Garden Power Station

On March 27, 2009, the Company was granted a Certificate of Public Convenience and Necessity ("CPCN") by the SCC to construct and operate a 580[3] (nominal) MW CC natural gas- and oil-fired facility in Buckingham County, Virginia. The new generating facility will include two natural gas CT generators, two heat recovery steam generators with supplemental firing capability, and one steam turbine generator.

Bear Garden will contribute significant incremental, intermediate capacity to the Company's service territory. This will aid in serving customer load reliably while maintaining fuel diversity and reducing the Company's reliance on market purchases, thereby enhancing rate stability for its customers. Initial stages of the construction began on March 30, 2009 and Bear Garden is planned to be operational by June 2011.

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[3] PJM installed capacity rating is 590 MW.

Virginia City Hybrid Energy Center

On March 31, 2008, the Company was granted a CPCN by the SCC to construct and operate a 585 MW clean-coal powered electric generation facility located in Wise County, Virginia. The plant will use Circulating Fluidized Bed ("CFB") technology to burn waste coal from abandoned mines in the area. This technology will also allow the plant to remove 95% of SO_2, NO_x, and mercury from the coal. Additionally, the station's advanced design will allow the plant to consume up to 20% biomass fuel such as wood waste and wood by-products, which are renewable fuel resources. The station's two CFB boilers will also consume limestone to aid in the reduction of sulfur-dioxide emissions.

Construction of the VCHEC began in June 2008 and is expected to be completed in four years. Work recently began on building the station's industrial landfill for coal combustion by-products. Work also continues on other areas including the construction of foundations for major buildings and equipment, the installation of steel flues in the station's chimney, the preparation of the material handling area for coal, wood chips and limestone, and the installation of structural steel for the station's boiler and steam turbine generator buildings. The planned commercial operation date for the facility is in 2012. As of July 2009 the construction progress is on schedule and over one-third complete. Upon completion of the project, the VCHEC is expected to be one of the cleanest coal-burning power stations in the country.

Planned Generation Under Development:

The Warren County CC and the North Anna Unit 3 nuclear facility are under development as discussed below. Projects in this category are in early stages of the development process of permitting or approval. No final decision can be made to build any of the resources in this category until they are approved by the SCC.

Warren County Combined Cycle

The Warren County CC is expected to be a 640 MW plant located in the northwest area of Virginia. This project has received air and water permits. Based on the current schedule, the plant will come online in 2015.

The Warren County CC is expected to have significant regional benefits. The Company procured this project at a site in which a CC plant was already under development, which saved significant Company development effort. Additionally, this site is in close proximity to the Northern Virginia load center.

North Anna Unit 3

Nuclear power is a critical component of the Company's plan to achieve fuel diversity, stable long-term customer electric rates, and low emissions. North Anna Unit 3 would provide much needed baseload capacity to the region by 2018 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 do so to meet projected demand and energy requirements for electricity.

On November 27, 2007, the U.S. Nuclear Regulatory Commission ("NRC") issued an Early Site Permit to the Company's affiliate, Dominion Nuclear North Anna, LLC, for a site located at the Company's existing North Anna Power Station (Unit 3). 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 Early Site Permit to the Company and ODEC. The merger of Dominion Nuclear North Anna, LLC into the Company was effective December 1, 2008.

The North Anna 3 project is expected to provide the Company's customers with significant economic benefits. A portion of these benefits relates to the location of the project. The Company has been issued an Early Site Permit for the site. The two existing nuclear units will allow the third future unit to share some of the costs to meet fairly stringent safety and operating requirements. In March 2009, the Company issued a Request for Proposals ("RFP") to license, engineer, procure, and construct a nuclear unit at the North Anna Power Station. The Company continues to evaluate nuclear unit designs and submittals that have resulted from the RFP.

Appendix 3K provides in service dates and capacities for planned generation resources under construction and under development.

OTHER GENERATION RESOURCES

3.2.1 NON-UTILITY GENERATION

As referenced earlier in this section, 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 in excess of 1,770 MW made up of seven baseload units, one intermediate unit, and one peaking unit. NUGs noted as firm capacity resources are included in this 2009 Plan while the NUGs at customer sites, which are not firm capacity resources, are not included in this 2009 Plan.

Each of the NUG facilities listed as a capacity resource in Appendix 3B is under contract for supplying 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 is included as a resource in meeting the reserve requirements. The NUG contracts expire at different times during the Planning Period, with the last contract expiring in 2021. 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 or all of the NUG contracts may be renewed or extended at the expiration of their current contract terms, as the relevant economics warrant. These resources will most likely 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.

WHOLESALE & PURCHASED POWER

3.3.1 WHOLESALE & PURCHASED POWER

Purchased Power

Except for the NUG contracts described previously, 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, 2013.

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 two electric cooperatives. Appendix 3L provides a listing of wholesale power sales contracts to which the Company has committed or expects to sell power during the Planning Period.

Behind-the-Meter Generation

Behind-the-Meter Generation ("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. For planning purposes, the total BTMG unit output is netted against the customer's load. Additional or supplemental load required by these types of customers is included in the Company's load forecast. The unit descriptions are provided in Appendix 3B.

3.3.2 REQUEST FOR PROPOSALS

The Company conducted an RFP to solicit proposals for a gas-fired CC generating plant for commercial operation in 2011. An RFP was issued on December 6, 2007, requesting proposals for approximately 580 MW of new, intermediate capacity to be connected to the Company's bulk power transmission system. Based on the assessment of the proposals received, the Company determined that the Bear Garden CC Project was the best solution to meet the identified need. A Final Order has been issued in SCC Case No. PUE-2009-00014 regarding the Bear Garden CC Project.

CURRENT & PROPOSED DEMAND-SIDE MANAGEMENT RESOURCES

3.4.1 DEMAND-SIDE MANAGEMENT INTRODUCTION

The Company plans to promote DSM for all of its customers in Virginia and North Carolina. On July 28, 2009, the Company filed its initial DSM Portfolio of 12 Programs for its Virginia customers. The Company generally defines DSM as all activities or programs undertaken to influence the amount and timing of electricity use. For purposes of the Virginia DSM Programs, the Company applies the Virginia definitions set forth in Va. Code § 56-576. The Virginia definitions are summarized below:

- Energy Efficiency – 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 – 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. These programs will be dispatched by the Company or PJM in which customers must respond by reducing load during peak periods.
- 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.

At this time the Company has not filed for approval of DSM programs in North Carolina. When the Company files its energy efficiency and demand-side programs for North Carolina, it will ensure that it meets the North Carolina legislative definitions as given in General Statute § 62-133.8 (a) (2) and (4) for demand-side management and energy efficiency measures.

3.4.2 CURRENT DSM PROGRAMS

The following section includes a description of the current DSM programs being offered by the Company. The Company models existing demand-side pricing tariffs over a 15-year Planning Period, based on historical data from the Company's Customer Information Systems. These projections are modeled with diminishing returns assuming new DSM programs will offer more cost-effective choices in the future. No demand-side resources have been discontinued since the Company's 2008 Integrated Resource Plan.

STANDBY GENERATION & CURTAILABLE SERVICE TARIFFS

Program Type: Energy Efficiency - Demand Response

Target Class: Commercial & Industrial

Participants: 31 customers on Standby Generation in Virginia,
1 customer on Curtailment Service in Virginia,
7 customers on Schedule 6C in North Carolina

Capacity Available: See Figure 3.4.2.1

The Company currently offers two DSM pricing tariffs including Standby Generation ("SG") rate schedules in Virginia and North Carolina and Curtailable Service ("CS") rate schedules in Virginia and Schedule 6C (Curtailable Service) in North Carolina. 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 schedules require 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 program is primarily aimed at customers with the operational flexibility to store inventory or to curtail or reschedule production.

North Carolina Schedule 6C requires the participating customer to reduce its electric demand from normal levels to a contracted firm demand level when requested by the Company. Failure to comply with the Company's request to reduce demand to the contracted firm level results in a penalty, based on a demand charge that is approximately six times higher than the sum of the contract demand and firm demand charges on the customer's bill. The customer's contracted firm demand and the number of times the Company may request the curtailment differ by season.

During a load reduction event, a customer receiving service under one of the SG rate schedules is required to transfer a contracted level of load to its dedicated on-site backup generator while the customer receiving service under one of the CS rate schedules 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.

The Company has proposed closing Virginia jurisdictional Schedules SG and CS to new customers effective 60 days after the date of the SCC's Final Order in the 2009 Virginia Base Rate Case (Case No. PUE-2009-00019). The Company is proposing to close these rate schedules in anticipation of SCC approval of the new Commercial Distributed Generation ("DG") and Curtailment Service Programs that will provide comparable or greater benefits for customers with on-site generation or load interruption capabilities that wish to participate.

Figure 3.4.2.1 ESTIMATED LOAD RESPONSE DATA

	Summer 2008		Winter (2008-2009)	
	Number of Events	Estimated MW Reduction	Number of Events	Estimated MW Reduction
Standby Generation	19	22	3	15
Curtailable Service & NC Schedule 6C	19	5	3	5

<u>**COMPACT FLUORESCENT LIGHT – PRICE REDUCTION PROGRAM**</u>

Program Type: Energy Efficiency
Target Class: Primarily Residential; available for every type of energy consumer
Participants: 850,000 (Assuming four bulbs per participant)
Over 3,400,000 CFL Bulbs Sold as of June 1, 2009
Capacity Available: See Figure 3.4.2.2

In partnership with Honeywell and the Home Depot, the Company provides an instant discount of \$1.50 on single-packs and \$3.00 on multi-packs of ENERGY STAR® qualified Compact Fluorescent Light ("CFL") bulbs purchased at select Home Depot stores in the Company's Virginia service areas. The discount is provided automatically at the time of payment.

Figure 3.4.2.2 PARTICIPATION & EFFECTS OF CFL

Units	2007	2008	2009 (as of 6/1/2009)
MW	1.3	4.3	1.7
GWh	15.9	53.4	20.3
Bulbs Sold	568,822	1,909,687	727,360

3.4.3 CURRENT DSM PILOTS

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 Virginia SCC issued a Final Order on January 17, 2008, approving the Pilots and finding that these Pilots were necessary in order 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% by the year 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 demand-side 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 measurement and verification ("M&V") analyses, and an update on the two Pilots that have not yet ended. 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. In addition, the Company experienced greater success with Pilots that did not require in-home customer appointments for installation. The Final Report also noted that customers want information at the beginning of their enrollment as to how much savings to expect, what to expect on their first bill, and how to determine if they are reducing energy usage. For demand response programs, customers want more information on the frequency and duration of demand response events. All of this information is valuable in developing, marketing, and implementing future DSM programs.

The seven completed Pilots are:

1. Direct Load Control ("DLC") – 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

The following is a description of the two remaining Pilots.

PROGRAMMABLE THERMOSTATS WITH AMI AND CPP PILOT

Pilot Type: Demand Response
Target Class: Residential
Pilot Duration: Ends in November 2009

Pilot Description:

The Programmable Thermostats with Advanced Metering Infrastructure ("AMI") and Critical Peak Pricing ("CPP") Pilot allows the Company to cycle participants' central air-conditioning systems on and off and shift the temperature setting up or down during peak periods. The Company provides the participant with real-time energy cost via two-way communication based on the Company's CPP rate, Schedule 1-CPP Residential Critical Peak Pricing (Experimental).

DISTRIBUTED GENERATION / LOAD CURTAILMENT PILOT

Pilot Type: Demand Response
Target Class: Commercial, Industrial, & Governmental
Pilot Duration: Enrollment ends on December 31, 2009
Incentive payments end 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 to curtailed facilities at utility-specified times. 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 install, operate, and maintain the generators at participating customer facilities during such events.

3.4.4 CURRENT CONSUMER EDUCATION PROGRAMS

The Company's educational initiatives include providing demand and energy usage information, education, and online customer support options to assist the customer in managing energy consumption. Through consumer education, the Company is working to encourage the adoption of energy efficient technologies in residences and businesses in Virginia and North Carolina.

The Company's website has a page entitled, "Energy Conservation and the Environment," with helpful information for residential and non-residential customers. Examples of how the Company increases customer awareness include:

"Every Day"

The Company's Corporate Communications department is credited with "Every Day," a daily 30-second commercial and print ad that addresses the importance of energy conservation and renewable energy. This ad can be viewed through the Company website at http://www.dom.com/about/advertising/index.jsp.

Customer Connection Newsletter

The Customer Connection newsletter is sent to customers as an insert to their monthly power bills. It contains news on topics such as conservation 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 Customer Connection are located at: http://www.dom.com/dominion-virginia-power/index.jsp.

News Releases

The Company's Media Relations staff prepares news releases and reports on the latest developments on Company conservation 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 online by customers and other parties of interest through the Company's website at: http://www.dom.com/news/index.jsp.

Outreach Seminars

The Company's Media and Community Relations personnel as well as representatives from the Energy Conservation department conduct outreach seminars during which they share energy conservation information to both internal and external audiences. Company representatives positively impact the communities the Company serves through presentations they make in school systems within the service territory. Company employees give presentations about using energy wisely and environmental stewardship to elementary, middle, and high school students. They also provide helpful materials for students to share with their families. "Project Plant It!" is an innovative program in Virginia 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 provides this program at no cost to more than 34,000 elementary school students in the Company's service territory.

Online Energy Calculators

Home and business energy calculators are provided on the Company website to estimate electrical usage for residences and business facilities. These help customers understand specific energy use by their household or location, compare and analyze their bills from month to month, and discover new means to reduce usage and save money. An appliance energy usage calculator is also featured that allows for electric usage calculations, depending on the wattage of the appliance and the number of hours used. The energy calculators are available online:
http://www.dom.com/about/conservation/energy-calculators-help-find-energy-savings.jsp.

CFL Education

Another page on the website provides information on the Company's current CFL price reduction program available in Virginia including helpful facts about how to use CFLs. It also includes a list of participating Home Depot stores and CFLs eligible for the discount program, along with frequently asked questions about the use of CFLs. This webpage is available online: http://www.dom.com/dominion-virginia-power/customer-service/energy-conservation/save-big-on-cfls.jsp.

The website also provides information on increasing the environmental benefits of CFLs by recycling old bulbs and provides a link to http://earth911.com/ for a one-stop source of information about disposing of or recycling mercury-containing light bulbs.

Energy Conservation Blog

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 customers reduce energy consumption. It is also a means to report the current impacts achieved through Company conservation programs. The blog is located online: http://e-conserve.blogspot.com/.

Energy Saving Tip of the Day

One feature of the Company's website spotlights the "Energy-Saving Tip of the Day" which gives a specific suggestion on how to save energy in the customer's home or business. The full list of ideas for saving energy is maintained online for customer reference as more tips are added. The website also directs customers to organizations and agencies that relay helpful information on a variety of energy conservation related topics. The entire list of energy saving tips is located on the Company's website at: http://www.dom.com/about/conservation/energy-saving-tips-and-information.jsp.

Trade Shows, Exhibits, and Speaking Engagements

Through trade shows, exhibits and executive speaking engagements, the Company strives to emphasize and inform customers and communities about the importance of implementing energy-saving measures in homes and businesses.

The Company has not discontinued any educational programs since the Company's 2008 Plan.

3.4.5 PROPOSED DSM PORTFOLIO OF PROGRAMS

The Company filed for SCC approval of a portfolio of 12 DSM programs (individually "DSM Program(s)" or "Program(s)" and collectively, "DSM Portfolio" or "Portfolio") on July 28, 2009 (Case No. PUE-2009-00081). The proposed Portfolio demonstrates how the Company plans to reduce energy consumption through the implementation of these proposed energy efficiency and peak shaving Programs in Virginia. The Company plans to implement the Portfolio after SCC approval is obtained. These Programs will also be evaluated and considered for approval and implementation in the Company's North Carolina service territory. Refer to Appendices 3M, 3N, 3O, and 3P for the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and Program penetration for each proposed Program in the Portfolio.

AIR CONDITIONER CYCLING PROGRAM

Program Type: Peak Shaving

Target Class: Residential

Program Duration: Modeled to begin in 2010 and continue through 2024

Program Description:

This Program provides an external radio frequency cycling switch operating on central air conditioners and heat pump systems. Customers who enroll in this Program will allow the Company to cycle their central air-conditioning and heat pump systems during peak load periods. The cycling switch will be installed by a contractor and is located on or near the outdoor air conditioning unit(s). The Company plans to remotely signal the unit when peak load periods are expected to occur, and the air conditioning or heat pump system will be cycled off and on for short intervals.

COMMERCIAL DISTRIBUTED GENERATION PROGRAM

Program Type: Energy Efficiency - Demand Response
Target Class: Commercial & Industrial
Program Duration: Modeled to begin in 2010 and continue through 2024

Program Description:
The Commercial DG Program is an outgrowth of the DG/Load Curtailment Pilot, whereby a contractor will install, maintain, and dispatch generators when called upon by the Company for up to 120 hours per year. Customers who enroll in this Program pay a monthly backup generation service payment to the contractor and receive an incentive, or discount, from the contractor for capacity enrolled in the Program. When not being dispatched by the Company, the generators may be used at the participants' discretion in order to supply power during an outage, consistent with applicable environmental restrictions.

CURTAILMENT SERVICE PROGRAM

Program Type: Energy Efficiency - Demand Response
Target Class: Commercial & Industrial
Program Duration: Modeled to begin in 2010 and continue through 2024

Program Description:
The CS Program is structured to allow a contractor to directly control energy consuming assets at the participant's end-use facilities in order to reduce peak demand and conserve energy. The contractor will monitor participant facility reductions ensuring compliance, effective baseline methodologies, quality performance, and timely verification.

RESIDENTIAL LIGHTING PROGRAM

Program Type: Energy Efficiency
Target Class: Residential
Program Duration: Modeled to begin in 2010 and continue through 2024

Program Description:
This Program is an extension of the Company's current CFL price reduction program that began in October of 2007. The Company partners with manufacturers and retailers to make high-efficiency lighting purchases more affordable. CFLs, when compared to incandescent lamps, give the same amount of visible light, use approximately 75% less energy, and have an approximately 10 times longer rated life. This Program is expected to evolve in future years by including new emerging residential lighting technologies, such as light-emitting diode ("LED") technology.

LOW INCOME PROGRAM

Program Type: Energy Efficiency
Target Class: Residential
Program Duration: Modeled to begin in 2010 and will continue through 2024

Program Description:

This Program provides low income homeowners with free energy audits that identify certain areas within residences where participants can save money on their monthly energy bills. The energy auditor will identify simple measures that homeowners can take to improve the homes' energy efficiency. If homeowners approve, auditors will immediately make certain improvements while at the homes.

ENERGY STAR NEW HOMES PROGRAM

Program Type: Energy Efficiency
Target Class: Residential
Program Duration: Modeled to begin in 2010 and will continue through 2024

Program Description:

This Program provides home builders and developers the ability to conduct in-home inspections to ensure newly built homes meet ENERGY STAR Standards. ENERGY STAR qualified new homes must meet guidelines for energy efficiency set by the U.S. Environmental Protection Agency ("EPA"). These homes are at least 15% more energy efficient than homes built to the 2004 International Energy Conservation Code or International Residential Code and include additional energy-saving features that typically make these homes 20% to 30% more efficient than standard homes. The key objectives of this Program are to increase customer awareness, educate builders about the benefits of new homes built to the ENERGY STAR performance standards, and to reduce overall energy consumption.

RESIDENTAL HEAT PUMP TUNE-UP PROGRAM

Program Type: Energy Efficiency
Target Class: Residential
Program Duration: Modeled to begin in 2010 and continue through 2024

Program Description:

The Residential Heat Pump Tune-Up Program allows participants to tune-up their existing heat pumps one time every five years per unit in order to achieve maximum operational performance. A properly tuned system should increase efficiency, reduce operating costs, and prevent premature equipment failures.

RESIDENTIAL REFRIGERATOR TURN-IN PROGRAM

Program Type: Energy Efficiency
Target Class: Residential
Program Duration: Modeled to begin in 2010 and will continue through 2024

Program Description:
The Residential Refrigerator Turn-In Program is designed to dispose of a second inefficient refrigerator or freezer that is at least 20 years old and still drawing power. Participants will arrange for the Company or designee to pick up and properly dispose of the refrigerator at no cost and in an environmentally friendly way.

HEAT PUMP UPGRADE PROGRAM

Program Type: Energy Efficiency
Target Class: Residential
Program Duration: Modeled to begin in 2010 and will continue through 2024

Program Description:
The Heat Pump Upgrade Program gives customers an incentive to upgrade their heating and cooling systems to more energy efficient units. Participants replace their existing heat pumps with units having a greater Seasonal Energy Efficiency Ratio ("SEER"), and Heating Seasonal Performance Factor ("HSPF") rating than the current nationally mandated efficiency standard. These new, more efficient units should reduce overall consumption and lower participants' annual operating costs.

COMMERCIAL HVAC UPGRADE PROGRAM

Program Type: Energy Efficiency
Target Class: Commercial and Industrial
Program Duration: Modeled to begin in 2010 and will continue through 2024

Program Description:
Properly operating commercial Heating, Ventilating, and Air Conditioning ("HVAC") systems are essential to maintaining a comfortable, healthy, and productive work environment. Collectively, these systems account for approximately 40% of the electricity used in typical commercial buildings. This Program is designed to induce customers to replace or upgrade inefficient units. High efficiency HVAC upgrades should assure commercial customers that their heating and cooling systems are running at maximum efficiency while minimizing energy consumption. By taking advantage of the newest developments in HVAC technologies, participants can lower energy consumption while increasing comfort and occupant productivity.

VOLTAGE CONSERVATION PROGRAM

Program Type: Energy Efficiency
Target Class: Residential, Commercial, & Industrial
Program Duration: Modeled to begin in 2009 and continue through 2024

Program Description:

The Voltage Conservation 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.

This Program is enabled through the deployment of AMI, which allows 15 minute voltage and energy monitoring to the meter for all customers. The Company currently plans to deploy all AMI meters by the end of 2013.

COMMERCIAL LIGHTING PROGRAM

Program Type: Energy Efficiency
Target Class: Commercial and Industrial
Program Duration: Modeled to begin in 2010 and will continue through 2024

Program Description:

This Program provides commercial customers with an incentive to retrofit their existing inefficient lighting systems with more cost-effective, energy efficient lighting systems.

3.4.6 DSM PROPOSED PORTFOLIO COST-EFFECTIVENESS RESULTS

Figure 3.4.6.1 shows the individual Programs' cost-benefit results, the projected demand and energy reductions, and the Portfolio's overall performance at the system level. The test results for the entire Portfolio are greater than 1.0, supporting what the Company believes to be a viable cost-effective Portfolio for all stakeholders.

Figure 3.4.6.1 PROPOSED PROGRAMS COST-EFFECTIVENESS RESULTS

Proposed Programs	Participant	Utility	TRC	RIM	Projected MW Reduction in 2024	Projected GWH Savings in 2024
Peak Shaving Programs						
Air Conditioner Cycling Program	N/A	1.15	2.17	1.15	415	0
				Totals	415	0
Energy Efficiency - Demand Response Programs						
Commercial Distributed Generation Program	4.92	0.81	2.31	0.80	182	7
Curtailment Service Program	7.76	0.77	1.71	0.76	119	3
				Totals	301	10
Energy Efficiency Programs						
Residential Lighting Program	11.08	9.71	6.78	0.73	11	124
Low Income Program	N/A	0.30	1.96	0.23	3	19
ENERGY STAR® New Homes Program	1.28	2.20	0.82	0.62	5	41
Residential Heat Pump Tune-Up Program	3.42	2.14	2.17	0.74	46	159
Residential Refrigerator Turn-In Program	N/A	1.96	2.29	0.67	4	17
Heat Pump Upgrade Program	2.85	2.72	2.24	0.86	24	73
Commercial HVAC Upgrade Program	3.92	6.96	4.64	1.41	17	40
Voltage Conservation Program	N/A	2.75	2.75	2.75	0	2,283
Commercial Lighting Program	4.48	3.98	3.61	0.93	34	274
				Totals	145	3,029
Portfolio Results						
Proposed DSM Portfolio	4.96	2.05	2.60	1.41	861	3,039

Note: *The RIM calculation for Voltage Conservation Program excludes net loss revenues since all customers participate.*

OWNED TRANSMISSION RESOURCES

3.5.1 EXISTING TRANSMISSION RESOURCES

The Company has over 6,000 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 addition to existing transmission lines, one 230 kV line (Bristers-Gainesville) in Virginia was added to the power grid during 2009. In North Carolina, a new 115 kV line, Kitty Hawk to Colington, will come online in May 2010.

CONFIDENTIAL –

[redacted]

[redacted]

3.5.2 EXISTING TRANSMISSION & DISTRIBUTION LINES

Appendices 3Q, 3R, 3S, 3T, 3U, and 3V contain 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.

3.5.3 TRANSMISSION PROJECTS UNDER CONSTRUCTION

Appendix 3W contains the list of the Company's transmission interconnection projects under construction with associated enhancement costs. A list of the Company's transmission lines and associated facilities that are under construction or for which there are plans to be constructed may be found in Appendix 3X.

Chapter 4

Planning Assumptions

CHAPTER 4 –PLANNING ASSUMPTIONS

4.1 INTRODUCTION

This chapter describes the Company's transmission planning process, PJM capacity planning process and reserve requirements, renewable energy requirements, and market commodity price forecasts. The Company's planning process is designed to implement an Integrated Resource Plan that provides reliable electric service at the lowest reasonable cost over the long-term. The process relies upon a number of assumptions and constraints including requirements from PJM. This chapter describes assumptions and requirements associated with the 2009 Plan's development that are not discussed in previous chapters.

Over the long-term, the fundamentals of the energy market generally remain steady. Periodically, an event occurs that changes the long-term supply and demand of energy resources, resulting in a rebalancing of the Company's long-run view. The Company updates its planning assumptions annually to maintain a consistent view of relevant markets, the economy, and regulatory drivers. Data sets required to develop the forecast and use as modeling inputs to simulate the dispatch of the electric system are updated concurrently to maintain consistency across assumptions.

4.2 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 North American Electric Reliability Corporation ("NERC") Reliability Standards as well as the Southeastern Reliability Conference ("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 its 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 5-year and 15-year outlook. Specifically, for short-term planning, the 5-year outlook enables the Company to meet near-term load growth. For example, the PJM RTEP calls 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.

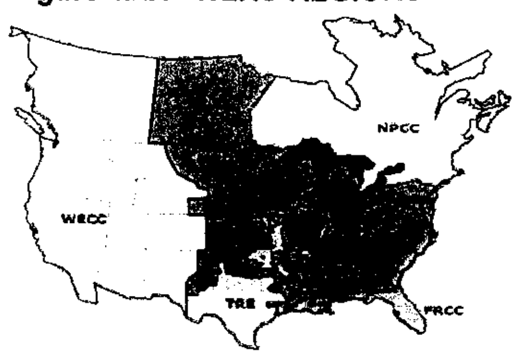
The Company evaluates its ability to support expected customer growth through the internal planning process. The results of this evaluation indicate if transmission improvements are needed, for which the Company seeks approval from the appropriate Commission and the PJM

RTEP process. Additionally, the Company performs seasonal operating studies to identify facilities in the Company's transmission system that could be critical during the upcoming season.

This process helps the Company expand its transmission infrastructure due to load growth in 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 4.2.1 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, Inc. (SPP)
Texas Regional Entity (TRE)
Western Electricity Coordinating Council (WECC)

Note: *Retrieved from the NERC website on April 23, 2009; http://www.nerc.com/page.php?cid=1|9|119*

4.3 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 the PJM's public website at http://www.pjm.com/markets-and-operations/etools/oasis/atc-information.aspx.

4.4 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. 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 14B posted on PJM's website at http://www.pjm.com/documents/~/media/documents/manuals/m14b.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 4.4.1 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. However, to accomplish this goal, the Company must comply and coordinate with a variety of regulatory bodies that address reliability, grid expansion, and costs which fall under the authority of NERC, PJM, and the SCC or 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 options for analyses that would support siting of potential generation resources and would include a transmission component which not only offers flexibility in locating facilities, but also the opportunity to locate units that offer additional grid benefits. Development of this aspect of the Company's long-term planning process will take time, and coordination with and incorporation of the PJM process will be critical to understand before this capability of the planning process may be realized.

4.5 PJM CAPACITY PLANNING PROCESS & RESERVE REQUIREMENTS

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

Short-Term Capacity Planning Process – Reliability Pricing Model

As a PJM member, the Company is a signatory to PJM's Reliability Assurance Agreement ("RAA") 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 4.5.1 provides estimated 2010 to 2012 capacity positions and associated reserve margins based on the 2009 PJM forecast and RPM auctions that have already been conducted.

Long-Term Capacity Planning Process – Reserve Requirement

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 2008 Reserve Requirement Study[4] recommends using a reserve margin of 16.2%[5] to satisfy the reliability criteria required by NERC, RFC, and Planned Reserve Sharing Group ("PRSG"). According to the PJM report, the

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[4] PJM's current reserve margin study, "2008 Reserve Requirement Study," is available at www.pjm.com.
[5] Previously PJM recommended a requirement of 15.5%

increase in the reserve margin from the previous study is a result of an increase in generator forced outage rates and a slight reduction in PJM/World load diversity[6].

Three assumptions are made by the Company when applying the PJM reserve margin to the Company's modeling efforts. First, PJM has a shorter planning period than the Company, so the Company takes the most recent study and assumes the reserve margin value will continue throughout its 2024 planning period. Second, PJM develops reserve margin estimates for planning years rather than calendar years, whereas the Company uses PJM values, and conducts its analysis, in calendar years. PJM planning years occur from June 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.

Finally, PJM reserve margin requirements are based on the PJM coincidental peak load forecast; however, 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. The coincidence factor for the Company's load is approximately 96.4% as calculated using PJM's January 2009 Load Forecast. In 2013, applying the PJM Installed Reserve Margin ("IRM") requirement of 16.2% with the Company's coincidence factor of 96.4% resulted in an effective reserve margin of 12.0% as shown in Figure 4.5.1. This reserve margin is then used for each of the remaining planning years.

[6] 2008 PJM Reserve Requirement Study page 2

Figure 4.5.1 PEAK LOAD FORECAST & RESERVE REQUIREMENT

Year	Net Summer Peak[1]	PJM Installed Reserve Margin Requirements[2]	Effective Reserve Margin	Reserve Requirement	Total Resource Requirement[3]
	MW	%	%	MW	MW
2010	16,940	-	17.4%	2,947	19,887
2011	17,582	-	16.1%	2,821	20,404
2012	17,918	-	16.7%	3,040	20,957
2013	18,383	16.2%	12.0%	2,191	20,574
2014	18,912	16.2%	12.0%	2,247	21,160
2015	19,165	16.2%	12.0%	2,275	21,440
2016	19,547	16.2%	12.0%	2,320	21,868
2017	19,925	16.2%	12.0%	2,365	22,290
2018	20,195	16.2%	12.0%	2,397	22,592
2019	20,598	16.2%	12.0%	2,445	23,043
2020	21,162	16.2%	12.0%	2,512	23,675
2021	21,581	16.2%	12.0%	2,562	24,143
2022	21,982	16.2%	12.0%	2,610	24,592
2023	22,373	16.2%	12.0%	2,657	25,029
2024	22,679	16.2%	12.0%	2,693	25,372

Note: *1) Includes all Load Adjustments. 2) 2010 – 2012 values reflect the Company's position following RPM base residual auctions that have cleared. 3) Includes wholesale obligations.*

The total resource requirement column in Figure 4.5.1 provides the total amount of peak capacity including the reserve margin used in the 2009 Plan. This represents the Company's total resource need 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 enhance the value and are an integral part of the Company's planning processes. For transmission planning, the Company takes advantage of 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 PJMs' reserve margin guidelines.

4.6 RENEWABLE ENERGY REQUIREMENTS

Virginia Renewable Energy Portfolio Standard ("RPS")

On July 28, 2009, and in accordance with Va. Code § 56-585.2, the Company filed its Virginia RPS Compliance Plan (Case No. PUE-2009-00082) with the SCC to participate in the voluntary RPS program. The RPS requirements prescribe that a percent of the Company's energy come from renewable resources. The Company can meet Virginia's RPS program through the generation of renewable energy, purchases of renewable energy, purchases of Renewable

Energy Certificates ("RECs"), or a combination of the three options. Figure 4.6.1 displays Virginia's RPS goals.

Figure 4.6.1 VIRGINIA RPS GOALS

Year	Percent of RPS	Annual GWh
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: *Base year sales are equal to 2007 VA jurisdictional retail sales, minus 2004 to 2006 average nuclear generation*

The Company has included renewable resources as an option to the resource planning model and will continue to consider the economics and RPS requirements as applicable to its Plan. Specifically, the Company is in the early stages of developing a variety of new renewable energy generation facilities, including: multiple wind projects for a total up to 245 MW net ownership for availability by 2025, and biomass units or conversion to biomass for a total of up to 100 MW for availability by 2025. Whether such facilities are constructed depends on a variety of factors which cannot be known at this time, including the market for renewable resources, access to capital, environmental laws, siting and permitting issues, federal legislation, and technical innovations. The 2009 Plan reiterates the Company's plan to meet Virginia's RPS guidelines at a reasonable cost and in a prudent manner as summarized below.

- Apply renewable energy from existing generating facilities, including NUGs.
- Purchase cost-effective RECs.
- Construct new renewable resources when and where feasible.

North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Plan

North Carolina General Statute § 62-133.8 requires the Company to comply with the state's REPS program. North Carolina's general REPS requirement can be met by energy efficiency measures (capped at 25% of the REPS requirements through 2020 and up to 40% thereafter), generating renewable energy, purchasing renewable energy, purchasing RECs, or a combination of the four options among others as permitted by § 62-133.8 (b) (2). The Company plans to meet a portion the general REPS requirements with many of the energy efficiency programs presented in this Plan after filing and gaining approval from the NCUC to offer the programs. Program specifics are detailed in the Company's North Carolina REPS Compliance Plan (Docket No. E-100, Sub 124) as filed simultaneously with this 2009 Plan with the NCUC as NC IRP Addendum 1.

Figure 4.6.2 displays North Carolina's overall REPS requirements.

Figure 4.6.2 NORTH CAROLINA REPS REQUIREMENTS

Year	Percent of REPS	Annual GWh[1]
2012	3% of 2011 NC Retail Sales	117
2013	3% of 2012 NC Retail Sales	121
2014	3% of 2013 NC Retail Sales	124
2015	6% of 2014 NC Retail Sales	252
2016	6% of 2015 NC Retail Sales	256
2017	6% of 2016 NC Retail Sales	261
2018	10% of 2017 NC Retail Sales	442
2019	10% of 2018 NC Retail Sales	449
2020	10% of 2019 NC Retail Sales	458
2021	12.5% of 2020 NC Retail Sales	584

***Notes:** 1) Annual GWh 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/or swine waste through the purchase of RECs and/or purchased energy, as applicable. These set aside requirements represent approximately 0.05% of system load by 2024 and will not materially alter the 2009 Plan.*

As part of the total REPS requirements North Carolina requires certain renewable set aside provisions, particularly solar energy, swine waste, and poultry waste resources[7] as shown in Figure 4.6.3, Figure 4.6.4, and Figure 4.6.5.

Figure 4.6.3 NORTH CAROLINA SOLAR REQUIREMENTS

Year	Requirement Target (%)	Annual GWh[1]
2010	0.02% of 2009 NC Retail Sales	0.757
2011	0.02% of 2010 NC Retail Sales	0.753
2012	0.07% of 2011 NC Retail Sales	2.723
2013	0.07% of 2012 NC Retail Sales	2.826
2014	0.07% of 2013 NC Retail Sales	2.894
2015	0.14% of 2014 NC Retail Sales	5.888
2016	0.14% of 2015 NC Retail Sales	5.980
2017	0.14% of 2016 NC Retail Sales	6.098
2018	0.20% of 2017 NC Retail Sales	8.836
2019	0.20% of 2018 NC Retail Sales	8.984
2020	0.20% of 2019 NC Retail Sales	9.155
2021	0.20% of 2020 NC Retail Sales	9.349

***Notes:** 1)* Annual GWh -an estimate based on latest forecast sales.

[7] The Company is currently awaiting a determination from the NCUC regarding its ability to apply RECs to meet these set aside requirements in Docket No. E-100, Sub 113.

Figure 4.6.4 NORTH CAROLINA SWINE WASTE REQUIREMENTS[1]

Year	Target[2]	Dominion Market Share (Est.)	Annual GWh[3]
2012	0.07% of 2011 NC Retail Sales	3.59%	2.723
2013	0.07% of 2012 NC Retail Sales	3.58%	2.826
2014	0.07% of 2013 NC Retail Sales	3.57%	2.894
2015	0.14% of 2014 NC Retail Sales	3.57%	5.888
2016	0.14% of 2015 NC Retail Sales	3.56%	5.980
2017	0.14% of 2016 NC Retail Sales	3.54%	6.098
2018	0.20% of 2017 NC Retail Sales	3.54%	8.836
2019	0.20% of 2018 NC Retail Sales	3.54%	8.984
2020	0.20% of 2019 NC Retail Sales	3.54%	9.155
2021	0.20% of 2020 NC Retail Sales	3.54%	9.349

***Notes:** 1) The Company is currently awaiting a determination from the NCUC regarding the Joint Motion Of Progress Energy Carolinas, Inc., Duke Energy Carolinas LLC, Dominion North Carolina Power, North Carolina Electric Membership Corporation, North Carolina Eastern Municipal Power Agency And North Carolina Municipal Power Agency Number 1 to modify the swine and poultry waste resource requirements of N.C. Gen. Stat. §§ 62-133.8 (e) and (f), respectively and to clarify the Electric Suppliers' obligations. 2) The Swine Waste Resource requirement is calculated as an aggregate target for NC Electric Suppliers distributed based on market share. 3) Annual GWh is an estimate only based on the latest forecast sales.*

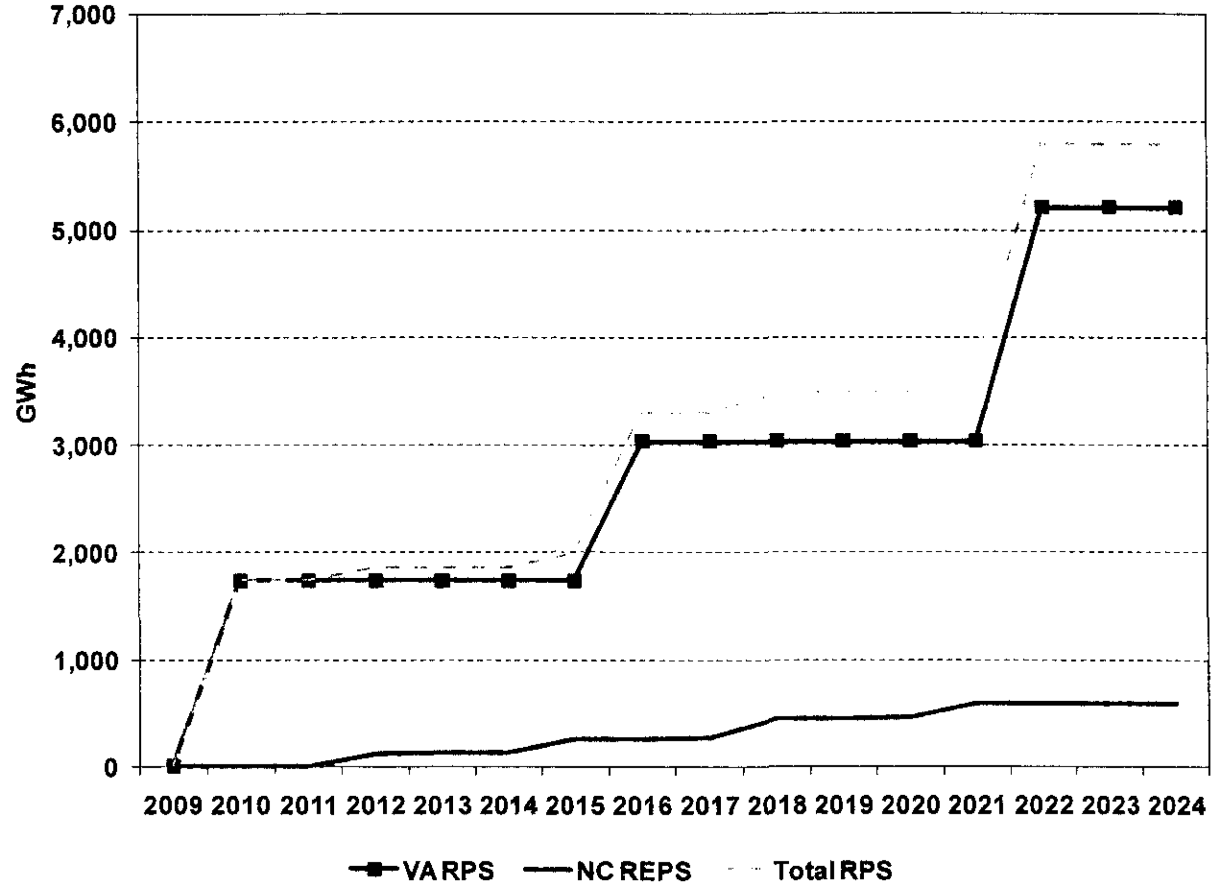
Figure 4.6.5 NORTH CAROLINA POULTRY WASTE REQUIREMENTS[1]

Year	Target (GWh)	Dominion Market Share (Est.)	Annual GWh[2]
2012	170	3.59%	6
2013	700	3.58%	25
2014	900	3.57%	32
2015	900	3.57%	32
2016	900	3.56%	32
2017	900	3.54%	32
2018	900	3.54%	32
2019	900	3.54%	32
2020	900	3.54%	32
2021	900	3.54%	32

***Notes:** 1) The Company is currently awaiting a determination from the NCUC regarding the Joint Motion Of Progress Energy Carolinas, Inc., Duke Energy Carolinas LLC, Dominion North Carolina Power, North Carolina Electric Membership Corporation, North Carolina Eastern Municipal Power Agency And North Carolina Municipal Power Agency Number 1 to modify the swine and poultry waste resource requirements of N.C. Gen. Stat. §§ 62-133.8 (e) and (f), respectively and to clarify the Electric Suppliers' obligations. 2) 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 on a system basis are shown in Figure 4.6.6.

Figure 4.6.6 Renewable Energy Requirements



4.7 Market Commodity Prices

The Company performed the analysis in this 2009 Plan using energy and commodity price forecasts provided by ICF International, Inc. ("ICF") in all periods except the first 18 months of the planning 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 CO_2 compliance costs, natural gas, coal, capacity, and energy costs.

The methodology used to develop the fuel and power market prices relied upon an integrated viewpoint which included the effects of the proposed Waxman-Markey legislation. Fuel price forecasts are displayed in Confidential Figure 4.7.1. Confidential Figure 4.7.2 displays forward price curves for SO_2, NO_x, and CO_2 emissions allowance prices on a dollar per ton basis. Confidential Figure 4.7.3 presents the estimated market clearing power prices for the PJM DOM Zone. The price forecast of PJM-DOM Zone capacity is presented in Confidential Figure 4.7.4. Appendix 4A provides delivered fuel price estimates.

*****Confidential*****

Figure 4.7.1 FUEL PRICE FORECASTS

[redacted]

*****Confidential*****

Figure 4.7.2 EFFLUENT PRICE FORECASTS

[redacted]

Confidential

Figure 4.7.3 POWER PRICE FORECASTS

[redacted]

Confidential

Figure 4.7.4 CAPACITY PRICE FORECASTS

[redacted]

Chapter 5

Future Resources

CHAPTER 5 – FUTURE RESOURCES

FUTURE SUPPLY-SIDE RESOURCES

5.1.1 SUPPLY-SIDE RESOURCES CONSIDERED

The Company remains up-to-date on viable commercial and utility-scale emerging generation technologies. Information gathered about generation technologies relies upon the Company's knowledge base across various departments including planning, financial analysis, construction, operation, and business development. This knowledge base of potential and emerging generation technologies has been developed from a mix of public and internal sources. The resources examined in this 2009 Plan include:

Biomass

Biomass facilities rely partially or completely on renewable fuel in their thermal generation process, which is generally waste wood in the Company's service territory. Biomass is considered carbon neutral from an emissions standpoint. The Company currently owns and operates an 83 MW biomass fuel plant at its Pittsylvania facility in Hurt, VA. Additionally, the Company is currently constructing the 585 MW Virginia City Hybrid Energy Center facility, which will be able to consume up to 20% of its fuel from biomass resources

Carbon Capture and Sequestration ("CCS")

CCS is a technology that is being researched which collects and traps carbon dioxide underground. This technology can be mated with most thermal generation technologies to reduce atmospheric carbon emissions; however, it is generally proposed to be used with coal burning facilities. An application was recently filed for federal stimulus funding to assist with the costs of CCS at the Company's VCHEC facility. The Company will continue to follow this technology and its associated economics.

Coal-Fired 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 BTU waste coal and wood products. The preferred location for this technology is within the vicinity of large quantities of waste coal fields. 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.

Coal-Fired Integrated Gasification Combined Cycle ("IGCC")

Currently, few IGCC demonstration facilities are operational in the United States. Many utilities and developers have proposals to construct additional facilities throughout the country; however, a significant number of these proposals have been canceled or postponed for a variety of reasons including the risks associated with the cost of construction, efficiency of operation, efficiency of carbon removal, and uncertainty of carbon emissions regulation. The Company will continue to monitor developments surrounding IGCC technology.

Gas-Fired Combined Cycle (CC-7FA)

The option that the Company has considered for analysis is the 2x1 GE 7FA plant configuration with heat recovery units and a steam generator. This is a proven technology with cost information readily available. The Company has significant operating experience with this technology, and the technology is going to be used at the Company's Bear Garden facility.

Gas-Fired Combustion Turbine (CT-7FA)

The option that the Company has considered for analysis is the GE 7FA plant configuration. This is a proven technology with cost information readily available. The Company has significant operating experience with this technology and recently started operating a fifth CT unit at its Ladysmith station.

Fuel Cell

Fuel cell technology has been heavily researched for many years by a variety of institutions. However, this technology has not appeared in utility-scale demonstration projects and has not been proven reliable or economic. The Company will continue to monitor developments surrounding fuel cell technology, but it was not considered for further analysis at this time.

Geothermal

Geothermal technology uses the heat from the earth to create steam which is then run through a steam turbine. The Company does not believe that this resource is currently available in its service territory.

Nuclear

The Company currently has a COL pending before the NRC for a third unit at its North Anna Power Station. While the Company has not committed to build the new unit, it recognizes the need for clean, efficient baseload generation. The Company is in the process of developing plans and cost estimates concerning this project.

Pulverized Coal ("PC")

PC is a very mature technology with hundreds of plants in operation across the United States and others under various stages of development. The Company incorporated super-critical PC technology that includes environmental controls consistent with current EPA standards.

Hydro Power

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.

Solar Photovoltaic ("PV")

Solar PV is an evolving technology with uncertain potential within the Company's service territory. Additionally, the output of this resource is highly dependent on climate and atmospheric conditions which typically result in a lower contribution in meeting peak load and reserve obligations than traditional thermal resources. The Company will continue to monitor developments surrounding Solar PV technology.

Solar Thermal

Solar thermal technology utilizes sunlight to collect heat to boil liquid which turns a turbine to produce electricity. This technology is currently experimental with uncertain capital costs. Additionally, it has not been tested in the Company's service territory. The Company will continue to monitor developments surrounding solar thermal technology.

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.

Wind

The Company has considered wind resources as a means of meeting the RPS goals and REPS requirements. 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 be 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 the state of Virginia that has sufficient wind characteristics. The Company is following the research of the potential installation of off-shore wind facilities.

5.1.2 ASSESSMENT OF ALTERNATIVE SUPPLY-SIDE RESOURCES

The process of selecting alternative resource types started with the identification and review of the characteristics of the available and emerging technologies, as well as any applicable statutory requirements. This was followed by an analysis to determine the current commercial status and market acceptance of alternative resources. The analysis includes determining whether particular alternatives were feasible in the near-term 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 based upon its operational characteristics and ability to be dispatched. The technology's operational characteristics were designated based on the type of load the resource would be matched with, which includes: baseload, intermediate capacity, peaking capacity, or intermittent capacity. The technology's ability to be dispatched was based on whether the resource was able to alter its output up or down in an economic fashion to balance the Company's instantaneously 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 an investment in technology would create for the Company and its customers, which could include site identification, development, infrastructure, and fuel procurement risks.

The feasibilities of both traditional and alternative resources were considered in utility-grade projects based on capital and operating expenses including fuel and operation and maintenance ("O&M"). Figure 5.1.2.1 summarizes all of the resource types that the Company reviewed as part of the IRP process. Those resources considered for further analysis in the busbar screening model are identified in the final column. The busbar screening model produced levelized busbar costs for a variety of resources.

Figure 5.1.2.1 ALTERNATIVE SUPPLY-SIDE RESOURCES

Resource	Resource Type	Dispatchable	Primary Fuel	Busbar Resource
Biomass	Base Load	Yes	Renewable	Yes
CFB	Base Load	Yes	Coal	Yes
Geothermal	Base Load	No	Renewable	No
IGCC with Sequestration	Base Load	Yes	Coal	No
IGCC	Base Load	Yes	Coal	Yes
Nuclear	Base Load	Yes	Uranium	Yes
PC	Base Load	Yes	Coal	Yes
CC with Sequestration	Intermediate	Yes	Natural Gas	No
Combined Cycle (CC 7FA)	Intermediate	Yes	Natural Gas	Yes
Fuel Cell	Intermediate	Yes	Natural Gas	No
Hydro Power	Intermittent	No	Renewable	Yes
Solar Photovoltaic	Intermittent	No	Renewable	Yes
Solar Thermal	Intermittent	No	Renewable	Yes
Tidal Power	Intermittent	No	Renewable	No
Wave Power	Intermittent	No	Renewable	No
Wind – Off-shore	Intermittent	No	Renewable	Yes
Wind – On-shore	Intermittent	No	Renewable	Yes
Combustion Turbine (CT 7FA)	Peak	Yes	Natural Gas	Yes

5.1.3 LEVELIZED BUSBAR COSTS

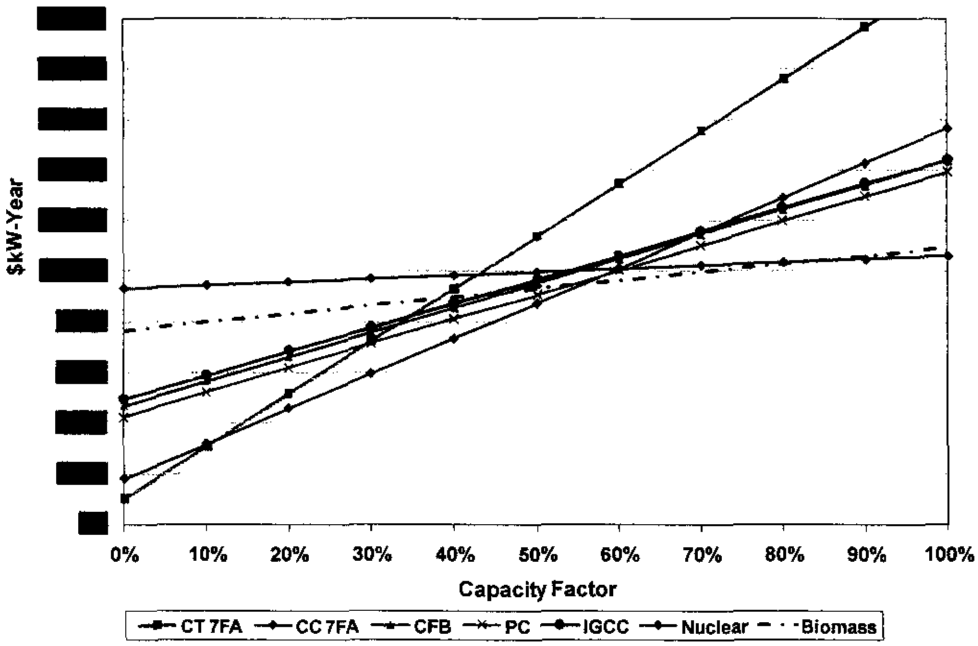
The Company's busbar model was designed to estimate the levelized busbar costs of various technologies on an equivalent basis. The busbar results show the levelized cost of power generation at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. These comparisons include: fuel, heat rate, emissions, variable and fixed operating maintenance costs, expected service life, and overnight construction costs. Options with poor economics were further screened out at this level. Project costs for the technologies below included a mix of internally developed cost information and data provided publicly by the Energy Information Administration[8].

Figure 5.1.3.1 and Figure 5.1.3.2 display summary results of the busbar model comparing the

[8] The Energy Information Administration's 2009 Annual Energy Outlook is available at http://www.eia.doe.gov.

economics of the different technologies discussed in Section 5.1.1. Due to the confidential nature of these costs, the complete figures have been filed separately under seal in this docket.

****CONFIDENTIAL****
PUBLIC VERSION
Figure 5.1.3.1 DISPATCHABLE LEVELIZED BUSBAR COSTS



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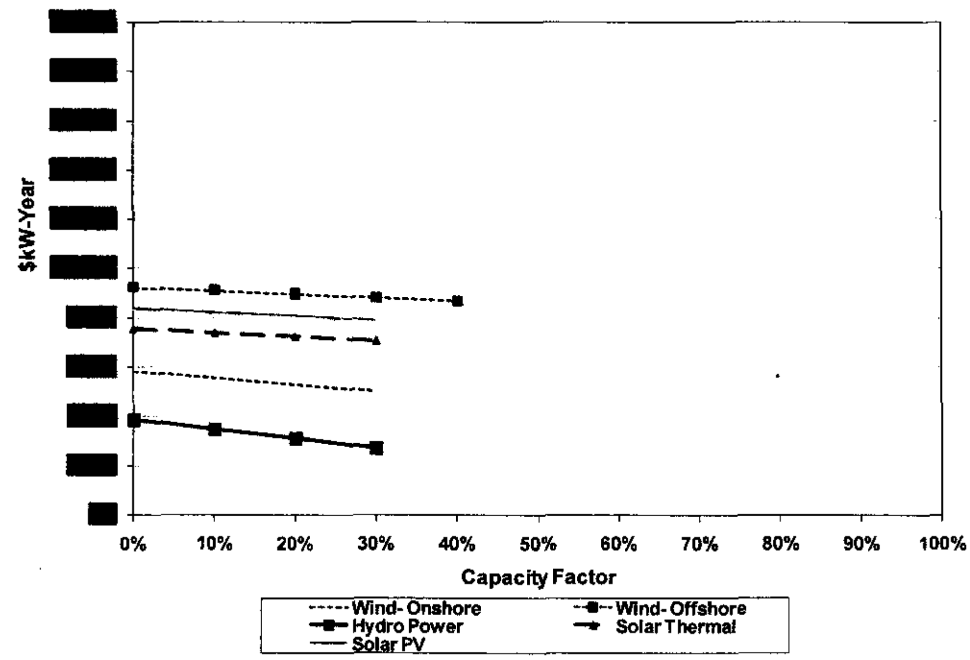
PUBLIC VERSION
Figure 5.1.3.2 NON-DISPATCHABLE LEVELIZED BUSBAR COSTS



Confidential Appendix 5A contains the tabular results of the screening level analysis. Confidential 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 carry charge.

In Figure 5.1.3.1, the lower right hand sections of the combined curves create an envelope representative of the least cost of all units at an associated operating range between 0 and 100%. Resources that lie above the curves forming the lower envelope in their entirety should generally fail to move forward in the resource optimization. Figure 5.1.3.1 shows that the CT-7FA technology is the most cost-effective option at low capacity factors and is an economical way of meeting peaking requirements. The CC-7FA technology is economical for capacity factors ranging from 10% to 55% and, therefore, is economical for meeting the Company's intermediate energy requirements. For capacity factors between 55% and 80%, biomass resources are cost-effective. However, there is a limited supply of biomass fuel available within the Company's service territory. Therefore, the Company can consider up to 100 MW of additional biomass capacity. Nuclear resources are the most cost-effective in meeting the Company's resource requirements above 80% capacity factors. As a result, dispatchable technologies that were included for further analysis were CT, CC, biomass and nuclear. While nuclear provided the lowest cost option at baseload capacity factors, its availability was limited to a single unit, North Anna 3. The next best option for baseload capacity based on the screening curve would have been traditional pulverized coal technology. However, the Company reviewed traditional coal economics and, due to uncertainties surrounding future CO_2 legislation and the development of carbon sequestration technology, chose not to move forward with further analysis at this time.

A comparison between dispatchable and non-dispatchable resources is not entirely equitable. Due to the intermittent production and thus limited dispatchability of electricity that wind, hydro, and solar plants produce, more capacity would be required to maintain the same level of reliability. Figure 5.1.3.2 displays the non-dispatchable resources that the Company considered in its busbar analysis. This figure indicates that the Company should consider non-dispatchable resources in the following order: hydro, on-shore wind, solar thermal, solar PV, and off-shore wind. The Company continues to examine appropriate sites for hydro facilities; however, it has not located any suitable sites at this time. On-shore wind becomes the next available resource in this category. However, due to the limitations on the amount of on-shore wind available within or near the Company's service territory, the Company has limited this to 200 MW of nameplate capacity. The Company will continue to monitor developments surrounding solar thermal and solar photovoltaic technologies. The Company has considered off-shore wind options for further analysis in this 2009 Plan.

The potential for off-shore 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 as well as relative cost data.

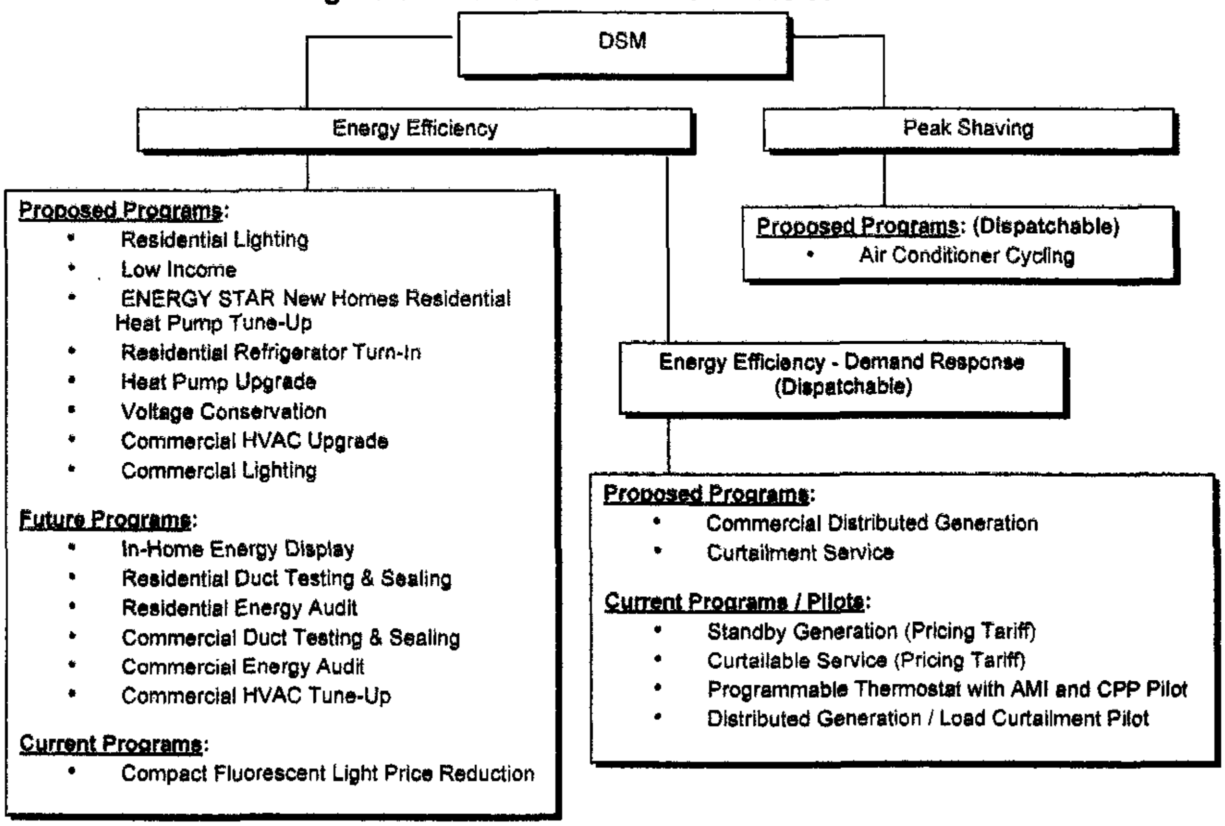
The assessment of alternative resource types and the busbar screening process provided a very useful foundation for selecting resources for further analysis. However, the busbar curve was somewhat static in nature because it relied on averaging all the cost data over a resources' lifetime. Further analysis was conducted in the Company's Strategist model which incorporated seasonal variations in cost and operating characteristics, while integrating new resources with existing system resources. The 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 which best fit the Company's existing generation and future needs.

FUTURE DSM PROGRAMS

5.2.1 DEMAND-SIDE OPTIONS OVERVIEW

The Company is committed to offering DSM programs as part of its portfolio of services to meet customers' needs and improve the environment. The Company's analysis of DSM programs concentrated on the cost-effectiveness of programs, stakeholder impacts, potential for achieving a high level of acceptance by customers, and potential for energy and demand reductions. These programs will also be evaluated and considered for approval and implementation in the Company's North Carolina service territory. Figure 5.2.1.1 shows not only the current DSM programs, pricing tariffs, and Pilots, but also the proposed DSM Programs which have been filed with the SCC and future DSM programs which have been evaluated and included in this 2009 Plan, but for which the Company has not yet filed for regulatory approval. Appendix 5C provides the estimated annual energy savings for all programs by year.

Figure 5.2.1.1 TYPES OF DSM PROGRAMS



The Company modeled new demand-side resources over a 15-year Planning Period, including input variables from many sources. These projections were based on the best available information, including industry data acquired from ICF, to essentially validate DSM program design parameters and reduce uncertainty and risk. The projected customer penetrations were based on market research for similar programs previously implemented in the United States.

5.2.2 STANDARD DSM TESTS

The Company utilized four of the five standard tests from the California Standards Practice Manual to evaluate DSM programs. Refer to Appendix 5D for a description of each test. The Company believes the "public interest" standard should be applied to a total portfolio of DSM programs rather than to individual DSM programs, and whether or not an individual program "passes" any particular cost/benefit test (score of > 1.0) is not the primary consideration in determining if the overall portfolio is in the public interest and should be implemented. The Company also believes there are important non-price criteria such as program performance risks, customer needs and acceptance levels, and public policy goals that should be considered when assessing whether or not a DSM portfolio is in the public interest.

5.2.3 FUTURE DSM PORTFOLIO OF PROGRAMS

As part of the IRP planning process, the Company evaluated possible additional DSM programs, referred to herein as "future programs." These DSM programs were evaluated as a standalone portfolio to determine their impact on the system with the assumption that the proposed DSM Portfolio, which is the subject of Case No. PUE-2009-00081, will be implemented as stated in the Company's petition and direct testimony filed with the SCC. Refer to Appendices 5E, 5F, 5G, and 5H for the non-coincidental peak savings, coincidental peak savings, energy savings, and program penetration for each future program in the portfolio. A brief description of each of the possible future DSM programs is listed below. These programs will also be evaluated and considered for approval and implementation in the Company's North Carolina service territory.

<u>IN-HOME ENERGY DISPLAY PROGRAM</u>

Program Type: Energy Efficiency
Target Class: Residential
Program Duration: Modeled to begin in 2011 and continue through 2024

Program Description:

The participant will receive an in-home display that will be pre-programmed with Company utility rates allowing participants to monitor their real-time energy consumption. The display unit, located inside the home, will read the participant's real-time consumption data from an AMI meter via wireless technology and will display consumption information in both dollars and kilowatt hours ("kWh"). The participant may change the display with a simple toggle switch on the device. The primary objective of this program is to increase customer awareness of personal energy consumption, usage patterns, and costs during different periods throughout the day. This knowledge should result in reduced energy consumption during most hours of the day.

RESIDENTIAL DUCT TESTING & SEALING PROGRAM

Program Type: Energy Efficiency
Target Class: Residential
Program Duration: Modeled to begin in 2011 and continue through 2024

Program Description:

This program is designed to reduce the demand and energy requirements on residential HVAC systems by promoting the testing and repair of poorly performing duct and Air Distribution Systems ("ADS"). Participants will be provided with an incentive for sealing ducts in their homes using a mastic material or foil tape with an acrylic adhesive to seal all joints and connections. The repairs are expected to reduce the average cubic feet per minute at 25 pascals of pressure ("CFM25") air leakage from 18% to 8% of a residential home's Conditioned Floor Area ("CFA"). Therefore a typical 2,000 square foot home would have a total air leakage of less than 2,160 CFM25 (2,000 x 1.08).

RESIDENTIAL ENERGY AUDIT PROGRAM

Program Type: Energy Efficiency
Target Class: Residential
Program Duration: Modeled to begin in 2011 and continue through 2024

Program Description:

In this program, an auditor will perform an on-site detailed review of a residential customer's home and energy consumption appliances with specific emphasis on energy efficiency measures with pre-rebate payback periods of three years or less. The participant will receive a written report showing the projected energy and cost savings that could be anticipated from implementation of options identified during the audit. The full audit price would be refunded to participants once they provide adequate documentation that some of the recommended energy efficiency improvements have been made and/or they have enrolled in another DSM program offered by the Company, whereby the participant's costs exceed the full audit price. Measures evaluated in this program include but are not limited to:

- Envelope sealing to 0.43 air changes per hour ("ACH") levels,
- R-4 insulation wrap for the domestic water heater,
- Low-flow showerheads - 1.8 gallons per minute, and
- Replacement of high usage incandescent light bulbs (average 75 watts) with CFLs (average 26 watts).

COMMERCIAL DUCT TESTING & SEALING PROGRAM

Program Type: Energy Efficiency
Target Class: Commercial
Program Duration: Modeled to begin in 2011 and continue through 2024

Program Description:
This Program will promote testing and general repair of poorly performing duct and ADS systems in Commercial facilities. Such systems include air handlers, return and supply plenums, and any connecting ducts. Participants would be provided an incentive for sealing ducts in existing buildings using aerosol sealant, mastic, or foil tape with an acrylic adhesive. This measure is expected to eliminate approximately 81% of the total duct losses.

COMMERCIAL ENERGY AUDIT PROGRAM

Program Type: Energy Efficiency
Target Class: Commercial
Program Duration: Modeled to begin in 2011 and continue through 2024

Program Description:
In this program an auditor will perform an on-site detailed energy audit of a commercial participant's facility. The participant will receive a written report showing the projected energy and cost savings that could be anticipated from implementation of options identified during the audit. The full audit price will be refunded to participants once they provide adequate documentation that some of the recommended energy efficiency improvements have been made, and/or they have enrolled in another DSM program offered by the Company, whereby the participant's costs exceed the full audit price. Program measures include but are not limited to:

- Central Processing Unit ("CPU") Power Management,
- Vending Machine Controller,
- Refrigeration Retro-Commissioning,
- Refrigerator Display Case Lighting Control, and
- Floating Head Pressure, Variable Set point, and Speed.

COMMERCIAL HVAC TUNE-UP PROGRAM

Program Type: Energy Efficiency
Target Class: Commercial
Program Duration: Modeled to begin in 2011 and continue through 2024

Program Description:
This program will allow commercial customers to tune-up their existing heat pumps or electric HVAC system to optimize performance, assuming a cooling efficiency improvement of 15%. The program will provide customers with an incentive to help offset the cost of the tune-up.

5.2.4 FUTURE DSM PORTFOLIO COST-EFFECTIVENESS RESULTS

Figure 5.2.4.1 shows the individual future DSM programs' cost-benefit results, the projected demand and energy reductions, and the portfolio's overall performance at the system level. The results of the four tests were greater than 1.0 for the entire portfolio, supporting what the Company believes to be a viable cost-effective portfolio for all stakeholders.

Figure 5.2.4.1 FUTURE PROGRAMS COST-EFFECTIVENESS RESULTS

Future Programs	Participant	Utility	TRC	RIM	Projected MW Reduction in 2024	Projected GWH Savings in 2024
Energy Efficiency Programs						
In-Home Energy Display Program	36.20	5.60	6.74	1.02	13	38
Residential Duct Testing & Sealing Program	3.32	4.11	3.85	1.21	7	12
Residential Energy Audit Program	2.74	1.19	1.56	0.63	3	9
Commercial Duct Testing & Sealing Program	12.01	2.66	7.16	0.95	20	84
Commercial Energy Audit Program	25.24	11.63	24.23	1.18	18	101
Commercial HVAC Tune-Up Program	6.98	2.62	4.44	1.24	20	34
				Totals	80	277
Portfolio Results						
Future DSM Portfolio	9.94	3.70	6.59	1.06	80	277

5.2.5 REJECTED DSM PROGRAMS

During the planning process, the Company rejected three programs and is not including these programs in its future DSM portfolio. Below is a short description of each of the rejected programs with the reason for each program's rejection.

RESIDENTIAL WATER HEATER CYCLING PROGRAM

Program Type: Peak Shaving
Target Class: Residential
Program Duration: Modeled to begin in 2011 and continue through 2024

Program Description:

This program was modeled to implement a cycling switch to control the electric water heater system for residential customers whereby the Company would have turned off water heaters during peak load conditions. Participants would have received a monthly credit for participating during control months. This program would have been AMI-enabled.

Reason for Program Rejection:

This program provided the greatest demand reductions in the winter months during the early morning hours when hot water consumption is typically peaking. The Company's system is currently summer peaking and projected to remain summer peaking over the Planning Period. Therefore, this program did not provide enough benefits through avoided generation capacity and energy costs to outweigh the program costs. This program failed all four cost/benefit tests, with scores of less than 0.5.

PROGRAMMABLE THERMOSTAT PROGRAM

Program Type: Energy Efficiency – Demand Response
Target Class: Residential
Program Duration: Modeled to begin in 2011 and continue through 2024

Program Description:
This program was modeled to provide participants with a rebate for the purchase of a programmable thermostat that would allow homeowners to raise their indoor temperature settings in the summer during unoccupied periods and/or lower their thermostat settings during unoccupied periods in the winter.

Reason for Program Rejection:
Although this program provided energy benefits to participants who set-back their thermostats during unoccupied and overnight hours, it contributed to higher demands for the Company during peak demand periods. Programmable thermostats are generally programmed to come out of their set-back modes in the winter during early morning hours and in the summer as occupants are returning from work, thereby contributing to those same peak hours where the Company is striving to reduce demands and receive the maximum benefit of the set-backs. This program failed three of the four cost/benefit tests with scores of less than 0.5.

RESIDENTIAL SOLAR WATER HEATING PROGRAM

Program Type: Energy Efficiency
Target Class: Residential
Program Duration: Modeled to begin in 2011 and continue through 2024

Program Description:
This program was modeled to provide participants with a rebate for the installation of a Solar Rating and Certification Corporation ("SRCC") certified solar water heating system. This program did not factor in tax incentives that would be available to participants, or RECs that may have been available to the utility. Therefore, this program will be re-evaluated at a future date once these variables are more firm. The program measures include:

- Solar thermal water heating systems (not photovoltaic) including:
  - Direct/Indirect Forced Circulation (i.e., active solar),
  - Direct/Indirect Thermosyphon (i.e., passive solar), and
  - Integral Collector Storage (i.e., direct passive solar).

Reason for Program Rejection:
The Solar Water Heating program would have had its greatest load shape impacts during the early morning and late evening hours when the Company is not typically peaking. Therefore, avoided capacity costs from this program were relatively small and the energy savings from the program were not large enough to outweigh the high cost of the solar water heating system. Additionally, the immaturity of the solar water heating market and the relatively large incentives

required by customers to participate in this program have led to low RIM and Utility test values. The Company plans to continue to monitor this program as the solar water heating market matures and/or other governmental incentives become available.

5.2.6 REJECTED DSM PROGRAMS COST-EFFECTIVENESS RESULTS

The Company has evaluated and rejected three DSM programs at this time based on the cost-effectiveness results as shown in Figure 5.2.6.1.

Figure 5.2.6.1 REJECTED PROGRAMS COST-EFFECTIVENESS RESULTS

Rejected Programs	Participant	Utility	TRC	RIM	Projected MW Reduction in 2024	Projected GWH Savings in 2024	Projected Program Penetration by 2024
Peak Shaving Programs							
Residential Water Heater Cycling Program	N/A	0.24	0.42	0.24	137	0	244,948
Energy Efficiency - Demand Response Programs							
Programmable Thermostat Program	4.56	0.02	0.02	0.01	17	12	67,136
Energy Efficiency Programs							
Residential Solar Water Heating Program	3.91	0.80	1.47	0.44	3	23	10,947
				Totals	157	34	323,031

5.2.7 NEW CONSUMER EDUCATION PROGRAMS

Future promotion of DSM programs will be communicated through mass marketing and targeted advertising in Virginia. The messages will communicate the monetary savings, environmental benefits, and the technologies used within the Company's DSM programs. Through consumer education programs, the Company aims to help customers understand their energy-usage patterns, the cost of their choices, and what it will take to achieve sustainable energy savings.

The Company also recognizes that energy education in schools can have an impact on how households consume energy. The Company plans to continue providing outreach to educational facilities by providing support and materials as needed.

5.2.8 ASSESSMENT OF OVERALL DEMAND-SIDE OPTIONS

Figure 5.2.8.1 represents approximately 3,315 GWh in energy savings from the proposed and future DSM programs at a system level.

Figure 5.2.8.1 DSM ENERGY REDUCTIONS

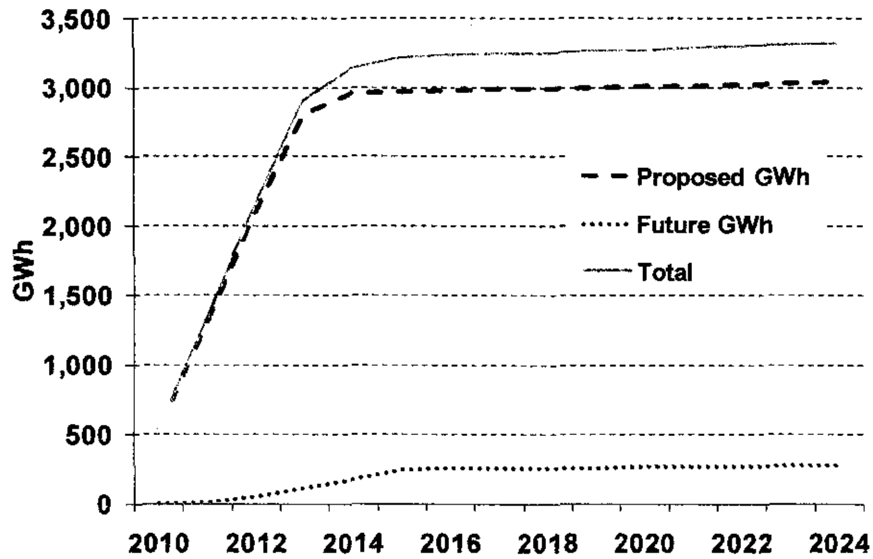
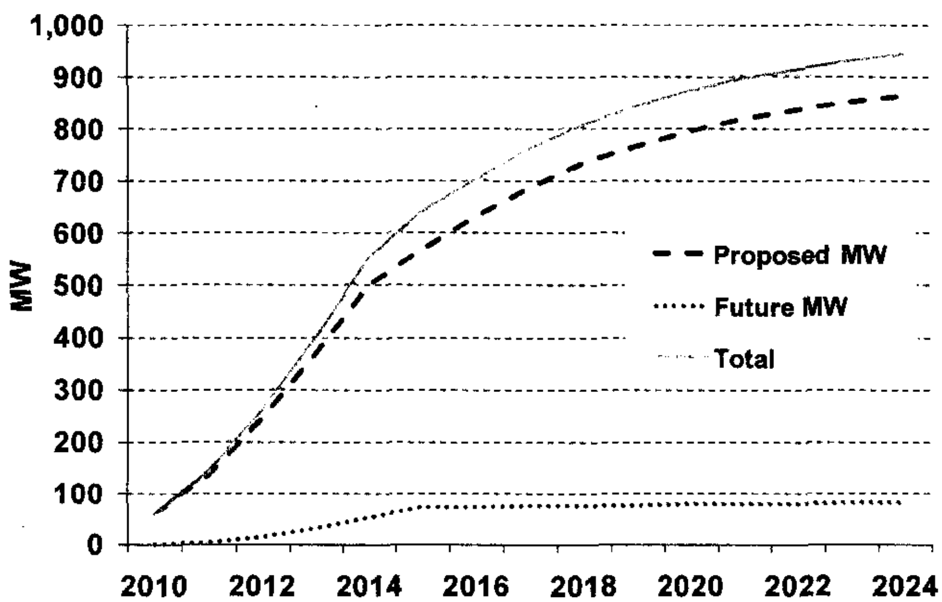


Figure 5.2.8.2 represents a system coincidental demand reduction of approximately 950 MW by 2024 from both the proposed and future DSM programs at a system level. The generation expansion plan that results after including the proposed and future DSM programs is anticipated to:

- Delay the Warren County CC one year during the Planning Period,
- Reduce the need for two potential generation resources (CC and CT), and
- Increase market capacity purchases slightly.

Figure 5.2.8.2 DSM DEMAND REDUCTIONS



Additionally, the Company has provided load duration curves for the years 2010, 2014, and 2024.

Figure 5.2.8.3 LOAD DURATION CURVE 2010

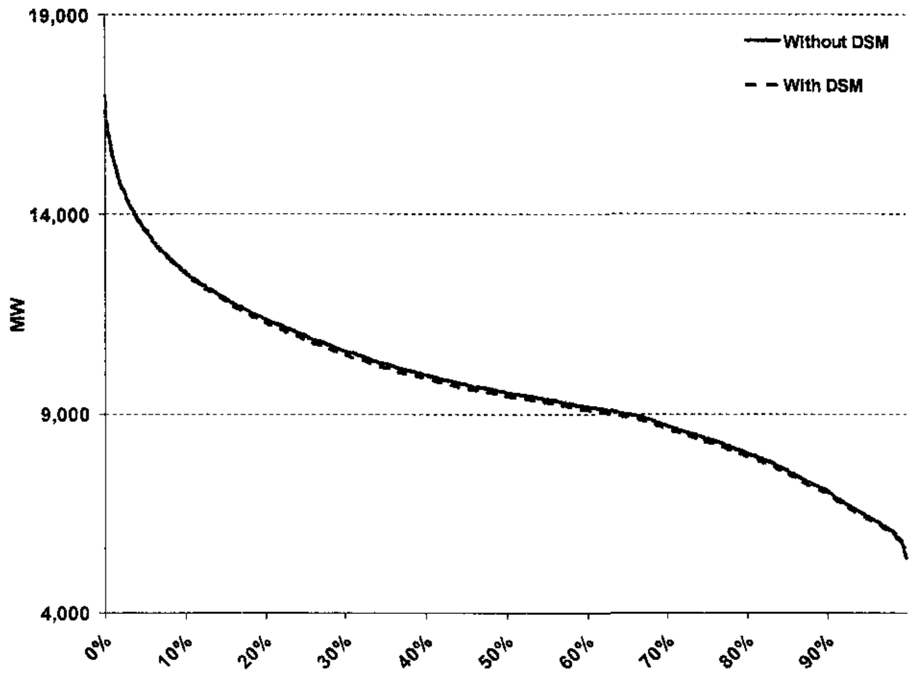


Figure 5.2.8.4 LOAD DURATION CURVE 2014

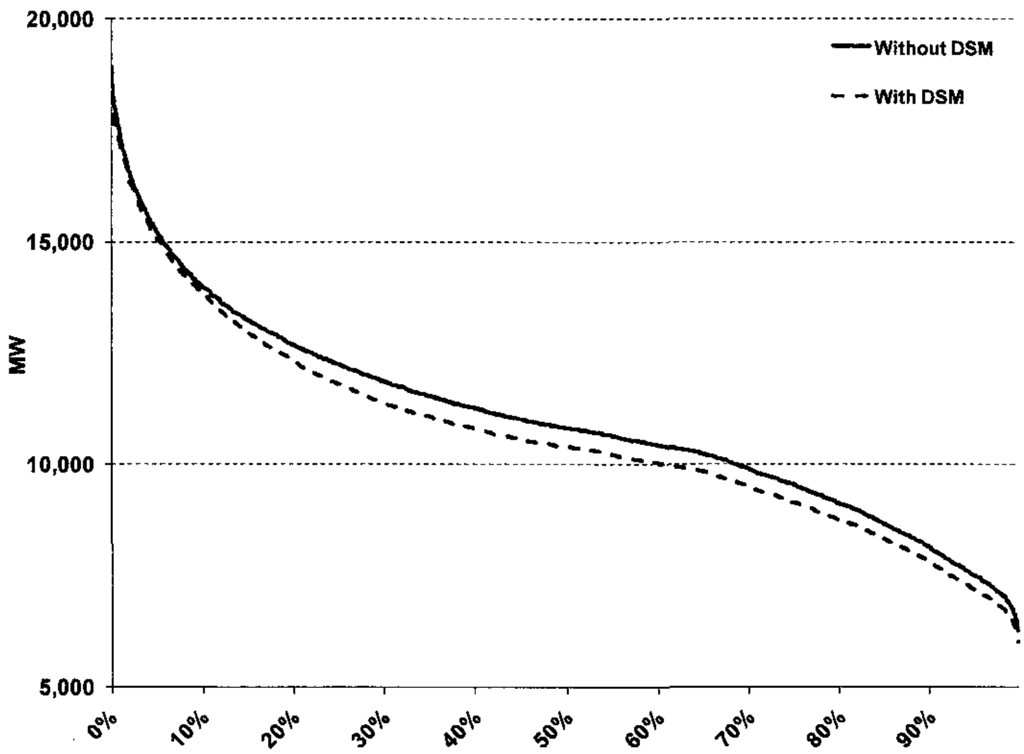
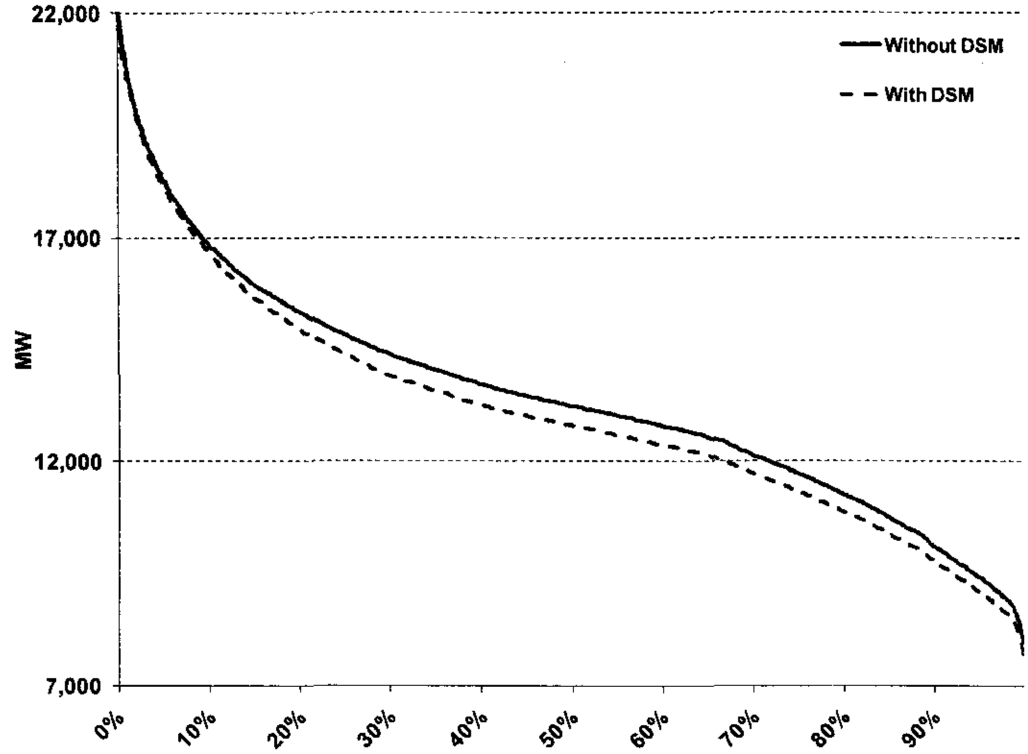


Figure 5.2.8.5 LOAD DURATION CURVE 2024



FUTURE TRANSMISSION PROJECTS

5.3.1 FUTURE TRANSMISSION PROJECTS

Appendix 5I provides a list of the Company's planned transmission interconnection projects for the Planning Period with associated enhancement costs. Appendix 5J 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 PLANNING PROCESS

The IRP process identifies, evaluates, and selects a variety of resources to meet customers' future capacity and energy needs to augment existing resources. The Company's approach to resource planning relies on integrating cost-effective energy efficiency and peak shaving programs with supply-side resources over the Planning Period. This integration is intended to produce a long-term resource plan that focuses on the Company's commitment to provide reliable electric service at a reasonable cost while meeting all regulatory requirements. The foundation of 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 supply- and demand-side resources are compared with expected load and reserve requirements. The difference in projected load and existing resources yields the Company's expected capacity needs to maintain reliable service for its customers on an annual and Planning Period basis.

After the resource need is identified, the Company must consider and evaluate the economics associated with various supply- and demand-side alternatives that complement existing resources and also meet capacity and energy requirements in conjunction with additional regulatory and legislative requirements.

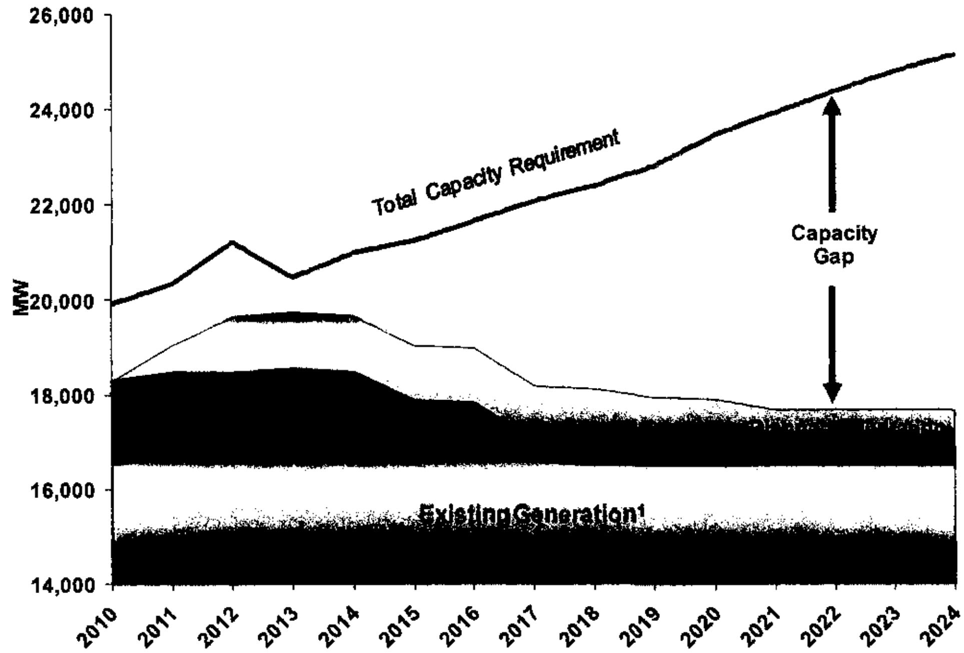
An initial screening analysis is conducted to determine supply- and-demand side resources that could potentially fit into the Company's resource mix. These resources and their associated economics are inputs to the Company's planning model, Strategist, which helps determine the quantity and timing of the resources selected to meet energy and capacity requirements. This step also yields a range of alternative plans which represent plausible future paths. Finally, alternative plans and assumptions are assessed using various sensitivities and scenarios to gauge the robustness of each alternative plan as compared to other plans under a variety of conditions.

The Company developed its 2009 Plan in consultation with various internal planning and operational groups. The results of the analysis of alternative plans were verified and reviewed for accuracy and reasonableness. Key internal reviewers throughout the Company examined the 2009 Plan and provided comments concerning the 2009 Plan's suitability towards meeting the goals of the Company's stakeholders. The resulting 2009 Plan is presented to the SCC and NCUC in this filing.

6.2 CAPACITY & ENERGY NEEDS

As discussed in Chapter 2 of this 2009 Plan, the Company forecasted an average annual growth rate of about 2.16% in peak demand and 2.39% in energy requirements through the Planning Period. Chapter 3 discussed the Company's existing supply- and demand-side resources, NUG contracts, and planned generation resources. Figure 6.2.1 shows the Company's supply-side resources plotted against 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 15-year planning horizon. The Company plans to meet this capacity gap through 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 COMPANY CAPACITY POSITION



Note: 1) Includes rating changes to existing units

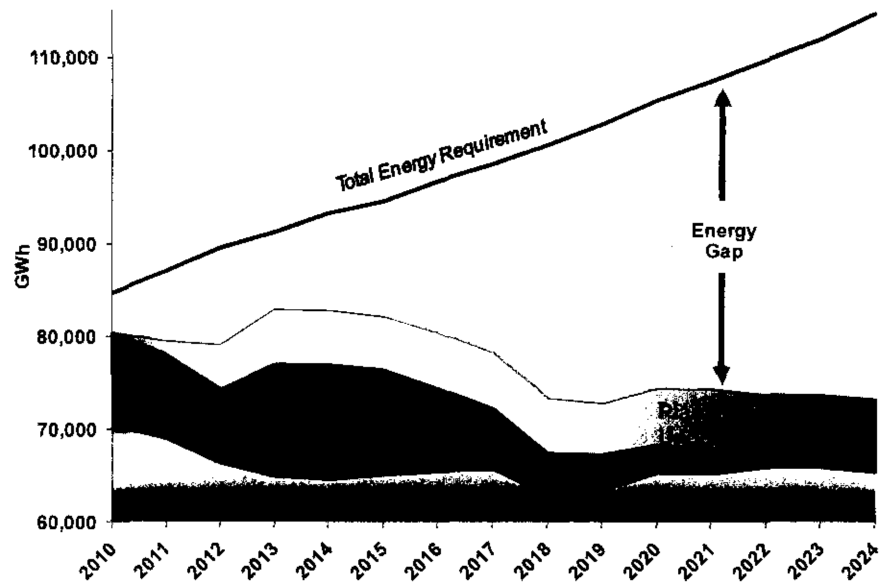
The Company's membership in PJM has given it access to a wide pool of generating resources for its energy and capacity needs. However, it is important that adequate reserves are maintained not just in PJM as a whole, but specifically in the DOM Zone to ensure that the Company's load can be reliably served.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

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 or all of the NUG contracts may be renewed or extended at the expiration of their current contract terms, as the relevant economics warrant. These resources will most likely 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. Therefore, the Company's analysis was conducted in a manner that economically compared the PJM energy and capacity market to the Company self-build options.

Figure 6.2.2 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.

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.

Figure 6.2.2 CURRENT COMPANY ENERGY POSITION



Note: 1) Includes rating changes to existing units.

6.3 MODELING PROCESSES & TECHNIQUES

The Company used a methodology that compares 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 in the Strategist model. Then, future assumptions including, but not limited to: load, fuel prices, emissions costs, maintenance, and resource costs were inputs to the model.

For the initial screening of demand-side resource options, an expansion plan with only supply-side resources was developed. Additionally, DSM options were compared to supply-side options with the opportunity to modify the expansion plan based on their economics. DSM programs as a resource were given the opportunity to eliminate, defer, or alter the need for future supply-side resources and market purchases. After cost-effective demand-side resources were identified, they were included as a portfolio of programs that serve as demand-side resources to modify the previously identified capacity and energy needs. Next, supply-side and proposed demand-side resource options were re-optimized along with the future DSM portfolio to arrive at a base plan. This ensures that supply- and demand-side resources were treated equally while meeting peak and energy requirements.

To assess an optimum resource strategy and the validity of the Company's 2009 Plan, the Company identified five alternative plans representing plausible future paths. Each of the alternative resource plans was analyzed with a set of sensitivities and scenarios as explained in Section 6.5. This process stressed each alternative plan to find the set of resources that best met the Company's goal of providing reliable electric service at the lowest reasonable cost to customers. All five alternative plans were then tested against a set of sensitivities and scenarios designed to measure the relative cost performance of each plan under varying market, commodity, and regulatory conditions. The alternative plan that performed best was then chosen as the Preferred Plan.

6.4 ALTERNATIVE PLANS

The Company's alternatives plans are identified and discussed below.

Plan A: Base Plan

Plan A is a cost-effective mix of DSM programs, as well as renewable, nuclear, combustion turbine, and combined cycle generation technology. The plan includes 3,800 MW combined cycle, 1,360 MW of combustion turbines, 300 MW (nameplate) of renewable and a 1,300 MW nuclear unit. The plan also contains DSM programs totaling approximately 1,000 MW.

Plan B: No DSM Plan

No DSM programs exist in this plan, resulting in an increase in supply-side resource requirements. This plan contains a mix of renewable, nuclear, combustion turbine, and combined cycle technology.

Plan C: No Nuclear Expansion Plan

Plan C delays the expansion of North Anna 3 past the Planning Period. The energy and capacity voids created due to this delay are filled with additional gas-fired generation and market purchases.

Plan D: No Renewable Plan

Plan D contains no renewable resources constructed by the Company. The Company's load requirements are met through the use of proposed and future DSM programs, nuclear, combined cycle, and combustion turbine resources.

Plan E: Federal Renewable Plan

Plan E presents a method for the Company to meet a potential Federal renewable energy standard of 20% by 2020 ("20 by 20"). To meet this target, the Company would be required to construct a significantly greater amount of renewable resources than in all other plans. It includes an additional 300 MW (nameplate) of incremental on-shore wind and 3,000 MW (nameplate) off-shore wind. However, there is a great deal of uncertainty as to the availability and amount of on-shore wind within the Company's service territory. Additionally, the amount of wind resources is extremely optimistic considering the permit and building process has yet to be determined. Online dates of the Company's off-shore wind farms have been accelerated, with the first facility online by 2015. Additionally, the Company has assumed that government granted Production Tax Credits will be available for this technology throughout the Planning Period. This plan moves the Company towards meeting an assumed level of renewable requirements with self-built resources.

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

Figure 6.4.1 ALTERNATIVE PLANS

Year	Base Plan			No Demand-Side Resources Plan		No Nuclear Expansion Plan			No Renewable Plan		Federal Renewable Plan		
	Traditional	Renewable	DSM	Traditional	Renewable	Traditional	Renewable	DSM	Traditional	DSM	Traditional	Renewable	DSM
2010			Pro.					Pro.		Pro.			Pro.
2011	Bear		Pro./Fut.	Bear		Bear		Pro./Fut.	Bear	Pro./Fut.	Bear		Pro./Fut.
2012	VCHEC			VCHEC		VCHEC			VCHEC		VCHEC		
2013													
2014				Warn							CT	WND	
2015	Warn			CC		Warn			Warn		Warn	WND 2OSW	
2016	2CT	Bio		2CT	Bio	2CT	Bio		2CT		CT	Bio 4WND 2OSW	
2017	CC	Bio 4WND		CC	Bio 4WND	CC	Bio 4WND		CC		CC	Bio 4WND 2OSW	
2018	NA3			CT NA3		CC			NA3		NA3		
2019	CT			CC		CC			CT		CT		
2020	CT			CT		2CT			CC		CT	2OSW	
2021	CC			CC		CC			CC		CC	2OSW	
2022	CC			CT		CC			CT		CT		
2023	CC			CC		CC			CC		CC		
2024	CC			CC		CC			CC		CC		

Note: *The Company intends to comply with the North Carolina REPS requirements, including the set-asides for energy derived from solar, poultry litter, and/or swine waste through the purchase of RECs and/or purchased energy, as applicable. Hence those resources do not appear in the above table. Moreover, the set aside requirements represent approximately 0.05% of system load by 2024 and will not materially alter the 2009 Plan.*

6.5 BASE CASE & SCENARIOS & SENSITIVITIES

The Company used a number of sensitivities and scenarios around its planning assumptions to test the robustness of 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 a total of 1 base case, 2 scenarios, and 15 sensitivities as explained below.

<u>Base Case (1)</u>

The Base Case used the expected or forecast "base" values described in the document through this point which include the load forecast (Chapter 2), existing system resources (Chapter 3), planning assumptions (Chapter 4), and new resources (Chapter 5).

Scenarios:

Scenarios provided an all-encompassing view of the variable future development of the markets and regulatory conditions. Many important assumptions were changed in a scenario which accounted for systemic changes in the view of the future. These changes included multiple or feedback effects of variables that were interrelated, such as emission and cost variables. The Company examined two separate scenarios, a high carbon emission cost case and a low carbon emission cost case.

High and Low Carbon Cost Scenarios (2-3)

Several of the biggest uncertainties for the electric utility industry are 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 base case assumed there will be carbon legislation by 2013 similar to the proposed Waxman-Markey House Bill considered by the U.S. House of Representatives. 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.

To cover the wide range of possibilities surrounding future carbon legislation, the Company developed two scenarios, called high and low carbon scenarios. The high carbon scenario refers to a situation where carbon caps are more stringent and therefore the price of emitting CO_2 is higher compared to the assumptions in the base case. The low carbon scenario represents a case in which carbon control legislation takes the opposite approach by increasing the amount of CO_2 that can be emitted and therefore resulting in lower CO_2 costs. In each of these scenarios, fuel and commodity processes were correlated appropriately to the effects of the modeled CO_2 market.

Major assumptions that were adjusted in these scenarios included:

- Fossil Fuel Prices (Coal, Gas, and Oil)
- Environmental Allowance Prices (SO_2, NO_X, Hg, and CO_2)
- Market Capacity and Energy Prices

Sensitivities:

A sensitivity case changes a single variable from the base set of 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 2009 Plan. The Company performed the following 15 sensitivities:

High and Low Fuel Costs Sensitivities (4-5)

Prices for natural gas, petroleum products, coal, emission allowances (NO_x, SO_x, and Hg), and electric energy were increased and decreased around the base forecast values by plus and minus 25%. This test was important because fuel cost is a significant portion of the final customer rates. Extreme volatility in rates in reaction to fuel price variance is generally viewed as undesirable. Therefore, plans that produce less variance in the fuel sensitivity should be preferred to other alternatives.

High and Low Load Growth Sensitivities (6-7)

Future load growth was one of the key inputs used to develop the 2009 Plan. Demand growth is significantly impacted by regional economic growth and technological changes. Base case average annual growth rate was 2.39% for energy and 2.16% for peak. High and low load growth sensitivities assumed a plus and minus 0.5% change in the annual growth rates for energy and peak demand. Alternative plans were tested against a high load growth scenario which 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 scenario may come from lower than expected economic growth, additional energy conservation, or a decline in real disposable income.

High and Low Construction Costs Sensitivities (8-9)

Power plant construction cost escalation represented a significant risk for all stakeholders. Recent trends indicate that the volatility of costs surrounding the construction of new facilities has climbed to rates above historical averages in the past few years. This represents a significant challenge to utilities, regulators, and customers as U.S. utilities focus on demand-side management and the construction of renewable and traditional new generation. The construction cost sensitivities were run to analyze the risk associated with potential future increases or decreases of the construction costs of CC, CT, nuclear, and renewable plants. These costs were increased 25% and decreased 25% in order to determine the economic impact of changes in the construction cost of planned units.

High and Low Transmission and Distribution Costs ("T&D") Sensitivities (10-11)

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

Plug-in Hybrid Electric Vehicles ("PHEV") Sensitivity (12)

Vehicle manufacturers are nearing the commercial release of PHEV passenger cars. These next generation vehicles are similar to currently deployed hybrid cars, with the added capability to recharge their batteries through a standard electric plug. Proliferation of PHEV may impact the electric demand over the long-term. The most significant uncertainty regarding PHEVs is the penetration rate of these vehicles and the charging patterns. The Company relied on the Electric Power Research Institute's PHEV study[9] to develop this sensitivity case. The objective of this

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

sensitivity case was to see the impact on electricity consumption patterns and identify resources needed to meet this potential new technology's requirements.

Production Tax Credit ("PTC") Sensitivity (13)
Renewable resources currently benefit from federal tax incentives. Currently, these tax incentives expire at the end of 2012 but may be extended to continue to incentivize the development of renewable generation. Therefore, for its base case, the Company assumed that these incentives will be extended through the end of the Planning Period. Under this sensitivity, however, all PTCs conclude at the end of 2012.

Carbon Legislation Sensitivity (14)
This sensitivity assumed no carbon legislation is passed during the Planning Period. Consequently, no CO_2 emission costs were added to the fossil fuel generation in this case. Additionally, CO_2 emission costs were removed from the forecast price of purchased power.

REC Sales Sensitivity (15)
The Company's base plan assumed that new renewable generation resources were able to sell RECs to others to reduce the cost to its ratepayers. In this sensitivity, RECs were not sold, therefore increasing the cost of renewable generation.

PTC and REC Sensitivity (16)
This sensitivity was a combination of the No REC Sales Sensitivity and the No PTC Sensitivity. It provides a view of renewables without some of the economic benefits that are currently available to them.

High and Low Cost Combination Sensitivities (17-18)
The High and Low cost combination sensitivities were a grouping of various individual sensitivities meant to form a more extreme case. The high cost combination case included the High Construction Cost, High Fuel and the No PTC sensitivities. The low cost combination case included the Low Construction Cost and Low Fuel cases.

6.6 INTEGRATED RESOURCE PLAN RANKING

The Company examined the alternative plans under the aforementioned scenarios and sensitivities to rank the plans against one another. The Company's methodology for determining the Preferred Plan from the set of alternative plans was the minimization of the net present value of total utility costs over the Planning Period. Figure 6.6.1 presents the results of the 5 plans analyzed against the 17 sensitivities and scenarios, plus 1 base case, for a total of 18 cases. The alternative plans were compared on an individual scenario or sensitivity basis so each row constitutes a grouping of plans that were considered for a particular sensitivity or scenario. The results are displayed as a percentage of costs above the lowest cost plan for each sensitivity or scenario in the respective row. The best performing alternative plan is labeled as 0.00% and is shaded for each sensitivity and scenario within Figure 6.6.1.

Figure 6.6.1 ALTERNATIVE PLAN COMPARISON UNDER SCENARIOS & SENSITIVITIES

		% Above Minimum by Case	NPV Relative to the Lowest Cost Plan				
			Base Plan	No Demand-Side Resources Plan	No Nuclear Expansion Plan	No Renewable Plan	Federal Renewable Plan
Scenarios and Sensitivities	1	Base Case	[redacted]	2.80%	0.80%	0.21%	4.17%
	2	High CO2 Scenario	[redacted]	3.03%	1.90%	0.40%	1.69%
	3	Low CO2 Scenario	0.08%	2.81%	[redacted]	0.17%	5.79%
	4	High Fuel Costs	[redacted]	3.01%	1.87%	0.35%	2.05%
	5	Low Fuel Costs	0.75%	3.28%	[redacted]	0.76%	8.01%
	6	High Load Growth	[redacted]	2.64%	0.71%	0.20%	3.86%
	7	Low Load Growth	[redacted]	3.17%	0.58%	0.18%	4.89%
	8	High Construction Cost	0.36%	3.43%	[redacted]	0.42%	7.35%
	9	Low Construction Cost	[redacted]	2.53%	2.02%	0.37%	1.22%
	10	High T&D Costs	[redacted]	2.87%	0.80%	0.21%	4.17%
	11	Low T&D Costs	[redacted]	2.72%	0.80%	0.21%	4.17%
	12	Plug-in Hybrid Cars	[redacted]	2.78%	0.84%	0.22%	3.99%
	13	PTC Tax Credit	0.03%	2.82%	0.82%	[redacted]	7.16%
	14	Carbon Legislation	1.06%	3.80%	[redacted]	1.04%	9.14%
	15	REC Sales	[redacted]	2.79%	0.80%	0.03%	5.75%
	16	PTC & REC	0.21%	3.00%	1.01%	[redacted]	8.93%
	17	High Cost Combination	[redacted]	3.22%	0.86%	0.02%	6.93%
	18	Low Cost Combination	[redacted]	2.17%	0.70%	0.20%	3.71%
		Plan Average	[redacted]	**2.82%**	**0.73%**	**0.15%**	**4.93%**

Note: *Lowest cost plan in each row is shown as 0.00%.*
High and Low sensitivities show a change of plus and minus 25% change in the main driver.

The results shown in Figure 6.6.1 indicate that the base plan is the Preferred Plan. The Preferred Plan was the top performing resource plan in 12 of 18 cases examined. Within the cases in which the base plan was not the best performing plan, it was within 1.06% of the lowest cost plan. This plan minimized changes in the Company's cost of providing service across the range of assumptions that the Company considered in its planning process.

The No Renewable Plan was the next best alternative plan on average relative to the Preferred Plan, at an additional cost of 0.15%. Across the 18 cases, it preformed best in 2 cases; however, it was the second best performing plan in 13 cases and the median cost plan in 3 cases.

The No Nuclear Plan was the medium-ranked alternative resource plan in 12 cases, the best plan in 4, and the second worst performing plan in 2 cases. Overall, this alternative plan resulted in an average increase of 0.73% in the Company's cost in providing service over the Planning Period, when compared to the Preferred Plan.

The alternative plans that lacked either the Company's portfolio of DSM programs or met a 20% RPS standard performed poorly under all cases and displayed a higher variance across the range of sensitivities and scenarios. The Federal RPS Plan was the worst performing alternative plan in 15 of the 18 cases. On average, this set of resources would cause the Company's total cost over the Planning Period to rise 4.93% over the Preferred Plan. The No DSM Plan costs averaged 2.82% above the Company's Preferred Plan.

The Base Plan versus the No Nuclear Plan warrants additional discussion because of the unique characteristics of a nuclear unit that would require additional analysis over a longer planning period. A nuclear unit is an extremely long-lived asset with an expected operating life of 60 years. The Planning Period in the 2009 Plan covered a 15-year window of which the nuclear unit was only represented in 7 years. While a nuclear unit is capital intensive, it provides reliable baseload energy at low variable costs and without carbon emissions. The fuel savings associated with the installation of a nuclear unit would increase as time goes on. As a result, lifetime fuel cost savings of a nuclear unit are not fully represented in a 15 year planning period and would require additional analysis. Similarly, as seen in the busbar curve presented in Chapter 5, the cost of a nuclear unit over its entire life proves to be very economical relative to other generating units.

Additionally, without a nuclear project, a significant amount of capacity and energy from other sources would be required. As shown in Figure 6.4.1, the No Nuclear Plan requires the Company to build 2 additional CC units which would significantly increase the Company's reliance on natural gas and decrease fuel diversity. Under the No Nuclear Plan, the Company also purchases more capacity and energy from the PJM market which exposes ratepayers to a potentially more volatile cost structure over the Planning Period which may make energy independence as described in the Virginia Energy Plan difficult to achieve.

6.7 PREFERRED PLAN

The Preferred Plan displayed in Figure 6.7.1 contains the preferred mix of supply- and demand-side options to meet expected future resource needs in the most efficient and cost-effective manner, while providing long-term rate stability. The Preferred Plan advocates a balanced resource mix relative to other plans the Company has analyzed. The balance includes an appropriate mix of baseload, intermediate, and peaking units along with a diverse fuel mixture that allows the Preferred Plan the flexibility to maintain reasonable costs and offer the reliability required to serve the Company's customers.

Figure 6.7.1 PREFERRED INTEGRATED RESOURCE PLAN

Year	Planned Generation Under Construction	Planned Generation Under Development	Potential Generation Resources	Renewable Generation Resources	Demand-Side Resources
2010					Proposed DSM Programs
2011	Bear Garden				Proposed & Future DSM Programs
2012	Virginia City				↓
2013					
2014					
2015		Warren			
2016			2CT	Bio	
2017			CC	Bio + 4 Wind	
2018		North Anna 3			
2019			CT		
2020			CT		
2021			CC		
2022			CC		
2023			CC		
2024			CC		

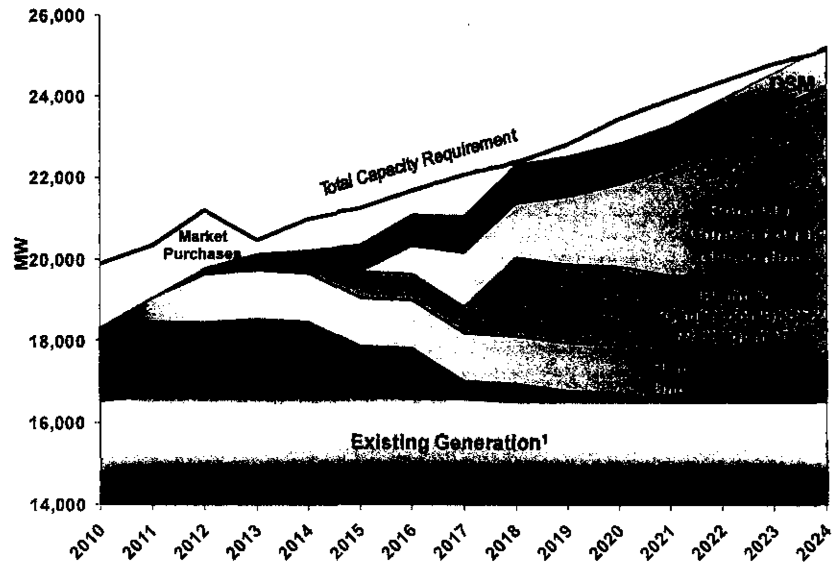
The major attributes of the Preferred Plan are listed below:

- *Existing Generation* – Uprates, downrates, and retirements allow the Company to expand existing generation capacity by approximately 100 MW by the end of the Planning Period.
- *Planned Generation Under Construction* – The Company currently has 2 units under construction including Bear Garden and the VCHEC with a combined capacity of approximately 1,200 MW.
- *Planned Generation Under Development* – The Company is in various stages of developing 2 new power plants: Warren County CC and North Anna 3.
- *Renewable Generation Resources* – Total renewable nameplate capacity of 300 MW is attributed to 200 MW of wind in 2017 (4 wind farms averaging 50 MW each) and 100 MW of biomass in 2016 and 2017 (2 units of 50 MW each).
- *Demand-Side Management* – Demand-side resources total approximately 950 MW by 2024, and defers 2 generating units beyond the Planning Period and delays another during the Planning Period.
- *Potential Generation Resources* - To meet the growing demand, the Preferred Plan identifies an additional 4,500 MW of CC and CT resources that would need to be constructed over the Planning Period based on current forecasts. These resources include:
    - Two CTs in 2016,
    - One CC in 2017,
    - One CT in 2019 and in 2020, and
    - One CC plant in each of the remaining years from 2021 to 2024.
- *Market Purchases* – The Company actively participates in PJM energy and capacity markets, buying and selling these commodities whenever it is economical for the Company. The Company is expected to be a net purchaser of energy and capacity over the Planning Period.

The total amount of new capacity proposed to be added between the years of 2010 and 2024 is approximately 8,900 MW. The Company will purchase or sell capacity from PJM operated capacity auctions as needed; however, it is expected that the Company will purchase, on average, 900 MW across the Planning Period. Additional details regarding the size and output of new generating units are in Appendices 6A and 6B. Appendix 6C provides details on existing, new, and DSM resources and the Company's capacity position relative to its requirement.

Figure 6.7.2 shows how the Company would fill the projected resource need with its Preferred Plan.

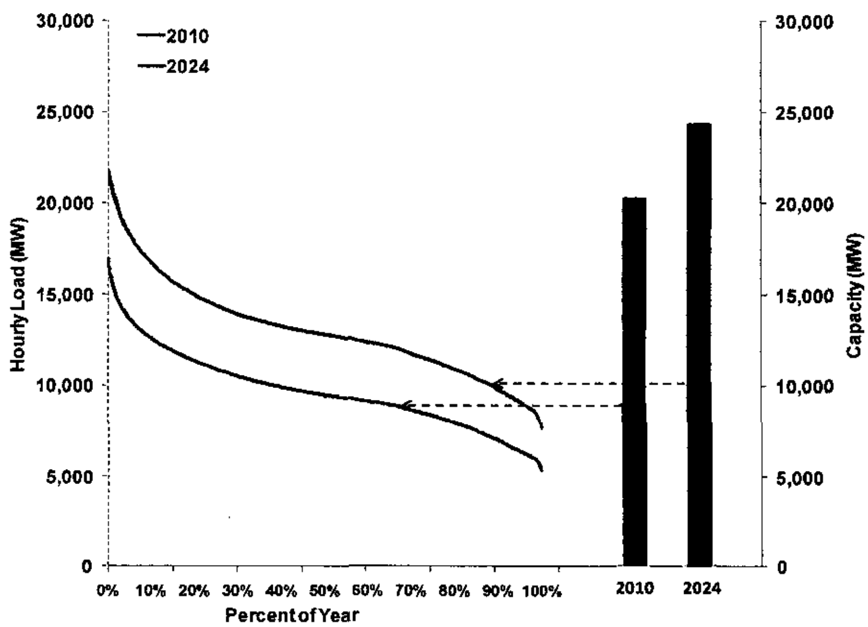
Figure 6.7.2 2010 - 2024 INTEGRATED RESOURCE PLAN



Note: 1) Includes rating changes to existing units.

The resulting resource mix that the Company is expected to have at the end of the Planning Period maintains an appropriate resource balance between baseload, intermediate, and peaking resources as shown in Figure 6.7.3. The addition of North Anna 3 would provide some of the baseload capacity necessary to meet the energy requirements between 2018 and 2024. Appendix 6D provides the construction cost estimates associated with the Preferred Plan. Appendix 6E provides capacity positions when the Preferred Plan is combined with existing resources.

Figure 6.7.3 2010 & 2024 LOAD DURATION CURVE VS. RESOURCE BASE

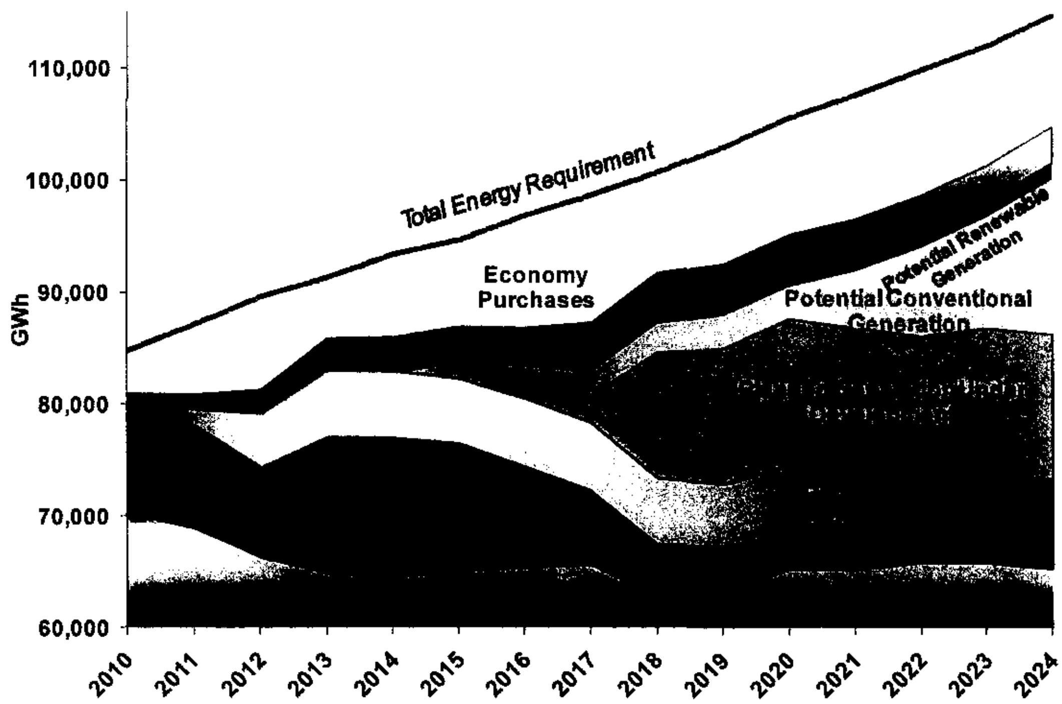


Note: Total capacity requirement consists of peak demand and planned reserve.

By the end of the Planning Period, the Company plans to have approximately 2,000 MW of additional baseload capacity, 4,400 MW of additional intermediate capacity, 1,300 MW of additional peaking capacity, and approximately 1,000 MW of DSM peak reduction. The Company considers this balance between resource types necessary to provide an appropriate tradeoff 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 shown in Figure 6.7.4. Planned generation under development, potential conventional generation, potential renewable generation, and energy provided by DSM programs are expected to stabilize the Company's market energy purchases. Following 2018, the Company's purchases of energy from the market are expected to shrink marginally in total and be reduced on a percentage basis.

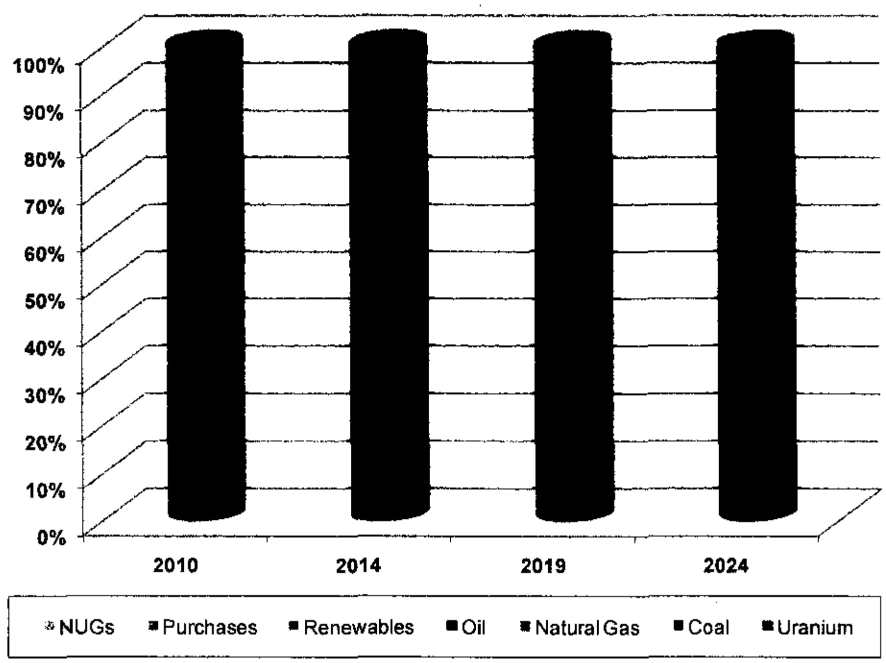
Figure 6.7.4 COMPANY PROJECTED ENERGY POSITION



Note: 1) Includes rating changes to existing units.

In addition to maintaining the balance between baseload, intermediate, and peaking capacity, the Company has considered the fuel mix that would result from its 2009 Plan. As displayed in Figure 6.7.5, the Company's current fuel mix includes uranium, coal, oil, natural gas, wind, and purchased power. Over-reliance on any particular type of fuel can lead to volatility in costs to serve customers. By the end of the Planning Period, the Company's reliance on outside resources will decrease while maintaining a diversified mix of fuels.

Figure 6.7.5 GENERATION BY FUEL TYPE



The Company expects its Preferred Plan will raise the Company's fuel procurement requirements to be in line with changing dispatch patterns and plant additions dictated by the growing demand for energy. The additional gas-fired units required by the Preferred Plan will require further incremental gas transmission infrastructure to be constructed. The Company identifies firm transmission needs on a portfolio basis, and therefore the exact requirements for incremental volumetric need of firm transportation service can vary depending upon absolute site locations. The Preferred Plan depends heavily on new gas units for both capacity and energy. However, a build-out of this much new gas capacity may require a significant expansion of the gas infrastructure for such a large amount of fuel to be deliverable in the Company's service territory. The Company is currently studying the need, feasibility, and cost of such additions.

The Company plans its capacity additions to meet the peak demand and reserve requirement. However, due to long lead times to develop new projects and the fact that generation capacity additions can be lumpy, it is difficult to meet the exact capacity requirements in any particular year. In reality, the Company will likely see a shortage or excess capacity compared to the target reserve margin on an annual basis. The Company's participation in the RPM will assist in buying during shortages and selling whenever there is capacity excess or need relative to the annual reserve target. During the next 15 years, the Company's Plan develops enough new generation capacity and DSM programs to significantly reduce the amount of capacity purchased from the capacity market. The Company does not intend to build capacity to sell into the capacity market; however, if in a particular year the Company has excess capacity, it can be sold into the PJM capacity market. As seen in Appendix 2I, the Company approaches its reserve margin requirements, but generally continues to make some market capacity purchases. In the event that the Company exceeds or does not meet its target reserve requirement, the Company will utilize the capacity market to purchase or sell as needed.

6.8 CONCLUSIONS

Based on the analyses and discussions presented, the Company's 2009 Plan provides a mix of supply- and demand-side resource options to meet the expected growth in customer demand while meeting the reliability requirements over the Planning Period at the lowest reasonable cost. The 2009 Plan was developed in accordance with the guidelines and rules enacted by the Company's regulators and provides a path toward the appropriate utilization of the Company's current resources with the addition of cost-effective resources to meet future customer demand.

In summary, over the next five years (2010-2014), the Company plans to add the Bear Garden CC, the VCHEC, and capacity uprates to existing units. These supply-side additions of approximately 1,200 MW will be complemented with over 500 MW of projected DSM reductions, which will reduce the Company's near-term reliance on market purchases for energy and capacity.

Additional resources in the long-term (2015-2024) will be required to balance changing supply and demand conditions that result from continuing load growth. Baseload growth will be met primarily with the addition of North Anna 3. Renewable resources are expected to increase with additions of wind and biomass units. DSM will account for approximately an additional 450 MW of reduction after 2014. The Company will also add approximately 3,800 MW of intermediate capacity and 1,400 MW of peaking capacity.

The Plan addresses a number of considerations including:

- Meeting load and reserve margin requirements in a cost-effective manner,
- Proposing DSM programs that reduce the demand for electricity and energy consumption,
- Reducing reliance on imported capacity and therefore decreasing market risk,
- Maintaining system reliability,
- Providing flexibility with regard to future resource selection,
- Meeting commercial operation dates for resources, and
- Remaining cost-effective under a range of future market conditions.

Uncertainty surrounding carbon regulations, renewable energy requirements, fuel costs, plant construction costs, and load growth are the major drivers that could significantly affect future costs to customers. To address these issues, the 2009 Plan provides fuel diversity, renewable resources, DSM resources, and a balanced mix of baseload, intermediate, and peaking capacity. As these drivers evolve over time and regulatory uncertainty is reduced, the Company will update its 2009 Plan to address these changes.

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 (2010 – 2014) in addition to a discussion of the specific actions currently being taken to meet the initiatives explained in this 2009 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 is pro-actively engaged in these developments by taking actions in the short-term to position the Company such that it can address these evolving developments over the long-term for the benefit of all the stakeholders. Major themes for the next five years are expected to be:

- Completion of the current infrastructure expansion projects in a timely manner. These projects include completion of the VCHEC and Bear Garden stations and completion of the Meadowbrook to Loudoun transmission lines,
- If approved by the regulators, start up of multiple DSM programs including implementation of smart grid technology,
- Setting up the processes and systems to comply with the NC REPS requirements,
- If approved, implementation of the VA RPS Plan and future development of cost-effective renewable resources,
- Decisions on various new infrastructure expansion projects such as North Anna 3, Warren County CC, and multiple transmission lines, and
- Continuous reviews of evolving technologies and business models for energy efficiency improvements, alternative energy production, smart grid information utilization, and carbon capture, transportation and storage.

A more detailed discussion of the current and planned activities over the next five years is given below.

7.1 CURRENT ACTIONS (2009)

Demand-Side Management:

1. Demand-Side Management Programs – On July 28, 2009, the Company filed a Petition in which it is seeking SCC approval to implement and recover the costs associated with 12 DSM programs.

Advanced Metering Infrastructure:

1. AMI Demonstration – In late January 2009, the Company began an AMI demonstration by deploying approximately 6,700 AMI meters on homes and businesses served by the Trabue substation distribution circuits in portions of Midlothian, Virginia. This demonstration confirmed the effectiveness of using AMI technology to achieve voltage conservation. As noted below, the Company is continuing its demonstration in Charlottesville, Virginia to gain key insights about deploying AMI in various geographic terrains.
2. SmartGrid Charlottesville – The Company is in the process of installing approximately 46,500 "smart meters" in the city of Charlottesville and Albermarle County by the end of

2009.

Generation:

1. Gravel Neck CT3 – 6 MW uprate effective April 2009
2. Gravel Neck CT4 – 6 MW uprate effective April 2009
3. Gravel Neck CT5 – 6 MW uprate effective April 2009
4. Gravel Neck CT6 – 6 MW uprate effective April 2009
5. Bath County 4 (60% DVP) – 48 MW uprate effective May 2009
6. Ladysmith 5 – 160 MW new facility came on-line in April 2009

Transmission:

1. Remington CT – Gainesville 230 kV Transmission Line – The Company filed a request (Case No. PUE-2009-00050) on June 15, 2009, that the SCC approve the construction of the proposed transmission facilities and grant a CPCN.
2. Hayes-Yorktown 230 kV Transmission Line – The Company filed a request (Case No. PUE-2009-00049) on July 1, 2009, that the SCC approve the construction of the proposed transmission facilities and grant a CPCN.
3. Elmont – Chickahominy – On May 28, 2009, the Company filed an application (Case No. PUE-2009-00045) with the SCC to amend the approved CPCN for a portion of the Elmont to Chickahominy 230 kV transmission line.

Renewable Energy Resources:

1. RPS Program – On July 28, 2009, the Company applied for SCC approval to participate in Virginia's voluntary RPS program.
2. REPS Program – The Company will begin complying with the NC REPS solar set aside requirement beginning in 2010 and the other REPS requirements, as applicable.

Other Initiatives:

1. Alternative Energy Solutions Department – In response to a greater focus on climate change and economic recovery initiatives at the state and federal levels, the Company created a department entitled Alternative Energy Solutions in April of this year to provide technology and research support to the Company's business units. This group will identify business opportunities, identify federal and state financial incentives, and assess federal and state renewable energy and efficiency targets and mandates. Additionally, this group will participate in the nation's energy policy development process and assess the technical, commercial, and financial viability of a growing number of new energy technologies that may be considered in both the near-term and long-term planning of demand-side and supply-side resources for the Company.

7.2 FUTURE ACTIONS (2010 – 2014)

DSM PROGRAMS

Figure 7.2.1 lists the projected demand and energy savings by 2014 from the proposed DSM Portfolio of Programs filed for SCC approval on July 28, 2009 as well as a future DSM portfolio that may be filed at a later date. The Company plans to file for NCUC approval of a portfolio of energy efficiency programs at the appropriate time.

Figure 7.2.1 DSM PROGRAMS PROJECTED SAVINGS IN 2014

Program	Type of Program	Projected MW Reduction in 2014	Projected GWh Savings in 2014
	Proposed DSM Portfolio		
Air Conditioner Cycling Program	Peak Shaving	170	0
Commercial Distributed Generation Program	Energy Efficiency/Demand Response	94	2
Curtailment Service Program	Energy Efficiency/Demand Response	105	3
Residential Lighting Program	Energy Efficiency	11	124
Low Income Program	Energy Efficiency	3	16
ENERGY STAR® New Homes Program	Energy Efficiency	4	36
Residential Heat Pump Tune-Up Program	Energy Efficiency	41	139
Residential Refrigerator Turn-In Program	Energy Efficiency	3	15
Heat Pump Upgrade Program	Energy Efficiency	21	63
Commercial HVAC Upgrade Program	Energy Efficiency	15	36
Voltage Conservation Program	Energy Efficiency	0	2,283
Commercial Lighting Program	Energy Efficiency	30	242
	Proposed DSM Portfolio Results	**497**	**2,958**
	Future DSM Portfolio		
In-Home Energy Display Program	Energy Efficiency	8	23
Residential Duct Testing & Sealing Program	Energy Efficiency	5	8
Residential Energy Audit Program	Energy Efficiency	2	6
Commercial Duct Testing & Sealing Program	Energy Efficiency	13	53
Commercial Energy Audit Program	Energy Efficiency	11	64
Commercial HVAC Tune-Up Program	Energy Efficiency	13	22
	Future DSM Portfolio Results	**51**	**176**
	Proposed and Future DSM Portfolio Results	**548**	**3,134**

GENERATION ADDITIONS:

Figure 7.2.2 lists the generation plants that are currently under construction and are expected to be operational before 2014.

Figure 7.2.2 GENERATION PLANTS UNDER CONSTRUCTION

Forecasted COD	Unit	Location	Primary Fuel	Unit Type[1]	Capacity (Net MW) Summer	Capacity (Net MW) Winter
June 2011	Bear Garden	Buckingham County, VA	Natural Gas	I	590	613
2012	Virginia City Hybrid Energy Center	Wise County, VA	Coal/ Biomass	B	585	635

Note: 1) Unit type: B= Baseload; I = Intermediate

GENERATION UPRATES/DOWNRATES:

Figure 7.2.3 lists the Company's planned changes to existing generating units.

Figure 7.2.3 PLANNED CHANGES TO EXISTING GENERATION

Unit Name	Type	MW	Date Effective Year
Bellemeade	Uprate	22	2010
North Anna 1	Uprate	14	2010
North Anna 2	Uprate	58	2010
Surry 1	Uprate	56	2010
Surry 2	Uprate	14	2010
Chesterfield 6	Uprate	7	2011
Chesterfield 5	Uprate	9	2011
Mt. Storm 2	Uprate	31	2011
Chesterfield 5	Downrate	-8	2011
Surry 2	Uprate	42	2011
Chesterfield 3	Downrate	-3	2012
Chesterfield 4	Downrate	-4	2012
Mt. Storm 3	Uprate	17	2012
North Anna 1	Uprate	47	2012
Gordonsville 1/South Anna 1	Uprate	10	2013
Gordonsville 2/South Anna 2	Uprate	10	2013
Possum Point 6	Uprate	34	2013
Mt. Storm 1	Uprate	30	2013

POTENTIAL GENERATION RETIREMENTS:

The Company currently anticipates that the units listed in Figure 7.2.4 will be considered for retirement within the first five years of the Plan.

Figure 7.2.4 POTENTIAL GENERATION RETIREMENTS

Unit Name	MW	Date Effective Year
Kitty Hawk CT1	-15	2012
Kitty Hawk CT2	-16	2012
Chesapeake CT7	-16	2012
Chesapeake CT8	-16	2012
Chesapeake CT9	-16	2012
Chesapeake CT10	-16	2012
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

Transmission:

Figure 7.2.5 lists the major transmission additions including expected operation target dates.

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Figure 7.2.5 PLANNED TRANSMISSION ADDITIONS

[redacted]				
Beaumeade – NIVO	230	1,047	April 2010	Approved
Fredericksburg – Four River to Ladysmith CT	230	1,047	May 2010	Approved
Pleasant View – Hamilton	230	1,047	May 2010	Approved
Harrisonburg – Valley	230	1,047	May 2010	Approved
Garrisonville Double Circuit	230	1,047/722[1]	May 2010	Approved
VCHEC – Clinch River Double Circuit	138	240	Sept 2010	Approved
Ft. Belvoir Single Circuit	230	1,047	Oct 2010	Approved
Elmont – Chickahominy	230	1,047	Nov 2010	Approved
Carson – Suffolk – Thrasher	500/230	3,460/1,047	May 2011	Approved
Meadowbrook – Loudoun	500	3,460	June 2011	Approved
Bear Garden – Bremo	230	1,047	June 2011	Approved
Remington CT – Gainesville	230	[redacted]	April 2012	Pending Approval
Arlington–Radnor Heights–Ballston	230	500	May 2012	Approved
Hayes – Yorktown	230	[redacted]	May 2012	Pending Approval
North Anna – Ladysmith	500	[redacted]	April 2014	Not Yet Filed
Harrisonburg – Merck	230	[redacted]	May 2014	Not Yet Filed

***Note:** 1) New line will be rated for 1,047 MVA; however, existing portion of the line will stay at 722 MVA.*

<u>RENEWABLE RESOURCES:</u>

Currently, approximately 416 MW of renewable generation is in operation and approximately 60 MW is under construction to be online by 2014. The Company plans to meet its VA RPS Goals at a reasonable cost and in a prudent manner by:

1. Applying current renewable generating facilities including NUGs,
2. Purchasing of cost-effective RECs, and
3. Developing new renewable resources when and where feasible and/or required by law.

The Company plans to meet its NC REPS requirements for set aside with either the purchase of bundled energy and/or RECs as determined by the NCUC. The Company's plans to meet the solar requirements are contained in the Company's 2009 REPS Compliance Plan.

As for the general REPS requirements, the Company intends to meet these requirements with a combination of:

1. Energy efficiency programs,
2. Purchases of out-of-state RECs, and

3. Developing new renewable energy resources when and where feasible and/or as permitted by North Carolina law.

Recently, the Company and BP Wind Energy North America Inc. announced that they had entered into an agreement to jointly own, operate and develop wind energy projects in Virginia. Subsequently, on January 22, 2009, the two announced that they were evaluating wind energy projects in Tazewell County, Va. and Wise County, Va. Both projects would be subject to all applicable local, state and federal permits and approvals. In addition to creating a viable source of renewable green energy, wind projects would bring construction, permanent jobs, and a significant source of tax revenue to their respective communities.

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Appendix

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
1999	23,934	21,760	11,013	8,716	274	4,225	69,922
2000	25,238	22,901	11,398	8,890	279	4,308	73,014
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	2,171	77,223
2005	29,942	27,023	10,331	10,120	280	1,735	79,431
2006	28,544	27,078	10,168	10,040	282	1,841	77,952
2007	30,469	28,416	10,094	10,660	283	1,995	81,917
2008	29,646	28,484	9,779	10,529	282	1,926	80,646
2009	29,851	27,739	9,306	10,267	287	1,883	79,334
2010	30,552	28,569	8,782	10,394	290	1,890	80,477
2011	31,199	30,519	9,060	10,641	293	1,932	83,643
2012	31,680	32,462	9,525	10,789	297	1,999	86,753
2013	32,039	34,198	9,704	10,990	301	2,027	89,259
2014	32,526	35,634	9,746	11,192	306	2,056	91,461
2015	33,145	36,718	9,756	11,359	311	2,097	93,384
2016	33,853	37,826	9,877	11,553	316	2,152	95,576
2017	34,377	38,807	9,923	11,686	321	2,191	97,305
2018	34,959	39,967	9,995	11,858	327	2,234	99,340
2019	35,545	41,200	10,117	12,061	332	2,281	101,537
2020	36,153	42,662	10,273	12,291	337	2,338	104,054
2021	36,612	43,850	10,379	12,447	342	2,380	106,010
2022	37,169	45,144	10,512	12,626	347	2,428	108,226
2023	37,724	46,505	10,611	12,800	353	2,477	110,469
2024	38,408	47,999	10,741	13,002	358	2,533	113,041

Note: *Historic (1999 – 2008), Projected (2009 – 2024)*

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

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
1999	22,726	21,108	9,824	8,598	265	3,212	65,733
2000	23,939	22,219	10,150	8,767	271	3,233	68,580
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	2,087	72,946
2005	28,359	26,243	8,621	9,976	272	1,651	75,123
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	28,293	27,011	7,955	10,128	279	1,834	75,500
2010	28,959	27,817	7,509	10,254	281	1,841	76,662
2011	29,572	29,716	7,751	10,497	284	1,882	79,703
2012	30,027	31,608	8,150	10,644	288	1,948	82,664
2013	30,368	33,298	8,298	10,842	293	1,975	85,074
2014	30,828	34,697	8,335	11,041	297	2,004	87,203
2015	31,415	35,753	8,341	11,205	302	2,044	89,060
2016	32,086	36,832	8,447	11,397	307	2,097	91,166
2017	32,583	37,786	8,487	11,528	312	2,135	92,831
2018	33,133	38,916	8,549	11,698	317	2,178	94,792
2019	33,690	40,117	8,650	11,899	322	2,224	96,902
2020	34,264	41,540	8,784	12,126	327	2,279	99,321
2021	34,701	42,698	8,876	12,279	332	2,320	101,207
2022	35,228	43,959	8,988	12,456	337	2,368	103,335
2023	35,755	45,283	9,076	12,627	343	2,415	105,498
2024	36,402	46,737	9,188	12,826	348	2,471	107,972

Note: *Historic (1999 – 2008), Projected (2009 – 2024)*

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
1999	1,207	653	1,189	118	9	1,014	4,189
2000	1,299	681	1,248	122	9	1,075	4,434
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	84	4,278
2005	1,583	780	1,709	143	8	84	4,308
2006	1,477	775	1,763	137	8	87	4,247
2007	1,579	810	1,735	140	8	89	4,361
2008	1,546	806	1,715	138	8	49	4,262
2009	1,558	729	1,352	139	8	49	3,834
2010	1,593	751	1,272	140	8	49	3,814
2011	1,627	803	1,308	143	8	50	3,940
2012	1,654	854	1,375	145	9	51	4,088
2013	1,671	899	1,406	148	9	52	4,186
2014	1,698	937	1,411	151	9	52	4,258
2015	1,730	965	1,414	153	9	53	4,324
2016	1,767	994	1,430	156	9	54	4,410
2017	1,795	1,020	1,436	158	9	55	4,473
2018	1,826	1,051	1,446	160	9	56	4,548
2019	1,855	1,083	1,467	163	10	57	4,635
2020	1,888	1,121	1,489	166	10	58	4,733
2021	1,911	1,152	1,503	168	10	59	4,803
2022	1,941	1,186	1,524	170	10	60	4,891
2023	1,970	1,222	1,535	172	10	61	4,971
2024	2,006	1,262	1,553	175	10	63	5,069

Note: *Historic (1999 – 2008), Projected (2009 – 2024)*

APPENDIX 2D – TOTAL CUSTOMER COUNT (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
1999	1,821,400	198,154	832	25,821	1,728	5	2,047,939
2000	1,855,891	202,428	805	25,998	1,778	5	2,086,904
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	2,140,584	232,524	576	29,271	2,650	3	2,405,608
2010	2,156,774	234,819	564	29,604	2,763	3	2,424,526
2011	2,177,530	237,388	552	29,868	2,882	3	2,448,222
2012	2,204,407	240,307	540	30,078	3,001	3	2,478,335
2013	2,234,896	243,438	528	30,293	3,119	3	2,512,277
2014	2,266,650	246,646	516	30,510	3,238	3	2,547,562
2015	2,299,544	249,933	504	30,744	3,357	3	2,584,084
2016	2,334,650	253,340	492	31,029	3,476	3	2,622,989
2017	2,369,800	256,754	480	31,349	3,595	3	2,661,981
2018	2,404,373	260,129	468	31,644	3,714	3	2,700,331
2019	2,439,275	263,521	456	31,913	3,833	3	2,739,000
2020	2,474,411	266,933	444	32,185	3,952	3	2,777,927
2021	2,509,881	270,359	432	32,453	4,071	3	2,817,198
2022	2,545,094	273,772	420	32,717	4,190	3	2,856,195
2023	2,580,061	277,171	408	32,977	4,309	3	2,894,929
2024	2,614,728	280,553	396	33,232	4,428	3	2,933,339

Note: *Historic (1999 – 2008), Projected (2009 – 2024)*

APPENDIX 2E – VIRGINIA CUSTOMER COUNT (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
1999	1,731,011	184,389	740	24,004	1,379	4	1,941,527
2000	1,764,063	188,340	716	24,192	1,438	4	1,978,751
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	1,868,437	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	2,038,195	216,544	514	27,342	2,239	2	2,284,836
2010	2,053,611	218,681	503	27,653	2,334	2	2,302,785
2011	2,073,374	221,074	492	27,900	2,435	2	2,325,277
2012	2,098,966	223,792	482	28,096	2,535	2	2,353,873
2013	2,127,996	226,708	471	28,297	2,636	2	2,386,110
2014	2,158,231	229,695	460	28,499	2,737	2	2,419,624
2015	2,189,552	232,756	450	28,718	2,837	2	2,454,314
2016	2,222,979	235,929	439	28,984	2,938	2	2,491,270
2017	2,256,448	239,109	428	29,283	3,038	2	2,528,308
2018	2,289,367	242,252	417	29,558	3,139	2	2,564,736
2019	2,322,600	245,411	407	29,810	3,239	2	2,601,468
2020	2,356,055	248,588	396	30,064	3,340	2	2,638,444
2021	2,389,828	251,778	385	30,315	3,440	2	2,675,748
2022	2,423,357	254,957	375	30,561	3,541	2	2,712,792
2023	2,456,652	258,123	364	30,804	3,641	2	2,749,585
2024	2,489,660	261,272	353	31,042	3,742	2	2,786,071

Note: *Historic (1999 – 2008), Projected (2009 – 2024)*

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

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
1999	90,388	13,765	92	1,817	348	1	106,412
2000	91,829	14,088	90	1,806	340	1	108,153
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	102,389	15,980	62	1,929	411	1	120,772
2010	103,163	16,138	60	1,951	428	1	121,741
2011	104,156	16,314	59	1,968	447	1	122,945
2012	105,441	16,515	58	1,982	465	1	124,462
2013	106,900	16,730	56	1,996	483	1	126,167
2014	108,419	16,951	55	2,011	502	1	127,938
2015	109,992	17,177	54	2,026	520	1	129,770
2016	111,671	17,411	53	2,045	539	1	131,719
2017	113,352	17,645	51	2,066	557	1	133,673
2018	115,006	17,877	50	2,085	576	1	135,595
2019	116,676	18,110	49	2,103	594	1	137,533
2020	118,356	18,345	47	2,121	613	1	139,483
2021	120,053	18,580	46	2,139	631	1	141,450
2022	121,737	18,815	45	2,156	649	1	143,403
2023	123,410	19,049	44	2,173	668	1	145,344
2024	125,068	19,281	42	2,190	686	1	147,268

Note: *Historic (1999 – 2008), Projected (2009 – 2024)*

APPENDIX 2G – SUMMER & WINTER PEAKS

Company Name: Virginia Electric and Power Company **Schedule 5**

POWER SUPPLY DATA

	(ACTUAL)								(PROJECTED)										
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
II. Load (MW)																			
1. Summer																			
a. Adjusted Summer Peak [(1)]	17,196	17,455	16,908	16,704	16,952	17,530	18,163	18,261	18,727	18,958	19,332	19,703	19,970	20,371	20,932	21,349	21,747	22,137	22,428
b. Other Commitments [(2)]	150	150	150	336	320	256	551	179	111	-64	-74	-81	-84	-86	-89	-91	-94	-114	-116
c. Total System Summer Peak	17,046	17,305	16,758	16,368	16,632	17,274	17,612	18,082	18,616	19,022	19,406	19,784	20,054	20,457	21,021	21,440	21,841	22,251	22,544
d. Percent Increase in Total Summer Peak		1.5%	-3.2%	-2.3%	1.6%	3.9%	2.0%	2.7%	3.0%	2.2%	2.0%	1.9%	1.4%	2.0%	2.8%	2.0%	1.9%	1.9%	1.3%
2. Winter																			
a. Adjusted Winter Peak [(1)]	14,444	16,060	15,135	14,596	14,603	14,890	15,141	15,578	15,903	16,013	16,309	16,501	16,924	17,257	17,600	17,936	18,182	18,496	18,942
b. Other Commitments [(2)]	150	150	150	308	308	308	276	208	156	-11	-18	-24	-26	-27	-29	-31	-33	-55	-57
c. Total System Winter Peak	14,294	15,910	14,985	14,288	14,295	14,582	14,864	15,370	15,748	16,024	16,327	16,525	16,950	17,284	17,630	17,967	18,216	18,551	18,999
d. Percent Increase in Total Winter Peak		11.3%	-5.8%	-4.6%	0.1%	2.0%	1.9%	3.4%	2.5%	1.8%	1.9%	1.2%	2.6%	2.0%	2.0%	1.9%	1.4%	1.8%	2.4%

(1) Peak after energy efficiency and demand-side programs, see Schedule 1

(2) To include 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] 2006	2007	2008	2009	(PROJECTED) 2010	2011	2012
1. Utility Peak Load (MW)							
A. Summer							
1a. Base Forecast	17,046	17,305	16,758	16,368	16,632	17,274	17,612
1b. Additional Forecast							
BTMG				158	158	158	155
NCEMC	150	150	150	150	150	150	150
2. Conservation, Efficiency				0	0	0	-31
3. Demand-Side and Response				-14	-44	-100	-181
4. Demand-Side and Response-Existing [2]	21	23	22	22	21	19	17
5. Peak Adjustment				28	12	-52	276
6. Adjusted Load	17,196	17,455	16,908	16,704	16,952	17,530	18,163
7. % Increase in Adjusted Load (from previous year)		1.5%	-3.1%	-1.2%	1.5%	3.4%	3.6%
B. Winter							
1. Base Forecast	14,294	15,910	14,985	14,288	14,295	14,582	14,864
1b. Additional Forecast							
BTMG				158	158	158	155
NCEMC	150	150	150	150	150	150	150
2. Conservation, Efficiency				0	0	0	-29
3. Demand-Side and Response				0	0	0	0
5. Adjusted Load	14,444	16,060	15,135	14,596	14,603	14,890	15,141
6. % Increase in Adjusted Load		11.2%	-5.8%	-3.6%	0.0%	2.0%	1.7%
2. Energy (GWh)							
A. Base Forecast	82,983	87,755	85,798	81,993	83,114	86,388	89,604
B. Additional Forecast							
BTMG				1,386	1,386	1,386	1,363
NCEMC				590	605	619	645
ODECsupp				161	119	0	0
C. PJM Energy Efficiency				-17	-18	-18	-19
D. Conservation & Demand Response				-94	-521	-1,293	-2,127
E. Adjusted Energy	82,983	87,755	85,798	84,018	84,685	87,082	89,467
F. % Increase in Adjusted Energy		5.8%	-2.2%	-2.1%	0.8%	2.8%	2.7%

	2013	2014	2015	2016	2017	2018
1. Utility Peak Load (MW)						
A. Summer						
1a. Base Forecast	18,082	18,616	19,022	19,406	19,784	20,054
1b. Additional Forecast						
BTMG	152	147	143	141	141	141
NCEMC	150	150	0	0	0	0
2. Conservation, Efficiency	-106	-170	-192	-200	-207	-210
3. Demand-Side and Response	-273	-369	-435	-495	-551	-595
4. Demand-Side and Response-Existing [2]	16	15	15	15	15	15
5. Peak Adjustment	-16	-16	-15	-15	-15	-15
6. Adjusted Load	18,261	18,727	18,958	19,332	19,703	19,970
7. % Increase in Adjusted Load (from previous year)	0.5%	2.5%	1.2%	2.0% !.	9%	1.4%2.
B. Winter						
1. Base Forecast	15,370	15,748	16,024	16,327	16,525	16,950
1b. Additional Forecast						
BTMG	152	147	143	141	141	141
NCEMC	150	150	0	0	0	0
2. Conservation, Efficiency	-95	-141	-154	-159	-165	-167
3. Demand-Side and Response	0	0	0	0	0	0
5. Adjusted Load	15,578	15,903	16,013	16,309	16,501	16,924
6. % Increase in Adjusted Load	2.9%	2.1%	0.7%	1.8% !.	2%	2.6%2.
2. Energy (GWh)						
A. Base Forecast	92,195	94,471	96,460	98,729	100,518	102,621
B. Additional Forecast						
BTMG	1,319	1,282	1,255	1,238	1,235	1,235
NCEMC	658	676	0	0	0	0
ODECsupp	0	0	0	0	0	0
C. PJM Energy Efficiency	-19	-20	-20	-21	-21	-22
D. Conservation & Demand Response	-2,866	-3,079	-3,158	-3,194	-3,231	-3,242
E. Adjusted Energy	91,287	93,329	94,537	96,752	98,500	100,592
F. % Increase in Adjusted Energy	2.0%	2.2%	1.3%	2.3% !.	8%	2.1%2.

	2019	2020	2021	2022	2023	2024
1. Utility Peak Load (MW)						
A. Summer						
1a. Base Forecast	20,457	21,021	21,440	21,841	22,251	22,544
1b. Additional Forecast						
BTMG	141	141	141	141	121	121
NCEMC	0	0	0	0	0	0
2. Conservation, Efficiency	-212	-215	-217	-220	-222	-224
3. Demand-Side and Response	-627	-654	-677	-692	-705	-716
4. Demand-Side and Response-Existing [2]	15	15	15	15	15	15
5. Peak Adjustment	-15	-15	-15	-15	-13	-13
6. Adjusted Load	20,371	20,932	21,349	21,747	22,137	22,428
7. % Increase in Adjusted Load (from previous year)	0%2.8	%	2.0% !.9	%	1.8% !.3	%
B. Winter						
1. Base Forecast	17,284	17,630	17,967	18,216	18,551	18,999
1b. Additional Forecast						
BTMG	141	141	141	141	121	121
NCEMC	0	0	0	0	0	0
2. Conservation, Efficiency	-168	-170	-172	-174	-176	-178
3. Demand-Side and Response	0	0	0	0	0	0
5. Adjusted Load	17,257	17,600	17,936	18,182	18,496	18,942
6. % Increase in Adjusted Load	0%2.0	%	1.9% !.4	%	1.7%2.4	%
2. Energy (GWh)						
A. Base Forecast	104,895	107,494	109,519	111,813	114,135	116,795
B. Additional Forecast						
BTMG	1,235	1,238	1,235	1,235	1,064	1,181
NCEMC	0	0	0	0	0	0
ODECsupp	0	0	0	0	0	0
C. PJM Energy Efficiency	-22	-23	-23	-24	-24	-25
D. Conservation & Demand Response	-3,252	-3,263	-3,273	-3,283	-3,293	-3,304
E. Adjusted Energy	102,856	105,447	107,458	109,741	111,882	114,647
F. % Increase in Adjusted Energy	2%2.5	%	1.9%2.1	%	2.0%2.5	%

(1) 88% of zonal load
(2) Existing DSM programs are included in the load forecast

APPENDIX 2I – REQUIRED RESERVE MARGIN

Company Name: Virginia Electric and Power Company

Schedule 6

POWER SUPPLY DATA (continued)

	(ACTUAL)				(PROJECTED)														
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
I. Reserve Margin [1]																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW [1]	645	494	1,312	3,476	2,947	2,821	3,040	2,191	2,247	2,275	2,320	2,365	2,397	2,445	2,512	2,562	2,610	2,657	2,693
b. Percent of Load	3.8%	2.9%	7.8%	21.3%	17.4%	16.1%	16.7%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
c. Actual Reserve Margin [4]	N/A	N/A	N/A	10.17%	8.9%	9.6%	9.0%	10.3%	7.7%	6.9%	8.6%	6.4%	11.2%	10.1%	8.6%	8.6%	9.6%	10.5%	11.9%
2. Winter Reserve Margin																			
a. MW [1]	N/A	N/A	N/A	N/A	7,236	7,241	7,911	6,632	6,809	7,520	7,439	8,506	7,877	8,183	8,458	8,788	8,883	9,035	8,928
b. Percent of Load	N/A	N/A	N/A	N/A	49.6%	48.6%	52.2%	42.6%	42.8%	47.0%	45.6%	51.5%	46.5%	47.4%	48.1%	49.0%	48.9%	48.9%	47.1%
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]	708	494	1,312	3,476	2,947	2,821	3,040	2,191	2,247	2,275	2,320	2,365	2,397	2,445	2,512	2,562	2,610	2,657	2,693
b. Percent of Load	3.0%	2.9%	7.8%	21.3%	17.4%	16.1%	16.7%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
c. Actual Reserve Margin [4]	N/A	N/A	N/A	10.2%	8.9%	9.6%	9.0%	10.3%	7.7%	6.9%	8.6%	6.4%	11.2%	10.1%	8.6%	8.6%	9.6%	10.5%	11.9%
2. Winter Reserve Margin																			
a. MW [1]	N/A	N/A	N/A	N/A	7,236	7,241	7,911	6,632	6,809	7,520	7,439	8,506	7,877	8,183	8,458	8,788	8,883	9,035	8,928
b. Percent of Load	N/A	N/A	N/A	N/A	49.6%	48.6%	52.2%	42.6%	42.8%	47.0%	45.6%	51.5%	46.5%	47.4%	48.1%	49.0%	48.9%	48.9%	47.1%
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 no units in Cold Reserve past 2006

(3) The Company and PJM forecasts a summer peak throughout the Planning Period

(4) Does not include spot purchases of capacity

(5) The Company folows 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	63
Bath County Units 1-6	Warm Springs, VA	Intermediate	Hydro-Pumped Storage	Dec-1985	1,802	1,788
Bellemeade Combined Cycle	Richmond, VA	Intermediate	Natural Gas-CC	Mar-1991	245	259
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	51	69
Chesapeake CT 2	Chesapeake, VA	Peak	Light Fuel Oil	Dec-1969	64	99
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	329	336
Chesterfield 6	Chester, VA	Base	Coal	Dec-1969	645	656
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
Commonwealth Atlantic (Company-owned)	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	348	365
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
Gaston Hydro	Roanoke Rapids, NC	Intermediate	Hydro-Conventional	Feb-1963	225	225
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	85	92
Gravel Neck 4	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85	91
Gravel Neck 5	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85	92
Gravel Neck 6	Surry, VA	Peak	Natural Gas-Turbine	Nov-1989	85	91
Hopewell	Hopewell, VA	Base	Coal	Jul-1989	63	63
Kitty Hawk	Kitty Hawk, NC	Peak	Light Fuel Oil	Mar-1971	31	45
Ladysmith 1	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	158	183
Ladysmith 2	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	158	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
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	524	539
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
Multitrade (Company-owned)	Hurt, VA	Base	Renewable	Jun-1994	83	83
North Anna 1	Mineral, VA	Base	Nuclear	Jun-1978	798	808
North Anna 2	Mineral, VA	Base	Nuclear	Dec-1980	798	810
North Anna Hydro	Mineral, VA	Intermediate	Hydro-Conventional	Dec-1987	1	1
North Branch	Gormania, WV	Base	Coal	Jan-1992	74	77
Northern Neck CT	Warsaw, VA	Peak	Light Fuel Oil	Jul-1971	47	70
Possum Point 3	Dumfries, VA	Intermediate	Natural Gas	Jun-1955	96	100
Possum Point 4	Dumfries, VA	Intermediate	Natural Gas	Apr-1962	220	225
Possum Point 5	Dumfries, VA	Intermediate	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	Roanoke Rapids, NC	Intermediate	Hydro-Conventional	Sep-1955	99	99
Panda Company-owned	Roanoke Rapids, NC	Intermediate	Natural Gas-CC	Dec-1990	165	186
Southampton	Franklin, VA	Base	Coal	Mar-1992	63	63
Surry 1	Surry, VA	Base	Nuclear	Dec-1972	799	812
Surry 2	Surry, VA	Base	Nuclear	May-1973	799	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	Intermediate	Heavy Fuel Oil	Dec-1974	818	820

(1) Commercial Online Date

APPENDIX 3B – NON-UTILITY 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	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Non-Utility Generation (NUG) Units							
Cogentrix-Richmond 1	Richmond, VA	Base	Coal	115,500	Yes	8/1/1992	7/3/2017
Cogentrix-Richmond 2	Richmond, VA	Base	Coal	85,000	Yes	8/1/1992	7/31/2017
Cogentrix-Rocky Mount	Battleboro, NC	Base	Coal	115,500	Yes	10/15/1990	10/14/2015
Doswell Complex	Ashland, VA	Peak	Natural Gas	604,998	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	92,000	Yes	5/5/1990	5/31/2015
Roanoke Valley II	Weldon, NC	Base	Coal	44,000	Yes	5/29/1994	5/28/2019
Roanoke Valley Project	Weldon, NC	Base	Coal	165,000	Yes	6/1/1995	5/3/2020
SEI Birchwood	King George, VA	Base	Coal	217,800	Yes	11/15/1996	11/14/2021
Behind-The-Meter (BTM) Generation Units							
BTM - 119 Goose Castle Road	NC	Must Take	Solar	3	No	3/18/2008	Auto renew
BTM - 1210 Ocean Trail	NC	Must Take	Wind	2	No	9/14/2008	Auto renew
BTM - 142 Owens Road	NC	Must Take	Wind	2	No	5/16/2008	Auto renew
BTM - 4113 Lindberg Ave	NC	Must Take	Solar	2	No	2/19/2008	Auto renew
BTM - Alexandria MSW	VA	NUG	MSW	21,000	No	1/29/1988	1/28/2023
BTM - Banister	VA	Must Take	Hydro	1,785	No	9/28/2008	Auto renew
BTM - Brasfield Dam	VA	Must Take	Hydro	2,485	No	10/12/1993	10/11/2013
BTM - Champman Dam	VA	Must Take	Hydro	300	No	10/17/1984	12/31/2010
BTM - Columbia Mills	VA	Must Take	Hydro	147	No	2/7/1985	2/6/2015
BTM - Coquina Beach	NC	Must Take	Wind	2	No	8/22/2006	Auto renew
BTM - Domtar*	NC	NUG	Coal/biomass	28,400	No	7/27/1991	Auto renew
BTM - I-95 Landfill	VA	Must Take	Methane	3,000	No	1/1/1992	12/31/2011
BTM - I-95 Phase II	VA	Must Take	Methane	3,000	No	2/10/1993	2/9/2013
BTM - Lakeview Hydro	VA	Must Take	Hydro	400	No	11/26/2008	Auto renew
BTM - Richmond Electric Generation	VA	Must Take	Methane	2,900	No	8/27/1993	8/26/2013
BTM - Rivanna Water and Sewer	VA	Must Take	Hydro	100	No	4/21/1998	Auto renew
BTM - Schoolfield Dam	VA	Must Take	Hydro	2,500	No	12/1/1990	11/30/2015
BTM - Stone Container*	VA	NUG	Coal/biomass	48,400	No	3/21/1981	10/26/2009
BTM - Suffolk Landfill #1	VA	Must Take	Methane	3,000	No	11/3/1992	11/3/2014
BTM - Westvaco	VA	NUG	Coal/Biomass	70,000	No	11/3/1982	Auto renew

* Agreement to provide excess energy only.

APPENDIX 3B Cont. – NON-UTILITY GENERATION UNITS

Customer Owned	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
-	VA	Standby	Coal	6,000	No	N/A	N/A
-	VA	Standby	Diesel	50	No	N/A	N/A
-	VA	Standby	Diesel	1,270	No	N/A	N/A
-	VA	Standby	Diesel	300	No	N/A	N/A
-	VA	Standby	Diesel	475	No	N/A	N/A
-	VA	Standby	Diesel	2 - 60	No	N/A	N/A
-	VA	Standby	Diesel	14,000	No	N/A	N/A
-	VA	Standby	Diesel	10,000	No	N/A	N/A
-	VA	Standby	Diesel	4,000	No	N/A	N/A
-	VA	Standby	Diesel	4,470	No	N/A	N/A
-	VA	Standby	Diesel	5,650	No	N/A	N/A
-	VA	Standby	Diesel	22,950	No	N/A	N/A
-	VA	Standby	Diesel	50	No	N/A	N/A
-	VA	Standby	Diesel	3,000	No	N/A	N/A
-	VA	Standby	Diesel	900	No	N/A	N/A
-	VA	Standby	Diesel	20,110	No	N/A	N/A
-	VA	Standby	Diesel	3,500	No	N/A	N/A
-	VA	Standby	NG	10	No	N/A	N/A
-	VA	Standby	LP	120	No	N/A	N/A
-	VA	Standby	Diesel	2,000	No	N/A	N/A
-	VA	Standby	Diesel	500	No	N/A	N/A
-	VA	Standby	Diesel	2,500	No	N/A	N/A
-	VA	Standby	Diesel	700	No	N/A	N/A
-	VA	Standby	Diesel	75	No	N/A	N/A
-	VA	Standby	Unknown	1,000	No	N/A	N/A
-	VA	Standby	Unknown	4,500	No	N/A	N/A
-	VA	Standby	Diesel	2,000	No	N/A	N/A
-	VA	Standby	Diesel	9,000	No	N/A	N/A
-	VA	Standby	Diesel	2,250	No	N/A	N/A
-	VA	Standby	Diesel	3,500	No	N/A	N/A
-	VA	Standby	Diesel	2,000	No	N/A	N/A
-	VA	Standby	Diesel	2,000	No	N/A	N/A
-	VA	Merchant	Coal	92,000	No	N/A	N/A
-	VA	Merchant	Coal	115,000	No	N/A	N/A
-	VA	Standby	Diesel	2,800	No	N/A	N/A
-	VA	Standby	Diesel	30,000	No	N/A	N/A
-	VA	Standby	Diesel	40,000	No	N/A	N/A
-	VA	Standby	Diesel	13,042	No	N/A	N/A
-	VA	Standby	Diesel	1,885	No	N/A	N/A
-	VA	Standby	Diesel	12,710	No	N/A	N/A
-	VA	Standby	NG	13,760	No	N/A	N/A
-	VA	Standby	LP	81	No	N/A	N/A
-	VA	Standby	NG	1,341	No	N/A	N/A
-	VA	Standby	LP	126	No	N/A	N/A
-	VA	Standby	Diesel	828	No	N/A	N/A
-	VA	Standby	Diesel	200	No	N/A	N/A
-	VA	Standby	Diesel	8,000	No	N/A	N/A
-	VA	Standby	Diesel	1,750	No	N/A	N/A
-	VA	Standby	Diesel	16,000	No	N/A	N/A
-	VA	Standby	Unknown	750	No	N/A	N/A
-	VA	Merchant	NG	50,000	No	N/A	N/A
-	VA	Standby	Diesel	69,000	No	N/A	N/A
-	VA	Standby	Steam	20,000	No	N/A	N/A
-	VA	Standby	Diesel	415	No	N/A	N/A
-	VA	Standby	Diesel	50	No	N/A	N/A
-	VA	Merchant	Hydro	2,700	No	N/A	N/A
-	VA	Standby	Diesel	35,000	No	N/A	N/A
-	VA	Standby	Diesel	20,205	No	N/A	N/A
-	VA	Standby	NG	2,139	No	N/A	N/A
-	VA	Standby	LP	292	No	N/A	N/A
-	VA	Standby	Diesel	?	No	N/A	N/A
-	VA	Standby	Diesel	6,500	No	N/A	N/A
-	VA	Standby	Diesel	2 - 750	No	N/A	N/A
-	VA	Standby	Diesel	5,350	No	N/A	N/A
-	VA	Standby	Diesel	16,400	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A

APPENDIX 3B Cont. – NON-UTILITY GENERATION UNITS

-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	350	No	N/A	N/A
-	VA	Standby	Diesel	22,690	No	N/A	N/A
-	VA	Standby	Diesel	5,000	No	N/A	N/A
-	VA	Standby	Diesel	15,100	No	N/A	N/A
-	VA	Standby	Diesel	1,250	No	N/A	N/A
-	VA	Standby	Diesel	500	No	N/A	N/A
-	VA	Standby	Diesel	1,000	No	N/A	N/A
-	VA	Standby	Diesel	2 - 910	No	N/A	N/A
-	VA	Standby	Diesel	1,000	No	N/A	N/A
-	VA	Standby	Diesel	4 - 750	No	N/A	N/A
-	VA	Standby	Diesel	2,100	No	N/A	N/A
-	VA	Standby	Diesel	710	No	N/A	N/A
-	VA	Standby	Diesel	1,500	No	N/A	N/A
-	VA	Standby	Diesel	50	No	N/A	N/A
-	VA	Standby	coal/biomass	145,000	No	N/A	N/A
-	VA	Standby	Diesel	750	No	N/A	N/A
-	VA	Standby	Diesel	600	No	N/A	N/A
-	VA	Standby	Diesel	250	No	N/A	N/A
-	VA	Standby	Diesel	100	No	N/A	N/A
-	VA	Standby	Diesel	500	No	N/A	N/A
-	VA	Standby	Diesel	200	No	N/A	N/A
-	VA	Standby	Diesel	250	No	N/A	N/A
-	VA	Standby	Diesel	500	No	N/A	N/A
-	VA	Standby	NG	1,050	No	N/A	N/A
-	VA	Standby	Diesel	6,400	No	N/A	N/A
-	VA	Standby	Diesel	500	No	N/A	N/A
-	VA	Standby	Nat gas	6,000	No	N/A	N/A
-	VA	Standby	Diesel	5,000	No	N/A	N/A
-	VA	Standby	#2 FO	5,000	No	N/A	N/A
-	VA	Standby	Diesel	50	No	N/A	N/A
-	VA	Standby	Diesel	5,000	No	N/A	N/A
-	VA	Standby	Diesel	200	No	N/A	N/A
-	VA	Standby	Diesel	1,000	No	N/A	N/A
-	VA	Standby	Diesel	1,000	No	N/A	N/A
-	VA	Standby	Diesel	1,500	No	N/A	N/A
-	VA	Standby	Diesel	3,000	No	N/A	N/A
-	VA	Standby	Diesel	750	No	N/A	N/A
-	VA	Standby	Coal	500	No	N/A	N/A
-	VA	Standby	Diesel	1,500	No	N/A	N/A
-	VA	Standby	Diesel	1,000	No	N/A	N/A
-	VA	Standby	Diesel	1,000	No	N/A	N/A
-	VA	Standby	Diesel	3,000	No	N/A	N/A
-	VA	Standby	NG	6,000	No	N/A	N/A
-	VA	Standby	Diesel	2,000	No	N/A	N/A
-	VA	Standby	Diesel	8,000	No	N/A	N/A
-	VA	Standby	Diesel	500	No	N/A	N/A
-	VA	Standby	Diesel	4,000	No	N/A	N/A
-	VA	Standby	Diesel	10,000	No	N/A	N/A
-	VA	Standby	Diesel	5,000	No	N/A	N/A
-	VA	Standby	Diesel	12,000	No	N/A	N/A
-	VA	Standby	Unknown	50,000	No	N/A	N/A
-	VA	Standby	Diesel	100	No	N/A	N/A
-	VA	Standby	Diesel	18,100	No	N/A	N/A
-	VA	Merchant	RDF	60,000	No	N/A	N/A
-	VA	Standby	Diesel	750	No	N/A	N/A
-	VA	Standby	Diesel	750	No	N/A	N/A
-	VA	Standby	Diesel	5,150	No	N/A	N/A
-	VA	Standby	Diesel	7,000	No	N/A	N/A
-	VA	Standby	Diesel	8,000	No	N/A	N/A
-	VA	Standby	Diesel	1,000	No	N/A	N/A

APPENDIX 3B Cont. – NON-UTILITY GENERATION UNITS

-	VA	Standby	Diesel	6,000	No	N/A	N/A
-	VA	Standby	Diesel	500	No	N/A	N/A
-	VA	Standby	NG	50,000	No	N/A	N/A
-	VA	Standby	Unknown	4,000	No	N/A	N/A
-	VA	Standby	Diesel	10,000	No	N/A	N/A
-	VA	Standby	Diesel	13,000	No	N/A	N/A
-	VA	Standby	Water	227,000	No	N/A	N/A
-	VA	Standby	Diesel	300	No	N/A	N/A
-	VA	Standby	Diesel	1,000	No	N/A	N/A
-	VA	Standby	Diesel	1,500	No	N/A	N/A
-	VA	Standby	Diesel	30	No	N/A	N/A
-	VA	Standby	Diesel	1,000	No	N/A	N/A
-	VA	Standby	Diesel	12,000	No	N/A	N/A
-	VA	Standby	Diesel	3,000	No	N/A	N/A
-	VA	Standby	Diesel	30,000	No	N/A	N/A
-	VA	Standby	Diesel	5,000	No	N/A	N/A
-	VA	Standby	Diesel	2,000	No	N/A	N/A
-	VA	Standby	Diesel	16,000	No	N/A	N/A
-	VA	Standby	Diesel	6,450	No	N/A	N/A
-	VA	Standby	Diesel	2,000	No	N/A	N/A
-	VA	Standby	Diesel	12 - 2000	No	N/A	N/A
-	VA	Standby	Diesel	6,050	No	N/A	N/A
-	VA	Standby	Diesel	150	No	N/A	N/A
-	VA	Standby	Diesel	500	No	N/A	N/A
-	VA	Standby	Diesel	1,500	No	N/A	N/A
-	NC	Standby	diesel	1,250	No	N/A	N/A
-	NC	Standby	diesel	585	No	N/A	N/A
-	NC	Standby	diesel	10,000	No	N/A	N/A
-	NC	Standby	diesel	400	No	N/A	N/A
-	NC	Standby	diesel	400	No	N/A	N/A
-	NC	Standby	diesel	500	No	N/A	N/A
-	NC	Standby	diesel	350	No	N/A	N/A
-	NC	Standby	diesel	400	No	N/A	N/A
-	NC	Standby	diesel	450	No	N/A	N/A
-	NC	Standby	diesel	400	No	N/A	N/A
-	NC	Standby	diesel	500	No	N/A	N/A
-	NC	Standby	diesel	500	No	N/A	N/A
-	NC	Standby	diesel	500	No	N/A	N/A
-	NC	Standby	diesel	700	No	N/A	N/A
-	NC	Standby	diesel	700	No	N/A	N/A
-	NC	Standby	diesel	700	No	N/A	N/A
-	NC	Standby	coal	25,000	No	N/A	N/A
-	NC	Standby	diesel	300	No	N/A	N/A
-	NC	Standby	diesel	800	No	N/A	N/A
-	NC	Standby	diesel	4,000	No	N/A	N/A
-	NC	Standby	diesel	1,200	No	N/A	N/A
-	NC	Standby	diesel	750	No	N/A	N/A
-	NC	Standby	diesel	450	No	N/A	N/A
-	NC	Standby	unknown	2,000	No	N/A	N/A
-	NC	Standby	diesel	1,800	No	N/A	N/A

APPENDIX 3C – EQUIVALENT AVAILABILITY FACTOR (%)

Company Name: Virginia Electric and Power Company

Schedule 8

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

Unit Name	2006 (ACTUAL)	2007	2008	2009	2010 (PROJECTED)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Altavista	90	92	96	94	94	93	93	93	93	93	93	93	93	93	93	93	93	93	93
Bath County Units 1-6	87	89	85	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bellemeade Combined Cycle	88	80	86	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87
Bremo 3	98	76	95	94	94	93	93	93	93	93	93	93	93	93	93	93	93	93	93
Bremo 4	93	84	86	90	90	90	89	94	94	94	94	94	94	94	94	94	94	94	94
Chesapeake 1	96	93	93	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Chesapeake 2	95	95	95	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Chesapeake 3	93	79	90	91	91	91	91	90	90	90	90	90	90	90	90	90	90	90	90
Chesapeake 4	91	88	91	92	92	91	91	91	91	91	91	91	91	91	91	91	91	91	91
Chesapeake CT 1	96	94	84	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Chesapeake CT 2	96	95	93	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Chesterfield 3	78	70	94	92	91	91	91	90	90	90	90	90	90	90	90	90	90	90	90
Chesterfield 4	76	73	88	88	87	87	91	91	91	91	91	91	91	91	91	91	91	91	91
Chesterfield 5	83	91	80	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
Chesterfield 6	81	81	75	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
Chesterfield 7	90	78	91	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Chesterfield 8	76	86	78	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Clover 1	98	95	94	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Clover 2	98	95	92	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Commonwealth Atlantic (Company-owned)	94	97	87	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Cushaw Hydro Unit	100	100	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 1	94	99	95	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Darbytown 2	91	77	78	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Darbytown 3	96	91	92	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Darbytown 4	96	99	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gaston Hydro	98	91	94	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1	93	96	97	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87
Gordonsville 2	93	94	88	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Gravel Neck 1	71	93	85	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Gravel Neck 3	100	95	83	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gravel Neck 4	99	95	85	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gravel Neck 5	98	94	87	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gravel Neck 6	99	97	87	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Hopewell	N/A	88	89	89	89	89	89	89	89	89	89	89	89	89	89	89	89	89	89
Kitty Hawk	80	92	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Ladysmith 1	98	96	92	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Ladysmith 2	98	95	91	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Ladysmith 3	N/A	N/A	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Ladysmith 4	N/A	N/A	94	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Ladysmith 5	N/A	N/A	N/A	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Lowmoor CT	95	81	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Mecklenburg 1 (Company-owned)	94	91	98	96	96	96	95	95	95	95	95	95	95	95	95	95	95	95	95
Mecklenburg 2 (Company-owned)	94	91	98	96	96	96	95	95	95	95	95	95	95	95	95	95	95	95	95

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

Mount Storm 1	83	78	91	91	91	91	90	91	91	91	91	91	91	91	91	91	91	91	91
Mount Storm 2	92	82	96	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
Mount Storm 3	89	76	69	91	91	91	93	93	93	93	93	93	93	93	93	93	93	93	93
Mount Storm CT	100	100	93	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Multitrade (Company-owned)	90	91	91	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
North Anna 1	88	89	99	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
North Anna 2	100	85	81	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
North Anna Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Branch	75	85	87	90	94	94	93	93	93	93	93	93	93	93	93	93	93	93	93
Northern Neck CT	97	98	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Panda Company-owned	96	76	96	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Possum Point 3	92	77	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
Possum Point 4	87	72	93	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Possum Point 5	80	85	80	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Possum Point 6	90	92	82	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Possum Point CT	100	76	98	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Remington 1	99	95	89	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Remington 2	99	98	88	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Remington 3	99	98	90	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Remington 4	99	99	92	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
Roanoke Rapids Hydro	78	99	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southampton	71	84	93	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Surry 1	89	87	97	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Surry 2	87	100	93	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Yorktown 1	87	84	89	90	90	89	89	89	89	89	89	89	89	89	89	89	89	89	89
Yorktown 2	90	75	94	93	93	93	92	92	92	92	92	92	92	92	92	92	92	92	92
Yorktown 3	85	84	92	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Bear Garden	-	-	-	98	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	95
North Anna 3:2018:294	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Warren County :2015:300	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
BIOMASS UNIT:2016:297	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
BIOMASS UNIT:2017:295	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Combined Cycle 7FA :2017:296	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Combined Cycle 7FA :2021:291	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Combined Cycle 7FA :2022:290	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Combined Cycle 7FA :2023:289	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Combined Cycle 7FA :2024:288	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
NEW On-shore WIND :2017:100	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NEW ON-SHORE WIND :2017:97	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NEW ON-SHORE WIND :2017:98	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NEW ON-SHORE WIND :2017:99	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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

Simple Cycle 7FA:2016:298	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Simple Cycle 7FA:2016:299	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Simple Cycle 7FA:2019:293	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Simple Cycle 7FA:2020:292	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Cogentrix-Richmond 1	-	-	-	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Cogentrix-Richmond 2	-	-	-	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Cogentrix-Rocky Mount	-	-	-	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96
Doswell Complex	-	-	-	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Hopewell Cogen	-	-	-	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96
Ogden-Martin Fairfax	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Roanoke Valley II	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Roanoke Valley Project	-	-	-	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
SEI Birchwood	-	-	-	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
BTM - 119 Goose Castle Road	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - 1210 Ocean Trail	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - 142 Owens Road	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - 4113 Lindberg Ave	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Alexandria MSW	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Banister	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Brasfield Dam	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Champman Dam	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Columbia Mills	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Coquina Beach	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Domtar	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - I-95 Landfill	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - I-95 Phase II	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Lakeview Hydro	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Richmond Electric Generation	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Rivanna Water and Sewer	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Schoolfield Dam	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Stone Container	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Suffolk Landfill #1	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Westvaco	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

APPENDIX 3D – NET CAPACITY FACTOR

Schedule 9

Company Name: Virginia Electric and Power Company

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

Unit Name	(ACTUAL)				(PROJECTED)														
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Altavista	63	66	34	64	72	60	52	27	26	26	23	21	18	18	18	23	17	15	15
Bath County Units 1-6	17	16	12	8	10	11	12	10	12	12	12	13	12	12	12	12	12	11	11
Bellemeade Combined Cycle	18	19	20	31	18	15	12	15	14	15	13	12	10	11	11	11	10	10	10
Bremo 3	61	66	51	56	69	61	43	21	4	4	3	3	3	2	3	2	1	1	1
Bremo 4	79	77	64	71	83	75	65	58	14	14	11	11	10	10	10	10	9	9	9
Chesapeake 1	63	74	56	49	49	50	50	29	26	28	26	27	25	22	22	30	20	26	28
Chesapeake 2	66	76	59	53	52	57	52	31	29	30	29	30	28	24	25	35	24	30	34
Chesapeake 3	80	72	75	65	69	60	58	42	41	41	42	52	36	45	47	47	46	45	44
Chesapeake 4	70	77	71	65	66	60	64	35	38	37	40	45	35	39	43	47	47	46	48
Chesapeake CT 1	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-
Chesapeake CT 2	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	45	57	58	75	74	66	47	40	41	41	44	48	34	37	35	36	36	37	38
Chesterfield 4	57	63	68	81	81	59	75	64	65	72	65	72	63	68	63	59	71	69	63
Chesterfield 5	75	86	78	89	89	63	83	75	74	73	83	82	73	72	75	78	83	73	76
Chesterfield 6	73	77	67	84	63	85	80	77	70	76	76	69	74	74	77	75	79	78	76
Chesterfield 7	27	46	45	60	44	30	24	27	33	31	48	42	38	37	42	45	49	43	49
Chesterfield 8	24	49	40	65	48	37	23	33	34	42	44	50	39	48	45	52	47	46	46
Clover 1	92	88	77	83	96	94	78	84	84	77	85	83	74	82	83	83	86	85	85
Clover 2	92	88	76	82	96	88	91	84	75	84	83	75	82	80	81	81	84	83	84
Commonwealth Atlantic (Company-owned)	2	6	3	3	5	3	1	3	2	2	1	2	1	0	0	0	0	0	0
Cushaw Hydro Unit	53	80	70	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
Darbytown 1	3	6	3	5	4	4	2	4	4	3	3	3	2	1	1	1	1	1	1
Darbytown 2	3	5	4	5	3	4	2	4	4	3	3	3	2	1	1	1	1	1	1
Darbytown 3	3	4	3	4	3	3	2	4	3	3	3	2	1	1	1	1	1	1	1
Darbytown 4	3	5	3	4	3	3	2	3	3	3	2	2	1	1	1	1	1	1	1
Gaston Hydro	12	12	8	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Gordonsville 1	16	23	20	43	26	16	13	18	18	20	18	16	13	14	14	15	14	13	13
Gordonsville 2	14	24	16	37	26	16	13	20	19	20	17	16	13	14	14	14	14	13	13
Gravel Neck 1	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-
Gravel Neck 3	2	4	2	6	6	5	3	3	3	3	2	2	1	1	1	1	1	1	1
Gravel Neck 4	2	4	1	5	6	4	3	3	3	3	2	2	1	1	1	1	0	1	1
Gravel Neck 5	2	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gravel Neck 6	2	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hopewell	-	76	46	42	51	41	35	21	20	20	17	16	14	14	15	17	14	13	13
Kitty Hawk	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	4	8	6	13	10	7	5	8	7	7	7	6	6	5	6	6	5	4	4
Ladysmith 2	4	8	6	15	11	9	6	10	9	9	8	7	7	7	6	7	6	6	4
Ladysmith 3	-	-	7	17	12	9	7	11	9	10	8	8	7	7	7	8	6	7	5
Ladysmith 4	-	-	7	15	11	8	6	9	8	8	7	7	6	6	6	7	6	5	4
Ladysmith 5	-	-	-	11	10	8	6	9	8	8	7	7	6	6	6	7	5	5	4
Lowmoor CT	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1 (Company-owned)	59	62	44	80	76	75	63	37	38	37	36	39	32	30	33	35	34	35	33
Mecklenburg 2 (Company-owned)	59	61	43	80	82	75	63	33	36	33	34	38	31	29	32	34	33	34	33

Company Name: Virginia Electric and Power Company

Schedule 9

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

Unit Name	2006 (ACTUAL)	2007	2008	2009	2010 (PROJECTED)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Mount Storm 1	81	75	89	52	85	84	81	69	77	79	74	80	79	72	82	82	84	84	84
Mount Storm 2	91	78	82	87	88	78	84	82	75	82	83	75	81	81	84	84	86	86	86
Mount Storm 3	86	74	63	87	84	81	72	74	76	70	77	77	69	76	79	79	81	80	80
Mount Storm CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Multitrade (Company-owned)	67	60	67	56	79	74	62	80	86	87	87	87	87	86	91	91	92	91	92
North Anna 1	88	89	99	90	89	97	87	90	97	89	90	97	89	90	97	89	90	97	90
North Anna 2	100	85	81	97	87	89	97	89	89	97	90	89	97	88	90	97	89	89	97
North Anna Hydro	-	-	-	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
North Branch	70	83	87	44	76	71	47	19	20	20	18	16	14	13	14	13	13	12	12
Northern Neck CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Panda Company-owned	8	7	13	20	14	11	7	12	12	13	11	10	9	9	9	9	8	8	8
Possum Point 3	5	6	7	11	10	8	5	12	10	11	9	8	8	8	8	8	7	8	8
Possum Point 4	4	10	8	13	11	9	5	13	12	12	10	9	8	8	9	9	8	8	8
Possum Point 5	4	7	5	3	1	0	0	1	2	1	1	1	1	2	2	2	3	3	3
Possum Point 6	28	47	43	52	44	34	26	40	40	43	38	40	39	38	37	38	38	39	41
Possum Point CT	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0
Remington 1	1	3	5	9	8	6	4	7	6	6	4	4	3	3	3	4	3	3	3
Remington 2	2	4	5	7	6	5	3	5	4	4	3	3	2	2	3	3	2	2	2
Remington 3	3	4	4	8	7	5	4	7	5	5	4	4	3	3	3	3	3	3	2
Remington 4	3	4	4	8	7	5	3	6	5	5	3	4	3	3	3	3	2	3	2
Roanoke Rapids Hydro	29	28	20	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Southampton	52	71	49	47	64	55	44	22	23	24	21	21	18	18	18	23	18	16	15
Surry 1	90	88	97	90	81	96	89	89	96	89	89	96	89	89	97	89	89	96	89
Surry 2	88	100	93	90	96	86	89	96	89	89	97	89	89	96	89	89	96	89	89
Yorktown 1	70	74	65	76	80	71	56	48	51	57	56	58	47	55	47	47	54	51	50
Yorktown 2	67	66	69	81	84	69	62	47	51	56	61	60	43	53	51	48	54	52	53
Yorktown 3	3	12	5	5	2	2	1	3	3	3	3	3	3	4	4	4	4	4	5
Bear Garden	-	-	-	0	0	28	27	37	38	39	41	43	43	41	43	46	51	55	55
Virginia City	-	-	-	0	0	0	61	71	69	65	69	67	65	61	69	69	71	70	71
North Anna 3:2018:294	-	-	-	0	0	0	0	0	0	0	0	0	81	89	97	89	89	97	97
Warren County :2015:300	-	-	-	0	0	0	0	0	0	26	43	41	32	32	34	38	35	34	32
BIOMASS UNIT:2016:297	-	-	-	0	0	0	0	0	0	0	55	93	93	92	91	91	91	91	92
BIOMASS UNIT:2017:295	-	-	-	0	0	0	0	0	0	0	0	55	93	92	92	91	91	92	92
Combined Cycle 7FA :2017:296	-	-	-	0	0	0	0	0	0	0	0	31	40	43	39	43	42	38	37
Combined Cycle 7FA :2021:291	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	33	52	41	42
Combined Cycle 7FA :2022:290	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	34	45	48
Combined Cycle 7FA :2023:289	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	37	62
Combined Cycle 7FA :2024:288	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	39
NEW On-shore WIND :2017:100	-	-	-	0	0	0	0	0	0	0	0	31	31	31	31	31	31	31	31
NEW ON-SHORE WIND :2017:97	-	-	-	0	0	0	0	0	0	0	0	31	31	31	31	31	31	31	31
NEW ON-SHORE WIND :2017:98	-	-	-	0	0	0	0	0	0	0	0	31	31	31	31	31	31	31	31
NEW ON-SHORE WIND :2017:99	-	-	-	0	0	0	0	0	0	0	0	31	31	31	31	31	31	31	31
Simple Cycle 7FA:2016:298	-	-	-	0	0	0	0	0	0	0	6	6	5	5	5	5	4	5	5
Simple Cycle 7FA:2016:299	-	-	-	0	0	0	0	0	0	0	5	5	4	4	4	5	4	4	5
Simple Cycle 7FA:2019:293	-	-	-	0	0	0	0	0	0	0	0	0	0	5	5	6	4	5	6

(1) Calculated using PJM Methodology

Company Name: Virginia Electric and Power Company

Schedule 9

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Simple Cycle 7FA:2020:292	-	-	-	0	0	0	0	0	0	0	0	0	0	0	5	6	5	6	6
Cogentrix-Richmond 1	-	-	-	84	92	91	90	90	90	91	90	55	0	0	0	0	0	0	0
Cogentrix-Richmond 2	-	-	-	80	85	82	75	89	89	90	90	55	0	0	0	0	0	0	0
Cogentrix-Rocky Mount	-	-	-	84	88	86	82	89	89	78	0	0	0	0	0	0	0	0	0
Doswell Complex	-	-	-	39	25	21	11	45	45	43	44	17	0	0	0	0	0	0	0
Hopewell Cogen	-	-	-	45	42	29	20	44	50	40	0	0	0	0	0	0	0	0	0
Ogden-Martin Fairfax	-	-	-	84	93	93	87	91	91	40	0	0	0	0	0	0	0	0	0
Roanoke Valley II	-	-	-	89	86	89	89	89	89	89	89	88	89	88	40	0	0	0	0
Roanoke Valley Project	-	-	-	85	88	88	88	88	88	88	88	87	87	39	0	0	0	0	0
SEI Birchwood	-	-	-	27	41	35	34	83	84	86	87	87	88	87	88	84	0	0	0
BTM - 119 Goose Castle Road	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BTM - 1210 Ocean Trail	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BTM - 142 Owens Road	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BTM - 4113 Lindberg Ave	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BTM - Alexandria MSW	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	8	0
BTM - Banister	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Brasfield Dam	-	-	-	100	100	100	100	83	0	0	0	0	0	0	0	0	0	0	0
BTM - Champman Dam	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Columbia Mills	-	-	-	100	100	100	100	100	100	16	0	0	0	0	0	0	0	0	0
BTM - Coquina Beach	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BTM - Domtar	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - I-95 Landfill	-	-	-	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0
BTM - I-95 Phase II	-	-	-	100	100	100	100	16	0	0	0	0	0	0	0	0	0	0	0
BTM - Lakeview Hydro	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Richmond Electric Generation	-	-	-	100	100	100	100	67	0	0	0	0	0	0	0	0	0	0	0
BTM - Rivanna Water and Sewer	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Schoolfield Dam	-	-	-	100	100	100	100	100	100	92	0	0	0	0	0	0	0	0	0
BTM - Stone Container	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BTM - Suffolk Landfill #1	-	-	-	100	100	100	100	100	92	0	0	0	0	0	0	0	0	0	0
BTM - Westvaco	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

(1) Calculated using PJM Methodology

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Appendix 3E - Heat Rates

Confidential Information
Redacted

Company Name: Virginia Electric and Power Company

Schedule 10a

UNIT PERFORMANCE DATA

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

Unit Name	2006 (ACTUAL)	2007	2008	2009 (PROJECTED)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Altavista	[redacted]																		
Bath County Units 1-6	[redacted]																		
Bellemeade Combined Cycle	[redacted]																		
Bremo 3	[redacted]																		
Bremo 4	[redacted]																		
Chesapeake 1	[redacted]																		
Chesapeake 2	[redacted]																		
Chesapeake 3	[redacted]																		
Chesapeake 4	[redacted]																		
Chesapeake CT 1	[redacted]																		
Chesapeake CT 2	[redacted]																		
Chesterfield 3	[redacted]																		
Chesterfield 4	[redacted]																		
Chesterfield 5	[redacted]																		
Chesterfield 6	[redacted]																		
Chesterfield 7	[redacted]																		
Chesterfield 8	[redacted]																		
Clover 1	[redacted]																		
Clover 2	[redacted]																		
Commonwealth Atlantic (Company-owned)	[redacted]																		
Cushaw Hydro Unit	[redacted]																		
Darbytown 1	[redacted]																		
Darbytown 2	[redacted]																		
Darbytown 3	[redacted]																		
Darbytown 4	[redacted]																		
Gaston Hydro	[redacted]																		
Gordonsville 1	[redacted]																		
Gordonsville 2	[redacted]																		
Gravel Neck 1	[redacted]																		
Gravel Neck 3	[redacted]																		
Gravel Neck 4	[redacted]																		
Gravel Neck 5	[redacted]																		
Gravel Neck 6	[redacted]																		
Hopewell	[redacted]																		
Kitty Hawk	[redacted]																		
Ladysmith 1	[redacted]																		
Ladysmith 2	[redacted]																		
Ladysmith 3	[redacted]																		
Ladysmith 4	[redacted]																		
Ladysmith 5	[redacted]																		
Lowmoor CT	[redacted]																		
Mecklenburg 1 (Company-owned)	[redacted]																		

Company Name: Virginia Electric and Power Company

Revised 9/15/09

Schedule 10a

Confidential Information Redacted

UNIT PERFORMANCE DATA

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

	(ACTUAL)			(PROJECTED)															
Unit Name	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Mecklenburg 2 (Company-owned)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mount Storm 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mount Storm 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mount Storm 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mount Storm CT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Multitrade (Company-owned)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Anna 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Anna 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Anna Hydro	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Branch	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Northern Neck CT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Panda Company-owned	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Possum Point 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Possum Point 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Possum Point 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Possum Point 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Possum Point CT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Remington 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Remington 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Remington 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Remington 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Roanoke Rapids Hydro	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Southampton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Surry 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Surry 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Yorktown 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Yorktown 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Yorktown 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Bear Garden	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Virginia City	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Anna 3:2018:294	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Warren County :2015:300	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BIOMASS UNIT:2016:297	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BIOMASS UNIT:2017:295	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 7FA :2017:296	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 7FA :2021:291	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 7FA :2022:290	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 7FA :2023:289	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 7FA :2024:288	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NEW On-shore WIND :2017:100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NEW ON-SHORE WIND :2017:97	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NEW ON-SHORE WIND :2017:98	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NEW ON-SHORE WIND :2017:99	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Cycle 7FA:2016:298	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Company Name: Virginia Electric and Power Company

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Schedule 10a

Confidential Information Redacted

UNIT PERFORMANCE DATA

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

	(ACTUAL)				(PROJECTED)														
Unit Name	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Simple Cycle 7FA:2016:299	[redacted]																		
Simple Cycle 7FA:2019:293																			
Simple Cycle 7FA:2020:292																			
Cogentrix-Richmond 1																			
Cogentrix-Richmond 2																			
Cogentrix-Rocky Mount																			
Doswell Complex																			
Hopewell Cogen																			
Ogden-Martin Fairfax																			
Roanoke Valley II																			
Roanoke Valley Project																			
SEI Birchwood																			
BTM - 119 Goose Castle Road																			
BTM - 1210 Ocean Trail																			
BTM - 142 Owens Road																			
BTM - 4113 Lindberg Ave																			
BTM - Alexandria MSW																			
BTM - Banister																			
BTM - Brasfield Dam																			
BTM - Champman Dam																			
BTM - Columbia Mills																			
BTM - Coquina Beach																			
BTM - Domtar																			
BTM - I-95 Landfill																			
BTM - I-95 Phase II																			
BTM - Lakeview Hydro																			
BTM - Richmond Electric Generation																			
BTM - Rivanna Water and Sewer																			
BTM - Schoolfield Dam																			
BTM - Stone Container																			
BTM - Suffolk Landfill #1																			
BTM - Westvaco																			

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Appendix 3E Cont. - Heat Rates

Confidential Information
Redacted

Schedule 10b

Company Name: Virginia Electric and Power Company
UNIT PERFORMANCE DATA
Average Heat Rate - (mmBtu/MWh) (At Minimum)

	(ACTUAL)			(PROJECTED)															
Unit Name	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Altavista				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Bath County Units 1-6				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Bellemeade Combined Cycle				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Bremo 3				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Bremo 4				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeake 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeake 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeake 3				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeake 4				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeake CT 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesapeake CT 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesterfield 3				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesterfield 4				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesterfield 5				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesterfield 6				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesterfield 7				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chesterfield 8				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Clover 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Clover 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commonwealth Atlantic (Company-owned)				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cushaw Hydro Unit				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Darbytown 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Darbytown 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Darbytown 3				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Darbytown 4				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gaston Hydro				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gordonsville 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gordonsville 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gravel Neck 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gravel Neck 3				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gravel Neck 4				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gravel Neck 5				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gravel Neck 6				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hopewell				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kitty Hawk				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ladysmith 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ladysmith 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ladysmith 3				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ladysmith 4				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ladysmith 5				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lowmoor CT				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mecklenburg 1 (Company-owned)				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mecklenburg 2 (Company-owned)				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Revised 9/15/09

Company Name: Virginia Electric and Power Company — Schedule 10b — Confidential Information Redacted

UNIT PERFORMANCE DATA

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

Unit Name	(ACTUAL) 2006	2007	2008	(PROJECTED) 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Mount Storm 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mount Storm 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mount Storm 3				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mount Storm CT				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Multitrade (Company-owned)				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Anna 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Anna 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Anna Hydro				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Branch				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Northern Neck CT				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Panda Company-owned				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Possum Point 3				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Possum Point 4				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Possum Point 5				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Possum Point 6				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Possum Point CT				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Remington 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Remington 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Remington 3				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Remington 4				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Roanoke Rapids Hydro				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Southampton				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Surry 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Surry 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Yorktown 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Yorktown 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Yorktown 3				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Bear Garden				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Virginia City				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Anna 3:2018:294				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Warren County :2015:300				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BIOMASS UNIT:2016:297				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BIOMASS UNIT:2017:295				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 7FA :2017:296				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 7FA :2021:291				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 7FA :2022:290				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 7FA :2023:289				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 7FA :2024:288				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NEW On-shore WIND :2017:100				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NEW ON-SHORE WIND :2017:97				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NEW ON-SHORE WIND :2017:98				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NEW ON-SHORE WIND :2017:99				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Cycle 7FA:2016:298				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Cycle 7FA:2016:299				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Cycle 7FA:2019:293				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Revised 9/15/09

Company Name: Virginia Electric and Power Company

Schedule 10b

Confidential Information Redacted

UNIT PERFORMANCE DATA

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

	(ACTUAL)			(PROJECTED)															
Unit Name	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Simple Cycle 7FA:2020:292				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cogentrix-Richmond 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cogentrix-Richmond 2				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cogentrix-Rocky Mount				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Doswell Complex				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hopewell Cogen				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ogden-Martin Fairfax				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Roanoke Valley II				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Roanoke Valley Project				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SEI Birchwood				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - 119 Goose Castle Road				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - 1210 Ocean Trail				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - 142 Owens Road				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - 4113 Lindberg Ave				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Alexandria MSW				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Banister				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Brasfield Dam				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Champman Dam				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Columbia Mills				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Coquina Beach				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Domtar				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - I-95 Landfill				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - I-95 Phase II				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Lakeview Hydro				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Richmond Electric Generation				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Rivanna Water and Sewer				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Schoolfield Dam				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Stone Container				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Suffolk Landfill #1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BTM - Westvaco				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

APPENDIX 3F – EXISTING CAPACITY

Company Name: Virginia Electric and Power Company

Schedule 7

CAPACITY DATA

	(ACTUAL)				(PROJECTED)														
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
I. Installed Capacity (MW) (1)																			
a. Nuclear	3,219	3,194	3,194	3,195	3,266	3,392	3,436	3,436	3,436	3,436	3,436	3,436	4,709	4,709	4,709	4,709	4,709	4,709	4,709
b. Coal (2)	4,719	4,792	4,774	4,778	4,778	4,817	5,413	5,443	5,443	5,438	5,438	5,438	5,438	5,438	5,438	5,438	5,438	5,438	5,438
c. Heavy Fuel Oil	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604
d. Light Fuel Oil	345	354	352	352	321	321	257	257	185	126	79	79	0	0	0	0	0	0	0
e. Natural Gas-Boiler	309	312	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316
f. Natural Gas-Combined Cycle	1,543	1,544	1,584	1,584	1,606	2,196	2,196	2,250	2,250	2,890	2,890	3,530	3,530	3,530	3,530	4,170	4,810	5,450	6,090
g. Natural Gas-Turbine	1,750	1,807	2,231	2,428	2,428	2,428	2,428	2,428	2,428	2,428	3,108	3,108	3,108	3,448	3,788	3,788	3,788	3,788	3,788
h. Hydro-Conventional	327	327	318	327	327	327	327	327	327	327	327	327	327	327	327	327	327	327	327
i. Pumped Storage	1,656	1,706	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
j. Renewable	80	83	83	83	83	83	83	83	83	83	133	209	209	209	209	209	209	209	209
k. Total Company Installed	15,552	15,723	16,210	16,469	16,531	17,287	17,862	17,946	17,874	18,450	19,133	19,849	21,043	21,383	21,723	22,363	23,003	23,643	24,283
l. Other (NUG)	1,966	1,966	1,749	1,776	1,776	1,776	1,776	1,776	1,776	1,232	1,232	427	434	267	222	0	0	0	0
m. Other (BTM)	110	110	111	158	158	158	155	152	147	143	141	141	141	141	141	141	141	121	121
n. Total	17,628	17,799	18,070	18,403	18,466	19,221	19,793	19,874	19,797	19,826	20,506	20,417	21,618	21,791	22,086	22,504	23,144	23,764	24,404
II. Installed Capacity Mix (%) (3)																			
a. Nuclear	18.3%	17.9%	17.7%	17.4%	17.7%	17.6%	17.4%	17.3%	17.4%	17.3%	16.8%	16.8%	21.8%	21.6%	21.3%	20.9%	20.3%	19.8%	19.3%
b. Coal (2)	26.8%	26.9%	26.4%	26.0%	25.9%	25.1%	27.3%	27.4%	27.5%	27.4%	26.5%	26.6%	25.2%	25.0%	24.6%	24.2%	23.5%	22.9%	22.3%
c. Heavy Fuel Oil	9.1%	9.0%	8.9%	8.7%	8.7%	8.3%	8.1%	8.1%	8.1%	8.1%	7.8%	7.9%	7.4%	7.4%	7.3%	7.1%	6.9%	6.7%	6.6%
d. Light Fuel Oil	2.0%	2.0%	1.9%	1.9%	1.7%	1.7%	1.3%	1.3%	0.9%	0.6%	0.4%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
e. Natural Gas-Boiler	1.8%	1.8%	1.7%	1.7%	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.5%	1.5%	1.5%	1.5%	1.4%	1.4%	1.4%	1.3%	1.3%
f. Natural Gas-Combined Cycle	8.8%	8.7%	8.8%	8.6%	8.7%	11.4%	11.1%	11.3%	11.4%	14.6%	14.1%	17.3%	16.3%	16.2%	16.0%	18.5%	20.8%	22.9%	25.0%
g. Natural Gas-Turbine	9.9%	10.2%	12.3%	13.2%	13.1%	12.6%	12.3%	12.2%	12.3%	12.2%	15.2%	15.2%	14.4%	15.8%	17.2%	16.8%	16.4%	15.9%	15.5%
h. Hydro-Conventional	1.9%	1.8%	1.8%	1.8%	1.8%	1.7%	1.7%	1.6%	1.7%	1.6%	1.6%	1.6%	1.5%	1.5%	1.5%	1.5%	1.4%	1.4%	1.3%
i. Pumped Storage	9.4%	9.6%	9.7%	9.8%	9.8%	9.4%	9.1%	9.1%	9.1%	9.1%	8.8%	8.8%	8.3%	8.3%	8.2%	8.0%	7.8%	7.6%	7.4%
j. Renewable	0.5%	0.5%	0.5%	0.5%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.6%	1.0%	1.0%	1.0%	0.9%	0.9%	0.9%	0.9%	0.9%
l. Other (NUG)	11.2%	11.0%	9.7%	9.7%	9.6%	9.2%	9.0%	8.9%	9.0%	6.2%	6.0%	2.1%	2.0%	1.2%	1.0%	0.0%	0.0%	0.0%	0.0%
m. Other (BTM)	0.6%	0.6%	0.6%	0.9%	0.9%	0.8%	0.8%	0.8%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%
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) Includes biomass co-firing

(3) 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)														
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
I. System Output (GWh)																			
a. Nuclear	25,814	25,619	26,232	26,038	26,322	28,105	28,073	28,178	28,767	28,175	28,257	28,769	37,428	38,279	39,942	38,398	38,377	39,828	39,350
b. Coal (1)	31,555	31,193	28,775	31,988	33,539	32,118	34,421	31,297	30,171	30,685	31,375	30,986	29,462	29,697	31,220	31,437	32,352	31,863	31,921
c. Heavy Fuel Oil	487	1,232	466	574	192	143	104	341	376	310	335	255	304	372	408	398	530	513	568
d. Light Fuel Oil	49	186	68	2	4	3	2	7	4	3	1	1	0	0	0	0	0	0	0
e. Natural Gas-Boiler	108	225	205	355	314	244	150	353	317	334	283	256	232	229	236	244	214	231	236
f. Natural Gas-Combined Cycle	2,930	4,794	4,640	7,313	5,542	5,641	4,509	6,385	6,522	8,473	9,558	11,279	10,845	11,085	11,055	13,818	16,830	18,805	22,772
g. Natural Gas-Turbine	355	742	556	1,995	1,704	1,285	863	1,431	1,220	1,235	1,359	1,385	1,133	1,224	1,445	1,572	1,231	1,376	1,291
h. Hydro-Conventional	506	470	336	611	611	611	611	611	611	611	611	611	611	611	611	611	611	611	611
i. Hydro-Pumped Storage	2,643	2,171	1,712	1,197	1,565	1,679	1,900	1,630	1,819	1,860	1,920	2,035	1,919	1,936	1,813	1,864	1,925	1,731	1,651
j. Renewable	470	65	488	411	573	539	447	581	625	630	877	1,808	1,974	1,963	1,995	1,987	1,991	1,988	2,000
k. Total Generation	64,918	66,697	63,478	70,485	70,365	70,369	71,081	70,813	70,433	72,317	74,577	77,386	83,908	85,396	88,725	90,330	94,061	96,948	100,400
l. Purchased Power	22,065	23,863	24,495	16,391	17,247	19,499	21,367	24,576	26,315	26,049	25,510	24,251	20,321	20,804	19,841	20,679	19,177	18,611	18,274
m. Total Payback Energy					1	1	2	4	7	7	7	10	5	8	10	8	12	10	11
n. Less Pumping Energy	-3,331	-2,732	-2,150	-1,504	-1,966	-2,110	-2,387	-2,047	-2,285	-2,337	-2,412	-2,556	-2,410	-2,432	-2,278	-2,342	-2,418	-2,175	-2,074
o. Less Other Sales (2)	-669	-73	-24	-1,338	-945	-659	-578	-2,038	-1,122	-1,479	-909	-569	-1,210	-898	-829	-1,194	-1,067	-1,489	-1,939
p. Total System Firm Energy Req.	82,983	87,755	85,798	84,035	84,703	87,100	89,486	91,307	93,349	94,557	96,773	98,522	100,614	102,878	105,470	107,481	109,765	111,906	114,672
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) Includes All GWh from Altavista & VCHEC

(2) To include all sales or delivery transactions with other electric utilities, i.e., firm sales, diversity exchange, etc.

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

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

GENERATION

	(ACTUAL)			(PROJECTED)																
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
III. System Output Mix (%)																			
a. Nuclear	30.9%	29.2%	30.6%	31.0%	31.1%	32.3%	31.4%	30.9%	30.8%	29.8%	29.2%	29.2%	37.2%	37.2%	37.9%	35.7%	35.0%	35.6%	34.3%
b. Coal [1]	37.7%	35.5%	33.5%	38.1%	39.6%	36.9%	38.5%	34.3%	32.3%	32.5%	32.4%	31.5%	29.3%	28.9%	29.6%	29.2%	29.5%	28.5%	27.8%
c. Heavy Fuel Oil	0.6%	1.4%	0.5%	0.7%	0.2%	0.2%	0.1%	0.4%	0.4%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.5%	0.5%	0.5%
d. Light Fuel Oil	0.1%	0.2%	0.1%	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%
e. Natural Gas-Boiler	0.1%	0.3%	0.2%	0.4%	0.4%	0.3%	0.2%	0.4%	0.3%	0.4%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
f. Natural Gas-Combined Cycle	3.5%	5.5%	5.4%	8.7%	6.5%	6.5%	5.0%	7.0%	7.0%	9.0%	9.9%	11.4%	10.8%	10.8%	10.5%	12.9%	15.3%	16.8%	19.9%
g. Natural Gas-Turbine	0.4%	0.8%	0.6%	2.4%	2.0%	1.5%	1.0%	1.6%	1.3%	1.3%	1.4%	1.4%	1.1%	1.2%	1.4%	1.5%	1.1%	1.2%	1.1%
h. Hydro-Conventional	0.6%	0.5%	0.4%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%
i. Hydro-Pumped Storage	-0.8%	-0.6%	-0.5%	1.4%	1.8%	1.9%	2.1%	1.8%	1.9%	2.0%	2.0%	2.1%	1.9%	1.9%	1.7%	1.7%	1.8%	1.5%	1.4%
j. Renewable Resources	0.6%	0.1%	0.6%	0.5%	0.7%	0.6%	0.5%	0.6%	0.7%	0.7%	0.9%	1.8%	2.0%	1.9%	1.9%	1.8%	1.8%	1.8%	1.7%
k. Total Generation	78.2%	76.0%	74.0%	83.9%	83.1%	80.8%	79.4%	77.6%	75.5%	76.5%	77.1%	78.5%	83.4%	83.0%	84.1%	84.0%	85.7%	86.6%	87.6%
l. Purchased Power	26.6%	27.2%	28.5%	19.5%	20.4%	22.4%	23.9%	26.9%	28.2%	27.5%	26.4%	24.6%	20.2%	20.2%	18.8%	19.2%	17.5%	16.6%	15.9%
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	-4.0%	-3.1%	-2.5%	-1.8%	-2.3%	-2.4%	-2.7%	-2.2%	-2.4%	-2.5%	-2.5%	-2.6%	-2.4%	-2.4%	-2.2%	-2.2%	-2.2%	-1.9%	-1.8%
o. Less Other Sales [2]	-0.8%	-0.1%	0.0%	-1.6%	-1.1%	-0.8%	-0.6%	-2.2%	-1.2%	-1.6%	-0.9%	-0.6%	-1.2%	-0.9%	-0.8%	-1.1%	-1.0%	-1.3%	-1.7%
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	55.1%	57.4%	57.9%	57.4%	57.0%	56.7%	56.1%	57.1%	56.9%	56.9%	57.0%	57.1%	57.5%	57.6%	57.3%	57.5%	57.6%	57.7%	58.2%

(1) Includes All GWh from Altavista & VCHEC
(2) Economy Energy

APPENDIX 3I – PLANNED CHANGES TO EXISTING GENERATION UNITS

Schedule 13a

Company Name: Virginia Electric and Power Company
UNIT PERFORMANCE DATA (1)
Unit Size (MW) Uprate and Derate

	(ACTUAL)				(PROJECTED)														
Unit Name	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Altavista	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County Units 1-6	48	50	48	48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bellemeade Combined Cycle	2	-	13	-	22	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1	-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 2	-25	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	-	-	-	-	-	-	-3	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	-	-	-	-	-	-	-3	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	-	19	-5	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	-	-	-13	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 1	-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 2	-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commonwealth Atlantic (Company-owned)	-12	-	48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cushaw Hydro Unit	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 1	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 2	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 3	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 4	-	6	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gaston Hydro	-	-	-5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 2	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1	-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	-2	6	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 4	-2	6	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 5	-2	6	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 6	-2	6	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kitty Hawk	-12	-	-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	-	1	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 2	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 3	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 4	-	-	9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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

Lowmoor CT	-12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1 (Company-owned)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2 (Company-owned)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	-	-	-1	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 2	-	-	-	-	-	31	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 3	-	-9	-	-	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Multitrade (Company-owned)	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	-	-19	-	-	14	-	43	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 2	-	-6	-	-	58	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Branch	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Panda Company-owned	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	-8	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 4	-5	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	-14	1	27	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT	-12	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 2	-	1	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 3	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 4	-	1	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Rapids Hydro	-		-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southampton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	-	-	-	-	-	63	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 2	-	-	-	-	-	63	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 1	-1	-	-	-	-	-	-	-	-	-2	-	-	-	-	-	-	-	-	-
Yorktown 2	-2	-	-	-	-	-	-	-	-	-3	-	-	-	-	-	-	-	-	-
Yorktown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bear Garden	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Virginia City	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 3:2018:294	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Warren County :2015:300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BIOMASS UNIT:2016:297	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BIOMASS UNIT:2017:295	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle 7FA :2017:296	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle 7FA :2021:291	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle 7FA :2022:290	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle 7FA :2023:289	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle 7FA :2024:288	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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

NEW On-shore WIND :2017:100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NEW ON-SHORE WIND :2017:97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NEW ON-SHORE WIND :2017:98	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NEW ON-SHORE WIND :2017:99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Simple Cycle 7FA:2016:298	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Simple Cycle 7FA:2016:299	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Simple Cycle 7FA:2019:293	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Simple Cycle 7FA:2020:292	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cogentrix-Richmond 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cogentrix-Richmond 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cogentrix-Rocky Mount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Doswell Complex	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell Cogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ogden-Martin Fairfax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley II	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley Project	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SEI Birchwood	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - 119 Goose Castle Road	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - 1210 Ocean Trail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - 142 Owens Road	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - 4113 Lindberg Ave	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Alexandria MSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Banister	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Brasfield Dam	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Champman Dam	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Columbia Mills	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Coquina Beach	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Domtar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - I-95 Landfill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - I-95 Phase II	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Lakeview Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Richmond Electric Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Rivanna Water and Sewer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Schoolfield Dam	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Stone Container	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Suffolk Landfill #1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BTM - Westvaco	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

EXTRAORDINARILY SENSITIVE

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 Description	Expected Removal Date	Expected Return Date	Base Rating	Revised Rating	MW
Bellemeade Combined Cycle	Turbine/Compressor Upgrade	[redacted]	[redacted]	245	267	22
Chesterfield 3	Scrubber Installation	[redacted]	[redacted]	100	97	-3
Chesterfield 4	Scrubber Installation	[redacted]	[redacted]	166	163	-3
Chesterfield 5	Turbine Rotor	[redacted]	[redacted]	329	338	9
Chesterfield 5	Scrubber Installation	[redacted]	[redacted]	338	330	-8
Chesterfield 6	Turbine Rotor	[redacted]	[redacted]	645	652	7
Gordonsville 1	Wet Compression + Inlet Fogging	[redacted]	[redacted]	109	119	10
Gordonsville 2	Wet Compression + Inlet Fogging	[redacted]	[redacted]	109	119	10
Mount Storm 1	Turbine Rotor	[redacted]	[redacted]	524	554	30
Mount Storm 2	Turbine Rotor	[redacted]	[redacted]	524	555	31
Mount Storm 3	Turbine Rotor	[redacted]	[redacted]	512	529	17
Possum Point 6	Chiller	[redacted]	[redacted]	559	593	34
Yorktown 1	Scrubber Installation	[redacted]	[redacted]	159	157	-2
Yorktown 2	Scrubber Installation	[redacted]	[redacted]	164	161	-3
North Anna 1	Measurement Uncertainty Recapture (MUR)	[redacted]	[redacted]	798	812	14
North Anna 1	Turbine Uprate	[redacted]	[redacted]	812	856	43
North Anna 2	MUR and Turbine Uprate	[redacted]	[redacted]	798	856	58
Surry 1	MUR and Turbine Uprate	[redacted]	[redacted]	799	862	63
Surry 2	Measurement Uncertainty Recapture	[redacted]	[redacted]	799	813	14
Surry 2	Turbine Uprate	[redacted]	[redacted]	813	862	49

(1) Peak net dependable capability as of filing. Incremental Uprates shown as positive (+) and decremental Derates shown as negative (-).

Extraordinarily Sensitive
Information Redacted

APPENDIX 3J – POTENTIAL UNIT RETIREMENTS

Potential Unit Retirements [1]

Unit Name	Location	Unit Type	Primary Fuel Type	Projected Retirement Year	MW Summer	MW Winter
Kitty Hawk	**Kitty Hawk, NC**	**Combustion Turbine**	**Light Fuel Oil**	**2012**	**31**	**45**
Kitty Hawk CT1					15	
Kitty Hawk CT2					16	
Chesapeake CT 2	**Chesapeake, VA**	**Combustion Turbine**	**Light Fuel Oil**	**2012**	**64**	**99**
Chesapeake CT7					16	
Chesapeake CT8					16	
Chesapeake CT9					16	
Chesapeake CT10					16	
Possum Point CT	**Dumfries, VA**	**Combustion Turbine**	**Light Fuel Oil**	**2013**	**72**	**106**
Possum Point CT1					12	
Possum Point CT2					12	
Possum Point CT3					12	
Possum Point CT4					12	
Possum Point CT5					12	
Possum Point CT6					12	
Lowmoor CT	**Covington, VA**	**Combustion Turbine**	**Light Fuel Oil**	**2014**	**48**	**65**
Lowmoor CT1					12	
Lowmoor CT2					12	
Lowmoor CT3					12	
Lowmoor CT4					12	
Mount Storm CT	**Mt. Storm, WV**	**Combustion Turbine**	**Light Fuel Oil**	**2014**	**11**	**15**
Mt. Storm CT1					11	
Northern Neck CT	**Warsaw, VA**	**Combustion Turbine**	**Light Fuel Oil**	**2015**	**47**	**70**
Northern Neck CT1					12	
Northern Neck CT2					11	
Northern Neck CT3					12	
Northern Neck CT4					12	
Chesapeake CT 1	**Chesapeake, VA**	**Combustion Turbine**	**Light Fuel Oil**	**2017**	**51**	**69**
Chesapeake CT1					15	
Chesapeake CT2					12	
Chesapeake CT4					12	
Chesapeake CT6					12	
Gravel Neck 1	**Surry, VA**	**Combustion Turbine**	**Light Fuel Oil**	**2017**	**28**	**38**
Gravel Neck CT1					12	
Gravel Neck CT2					16	

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

APPENDIX 3K – PLANNED GENERATION RESOURCES

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						
Bear Garden	Buckingham, VA	Intermediate	Natural Gas-CC	May-2011	590	613
Virginia City	Wise County, VA	Base	Coal	Apr-2012	585	635
Under Development						
Warren County :2015:300	Warren County, VA	Intermediate	Natural Gas-CC	N/A	640	662
North Anna 3:2018:294	Mineral, VA	Base	Nuclear	N/A	1,273	1,304

(1) Commercial Online Date

APPENDIX 3L – WHOLESALE POWER SALES CONTRACTS

WHOLESALE POWER SALES CONTRACTS (MW)(1)

			(ACTUAL)				(PROJECTED)														
Entity	Expiration	Type	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Old Dominion Electric Coop	12/31/2009	Non-Firm Partial Requirements	928	930	930	600															
North Carolina Electric Membership Coop	12/31/2014	Non-Firm Partial Requirements	150	150	150	150	150	150	150	150	150										
Craig-Botetourt Electric Coop	12-Month Termination Notice	Full Requirements[1]	6	6	6	7	7	7	7	7	7	7	8	8	8	8	8	8	8	9	9
Town of Windsor, North Carolina	12-Month Termination Notice	Full Requirements[1]	9	9	9	10	11	11	11	11	11	11	12	12	12	12	12	13	13	13	13
Virginia Municipal Electric Association	12/31/2010 with annual renewal	Full Requirements[1]	247	252	253	235	238	243	251	255	258	263	269	275	280	286	292	299	305	311	317

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

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

Programs	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Air Conditioner Cycling Program	0	9,254	34,032	73,876	120,275	169,876	212,180	260,035	298,228	329,246	355,490	[illegible]	383,685	403,209	410,368	415,140
Commercial Distributed Generation Program	14,289	28,577	44,974	61,370	77,766	94,162	110,558	126,955	143,351	154,984	159,473	163,962	168,451	172,940	177,429	181,918
Curtailment Service Program	0	6,006	21,362	46,028	74,839	105,071	106,812	108,134	109,455	110,777	112,098	113,419	114,741	116,062	117,384	118,705
Residential Lighting Program	14,287	26,731	39,175	39,175	39,175	39,175	39,175	39,175	39,175	39,175	39,175	39,175	39,175	39,175	39,175	39,175
Low Income Program	0	204	830	1,920	4,219	5,869	6,225	6,303	6,382	6,461	6,539	6,618	6,697	6,775	6,854	6,933
ENERGY STAR® New Homes Program	0	1,847	6,886	15,046	24,653	34,769	35,677	36,127	36,576	37,026	37,475	37,924	38,374	38,823	39,273	39,722
Residential Heat Pump Tune-Up Program	0	2,823	10,523	22,994	37,671	53,127	54,515	55,202	55,890	56,578	57,265	57,953	58,640	59,328	60,015	60,703
Residential Refrigerator Turn-In Program	0	254	947	2,069	3,390	4,781	4,904	4,963	5,023	5,0835,	143	5,202	5,262	5,322	5,381	5,441
Heat Pump Upgrade Program	0	1,804	6,725	14,694	24,074	33,952	34,889	35,380	35,872	36,364	36,857	37,349	37,840	38,333	38,825	39,317
Commercial HVAC Upgrade Program	0	941	3,418	7,432	12,122	17,037	17,316	17,528	17,740	17,951	18,163	18,375	18,587	18,799	19,011	19,223
Voltage Conservation Program	9,378	78,914	204,009	325,101	442,616	442,816	442,616	427,354	442,616	442,616	442,616	427,354	442,616	442,616	442,616	427,354
Commercial Lighting Program	0	2,571	9,478	20,620	33,626	47,289	48,095	48,700	49,305	49,910	50,515	51,120	51,725	52,330	52,935	53,540

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

Programs	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Air Conditioner Cycling Program	0	9,254	34,032	73,676	120,275	169,876	217,180	260,035	298,228	329,246	355,490	376,964	393,665	403,209	410,368	415,140
Commercial Distributed Generation Program	14,289	28,577	44,974	61,370	77,766	94,162	110,558	126,955	143,351	154,984	159,473	163,962	168,451	172,940	177,429	181,918
Curtailment Service Program	0	6,006	21,362	46,028	74,839	105,071	106,812	108,134	109,455	110,777	112,098	113,419	114,741	116,062	117,384	118,705
Residential Lighting Program	3,954	7,399	10,843	10,843	10,843	10,843	10,843	10,843	10,843	10,843	10,843	10,843	10,843	10,843	10,843	10,843
Low Income Program	0	107	437	1,011	2,121	2,950	3,129	3,168	3,208	3,247	3,287	3,326	3,366	3,405	3,445	3,484
ENERGY STAR® New Homes Program	0	210	783	1,710	2,802	3,951	4,055	4,106	4,157	4,208	4,259	4,310	4,361	4,412	4,463	4,514
Residential Heat Pump Tune-Up Program	0	2,157	8,040	17,567	28,780	40,588	41,648	42,173	42,699	43,224	43,749	44,275	44,800	45,325	45,850	46,376
Residential Refrigerator Turn-In Program	0	169	629	1,374	2,251	3,174	3,256	3,296	3,335	3,375	3,415	3,454	3,494	3,534	3,573	3,613
Heat Pump Upgrade Program	0	1,121	4,181	9,135	14,966	21,107	21,689	21,995	22,301	22,607	22,913	23,219	23,525	23,830	24,136	24,442
Commercial HVAC Upgrade Program	0	841	3,055	6,643	10,835	15,228	15,477	15,666	15,856	16,045	16,235	16,424	16,614	16,803	16,992	17,182
Voltage Conservation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	0	1,651	6,088	13,244	21,598	30,373	30,891	31,280	31,668	32,057	32,445	32,834	33,222	33,611	34,000	34,388
Totals	18,243	57,493	134,423	242,601	367,075	497,324	565,538	627,650	685,100	730,612	764,207	793,030	817,081	833,975	848,483	860,605

APPENDIX 3O – PROPOSED PROGRAMS ENERGYSAVINGS
(MWh) (System-Level)

Programs	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Air Conditioner Cycling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Distributed Generation Program	465	707	565	528	1,924	2,124	1,866	2,143	3,423	1,370	1,601	1,447	1,419	2,911	2,987	6,755
Curtailment Service Program	0	171	607	1,308	2,126	2,986	3,035	3,073	3,110	3,148	3,185	2,878	3,260	2,645	2,772	2,803
Residential Lighting Program	45,191	84,551	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912
Low Income Program	0	685	2,383	5,511	11,398	15,855	16,816	17,028	17,241	17,453	17,666	[illegible]	[illegible]	18,303	18,516	18,728
ENERGY STAR® New Homes Program	0	1,909	7,118	15,553	25,484	35,940	36,879	37,344	37,808	38,273	38,737	39,202	39,666	40,131	40,595	41,060
Residential Heat Pump Tune-Up Program	0	7,378	27,501	60,091	98,447	138,840	142,466	144,263	146,059	147,856	149,653	151,450	153,247	155,044	156,841	158,638
Residential Refrigerator Turn-In Program	0	778	2,900	6,336	10,381	14,640	15,016	15,199	15,382	15,565	15,748	15,931	16,114	16,296	16,479	16,662
Heat Pump Upgrade Program	0	3,389	12,659	27,443	44,961	63,409	65,158	66,076	66,995	67,914	68,833	69,752	[illegible]	71,590	72,509	73,428
Commercial HVAC Upgrade Program	0	1,963	7,133	15,511	25,298	35,556	36,137	36,579	37,021	37,464	37,906	38,348	38,791	39,233	39,676	40,118
Voltage Conservation Program	48,365	406,993	1,052,159	1,736,564	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759
Commercial Lighting Program	0	13,156	48,497	105,507	172,062	241,971	246,098	249,194	252,289	255,385	258,480	261,576	264,671	267,767	270,863	273,958
Totals	94,021	521,560	1,285,335	2,096,285	2,798,753	2,957,991	2,970,140	2,977,568	2,986,000	2,991,098	2,998,480	3,004,933	3,012,609	3,020,492	3,027,908	3,036,821

APPENDIX 3P – PROPOSED PROGRAM PENETRATION
(System-Level)

Programs	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Air Conditioner Cycling Program	0	9,244	33,996	73,598	120,148	169,697	216,951	259,761	297,914	328,899	355,115	376,567	393,261	402,859	409,936	414,703
Commercial Distributed Generation Program[1,2,7]	14	27	43	58	74	89	105	120	136	147	151	156	160	164	168	173
Curtailment Service Program[7]	0	285	1,052	2,284	3,723	5,233	5,320	5,386	5,452	5,518	5,584	5,650	5,716	5,782	5,848	5,914
Residential Lighting Program[3,4]	1,612,000	3,016,000	4,420,000	4,420,000	4,420,000	4,420,000	4,420,000	4,420,000	4,420,000	4,420,000	4,420,000	4,420,000	4,420,000	4,420,000	4,420,000	4,420,000
Low Income Program	0	1,414	5,786	13,332	22,793	31,707	33,628	34,053	34,478	34,903	35,328	35,753	36,178	36,603	37,028	37,453
ENERGY STAR® New Homes Program	0	752	2,804	6,127	10,039	14,158	14,528	14,711	14,894	15,077	15,260	15,443	15,626	15,809	15,992	16,175
Residential Heat Pump Tune-Up Program	0	10,203	38,033	83,103	138,148	192,009	197,023	199,508	201,993	204,478	206,963	209,448	211,933	214,418	216,903	219,388
Residential Refrigerator Turn-In Program	0	1,677	6,248	13,651	22,365	31,541	32,352	32,746	33,140	33,534	33,928	34,322	34,716	35,110	35,504	35,898
Heat Pump Upgrade Program	0	4,396	16,388	35,809	58,667	82,739	85,020	86,219	87,418	88,617	89,816	91,015	92,214	93,413	94,612	95,811
Commercial HVAC Upgrade Program[7]	0	71	258	561	915	1,286	1,307	1,323	1,339	1,355	1,371	1,387	1,403	1,419	1,435	1,451
Voltage Conservation Program[5,6]	63,000	446,000	1,153,000	1,903,000	2,501,543	2,501,543	2,501,543	2,501,543	2,501,543	2,501,543	2,501,543	2,501,543	2,501,543	2,501,543	2,501,543	2,501,543
Commercial Lighting Program	0	51	188	409	667	938	954	966	978	990	1,002	1,014	1,026	1,038	1,050	1,062

1 Number of 1,000 kW participants
2 Values in 2009 reflect the continuation of the DG/Load Curtailment Pilot
3 Number of bulbs
4 Values in 2009 reflect the continuation of the CFL price reduction program
5 Does not include new connects after 2014 due to AMI becoming standard equipment
6 Values in 2009 reflect the AMI Demonstration
7 Program penetrations have been adjusted for exempt customers

Appendix 3Q – FERC FORM 422

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 2008/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	SURRY	YADKIN (531)	500.00	500.00	STEEL	41.82		1
2		(531)	500.00	500.00	ALUM TOWER	6.66		
3	DOOMS	CUNNINGHAM (534)	500.00	500.00	STEEL	32.68		1
4	OX	BRISTERS (539)	500.00	500.00	STEEL	23.01		1
5	FLUVANA PWR STA	CUNNINGHAM (542)	500.00	500.00	STEEL	0.28		1
6	PLEASANT VIEW	DOUBS (543)	500.00	500.00	STEEL	3.26		1
7	BRISTERS	MORRISVILLE (545)	500.00	500.00	STEEL	7.65		1
8	LEXINGTON	BATH (547)	500.00	500.00	STEEL	34.70		1
9	BATH	VALLEY (548)	500.00	500.00	LATTICE	51.82		1
10	VALLEY	DOOMS (549)	500.00	500.00	STEEL	17.72		1
11	MT. STORM	VALLEY (550)	500.00	500.00	STEEL	64.39		1
12	MT. STORM	DOUBS (551)	500.00	500.00	STEEL	96.40		1
13	BRISTERS	LADYSMITH (552)	500.00	500.00	STEEL	35.57		1
14		(552)	500.00	500.00	STEEL		1.20	
15	CUNNINGHAM	ELMONT (553)	500.00	500.00	STEEL	51.09		1
16	DOOMS	LEXINGTON (555)	500.00	500.00	STEEL	39.04		1
17	CLOVER	CARSON (556)	500.00	500.00	STEEL	76.72		1
18	ELMONT	CHICKAHOMINY (557)	500.00	500.00	STEEL	27.73		1
19	LOUDOUN	PLEASANT VIEW (558)	500.00	500.00	STEEL	13.01		1
20	LOUDOUN	CLIFTON (559)	500.00	500.00	STEEL	12.01		1
21	POSSUM POINT	BURCHES-PEPCO (560)	500.00	500.00	H.FRAME	0.19		1
22	CLIFTON	OX (561)	500.00	500.00	STEEL	7.06		1
23	CARSON	SEPTA (562)	500.00	500.00	STEEL	38.47		1
24	CARSON	MIDLOTHIAN (563)	500.00	500.00	STEEL	37.43		1
25	CUNNINGHAM	FLUVANA PWR STA (564)	500.00	500.00	STEEL	0.26		1
26	LEXINGTON	CLOVERDALE-APCO (566)	500.00	500.00	STEEL	7.09		1
27	CHICKAHOMINY	SURRY (567)	500.00	500.00	STEEL	44.44		1
28	POSSUM POINT	LADYSMITH (565)	500.00	500.00	STEEL	47.70		1
29	LOUDOUN	MORRISVILLE (569)	500.00	500.00	STEEL	21.48		1
30		(569)	500.00	500.00	STEEL	10.29		
31	CARSON	WAKE (570)	500.00	500.00	STEEL	56.40		1
32	OX	POSSUM POINT (571)	500.00	500.00	H.FRAME	12.66		1
33	NORTH ANNA	MORRISVILLE (573)	500.00	500.00	STEEL	32.90		1
34	ELMONT	LADYSMITH (574)	500.00	500.00	STEEL	26.19		1
35	NORTH ANNA	LADYSMITH (575)	500.00	500.00	STEEL	13.59		1
36					TOTAL	5,276.30	621.47	409

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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		(575)	500.00	500.00	H.FRAME	0.94		1
2	MIDLOTHIAN	NORTH ANNA (576)	500.00	500.00	STEEL	41.15		1
3	SEPTA	SURRY (578)	500.00	500.00	STEEL	11.41		1
4	FENTRESS	SEPTA (579)	500.00	500.00	LATTICE	46.66		1
5	MORRISVILLE	MEADOWBROOK (580)	500.00	500.00	STEEL	47.67		1
6								
7	SUBTOTAL-500KV		500.00	500.00		1,142.10	1.20	37
8								
9	PENDER	BULL RUN (200)	230.00	230.00	STEEL	0.63		1
10		(200)	230.00	230.00	H.FRAME	2.87		
11		(200)	230.00	230.00	STEEL POLE	3.99		
12	BRAMBLETON	PLEASANT VIEW (201)	230.00	230.00	STEEL	7.97		1
13	IDYLWOOD	CLARK (202)	230.00	230.00	STEEL	4.05		1
14	PLEASANT VIEW	DICKERSON (203)	230.00	230.00	STEEL	3.08		1
15	GUM SPRINGS	JEFFERSON ST (204)	230.00	230.00	STEEL	6.67		1
16		(204)	230.00	230.00	WOOD POLE	4.12		
17	CHESTERFIELD	LOCKS (205)	230.00	230.00	STEEL	2.81		1
18		(205)	230.00	230.00	STEEL	9.42		
19	BRADDOCK	IDYLWOOD (207)	230.00	230.00	STEEL		4.68	1
20	CHESTERFIELD	SOUTHWEST (208)	230.00	230.00	STEEL	10.81		1
21		(208)	230.00	230.00	STEEL	3.76		
22	WALLER	YORKTOWN (209)	230.00	230.00	WOOD	14.13		1
23		(209)	230.00	230.00	STEEL	4.57		
24	HAYFIELD	VAN DORN (210)	230.00	230.00	STEEL		2.90	1
25	CHESTERFIELD	HOPEWELL (211)	230.00	230.00	STEEL	11.17		1
26	HOPEWELL	SURRY (212)	230.00	230.00	H.FRAME	0.27		1
27		(212)	230.00	230.00	STEEL	42.70		
28	CAROLINA	THELMA (213)	230.00	230.00	STEEL	10.07		1
29	SURRY	WINCHESTER (214)	230.00	230.00	STEEL	13.90		1
30		(214)	230.00	230.00	STEEL		23.71	
31	POSSUM POINT	HAYFIELD (215)	230.00	230.00	STEEL	12.44		1
32		(215)	230.00	230.00	STEEL	7.62		
33	LAKESIDE	ELMONT (216)	230.00	230.00	H.FRAME	5.74		1
34	LAKESIDE	CHESTERFIELD (217)	230.00	230.00	H.FRAME	20.87		1
35		(217)	230.00	230.00	STEEL		0.63	
36					TOTAL	5,276.30	821.47	409

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	EVERETTS	GREENVILLE (CP&L) (218)	230.00	230.00	H.FRAME	20.32		1
2		(218)	230.00	230.00	STEEL	1.33		
3	MIDLOTHIAN	SOUTHWEST (219)	230.00	230.00	STEEL POLE	13.77		1
4		(219)	230.00	230.00	STEEL		7.52	
5	OX	GUM SPRINGS (220)	230.00	230.00	STEEL		9.68	1
6		(220)	230.00	230.00	WOOD POLE		4.53	
7	NORTHWEST	ELMONT (221)	230.00	230.00	STEEL	5.88		1
8	NORTHWEST	SOUTHWEST (222)	230.00	230.00	STEEL	10.25		1
9	SURRY	YADKIN (223)	230.00	230.00	STEEL	44.10		1
10	NORTHERN NECK	LANEXA (224)	230.00	230.00	STEEL	41.27		1
11	LAKEVIEW	THELMA (225)	230.00	230.00	STEEL	8.66		1
12	SURRY	CHURCHLAND (226)	230.00	230.00	STEEL		37.63	1
13		(226)	230.00	230.00	STEEL POLE		0.11	
14	BEAUMEADE	BRAMBLETON (227)	230.00	230.00	STEEL	5.18		1
15		(227)	230.00	230.00	STEEL	0.18		
16		(227)	230.00	230.00	STEEL		7.88	
17	CHESTERFIELD	HOPEWELL (228)	230.00	230.00	STEEL		10.97	1
18	EVERETTS	EDGECOMBE (229)	230.00	230.00	STEEL POLE	0.28		1
19		(229)	230.00	230.00	H.FRAME	42.04		
20		(229)	230.00	230.00	STEEL	2.59		
21	YADKIN	LANDSTOWN (231)	230.00	230.00	STEEL	13.18		1
22		(231)	230.00	230.00	STEEL	2.92		
23	GASTON	THELMA (232)	230.00	230.00	STEEL	0.17		1
24	CHARLOTTSVILLE	DOOMS (233)	230.00	230.00	STEEL POLE		22.46	1
25	WINCHESTER	WHEALTON (234)	230.00	230.00	STEEL	0.22		1
26	FARMVILLE	CLOVER (235)	230.00	230.00	STEEL	4.31		1
27		(235)	230.00	230.00	H.FRAME	47.51		
28		(235)	230.00	230.00	H.FRAME	3.64		
29	SOUTHWEST	PLAZA (236)	230.00	230.00	STEEL POLE	3.30		1
30		(236)	230.00	230.00	STEEL POLE	0.74		
31	POSSUM POINT	BRADDOCK (237)	230.00	230.00	STEEL		13.55	
32		(237)	230.00	230.00	STEEL		7.64	
33		(237)	230.00	230.00	STEEL POLE	0.53		
34	CARSON	CLUBHOUSE (238)	230.00	230.00	STEEL	1.02		1
35		(238)	230.00	230.00	H.FRAME	27.53		
36					TOTAL	5,276.90	821.47	409

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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	LAKEVIEW	HORNERTOWN (239)	230.00	230.00	WOOD	2.51		1
2		(239)	230.00	230.00	STEEL		1.73	
3	HOPEWELL	SURRY (240)	230.00	230.00	STEEL		42.97	1
4	JEFFERSON ST.	HAYFIELD (241)	230.00	230.00	STEEL	6.21		1
5	MIDLOTHIAN	TRABUE TAP PT (242)	230.00	230.00	STEEL		3.09	1
6	OX	VAN DORN (243)	230.00	230.00	STEEL	9.68		1
7		(243)	230.00	230.00	STEEL POLE	2.64		
8	BULL RUN	BURKE (244)	230.00	230.00	STEEL POLE	6.67		1
9	GREEN RUN	GREENWICH (245)	230.00	230.00	CON/STEEL	3.99	1.12	1
10	SUFFOLK	EARLEYS (246)	230.00	230.00	H.FRAME	41.29		1
11		(246)	230.00	230.00	STEEL	3.10		
12		NUCOR (246)	230.00	230.00	STEEL POLE	6.36		
13	SUFFOLK	WINFALL (247)	230.00	230.00	H.FRAME	35.28		1
14	GLEBE	OX (248)	230.00	230.00	STEEL POLE	4.95		1
15		(248)	230.00	230.00	STEEL POLE	1.37	8.12	
16		(248)	230.00	230.00	UG-HPOF	3.12		
17		(248)	230.00	230.00	STEEL POLE	0.74		
18	LOCKS	CARSON (249)	230.00	230.00	H.FRAME	7.07		1
19		(249)	230.00	230.00	STEEL		3.64	
20	ARLINGTON	GLEBE (250)	230.00	230.00	STEEL POLE		2.50	1
21	ARLINGTON	IDYLWOOD (251)	230.00	230.00	CONCRETE	0.06		1
22		(251)	230.00	230.00	STEEL POLE		7.70	
23	FREDERICKSBURG	POSSUM POINT (252)	230.00	230.00	STEEL	13.18	11.31	1
24	VALLEY	HARRISONBURG (253)	230.00	230.00	STEEL	10.62		1
25	CLUBHOUSE	LAKEVIEW (254)	230.00	230.00	H. FRAME	16.00		1
26	SOUTH ANNA PWR STA	NORTH ANNA (255)	230.00	230.00	H. FRAME	26.96		1
27		(255)	230.00	230.00	STEEL	3.13		
28		(255)	230.00	230.00	H. FRAME	0.63		
29	FOUR RIVERS	FREDERICKSBURG (256)	230.00	230.00	H. FRAME	34.15		1
30	CHURCHLAND	SEWELLS POINT (257)	230.00	230.00	STEEL POLE	5.22		1
31		(257)	230.00	230.00	SUBMARINE	1.59		
32	ARLINGTON	GLEBE (258)	230.00	230.00	STEEL POLE	2.49		1
33	BASIN	CHESTERFIELD (259)	230.00	230.00	WOOD POLE	0.17		1
34		(259)	230.00	230.00	STEEL	3.65	3.83	
35		(259)	230.00	230.00	STEEL POLE	4.55		
36					TOTAL	5,276.30	821.47	409

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 2008/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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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	GROTTOES	HARRISONBURG (260)	230.00	230.00	H. FRAME	10.63		1
2	NEWPORT NEWS	SHELLBANK (261)	230.00	230.00	STEEL POLE	4.90		1
3	YADKIN	GREENWICH (262)	230.00	230.00	STEEL	10.62		1
4		(262)	230.00	230.00	H. FRAME	0.10		
5		(262)	230.00	230.00	STEEL	2.83		
6	CHUCKATUK	NEWPORT NEWS (263)	230.00	230.00	WOOD POLE	0.22		1
7		(263)	230.00	230.00	STEEL	0.09	15.24	
8	HUNTER	RESTON (264)	230.00	230.00	STEEL	2.87		1
9	CLIFTON	SULLY (265)	230.00	230.00	STEEL		2.68	1
10		(265)	230.00	230.00	STEEL		4.87	
11		(265)	230.00	230.00	STEEL POLE		5.25	
12		(265)	230.00	230.00	STEEL POLE		1.16	
13	CLIFTON	GLEN CARLYN (266)	230.00	230.00	STEEL	7.01		1
14		(266)	230.00	230.00	STEEL POLE	5.15		
15		(266)	230.00	230.00	STEEL POLE	12.44		
16	CHURCHLAND	YADKIN (267)	230.00	230.00	STEEL	9.01	2.29	1
17		(267)	230.00	230.00	STEEL POLE		0.11	
18	COGENTRIX	HOPEWELL (268)	230.00	230.00	STEEL	1.00		1
19	SHAWBORO	FENTRESS (269)	230.00	230.00	STEEL	4.35		1
20		(269)	230.00	230.00	H. FRAME	21.00		
21	BURKE	RAVENSWORTH (270)	230.00	230.00	STEEL	2.98		1
22		(270)	230.00	230.00	U.G.=HPOF	2.18		
23	FENTRESS	LANDSTOWN (271)	230.00	230.00	STEEL	6.80		1
24		(271)	230.00	230.00	CONCRETE	0.17		
25	DOOMS	GROTTOES (272)	230.00	230.00	STEEL	11.53		1
26	GLEN CARLYN	ARLINGTON (273)	230.00	230.00	STEEL		2.44	1
27	BEAUMEADE	PLEASANT VIEW (274)	230.00	230.00	STEEL		0.16	1
28		(274)	230.00	230.00	STEEL POLE		0.18	
29		(274)	230.00	230.00	STEEL		5.06	
30	GLEBE	CRYSTAL (275)	230.00	230.00	U.G.=HPOF	1.23		1
31	GLEBE	CRYSTAL (276)	230.00	230.00	U.G.=HPOF	1.20		1
32	GLEN CARLYN	CLARENDON (277)	230.00	230.00	U.G.=HPOF	1.95		1
33	GLEN CARLYN	CLARENDON (278)	230.00	230.00	U.G.=HPOF	1.96		1
34	FENTRESS	REEVES AVENUE (279)	230.00	230.00	STEEL POLE	12.36		1
35	MARSH RUN CT	REMINGTON (280)	230.00	230.00	STEEL		1.24	1
36					TOTAL	5,276.30	621.47	409

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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	BRADDOCK	RAVENSWORTH (281)	230.00	230.00	STEEL		2.06	1
2	SPRUANCE	MIDLOTHIAN (282)	230.00	230.00	STEEL	18.47		1
3		(282)	230.00	230.00	STEEL POLE		3.12	
4	ELMONT	NORTHEAST (283)	230.00	230.00	STEEL	5.22		1
5		(283)	230.00	230.00	H. FRAME	7.97		
6	BASIN	NORTHEAST (284)	230.00	230.00	STEEL	6.27		1
7		(284)	230.00	230.00	H. FRAME	2.26		
8	WALLER	YORKTOWN (285)	230.00	230.00	STEEL POLE	13.53		
9		(285)	230.00	230.00	STEEL	6.43		
10	DARBYTOWN	WHITE OAK (286)	230.00	230.00	STEEL	10.43		1
11		(286)	230.00	230.00	STEEL POLE	3.51		
12	CHESTERFIELD	CHICKAHOMINY (287)	230.00	230.00	H. FRAME		13.95	1
13		(287)	230.00	230.00	STEEL		0.83	
14	PENINSULA	YORKTOWN (288)	230.00	230.00	WOOD POLE		3.21	1
15		(288)	230.00	230.00	STEEL		6.00	
16	SUFFOLK	CHUCKATUCK (289)	230.00	230.00	H. FRAME	0.13		1
17		(289)	230.00	230.00	STEEL	9.65	4.31	
18		(289)	230.00	230.00	3-POLE	0.33		
19	SURRY	CHUCKATUCK (290)	230.00	230.00	STEEL		23.57	1
20		(290)	230.00	230.00	CONCRETE		0.11	
21	DOOMS	CHARLOTTSVILLE (291)	230.00	230.00	STEEL POLE		22.52	1
22	WHEALTON	YORKTOWN (292)	230.00	230.00	STEEL	10.55		1
23		(292)	230.00	230.00	H. FRAME	3.80		
24	VALLEY	DOOMS (293)	230.00	230.00	H. FRAME	17.73		1
25		(293)	230.00	230.00	STEEL		14.87	
26		(293)	230.00	230.00	STEEL POLE		1.37	
27	ANNANDALE	BRADDOCK (294)	230.00	230.00	U.G.=HPOF	3.58		1
28	LOUDOUN	BULL RUN (295)	230.00	230.00	STEEL		8.61	1
29	HALIFAX	PERSON-CP&L (296)	230.00	230.00	H. FRAME	20.41		1
30	ANNANDALE	BRADDOCK (297)	230.00	230.00	U.G.=HPOF	3.58		1
31	BREMO	FARMVILLE (298)	230.00	230.00	H. FRAME	15.48		1
32		(298)	230.00	230.00	H.FRAME	12.79		
33	REMINGTON CT	MARSH RUN CT (299)	230.00	230.00	STEEL	1.15		1
34		(299)	230.00	230.00	STEEL POLE	0.56		
35	OCCOQUAN	POSSUM POINT (2001)	230.00	230.00	WOOD POLE	0.17		1
36					TOTAL	5,276.30	821.47	409

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1		(2001)	230.00	230.00	STEEL		12.44	
2	CARSON	POE (2002)	230.00	230.00	WD 3 POLE	0.16		1
3		(2002)	230.00	230.00	STEEL	1.16	4.57	
4		(2002)	230.00	230.00	H.FRAME	6.76		
5	CHESTERFIELD	POE (2003)	230.00	230.00	WOOD POLE	0.24		1
6		(2003)	230.00	230.00	STEEL	7.00		
7		(2003)	230.00	230.00	STEEL		3.13	
8		(2003)	230.00	230.00	STEEL		9.02	
9	PENINSULA	SHELLBANK (2004)	230.00	230.00	STEEL	0.37		1
10		(2004)	230.00	230.00	STEEL POLE	5.92		
11	CLARK	HUNTER (2005)	230.00	230.00	STEEL	2.57		1
12	CHURCHLAND	LAKE KINGMAN (2006)	230.00	230.00	CON/STEEL	1.47		1
13	THALIA	LYNNHAVEN (2007)	230.00	230.00	CON/STEEL	3.37		1
14	LOUDOUN	DULLES (2008)	230.00	230.00	STEEL	4.58		1
15		(2008)	230.00	230.00	STEEL POLE	5.25		
16		(2008)	230.00	230.00	STEEL POLE		3.26	
17		(2008)	230.00	230.00	STEEL POLE	0.21		
18	MIDLOTHIAN	ELMONT (2009)	230.00	230.00	H. FRAME	34.50		1
19	RESTON	TYSONS (2010)	230.00	230.00	STEEL POLE	0.42		1
20		(2010)	230.00	230.00	CONCRETE	4.63		
21		(2010)	230.00	230.00	WOOD POLE	2.78		
22	CLIFTON	CANNON BRANCH (2011)	230.00	230.00	STEEL POLE	7.46		1
23	ROANOLE VALLEY NUG	EARLEYS (2012)	230.00	230.00	STEEL	3.60		1
24		(2012)	230.00	230.00	H. FRAME		36.58	
25		(2012)	230.00	230.00	H. FRAME		2.09	
26		(2012)	230.00	230.00	H. FRAME		5.68	
27	OCCOQUAN	OX (2013)	230.00	230.00	STEEL POLE		1.45	1
28	EARLEYS	EVERETTS (2014)	230.00	230.00	H. FRAME	32.36	0.26	1
29	RESTON	DULLES (2015)	230.00	230.00	STEEL	1.42		1
30		(2015)	230.00	230.00	STEEL	3.64		
31		(2015)	230.00	230.00	CONC	0.14		
32	LANEXA	HARMONY VILLAGE (2016)	230.00	230.00	STEEL	5.19		1
33		(2016)	230.00	230.00	H. FRAME	25.64		
34	HARRISONBURG	ENDLESS CAVERNS (2017)	230.00	230.00	CONC	19.78		1
35	GREENWICH	E. RIVER NUG (2018)	230.00	230.00	STEEL		11.13	1
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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	THALIA	GREENWICH (2019)	230.00	230.00	STEEL POLE	2.63		1
2	ELIZABETH CITY	WINFALL (2020)	230.00	230.00	H. FRAME	15.28		1
3	ELIZABETH CITY	SHAWBORO (2021)	230.00	230.00	H. FRAME	10.26		1
4	RAVENSWORTH	POSSUM POINT (2022)	230.00	230.00	STEEL	13.63		1
5		(2022)	230.00	230.00	STEEL POLE		0.53	
6		(2022)	230.00	230.00	STEEL POLE	5.65		
7	GLEBE	JEFFERSON STREET (2023)	230.00	230.00	STEEL POLE		0.63	1
8		(2023)	230.00	230.00	UG-HPOF		3.10	
9	CHICKAHOMINY	LANEXA (2024)	230.00	230.00	STEEL	14.26		1
10	GREEN RUN	LYNNHAVEN (2025)	230.00	230.00	STEEL	5.28		1
11		(2025)	230.00	230.00	CONCRETE	1.65		
12	LANDSTOWN	LYNNHAVEN (2026)	230.00	230.00	STEEL		5.94	1
13	MIDLOTHIAN	BREMO (2027)	230.00	230.00	WOOD/ST	29.26	5.98	1
14	CHARLOTTSVILLE	BREMO (2028)	230.00	230.00	STEEL	25.53		1
15	CIA	TYSON (2029)	230.00	230.00	STEEL POLE	6.56		1
16	LOUDOUN	GAINSVILLE (2030)	230.00	230.00	H. FRAME	7.61		1
17	FOUR RIVERS	ELMONT (2032)	230.00	230.00	H. FRAME	8.93		1
18	CLARK	STERLING PARK (2033)	230.00	230.00	STEEL	2.47		1
19		(2033)	230.00	230.00	STEEL	2.63		
20		(2033)	230.00	230.00	STEEL POLE	1.59		
21		(2033)	230.00	230.00	STEEL	3.75		
22	EARLEYS	TROWBRIDGE (2034)	230.00	230.00	H. FRAME	28.50		1
23		(2034)	230.00	230.00	STEEL	6.72		
24	IDYLWOOD	CIA (2035)	230.00	230.00	CONCRETE	6.41		1
25	GLEBE	PENTAGON (2036)	230.00	230.00	U.G. HPFF	2.37		1
26	GLEBE	PENTAGON (2037)	230.00	230.00	U.G. HPFF	2.37		1
27	GREENWICH	REEVES AVENUE (2038)	230.00	230.00	STEEL POLE	1.63	3.92	1
28	MORRISVILLE	MARSH RUN CT (2039)	230.00	230.00	STEEL	3.92		1
29	MORRISVILLE	MARSH RUN CT (2040)	230.00	230.00	STEEL		3.92	1
30	HOPEWELL	HCF NUG (2041)	230.00	230.00	H.FRAME	0.03		1
31	OCCOQUAN	OGDEN MARTIN (2042)	230.00	230.00	WOOD/ST	2.95	0.36	1
32	DISCOVERY	RESTON (2043)	230.00	230.00	STEEL POLE	1.82		1
33		(2043)	230.00	230.00	STEEL		3.62	
34		(2043)	230.00	230.00	STEEL		1.46	
35	BEAR ISLAND	FOUR RIVERS (2044)	230.00	230.00	WOOD POLE	0.06		1
36					TOTAL	5,276.30	621.47	409

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 2008/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	LOUDOUN	BRAMBLETON (2046)	230.00	230.00	ST TOWER	5.06		1
2	HOPEWELL	POLYESTER PWR STA	230.00	230.00	STEEL POLE	0.72		1
3	SURRY	GRAVEL NECK (2047)	230.00	230.00	CONCRETE	0.31		1
4	SURRY	GRAVEL NECK (2048)	230.00	230.00	CONCRETE	0.44		1
5	CHESTERFIELD	ALLIED (2049)	230.00	230.00	STEEL	2.88		1
6		(2049)	230.00	230.00	STEEL POLE	1.67		
7		(2049)	230.00	230.00	H. FRAME	5.35		
8	ALLIED	CHICKAHOMINY (2050)	230.00	230.00	STEEL	5.98		1
9		(2050)	230.00	230.00	H. FRAME	6.58		
10		(2050)	230.00	230.00	STEEL POLE	2.47		
11	CLIFTON	PENDER (2051)	230.00	230.00	STEEL POLE		6.76	1
12		(2051)	230.00	230.00	STEEL	2.88		
13	LEXINGTON	CLIFTON FORGE (2052)	230.00	230.00	STEEL	35.42		1
14	NORTHEAST	DARBYTOWN (2053)	230.00	230.00	STEEL POLE	5.67		1
15	CHARLOTTESVILLE	GORDONSVILLE (2054)	230.00	230.00	H. FRAME	8.41		1
16		(2054)	230.00	230.00	WOOD POLE	15.92		
17	BASIN	BELLEMEADE (2055)	230.00	230.00	STEEL	0.52	0.04	1
18	HORNERTOWN	ROCKY MT. CP&L (2056)	230.00	230.00	H. FRAME	26.47		1
19		(2056)	230.00	230.00	STEEL	2.66		
20		(2056)	230.00	230.00	STEEL		4.16	
21	HORNERTOWN	ROSEMARY (2057)	230.00	230.00	STEEL POLE	0.51		1
22	EDGECOMB	ROCKY MT. CP&L (2058)	230.00	230.00	STEEL	4.81		1
23	CAROLINA	ROCKY VALLEY NUG (2060)	230.00	230.00	STEEL	2.00		1
24		(2060)	230.00	230.00	H. FRAME	2.10		
25	FOUR RIVERS	FOUR RIVERS NUG (2061)	230.00	230.00	STEEL POLE	0.17		1
26	RESTON	DRANESVILLE (2062)	230.00	230.00	STEEL POLE	1.56		1
27		(2062)	230.00	230.00	CONCRETE	1.41		
28	CLIFTON	RAVENSWORTH (2063)	230.00	230.00	STEEL	7.02		1
29	SHAWBORO	KITTY HAWK (2064)	230.00	230.00	ST. H-FRAME	30.08		1
30		(2064)	230.00	230.00	CONC. POLE	2.67		
31		(2064)	230.00	230.00	WOOD POLE	5.96		
32	BASIN	SPRUANCE (2065)	230.00	230.00	STEEL POLE	3.19	0.47	1
33	MIDLOTHIAN	WINTERPOCK (2066)	230.00	230.00	STEEL POLE	2.63	2.74	1
34		(2066)	230.00	230.00	STEEL	2.91		
35		(2066)	230.00	230.00	STEEL		7.72	
36					TOTAL	5,276.30	821.47	409

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 2008/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		(2066)	230.00	230.00	STEEL		1.44	
2	FOUR RIVERS	FOUR RIVERS NUG (2067)	230.00	230.00	WOOD POLE	0.06		1
3	CLOVER	HALIFAX (2068)	230.00	230.00	H. FRAME	3.65		1
4		(2068)	230.00	230.00	H. FRAME	12.99		
5		(2068)	230.00	230.00	CON. H.	0.21		
6	YADKIN	ELIZABETH RIVER (2070)	230.00	230.00	STEEL POLE	2.56	0.72	1
7	ELIZABETH RIVER	E. RIVER PWR STA (2071)	230.00	230.00	STEEL POLE	0.06		1
8	LYNNHAVEN	VIRGINIA BEACH (2072)	230.00	230.00	CONCRETE	4.43		1
9	SHAWBORO	KITTY HAWK (2073)	230.00	230.00	ST. H-FRAME		30.06	1
10		(2073)	230.00	230.00	CONC. POLE		2.67	
11		(2073)	230.00	230.00	WOOD POLE	3.92		
12		AYDLETT	230.00	230.00	WD H-FRAME	1.63		
13	GORDONSVILLE	SOUTH ANNA (2074)	230.00	230.00	H. FRAME	0.83		1
14		(2074)	230.00	230.00	H. FRAME	0.19		
15		(2074)	230.00	230.00	STEEL POLE	0.21		
16	ELMONT	OLD CHURCH (2075)	230.00	230.00		15.91		1
17	BIRCHWOOD	NORTHERN NECK (2076)	230.00	230.00	H. FRAME	41.17		1
18		(2076)	230.00	230.00	H. FRAME	3.06		
19	REMINGTON	REMINGTON CT (2077)	230.00	230.00	ST. POLE	0.54		1
20	POSSUM POINT 500	POSSUM POINT 230 (2078)	230.00	230.00	H.FRAME	0.81		1
21	BEAUMEADE	DRANESVILLE (2079)	230.00	230.00	STEEL POLE	1.51	0.70	1
22		(2079)	230.00	230.00	STEEL	2.12		
23		(2079)	230.00	230.00	CONC POLE	0.04		
24		(2079)	230.00	230.00	STEEL		3.67	
25		(2079)	230.00	230.00	STEEL POLE		1.70	
26	BEAUMEADE	STERLING PARK (2081)	230.00	230.00	STEEL	0.72		1
27		(2081)	230.00	230.00	STEEL		2.24	
28		(2081)	230.00	230.00	CONC POLE		0.03	
29	SEWELLS POINT	NAVY NORTH (2082)	230.00	230.00	U.G. HPFF	2.02		1
30	BIRCHWOOD	FREDERCKSBURG (2083)	230.00	230.00	H. FRAME	12.18		1
31		(2083)	230.00	230.00	H. FRAME		3.05	
32	LEXINGTON	LOWMOOR (2084)	230.00	230.00	STEEL	37.37		1
33	LANDSTOWN	WEST LANDING (2085)	230.00	230.00	STEEL POLE	7.90		1
34	REMINGTON CT	WARRENTON (2086)	230.00	230.00	CONC. POLE	11.20		1
35		(2086)	230.00	230.00	STEEL POLE		0.61	
36					TOTAL	5,276.30	521.47	409

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 2008/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	FENTRESS	SHAWBORO (2087)	230.00	230.00	STEEL		4.33	1
2		(2087)	230.00	230.00	STEEL POLE	21.04		
3	GORDONSVILLE	LOUISA CT (2088)	230.00	230.00	H. FRAME	0.58		1
4		(2088)	230.00	230.00	STEEL POLE		0.21	
5	LADYSMITH	LADYSMITH CT (2089)	230.00	230.00	STEEL	3.94		1
6	WHITE OAK	CHICKAHOMINY (2091)	230.00	230.00	STEEL	3.62		1
7		(2091)	230.00	230.00	STEEL POLE	3.51		
8	SEWELLS POINT	NAVY NORTH (2093)	230.00	230.00	U.G. HPFF	2.01		1
9	BRAMBLETON	LOUDOUN (2094)	230.00	230.00	ST TOWER		5.09	1
10	BEAUMEADE	GREENWAY (2095)	230.00	230.00	STEEL		0.57	1
11		(2095)	230.00	230.00	STEEL POLE	2.58		
12	CLARENDON	BALLSTON (2096)	230.00	230.00	U.G. XLPE	0.42		1
13	OX	IDYLWOOD (2097)	230.00	230.00	STEEL	8.00		1
14		(2097)	230.00	230.00	STEEL	4.51		
15	CHURCHLAND	SEWELLS POINT (2099)	230.00	230.00	STEEL POLE		5.25	1
16		(2099)	230.00	230.00	SUBMARINE	1.56		
17	CHICKAHOMINY	WALLER (2102)	230.00	230.00	H. FRAME	14.12		1
18		(2102)	230.00	230.00	STEEL POLE	3.69		
19		(2102)	230.00	230.00	STEEL	10.74		
20	SULLY	DISCOVERY (2107)	230.00	230.00	STEEL POLE	1.16		1
21		(2107)	230.00	230.00	STEEL POLE	1.64		
22	LANEXA	WALLER (2113)	230.00	230.00	WOOD	14.48		1
23								
24								
25	SUBTOTAL - 230		230.00	230.00		1,926.33	580.63	191
26								
27	BREMO	SCOTTSVILLE APCO (8)	138.00	138.00	STEEL	7.30		1
28	FUDGE HOLLOW	APCO INTERCONNECT (14)	138.00	138.00	STEEL	14.94		1
29	EASTMILL	WESTVACO (109)	138.00	138.00	STEEL POLE		0.89	1
30	LOWMOOR	FUDGE HOLLOW (112)	138.00	138.00	STEEL	4.64	0.65	1
31		(112)	138.00	138.00	STEEL POLE	2.14		
32	CLIFTON FORGE	LOWMOOR (133)	138.00	138.00	STEEL	5.06		1
33	EDINBURG	STRASBURG PT. ED. (152)	138.00	138.00	WOOD POLE	16.54		1
34	WESTVACO	FUDGE HOLLOW (156)	138.00	138.00	STEEL POLE	0.57		1
35		(155)	138.00	138.00	WOOD POLE		1.35	
36					TOTAL	5,276.30	821.47	409

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 2008/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	LOWMOOR	EASTMILL (161)	138.00	138.00	WOOD POLE	6.41		1
2		(161)	138.00	138.00	STEEL POLE		3.43	
3								
4	SUBTOTAL - 138KV		138.00			57.59	6.32	8
5								
6	VARIOUS	VARIOUS	115.00		H. FRAME			
7			115.00		WOOD POLES	2,046.66	233.32	159
8			115.00		STEEL			
9								
10	SUBTOTAL - 115KV		115.00			2,046.66	233.32	159
11								
12	VARIOUS	VARIOUS	69.00	69.00	H. FRAME	87.33		6
13			69.00	69.00	WOOD POLES			
14			69.00	69.00	UG CABLE	14.27		8
15								
16	SUBTOTAL - 69KV		69.00	69.00		101.60		14
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	5,276.90	821.47	409

Appendix 3R – FERC FORM 423

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 2008/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
ACAR 2500								2
AAAC 2049.5								3
ACAR 2500								4
AAAC 2049.5								5
AAAC 2049.5								6
ACAR 2500								7
ACAR 2500								8
ACAR 2500								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
AAAC 2049.5								16
ACSR 1351.5								17
AAAC 2049.5								18
AAAC 2049.5								19
ACAR 2500								20
ACAR 1534								21
ACAR 2500								22
ACAR 2500								23
ACAR 2500								24
AAAC 2049.5								25
AAAC 2049.5								26
ACAR 2500								27
ACAR 2500								28
AAAC 2049.5								29
ACAR 2500								30
ACAR 2500								31
ACAR 1534								32
ACAR 2500								33
AAAC 2049.5								34
ACAR 2500								35
	240,151,009	850,338,734	1,090,489,743	9,121,673	8,424,739	22,289	17,568,701	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 2008/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.
SDC 2500								1
ACAR 2500								2
ACAR 2500								3
ACAR 2500								4
ACAR 2500								5
	83,199,272	286,561,883	369,761,155	1,710,266	1,579,594	4,179	3,294,039	6
	83,199,272	286,561,883	369,761,155	1,710,266	1,579,594	4,179	3,294,039	7
								8
ACSR 1033.5								9
ACAR 2500								10
ACAR 2500								11
ACAR 1109								12
ACAR 1192.5								13
ALUM 1177								14
ACAR 1033.5								15
ACAR 1109								16
ACAR 1109								17
ACSR 1033.5								18
ACSR 2500								19
ACSR 1033.5								20
ACAR 1109								21
ACSR1033.5								22
ACAR 721								23
ACAR 1109								24
ACAR 1109								25
ACAR 2500								26
ACAR 721								27
ACSR 1033.5								28
ACAR 1524								29
ACAR 721								30
ACAR 721								31
ACAR 2500								32
ACAR 2500								33
ACAR 795								34
ACAR 795								35
	240,151,009	850,338,734	1,090,489,743	9,121,673	8,424,739	22,289	17,568,701	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 2008/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)			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 1109								1
ACAR 1109								2
ACAR 721								3
ACAR 721								4
ACSR 1033.5								5
ACAR 1109								6
ACAR 721								7
ACSR 1033.5								8
ACAR 721								9
ACAR 1109								10
ACSR 1033.5								11
ACAR 721								12
ACAR 2500								13
SSAC 1192.5								14
ACSR 1590								15
ACSR 1033.5								16
ACAR 1109								17
ACAR 1534								18
ACSR 1033.5								19
ACSR 1033.5								20
AAAC 1177								21
ACSR 1033.5								22
ACSR 795								23
ACAR 545.6								24
ACAR 1534								25
ACSR 545.6								26
ACSR 545.6								27
ACSR 636								28
ACAR 2500								29
ACAR 721								30
ACSR 1033.5								31
SSAC 1033.5								32
ACAR 721								33
ACAR 721								34
ACAR 721								35
	240,151,009	850,338,734	1,090,489,743	9,121,673	8,424,739	22,289	17,568,701	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 2008/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) 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.
ACSR 1033.5								1
ACSR 1033.5								2
ACAR 721								3
ACAR 1033.5								4
ACAR 721								5
ACSR 1033.5								6
ACAR 1109								7
ACAR 1534								8
SSAC 1590								9
ACAR 545								10
ACAR 545								11
ACSR 636								12
ACAR 1109								13
ACAR 2500								14
ACAR 2500								15
CU 2500								16
ACSR 636								17
ACSR 795								18
ACSR 795								19
ACAR 2500								20
AAAC 1600								21
AAAC 1600								22
ACAR 721								23
ACAR 721								24
ACSR 795								25
ACAR 545.6								26
ACAR 545.6								27
ACAR 1534								28
ACSR 795								29
ACAR 721								30
COPPER 1250								31
ACAR 2500								32
ACAR 2500								33
ACSR 1033								34
ACAR 2500								35
	240,151,009	850,338,734	1,090,489,743	9,121,673	8,424,739	22,289	17,568,701	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 2008/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)	
ACAR 1109								1
ACAR 1109								2
ACSR 1033								3
ACSR 1033								4
ACAR 721								5
ACAR 1534								6
ACAR 1534								7
ACSR 1192								8
ACSR 1033.5								9
ACSR 1033.5								10
ACSR 1590								11
ACAR 1534								12
ACSR 1033.5								13
AAAC 1600								14
ACAR 2500								15
ACAR 721								16
ACAR 2500								17
ACAR 1109								18
ACAR 545								19
ACAR 545								20
ACAR 1534								21
COPPER 1750								22
ACAR 721								23
ACAR 2500								24
ACAR 721								25
ACAR 1600								26
SSAC 1192.5								27
ACSR 1590								28
ACSR 1192.50								29
COPPER 1750								30
COPPER 1750								31
COPPER 1750								32
COPPER 1750								33
ACAR 721								34
ACSS 795								35
	240,151,009	820,338,734	1,060,489,743	9,121,673	8,424,739	22,289	17,568,701	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 2008/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)	
ACAR 2500								1
ACAR 721								2
ACAR 2500								3
ACAR 721								4
ACAR 721								5
ACAR 721								6
ACAR 721								7
ACAR 721								8
ACAR 721								9
ACAR 721								10
								11
ACSR 1033.5								12
ACSR 1033.5								13
ACAR 721								14
ACAR 721								15
ACAR 2500								16
ACAR 721								17
ACAR 721								18
ACAR 721								19
ACAR 721								20
ACAR 545.6								21
ACSR 1033.5								22
ACAR 721								23
ACAR 545.6								24
ACAR 545.60								25
ACAR 545.6								26
COPPER 250								27
ACSR 1033								28
ACAR 545.6								29
COPPER 250								30
ACAR 545.6								31
ACAR 545.6								32
ACAR 545.6								33
ACSR 636								34
ACAR 2500								35
	240,151,009	850,338,734	1,090,489,743	9,121,673	8,424,739	22,289	17,568,701	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 2008/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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				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 721								1
ACAR 721								2
ACAR 721								3
ACAR 721								4
ACAR 2500								5
ACAR 721								6
ACAR 1109								7
ACSR 1033.5								8
ACAR 721								9
ACAR 721								10
ACSR 1192.5								11
ACAR 1534								12
ACAR 2500								13
SSAC 1033.5								14
ACSR 1590								15
ACSR 1590								16
ACSR 1590								17
ACSR 636								18
SSAC 1033.5								19
SSAC 1033.5								20
SSAC 1033.5								21
ACSR 1590								22
ACAR 545.6								23
ACAR 545.6								24
ACAR 1534								25
AAC 1590								26
ACAR 2500								27
ACAR 545.6								28
SSAC 1192.5								29
SSAC 1033.5								30
SSAC 1033.5								31
SSAC 1033.5								32
SSAC 1033.5								33
								34
ACAR 1534								35
	240,151,009	850,338,734	1,090,489,743	9,121,673	8,424,739	22,289	17,568,701	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

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SSAC 1590								1
ACAR 1109								2
ACAR 545.6								3
ACSR 1033.5								4
ACAR 721								5
ACAR 2500								6
ACAR 2500								7
CU 2500								8
ACAR 721								9
ACAR 721								10
ACAR 2500								11
ACAR 721								12
SSAC 1033.5								13
ACAR 721								14
SSAC 1033.5								15
ACAR 1109								16
ACSR 795								17
SSAC 1033.5								18
SSAC 1033.5								19
SSAC 1033.5								20
SSAC 1192.5								21
ACAR 545								22
ACAR 545								23
SSAC 1033.5								24
COPPER 1750								25
COPPER 1750								26
ACAR 2500								27
ACAR 545.6								28
SSAC 796								29
ACAR 1534								30
ACAR 1534								31
ACSR 1590								32
SSAC 1033.5								33
SSAC 1192.5								34
ACSR 795								35
	240,151,009	850,338,734	1,090,489,743	9,121,673	8,424,739	22,289	17,568,701	36

TRANSMISSION LINE STATISTICS (Continued)

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
ACCR 1033-T13								1
ACAR 1534								2
ACSR 1033.5								3
ACSR 1033.5								4
ACSR 636								5
ACSR 636								6
ACSR 636								7
ACSR 636								8
ACSR 636								9
ACSR 636								10
ACAR 2500								11
ACSR 1033.5								12
ACSR 1033								13
ACAR 721								14
ACAR 254.6								15
ACSR 477								16
ACAR 1534								17
ACSR 1033.5								18
ACSR 1033.5								19
ACAR 1109								20
ACAR 1534								21
ACAR 1109								22
ACAR 545.6								23
ACAR 1534								24
ACSR 1590								25
SSAC 1192.5								26
SSAC 1033.5								27
SSAC 1033.5								28
ACAR 545.6								29
ACSR/SD 795								30
ACAR 721								31
ACAR 2500								32
ACSR 636								33
ACSR 636								34
ACSR 636								35
	240,151,009	850,338,734	1,090,489,743	9,121,673	8,424,739	22,289	17,568,701	36

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TRANSMISSION LINE STATISTICS (Continued)

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ACAR 721								1
ACSR 1590								2
ACSR 636								3
ACSR 477								4
ACSR 545.6								5
ACSR 1534								6
ACSR 1590								7
ACAR 2500								8
ACAR 545.6								9
ACSR/SD 795								10
ACSR 1033.5								11
ACSR 477								12
ACSR 1590								13
ACSR 477								14
ACSR 477								15
								16
ACAR 545.6								17
ACAR 1534								18
ACSR 636								19
ACSR 636								20
ACSR 2-636								21
ACSR 1192.5								22
SSAC 1033.5								23
SSAC 1192.5								24
SSAC 1192.5								25
ACSR 1192.5								26
SSAC 1192.5								27
SSAC 1033.5								28
CU 2500								29
ACAR 545.6								30
ACAR 1534								31
ACSR 477								32
ACSR 636								33
ACAR 1109								34
ACAR 1109								35
	240,151,009	850,338,734	1,090,489,743	9,121,673	6,424,739	22,289	17,568,701	36

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ACAR 545.5								1
ACSR 636								2
ACSR 477								3
ACSR 477								4
ACSR 636								5
ACAR 721								6
ACSR 636								7
CU 2500								8
ACSS/TW 1233.6								9
ACSR 636								10
ACSR 636								11
CU 1500								12
ACSR 1033.5								13
ACSR 795								14
ACAR 721								15
COPPER 1250								16
ACSR 1033.5								17
ACAR 721								18
ACAR 721								19
ACAR 1534								20
ACSR 1590								21
ACSR 1033.5								22
								23
	84,477,291	362,245,105	446,722,396	3,750,169	3,463,640	9,164	7,222,973	24
	84,477,291	362,245,105	446,722,396	3,750,169	3,463,640	9,164	7,222,973	25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	240,151,009	850,338,734	1,090,489,743	9,121,673	8,424,739	22,289	17,568,701	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 2008/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)			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)	
								1
								2
	9,009,747	17,978,710	26,988,457	95,603	88,299	234	184,136	3
	9,009,747	17,978,710	26,988,457	95,603	88,299	234	184,136	4
								5
VARIOUS								6
								7
								8
	62,750,382	177,265,912	240,016,294	3,413,651	3,152,834	8,341	6,574,826	9
	62,750,382	177,265,912	240,016,294	3,413,651	3,152,834	8,341	6,574,826	10
								11
								12
								13
								14
	714,317	6,267,124	6,981,441	151,984	140,372	371	292,727	15
	714,317	6,267,124	6,981,441	151,984	140,372	371	292,727	16
								17
								18
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								34
								35
	240,151,009	850,338,734	1,090,489,743	9,121,673	8,424,739	22,289	17,568,701	36

Appendix 3S – FERC FORM 424

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 2008/Q4

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	Clarendon	Ballston	0.42	UG		1	1
2	Moutain Run	Culpeper Tap	5.29	ST POLE	10.00	2	2
3							
4							
5							
6							
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39							
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41							
42							
43							
44	TOTAL		5.71		10.00	3	3

Appendix 3T – FERC FORM 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 2009/Q4

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)	
1500	CU	Varies	230			6,142,714		6,142,714	1
1033.5	ACSR	12' VERTICAL	115		3,810,083	3,416,054		7,226,137	2
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									43
					3,810,083	9,558,768		13,368,851	44

Appendix 3U – FERC FORM 426

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 2008/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	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	BANISTER	D	138.00	34.50	
24	BARRACKS ROAD	D	230.00	34.50	
25	BASIN	D	115.00	13.20	
26	BASIN	T	230.00	115.00	13.20
27	BASIN	D	230.00	34.50	
28	BATTLEBORO	D	115.00	34.50	2.40
29	BATTLEFIELD	D	34.50	13.20	
30	BAYSIDE	D	34.50	13.20	
31	BAYSIDE	D	115.00	34.50	13.20
32	BAYSIDE	D	115.00	13.20	
33	BEARSKIN	T	138.00	69.00	7.92
34	BEAUMEADE	D	230.00	34.50	
35	BECO	D	230.00	34.50	
36	BELLE HAVEN	D	34.50	12.50	
37	BELLWOOD	D	115.00	13.20	
38	BELT LINE	D	34.50	4.16	
39	BELVOIR	D	230.00	34.50	
40	BENNS CHURCH	D	34.50	12.50	

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 2008/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	BERKLEY	D	115.00	11.00	
2	BETHEL CAROLINA	D	115.00	12.50	
3	BEVERLY HILLS	D	34.50	4.16	
4	BLOXOMS CORNER	D	115.00	23.00	
5	BOLLINGBROOK	D	34.50	4.16	
6	BOWERS HILL	D	230.00	34.50	
7	BOWERS HILL	D	115.00	34.50	13.20
8	BOYKINS	D	115.00	34.50	
9	BRADDOCK	D	34.50	12.50	
10	BRADDOCK	D	230.00	34.50	
11	BREMO	D	115.00	34.50	13.20
12	BREMO	T	138.00	115.00	13.20
13	BREMO	T	230.00	115.00	13.20
14	BRIARFIELD	D	23.00	6.00	
15	BRODNAX	D	115.00	12.50	
16	BRUNSWICK	T	115.00	69.00	13.20
17	BUCHANAN	D	46.00	12.50	
18	BUCKINGHAM	D	34.50	12.50	
19	BUCKINGHAM	D	230.00	34.50	
20	BUCKROE	D	23.00	6.00	
21	BUENA VISTA	D	115.00	12.50	
22	BULL RUN	T	230.00	115.00	13.20
23	BURKE	D	230.00	34.50	
24	BURTON	D	115.00	34.50	13.20
25	CALLAO	D	34.50	12.50	
26	CAMPOSTELLO	D	11.00	4.16	
27	CANNON BRANCH	D	115.00	34.50	
28	CANNON BRANCH	T	230.00	115.00	13.20
29	CAROLINA	D	115.00	13.20	
30	CAROLINA	T	230.00	115.00	13.20
31	CARROLL	D	34.50	13.20	
32	CARSON	T	500.00	230.00	34.50
33	CARTERSVILLE	D	115.00	34.50	
34	CARVER	D	115.00	34.50	
35	CARVER	D	115.00	13.20	
36	CASHIE	D	230.00	34.50	
37	CASH'S CORNER	T	230.00	115.00	
38	CENTRAL	D	115.00	12.50	
39	CENTRALIA	D	115.00	13.20	
40	CENTREVILLE	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 2008/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	CHANCELLOR	D	115.00	34.50	
2	CHANCELLOR	T	500.00	115.00	
3	CHARLES CITY RD	D	230.00	34.50	
4	CHARLOTTESVILLE	D	34.50	12.50	
5	CHARLOTTESVILLE	D	230.00	34.50	
6	CHASE CITY	T	115.00	69.00	13.20
7	CHASE CITY	D	115.00	12.50	
8	CHATHAM	D	69.00	12.50	
9	CHERRYDALE	D	34.50	12.50	
10	CHESTERBROOK	D	34.50	13.20	
11	CHESTERFIELD 230	T	230.00	115.00	13.20
12	CHICKAHOMINY	T	500.00	230.00	34.50
13	CHOWAN	D	115.00	34.50	
14	CHURCHLAND	D	115.00	13.20	
15	CHURCHLAND	T	230.00	115.00	13.20
16	CHURCHLAND	D	230.00	34.50	
17	CIA	D	230.00	34.50	
18	CITY HALL	D	34.50	11.00	
19	CLARENDON	D	230.00	34.50	
20	CLARK	D	230.00	34.50	
21	CLARKSVILLE	D	115.00	13.20	
22	CLARKSVILLE	D	69.00	13.20	2.40
23	CLIFTON	T	500.00	230.00	
24	CLIFTON FORGE	D	138.00	46.00	13.20
25	CLIFTON FORGE	D	138.00	12.50	
26	CLIFTON FORGE	T	230.00	138.00	13.20
27	CLOVER	T	500.00	230.00	
28	CLUBHOUSE	T	230.00	115.00	13.20
29	COLINGTON	D	115.00	34.50	
30	COLONIAL BEACH	D	34.50	12.50	
31	COLONIAL HEIGHTS	D	13.20	4.16	
32	COLONY	D	115.00	34.50	
33	COLONY	D	115.00	13.20	
34	COLUMBIA	D	34.50	12.50	
35	COLUMBIA FURNACE	D	34.50	23.00	
36	COOKS CORNER	D	34.50	12.50	
37	COPELAND PARK	D	115.00	23.00	
38	CORRECTIONAL	D	230.00	34.50	
39	COTTAGE PARK	D	34.50	13.20	
40	COVINGTON	D	46.00	12.50	

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 2008/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.
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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	COVINGTON	D	138.00	46.00	12.50
2	CRADOCK	D	115.00	34.50	13.20
3	CRADOCK	D	115.00	34.50	
4	CRAIGSVILLE	D	115.00	23.00	
5	CRANES CORNER	D	230.00	34.50	
6	CRESWELL	D	34.50	12.50	
7	CRESWELL	D	115.00	34.50	
8	CREWE	D	115.00	12.50	
9	CRITTENDEN	D	230.00	34.50	
10	CROMWELL ROAD	D	34.50	4.16	
11	CROZET	D	230.00	34.50	
12	CRYSTAL	D	230.00	34.50	
13	CULPEPER	D	115.00	34.50	
14	CULPEPER REA	D	34.50	12.50	
15	CUSHAW	D	12.50	2.40	
16	DAVIS CORNER	D	115.00	34.50	13.20
17	DAVIS CORNER	D	115.00	13.20	
18	DAYTON	D	230.00	34.50	
19	DEEP CREEK	D	115.00	13.20	
20	DELTAVLLE	D	34.50	12.50	
21	DENBIGH	D	230.00	34.50	
22	DIAMOND SPRINGS	D	34.50	13.20	
23	DINWIDDIE	D	34.50	13.20	
24	DISPUTANTA	D	115.00	13.20	
25	DOMINION	D	115.00	34.50	
26	DOOMS 115	D	115.00	23.00	
27	DOOMS 500	T	230.00	115.00	13.20
28	DOOMS 500	T	500.00	230.00	
29	DOOMS 500	T	500.00	230.00	34.50
30	DOZIER	D	34.50	13.20	
31	DOZIER	D	115.00	13.20	
32	DRANESVILLE	D	230.00	34.50	
33	DRY RUN	D	46.00	12.50	
34	DRYBURG	D	115.00	12.50	
35	DULLES	D	230.00	34.50	
36	DUMFRIES	D	230.00	34.50	
37	DUNNSVILLE	D	230.00	34.50	
38	DUPONT	D	115.00	13.20	
39	DWYER	D	34.50	4.16	
40	EAGLE ROCK	D	46.00	12.50	

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 2008/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.
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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	EARLEYS	D	115.00	34.50	
2	EARLEYS	T	230.00	115.00	13.20
3	EAST END	D	23.00	6.00	
4	EAST OCEAN VIEW	D	34.50	13.20	
5	EDENTON	D	115.00	12.50	
6	EDGEWATER	D	34.50	4.16	
7	EDINBURG	D	115.00	34.50	
8	EDINBURG	T	138.00	115.00	13.20
9	ELEVENTH STREET	D	34.50	4.16	
10	ELIZABETH CITY	D	230.00	34.50	
11	ELM	D	34.50	12.50	
12	ELMONT	T	230.00	115.00	13.20
13	ELMONT	D	230.00	34.50	
14	ELMONT	T	500.00	230.00	
15	ELMONT	T	500.00	230.00	34.50
16	EMPORIA	D	115.00	12.50	
17	ENDLESS CAVERNS	D	115.00	34.50	
18	ENDLESS CAVERNS	T	230.00	115.00	13.20
19	ENGLESIDE	D	34.50	12.50	
20	ENON	D	34.50	13.20	
21	ENON	D	230.00	34.50	
22	EVERETTS	T	230.00	115.00	13.20
23	EVERETTS	D	230.00	34.50	
24	FAIRFAX	D	34.50	12.50	
25	FAIRFIELD	D	115.00	23.00	
26	FALLS CHURCH	D	34.50	12.50	
27	FALLS CHURCH	D	230.00	34.50	
28	FARMVILLE	D	115.00	12.50	
29	FARMVILLE	T	230.00	115.00	13.20
30	FARMVILLE	D	230.00	34.50	
31	FENTRESS	D	230.00	34.50	13.20
32	FENTRESS	T	500.00	230.00	
33	FISHERSVILLE	D	115.00	23.00	
34	FLAGGY RUN	D	34.50	13.20	
35	FORT HUNT	D	34.50	12.50	
36	FORT LEE	D	115.00	13.20	
37	FORT MYER	D	34.50	12.50	
38	FORT PICKETT	D	115.00	12.50	
39	FOX HALL	D	34.50	4.16	
40	FRANCONIA	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 2008/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.
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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	FRANKLIN	D	115.00	13.20	
2	FREDERICKSBURG	D	115.00	34.50	
3	FREDERICKSBURG	D	115.00	13.20	
4	FREDERICKSBURG	T	230.00	115.00	13.20
5	FREDERICKSBURG	D	230.00	34.50	
6	GAINESVILLE	T	230.00	115.00	13.20
7	GAINESVILLE	D	230.00	34.50	
8	GALLOWS ROAD	D	230.00	34.50	
9	GARYSVILLE	D	34.50	13.20	
10	GATESVILLE	D	34.50	12.50	
11	GLASGOW	D	115.00	46.00	13.20
12	GLASGOW	D	115.00	12.50	
13	GLEBE	D	230.00	34.50	
14	GLEN CARLYN	D	230.00	34.50	
15	GLOUCESTER	D	34.50	12.50	
16	GOLDMINE DP	D	34.50	13.20	
17	GORDONSVILLE	D	115.00	34.50	
18	GORDONSVILLE	T	230.00	115.00	13.20
19	GOSHEN	D	115.00	46.00	4.16
20	GOSHEN	D	115.00	23.00	
21	GOWRIE PARK	D	34.50	4.16	
22	GRAFTON	D	115.00	34.50	
23	GRASSFIELD	D	115.00	34.50	13.20
24	GREAT BRIDGE	D	115.00	34.50	13.20
25	GREEN HILL	D	34.50	4.16	
26	GREEN RUN	D	230.00	34.50	13.20
27	GREENWAY	D	230.00	34.50	
28	GREENWICH	T	230.00	115.00	13.20
29	GREENWICH	D	230.00	34.50	13.20
30	GREENWICH	D	115.00	34.50	13.20
31	GRETNA	D	69.00	12.50	
32	GROTTOES	D	23.00	13.20	
33	GROTTOES	D	115.00	23.00	
34	GROTTOES	D	115.00	12.50	
35	GROTTOES	T	230.00	115.00	13.20
36	GROVE AVENUE	D	34.50	13.20	
37	GROVE AVENUE	D	34.50	4.16	
38	GROVELAND	D	34.50	13.20	
39	GUM SPRINGS	D	230.00	34.50	
40	HALIFAX	T	230.00	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 2008/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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HAMPTON	D	23.00	8.00	
2	HANOVER	D	115.00	13.20	
3	HANOVER	D	230.00	34.50	
4	HARBOUR VIEW	D	230.00	34.50	
5	HARMONY VILLAGE	D	115.00	34.50	
6	HARMONY VILLAGE	T	230.00	115.00	13.20
7	HARMONY VILLAGE	D	230.00	34.50	
8	HARRISONBURG	D	115.00	34.50	
9	HARRISONBURG	T	230.00	115.00	13.20
10	HARRISONBURG	T	230.00	69.00	13.20
11	HARROWGATE	D	115.00	13.20	
12	HARROWGATE	D	230.00	34.50	
13	HARVELL	D	13.20	4.16	
14	HARVELL	D	115.00	13.20	
15	HAYES	D	115.00	34.50	
16	HAYFIELD	D	230.00	34.50	
17	HERNDON PARK	D	230.00	34.50	
18	HERTFORD	D	34.50	13.20	
19	HICKORY	D	115.00	34.50	13.20
20	HICKORY	D	115.00	13.20	
21	HICKORY	T	230.00	115.00	13.20
22	HILLWOOD	D	34.50	13.20	
23	HILTON	D	34.50	8.00	
24	HODGES FERRY	D	115.00	34.50	
25	HODGES FERRY	D	115.00	13.20	
26	HOLLAND	D	115.00	13.20	
27	HOLLIN HALL	D	34.50	13.20	
28	HOLLYMEADE	D	230.00	34.50	
29	HOPEWELL	D	34.50	13.20	
30	HOPEWELL	D	230.00	34.50	13.20
31	HORNERTOWN	D	115.00	34.50	
32	HORNERTOWN	D	115.00	13.20	
33	HORNERTOWN	D	230.00	34.50	
34	HORSEPEN	D	34.50	4.16	
35	HULL ST	D	230.00	34.50	
36	HUME	D	34.50	4.16	
37	HUNTER	D	230.00	34.50	
38	IDYLWOOD	D	34.50	13.20	
39	IDYLWOOD	D	230.00	34.50	
40	IGLOO	D	34.50	12.50	

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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	ILDA	D	34.50	13.20	
2	INDUSTRIAL PARK	D	115.00	34.50	13.20
3	INDUSTRIAL PARK	D	115.00	13.20	
4	IRONBRIDGE	D	230.00	34.50	
5	IVOR	D	115.00	13.20	
6	IVY	D	23.00	6.00	
7	JACKSON RIVER	D	46.00	12.50	
8	JARRATT	D	115.00	13.20	
9	JEFFERSON STREET	D	230.00	34.50	
10	JETERSVILLE	D	115.00	34.50	
11	KEENE MILL	D	230.00	34.50	
12	KELFORD	D	115.00	34.50	
13	KENBRIDGE	D	115.00	12.50	
14	KILLAM	D	34.50	4.16	
15	KINDERTON	D	115.00	12.50	
16	KING GEORGE	D	34.50	13.20	
17	KINGS FORK	D	115.00	34.50	
18	KINGS FORK	D	115.00	13.20	
19	KINGS FORK	D	230.00	34.50	
20	KINGS MILL	D	115.00	34.50	
21	KINGS MILL	D	230.00	34.50	
22	KITTY HAWK	D	34.50	13.20	
23	KITTY HAWK	D	115.00	34.50	13.20
24	KITTY HAWK	T	230.00	115.00	13.20
25	KITTY HAWK	D	230.00	34.50	13.20
26	LABURNUM	D	34.50	4.16	
27	LADYSMITH	T	500.00	230.00	
28	LAFAYETTE	D	34.50	4.16	
29	LAKE GASTON	D	115.00	34.50	
30	LAKELAND	D	34.50	4.16	
31	LAKERIDGE	D	230.00	34.50	
32	LAKESIDE	D	115.00	13.20	
33	LAKESIDE	T	230.00	115.00	13.20
34	LAKESIDE	D	230.00	34.50	
35	LAKESIDE	D	230.00	13.20	
36	LANCASTER	D	115.00	34.50	
37	LANCASTER	D	115.00	13.20	
38	LANDSTOWN	T	230.00	115.00	13.20
39	LANDSTOWN	D	230.00	34.50	13.20
40	LANEXA	D	115.00	13.20	

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1	LANEXA	T	230.00	115.00	13.20
2	LAUREL AVE	D	34.50	4.16	
3	LAWRENCEVILLE	D	115.00	34.50	
4	LAWRENCEVILLE	D	115.00	12.50	
5	LEBANON	D	115.00	34.50	
6	LEBANON	D	115.00	13.20	
7	LEE D.P.	D	34.50	13.20	
8	LEESBURG	D	34.50	13.20	
9	LEMON	D	34.50	13.20	
10	LENOX	D	34.50	4.16	
11	LEXINGTON	T	230.00	115.00	13.20
12	LEXINGTON	T	500.00	230.00	
13	LIGHTFOOT	D	230.00	34.50	
14	LILLEY	D	34.50	12.50	
15	LIVINGSTON HEIGHT	D	34.50	13.20	
16	LOCKS	D	115.00	34.50	
17	LOCKS	D	115.00	13.20	
18	LOCKS	T	230.00	115.00	13.20
19	LONDON BRIDGE	D	115.00	34.50	13.20
20	LONG CREEK	D	115.00	34.50	13.20
21	LOUDOUN	T	230.00	115.00	13.20
22	LOUDOUN	T	500.00	230.00	
23	LOUDOUN	T	500.00	230.00	34.50
24	LOUISA	D	230.00	34.50	
25	LOVETTSVILLE	D	138.00	34.50	
26	LOW MOOR	T	230.00	138.00	13.20
27	LYNNHAVEN	D	34.50	13.20	
28	LYNNHAVEN	D	230.00	34.50	13.20
29	MADISON ST	D	13.20	4.16	
30	MAGRUDER	D	115.00	34.50	
31	MAGRUDER	D	115.00	13.20	
32	MANCHESTER	D	115.00	13.20	
33	MANTEO	D	34.50	13.20	
34	MARGARETTSVILLE	D	115.00	13.20	
35	MASSANUTTEN	D	34.50	12.50	
36	MATHEWS	D	34.50	13.20	
37	MCKENNEY	D	34.50	13.20	
38	MCLAUGHLIN	D	34.50	4.16	
39	MCLAUGHLIN	D	115.00	34.50	13.20
40	MCLEAN	D	34.50	13.20	

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1	MECHANICSVILLE	D	34.50	13.20	
2	MERCK 5	D	115.00	34.50	
3	MERCURY	D	115.00	23.00	
4	MERRIFIELD	D	34.50	13.20	
5	MERRY POINT	D	34.50	13.20	
6	METCALF	D	115.00	12.50	
7	MIDDLEBURG	D	115.00	34.50	
8	MIDDLETON D.P.	D	34.50	13.20	
9	MIDLOTHIAN 34.5	D	230.00	34.50	
10	MIDLOTHIAN 500	T	500.00	230.00	34.50
11	MINE ROAD	D	230.00	34.50	
12	MONTROSS	D	34.50	13.20	
13	MORRISVILLE	T	500.00	230.00	
14	MOUNT EAGLE	D	230.00	34.50	
15	MOUNT LAUREL	D	115.00	12.50	
16	MOUNTAIN ROAD	D	230.00	34.50	
17	MT JACKSON	D	115.00	34.50	
18	MT STORM (N.BRANCH)	T	500.00	115.00	13.20
19	MURPHY	D	115.00	34.50	
20	MYRTLE	D	115.00	34.50	
21	NAGS HEAD	D	115.00	34.50	
22	NASH	D	230.00	34.50	13.20
23	NEW MARKET	D	34.50	12.50	
24	NEWPORT NEWS #2	D	23.00	6.00	
25	NEWPORT NEWS #2	D	230.00	23.00	
26	NORTH ANNA 500/22	T	500.00	230.00	
27	NORTH POLE	D	230.00	34.50	
28	NORTH VA. BEACH	D	34.50	13.20	
29	NORTHEAST	D	115.00	13.20	
30	NORTHEAST	T	230.00	115.00	13.20
31	NORTHEAST	D	230.00	34.50	
32	NORTHERN NECK	D	115.00	34.50	
33	NORTHERN NECK	T	230.00	115.00	13.20
34	NORTHWEST	D	115.00	13.20	
35	NORTHWEST	T	230.00	115.00	13.20
36	NORTHWEST	D	230.00	34.50	
37	NORVIEW	D	34.50	4.16	
38	OAK GROVE	D	230.00	34.50	
39	OAK RIDGE	D	115.00	13.20	
40	OAKWOOD	D	115.00	34.50	13.20

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1	OAKWOOD	D	115.00	13.20	
2	OCCOQUAN	D	230.00	34.50	
3	OCEAN VIEW	D	34.50	4.16	
4	OFFICE HALL D.P.	D	34.50	13.20	
5	OKISKO	D	34.50	12.50	
6	OLD CHURCH	D	230.00	34.50	
7	ORANGE	D	115.00	34.50	
8	ORANGE	D	115.00	12.50	
9	OTTER RIVER	D	115.00	12.50	
10	OX	T	500.00	230.00	34.50
11	OX	T	500.00	230.00	
12	PAGAN	D	34.50	13.20	
13	PAMPLIN	D	34.50	23.00	
14	PAMPLIN	D	115.00	34.50	
15	PANTEGO	D	115.00	34.50	
16	PARMELE	D	115.00	12.50	
17	PEARSONS	D	230.00	34.50	
18	PENDER	D	230.00	34.50	
19	PENDLETON	D	115.00	34.50	13.20
20	PENINSULA	D	34.50	13.20	
21	PENINSULA	D	115.00	34.50	
22	PENINSULA	T	230.00	115.00	13.20
23	PENINSULA	D	230.00	34.50	
24	PENTAGON	T	230.00	69.00	
25	PERTH	D	115.00	34.50	
26	PHOEBUS	D	23.00	6.00	
27	PICKETT STREET	D	34.50	13.20	
28	PIMMIT	D	34.50	13.20	
29	PINE ST	D	34.50	11.00	
30	PLAZA	D	115.00	13.20	
31	PLAZA	T	230.00	115.00	13.20
32	PLAZA	D	230.00	34.50	
33	PLEASANT VIEW	D	230.00	34.50	
34	PLEASANT VIEW 500	T	500.00	230.00	
35	PLYMOUTH	D	115.00	34.50	
36	POE	D	34.50	13.20	
37	POE	T	230.00	115.00	34.50
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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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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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	SULLY	D	230.00	34.50	
10	SUNBURY	D	230.00	34.50	
11	SWINKS MILL	D	230.00	34.50	
12	TABB	D	230.00	34.50	
13	TAPPAHANNOCK	D	34.50	4.16	
14	TAR RIVER	D	115.00	12.50	
15	TARBORO	D	115.00	13.20	
16	TARBORO	T	230.00	115.00	13.20
17	TAUSSIG	D	115.00	34.50	13.20
18	TAUSSIG	D	115.00	13.20	
19	TEMPLE AVE.	D	115.00	34.50	
20	THALIA	D	34.50	13.20	
21	THALIA	D	230.00	34.50	13.20
22	THIRD STREET	D	23.00	12.50	
23	THIRD STREET	D	23.00	4.16	
24	THOLE ST	D	115.00	34.50	13.20
25	THOMPSONS CORNER	D	115.00	34.50	13.20
26	THOMPSONS CORNER	D	115.00	13.20	
27	THRASHER	D	230.00	34.50	13.20
28	TIMBERVILLE	D	115.00	12.50	
29	TITUSTOWN	D	34.50	4.16	
30	TOANO	D	115.00	34.50	
31	TRABUE	D	230.00	34.50	
32	TRAP	D	34.50	13.20	
33	TREGO	D	12.50	2.40	
34	TREGO	D	115.00	2.40	
35	TROWBRIDGE	T	230.00	115.00	13.20
36	TUNIS	D	115.00	34.50	
37	TURNER	D	115.00	34.50	
38	TURNER	D	230.00	34.50	
39	TWELFTH ST.	D	115.00	34.50	
40	TWELFTH ST.	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 2008/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	TWITTYS CREEK	D	34.50	12.50	
2	TWITTYS CREEK	D	115.00	34.50	
3	TYLER	D	115.00	13.20	
4	TYLER	D	230.00	34.50	
5	TYSONS	D	230.00	34.50	
6	UNIONVILLE DP	D	115.00	12.50	
7	VALLEY	T	500.00	230.00	
8	VAN DORN	D	230.00	34.50	
9	VERONA	D	115.00	23.00	
10	VICTORIA	D	115.00	12.50	
11	VIENNA	D	34.50	13.20	
12	VIRGINIA BEACH	D	115.00	34.50	13.20
13	VIRGINIA BEACH	D	115.00	13.20	
14	VIRGINIA BEACH	T	230.00	115.00	13.20
15	VIRGINIA HILLS	D	34.50	13.20	
16	VIRGINIA HILLS	D	230.00	34.50	
17	WAKEFIELD	D	13.20	4.16	
18	WAKEFIELD	D	115.00	34.50	
19	WAKEFIELD	D	115.00	13.20	
20	WALLER	D	230.00	34.50	
21	WALNEY	D	230.00	34.50	
22	WALNUT HILL	D	13.20	4.16	
23	WALTHALL	D	115.00	34.50	
24	WAN	D	115.00	34.50	
25	WAR	D	69.00	13.20	
26	WARRENTON	D	230.00	34.50	
27	WARSAW	D	34.50	13.20	
28	WARWICK	D	115.00	13.20	
29	WARWICK	D	230.00	34.50	
30	WATKINS CORNER	D	115.00	34.50	
31	WAVERLY	D	115.00	13.20	
32	WAYNE HILLS	D	23.00	12.50	
33	WAYNESBORO	D	115.00	23.00	
34	WELCO	D	115.00	34.50	
35	WELCO	D	115.00	12.50	
36	WESCOTT	D	34.50	13.20	
37	WEST LANDING	D	230.00	34.50	13.20
38	WEST STAUNTON	D	230.00	23.00	
39	WESTHAVEN	D	34.50	4.16	
40	WESTMINSTER	D	34.50	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 2008/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	WESTMORELAND	D	230.00	34.50	
2	WESTPOINT	D	115.00	34.50	
3	WEYERS CAVE	D	115.00	34.50	
4	WHEALTON	T	230.00	115.00	13.20
5	WHITAKERS	D	115.00	34.50	13.20
6	WHITEHALL DP	D	34.50	23.00	
7	WHITESHOP	D	34.50	13.20	
8	WHITESTONE	D	115.00	12.50	
9	WILLIAMSBURG	D	34.50	13.20	
10	WILLOUGHBY	D	13.20	4.16	
11	WILLOUGHBY	D	34.50	13.20	
12	WILLSTON	D	34.50	13.20	
13	WINCHESTER	D	34.50	13.20	
14	WINCHESTER	D	230.00	34.50	
15	WINFALL	D	115.00	34.50	
16	WINFALL	T	230.00	115.00	13.20
17	WINTERPOCK	D	230.00	34.50	
18	WOODBRIDGE	D	230.00	34.50	
19	WOODLAND	D	115.00	34.50	
20	WOODSTOCK	D	34.50	12.50	
21	WYTHE	D	23.00	6.00	
22	YADKIN	T	230.00	115.00	13.20
23	YADKIN	D	230.00	34.50	
24	YADKIN	T	500.00	230.00	34.50
25	YORKTOWN	T	230.00	115.00	13.20
26	Total Transmssn & Distribution		88860.10	24405.40	1750.88
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Appendix 3V – FERC FORM 427

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 2008/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
45	2					23
150	2					24
22	1					25
448	2					26
168	2					27
40	2					28
13	1					29
20	1					30
56	1					31
22	1					32
60	1	1				33
234	3					34
75	1					35
14	1					36
33	2					37
8	1					38
168	2					39
13	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 2008/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.
87	2					1
22	1					2
10	4					3
100	2					4
5	1					5
75	1					6
45	1					7
13	1					8
22	1					9
188	2					10
22	1					11
192	4	1				12
224	1					13
8	3					14
13	1					15
52	2					16
7	6	1				17
11	1					18
59	2					19
9	1					20
45	2					21
168	3					22
159	2					23
58	1					24
6	1					25
3	3					26
22	1					27
100	1					28
100	3					29
224	1					30
14	1					31
840	3	1				32
13	1					33
50	1					34
120	3					35
34	1					36
30	3	1				37
22	1					38
35	2					39
50	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 2008/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.
50	1					1
269	3	1				2
34	1					3
13	1					4
150	2					5
37	1					6
14	1					7
12	3					8
14	1					9
14	1					10
224	1					11
840	3	1				12
22	1					13
22	1					14
224	1					15
150	2					16
90	2					17
64	2					18
159	2					19
234	3					20
22	1					21
6	3					22
1680	6	1				23
20	1					24
22	1					25
250	1					26
840	3	2				27
168	1					28
56	3	1				29
6	1					30
5	1					31
159	2					32
22	1					33
5	1					34
15	1					35
3	1					36
45	2					37
34	1					38
24	2					39
25	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 2008/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.
90	2					1
40	1					2
67	2					3
6	3	1				4
120	2					5
5	1					6
22	1					7
14	1					8
50	1					9
5	1					10
67	1					11
598	4					12
65	2					13
22	1					14
5	1					15
95	2					16
42	2					17
100	2					18
45	2					19
6	1					20
90	2					21
14	1					22
4	1					23
6	1					24
22	1					25
96	2					26
673	3					27
560	2					28
1120	4					29
10	1					30
42	2					31
150	2					32
11	1					33
2	1					34
150	2					35
125	2					36
50	1					37
20	1					38
4	1					39
4	3	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 2008/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.
45	2					1
168	1					2
5	3					3
24	2					4
62	2					5
8	1					6
100	2					7
112	1					8
5	1					9
150	2					10
22	2					11
168	1					12
95	2					13
840	3					14
840	3	1				15
22	1					16
45	2					17
224	1					18
42	2					19
22	1					20
50	1					21
224	1					22
100	2					23
45	2					24
10	1					25
42	2					26
168	2					27
45	2					28
336	2					29
25	1					30
75	1					31
1680	6					32
45	2					33
13	1					34
40	2					35
22	1					36
9	1					37
20	1					38
5	1					39
168	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 2008/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.
45	2					1
75	1					2
42	2					3
168	1					4
84	1					5
393	4	1				6
118	2					7
159	2					8
8	1					9
5	1					10
22	1					11
22	1					12
159	2					13
234	3					14
7	2					15
11	1					16
22	1					17
392	2					18
30	3	1				19
13	1					20
5	1					21
50	1					22
34	1					23
67	2					24
5	1					25
196	2					26
150	2					27
448	2					28
50	1					29
84	1					30
9	3	1				31
9	1					32
13	1					33
22	1					34
224	1					35
14	1					36
8	1					37
9	1					38
159	2					39
448	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 2008/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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Total Capacity (In MVa) (k)	Line No.
6	3					1
20	1					2
50	1					3
34	1					4
22	1					5
168	3	1				6
56	1					7
56	2					8
224	1					9
224	6	1				10
45	2					11
45	1					12
10	2					13
74	2					14
45	2					15
167	2					16
75	1					17
14	1					18
50	1					19
22	1					20
112	1					21
28	2					22
9	3					23
50	1					24
20	1					25
4	1					26
22	1					27
45	1					28
80	2					29
392	5					30
22	1					31
42	2					32
45	1					33
6	1					34
134	3					35
5	3					36
150	2					37
14	1					38
336	2					39
11	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 2008/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
9	1					1
124	2					2
45	2					3
140	3					4
6	1					5
5	3					6
8	3					7
6	1					8
402	4					9
22	1					10
198	4					11
22	1					12
14	1					13
6	1					14
20	1					15
7	1					16
40	1					17
14	1					18
25	1					19
56	1					20
50	1					21
13	1					22
112	2					23
336	2	1				24
75	1					25
5	3					26
840	3	1				27
6	1					28
22	1					29
5	1					30
90	2					31
22	1					32
336	2					33
159	2					34
56	1					35
42	2					36
22	1					37
448	2					38
75	1					39
14	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 2008/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	1					1
9	2					2
20	1					3
13	1					4
22	1					5
22	1					6
7	1					7
33	2					8
13	1					9
5	1					10
336	2					11
672	6	1				12
150	2					13
14	1					14
22	1					15
56	1					16
42	2					17
336	2					18
56	1					19
45	2					20
336	2					21
1400	5	2				22
280	1					23
45	1					24
50	3	1				25
250	1	1				26
42	2					27
131	2					28
7	6	1				29
45	2					30
22	1					31
106	2					32
7	1					33
3	3					34
9	1					35
11	1					36
4	1					37
19	2					38
50	1					39
42	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 2008/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.
40	2					1
22	1					2
50	1					3
40	2					4
22	1					5
14	1					6
96	3					7
4	1					8
150	2					9
840	3					10
120	2					11
5	1					12
2220	6	1				13
50	1					14
22	1					15
125	2					16
22	1					17
100	3	1				18
45	2					19
22	1					20
113	6					21
50	1					22
3	1					23
5	3					24
224	2	1				25
672	6	1				26
50	1					27
22	2					28
42	2					29
224	1					30
224	2					31
45	2					32
168	3	1				33
22	1					34
168	1					35
168	2					36
5	1					37
50	1					38
45	2					39
168	3					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 2008/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.
42	2					1
150	2					2
9	2					3
6	1					4
5	1					5
50	1					6
22	1					7
22	1					8
45	2					9
840	3	1				10
840	3					11
13	1					12
8	3	1				13
42	2					14
13	1					15
13	1					16
75	1					17
252	3					18
112	2					19
11	1					20
45	2					21
224	1					22
45	1					23
504	3					24
45	2					25
5	3					26
13	1					27
9	1					28
17	2					29
42	2					30
168	1					31
56	1					32
225	3					33
840	3	1				34
45	2					35
67	2					36
168	1					37
168	1					38
150	2					39
34	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 2008/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
22	1					2
9	2					3
224	1					4
168	1					5
840	3	1				6
10	6					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
382	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	This Report Is:	Date of Report	Year/Period of Report
VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2008/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.
448	2					1
168	1					2
22	1					3
20	1					4
8	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
108	2					19
22	1					20
35	2					21
11	1					22
22	1					23
45	2					24
22	1					25
100	1					26
8	3					27
224	2					28
42	2					29
5	1					30
13	1					31
168	1					32
156	2					33
6	1					34
7	1					35
9	1					36
42	4					37
20	1					38
243	3					39
4	1					40

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VIRGINIA ELECTRIC AND POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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.
45	2					1
5	3					2
47	2					3
158	2					4
40	3	1				5
22	1					6
448	2					7
75	1					8
150	2					9
25	1					10
120	2					11
129	2					12
3	1					13
22	1					14
30	1					15
336	2					16
56	1					17
22	1					18
22	1					19
40	2					20
224	2					21
2	1					22
4	3					23
50	1					24
140	2					25
42	2					26
168	2					27
20	1					28
5	1					29
58	2					30
120	2					31
6	1					32
3	3					33
6	1					34
166	1					35
58	2					36
45	1					37
45	1					38
168	2					39
150	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 2008/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.
6	1					1
22	1					2
20	1					3
45	1					4
309	4					5
5	1					6
840	3	1				7
150	2					8
25	2					9
14	1					10
42	2					11
168	2					12
42	2					13
448	2					14
34	2					15
75	1					16
3	1					17
13	1					18
9	1					19
159	2					20
150	2					21
4	1					22
34	1					23
78	4	1				24
37	1					25
134	2					26
9	1					27
40	2					28
150	2					29
20	1					30
33	2					31
11	1					32
50	1					33
22	1					34
15	1					35
40	2					36
34	1					37
129	2					38
7	2					39
10	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 2008/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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Total Capacity (In MVa) (k)	Line No.
34	1					1
56	2					2
22	1					3
336	2					4
22	1					5
8	1					6
3	3					7
14	1					8
14	1					9
2	1					10
13	1					11
14	1					12
67	2					13
150	2					14
45	2					15
168	1					16
100	2					17
168	2					18
22	1					19
6	2					20
5	3					21
224	1					22
75	1					23
1680	6	1				24
224	1					25
68046	1071	45				26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

APPENDIX 3W – GENERATION INTERCONNECTION RELATED PROJECTS UNDER CONSTRUCTION

Line Terminal	PJM QUEUE	Line Voltage (kV)	Line Capacity (MVA)	Interconnection Cost (Million $)	Target Date	Location
Bremo – Bear Garden	P-38	230	1,047	5.1	Apr 2010	VA
Fredericksburg – Four River to Ladysmith CT	S-102	230	1,190	15.8	May 2010	VA
Hybrid Energy Center –Clinch River Double Circuit	Q-43 & S-100	138	600	34.8	Sep 2010	VA

CONFIDENTIAL

APPENDIX 3X – LIST OF TRANSMISSION LINES UNDER CONSTRUCTION

Line Terminal	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Garrisonville Double Circuit	230	[redacted]	Dec 2009	VA
Beaumeade – NIVO	230	[redacted]	Apr 2010	VA
Harrisonburg – Valley	230	[redacted]	May 2010	VA
Pleasant View – Hamilton	230	[redacted]	May 2010	VA
Line 2097 Re-conductor/ Uprate Ox – Idylwood	230	[redacted]	May 2010	VA
Ft. Belvoir Single Circuit	230	[redacted]	Oct 2010	VA
Elmont – Chickahominy	230	[redacted]	Nov 2010	VA
Chickahominy - Lanexa Sub	230	[redacted]	Nov 2010	VA
Uprate Pleasant View - Dickerson	230	[redacted]	May 2011	VA
Carson – Suffolk 500 kV Line, Suffolk Transformer and Suffolk – Thrasher 230 kV line	500/230	[redacted]	May 2011	VA
Meadowbrook – Loudoun Line	500	[redacted]	June 2011	VA

[redacted]

EXTRAORDINARILY SENSITIVE

APPENDIX 4A – DELIVERED FUEL DATA

Company Name: Virginia Electric and Power Company

Schedule 18

FUEL DATA[1]

	(ACTUAL)				(PROJECTED)														
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
I. Delivered Fuel Price ($/mmBtu)																			
a. Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
b. Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
c. Heavy Fuel Oil	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
d. Light Fuel Oil[2]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
e. Natural Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
f. Renewable[3]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
II. Primary Fuel Expenses (cents/kWh)																			
a. Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
b. Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
c. Heavy Fuel Oil	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
d. Light Fuel Oil[2]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
e. Natural Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
f. Renewable[3]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
g. NUG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
h. BTM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
i. Economy Energy Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
j. Purchases ($kW-Year)																			
Energy and Capacity Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

(1) Fuel data delivered fuel prices and fuel expenses reflect average delivered costs.

(2) Light fuel oil is used for reliability only at duel-fuel facilities.

(3) Per definition of § 56-576 of the Code of Virginia.

Extraordinarily Sensitive Information Redacted

EXTRAORDINARILY SENSITIVE

APPENDIX 5A – TABULAR RESULTS OF BUSBAR

Capacity Factor	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
CT 7FA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CC 7FA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CFB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IGCC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Solar Thermal	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
Solar PV	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
Wind- Onshore	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
Wind- Offshore	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-
Biomass	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hydro Power	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-

Extraordinarily Sensitive
Information Redacted

****EXTRAORDINARILY SENSITIVE****

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APPENDIX 5B – BUSBAR ASSUMPTIONS

Nominal [illegible]	Heat Rate [illegible]	Variable O&M [illegible]	Fixed O&M [illegible]	Service Life [illegible]	Overnight Costs [illegible]	Year 1 [illegible]
CT 7FA	[redacted]					
CC 7FA	[redacted]					
CFB	[redacted]					
PC	[redacted]					
IGCC	[redacted]					
Nuclear	[redacted]					
Solar Thermal	[redacted]					
Solar PV	[redacted]					
On-shore Wind	[redacted]					
Off-shore Wind	[redacted]					
Biomass	[redacted]					
Hydro Power	[redacted]					

APPENDIX 5C – DSM PROGRAM ENERGY SAVINGS (MWh)

Company Name: Virginia Electric & Power Company

Schedule 12

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

					(ACTUAL)						(PROJECTED)												
Program Type (1)	**Program Name**	**Date** (2)	**Life/ Duration** (3)	**Size MW** (4)	**2006**	**2007**	**2008**	**2009**	**2010**	**201120**	**12**	**2013**	**201420**	**15**	**2016**	**201720**	**18**	**2019**	**202020**	**21**	**2022**	**202320**	**24**
Peak Shaving	Air Conditioner Cycling Program (5)	2010	2024	415	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub-total				415	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 (5)	2010 (8)	2024	182	0	0	0	465	707	565	528	1,924	2,124	1,866	2,143	3,423	1,370	1,601	1,447	1,419	2,911	2,987	6,755
	Curtailment Service Program (5)	2010	2024	119	0	0	0	0	171	607	1,308	2,126	2,986	3,035	3,073	3,110	3,148	3,185	2,678	3,260	2,545	2,772	2,803
	Standby Generation (Pricing Tariff) (5)	2008	2013 (7)	0	2,690	2,961	2,573	2,960	2,664	1,579	789	296	0	0	0	0	0	0	0	0	0	0	0
	Curtailable Service & NC Schedule 6C (Pricing Tariff) (5)	2008	2010 (7)	0	740	740	740	740	740	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub-total				301	3,430	3,701	3,313	4,165	4,282	2,751	2,625	4,347	5,109	4,901	5,215	6,533	4,518	4,786	4,125	4,679	5,457	6,759	9,558
Energy Efficiency	Residential Lighting Program (6)	2010 (9)	2024	11	0	23,300	78,100	45,191	84,551	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912	123,912
	Low Income Program (6)	2010	2024	3	0	0	0	0	585	2,383	5,511	11,398	15,855	16,816	17,028	17,241	17,453	17,666	17,878	18,091	18,303	18,516	18,728
	ENERGY STAR® New Homes Program (6)	2010	2024	5	0	0	0	0	1,909	7,118	15,553	25,484	35,940	36,879	37,344	37,808	38,273	38,737	39,202	39,666	40,131	40,595	41,060
	Residential Heat Pump Tune-Up Program (6)	2010	2024	48	0	0	0	0	7,378	27,501	60,091	98,447	138,840	142,466	144,263	146,059	147,856	149,653	151,450	153,247	155,044	156,841	158,638
	Residential Refrigerator Turn-In Program (6)	2010	2024	4	0	0	0	0	778	2,900	6,336	10,381	14,640	15,016	15,199	15,382	15,565	15,748	15,931	16,114	16,296	16,479	16,662
	Heat Pump Upgrade Program (6)	2010	2024	24	0	0	0	0	3,369	12,559	27,443	44,961	63,409	65,158	66,076	66,995	67,914	68,833	69,752	70,671	71,590	72,509	73,428
	Commercial HVAC Upgrade Program (6)	2010	2024	17	0	0	0	0	1,963	7,133	15,511	25,298	35,556	36,137	36,579	37,021	37,464	37,906	38,348	38,791	39,233	39,676	40,118
	Voltage Conservation Program (6)	2009	2024	0	0	0	0	48,365	406,993	1,052,159	1,736,564	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759	2,282,759
	Commercial Lighting Program (6)	2010	2024	34	0	0	0	0	13,156	48,497	105,507	172,062	241,971	246,098	249,194	252,289	255,385	258,480	261,576	264,671	267,767	270,863	273,958
	In-Home Energy Display Program (6)	2011	2024	13	0	0	0	0	0	1,788	6,575	14,323	23,475	33,200	34,058	34,937	35,373	35,808	36,244	36,679	37,114	37,550	37,985
	Residential Duct Testing & Sealing Program (6)	2011	2024	7	0	0	0	0	0	587	2,160	4,676	7,604	10,674	10,811	10,947	11,083	11,219	11,356	11,492	11,628	11,765	11,901
	Residential Energy Audit Program (6)	2011	2024	3	0	0	0	0	0	921	2,428	4,183	6,006	7,844	7,943	8,042	8,141	8,241	8,340	8,439	8,538	8,637	8,736
	Commercial Duct Testing & Sealing Program (6)	2011	2024	20	0	0	0	0	0	4,149	15,225	32,827	53,399	74,951	76,061	76,845	77,792	78,739	79,858	80,633	81,580	82,528	83,654
	Commercial Energy Audit Program (6)	2011	2024	18	0	0	0	0	0	4,919	18,172	39,422	64,207	90,301	91,807	92,953	94,098	95,244	96,390	97,536	98,681	99,827	100,973
	Commercial HVAC Tune-Up Program (6)	2011	2024	20	0	0	0	0	0	1,812	6,232	13,290	21,513	30,131	30,523	30,892	31,273	31,654	32,046	32,415	32,796	33,177	33,570
Sub-total				225	0	23,300	78,100	93,556	520,682	1,298,339	2,147,221	2,903,423	3,129,086	3,212,341	3,223,556	3,234,083	3,244,341	3,254,599	3,265,041	3,275,116	3,285,374	3,295,632	3,306,082
Total Demand Side Management				940	3,430	27,001	81,413	97,721	524,964	1,301,090	2,149,846	2,907,769	3,134,195	3,217,241	3,228,771	3,240,616	3,248,859	3,259,385	3,269,166	3,279,795	3,290,830	3,301,391	3,315,640

(1) List each program within the 3 major categories of energy efficiency, energy efficiency - demand response, and peak shaving. Additionally, a description of each program is available in Section 3.4.2, Section 3.4.5, and Section 5.2.3.

(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 2024.

(5) Reductions available during on-peak hours.

(6) Reductions available during all hours.

(7)The Company makes these projections on the assumption that customers on these tariffs will drop off or switch.

(8)This program was an outgrowth of the Company's current Distributed Generation/Load Curtailment Pilot.

(9)This program was an extension of the Company's current CFL price reduction program that began in October of 2007.

APPENDIX 5D – STANDARD DSM TEST DESCRIPTIONS

Participant Test

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.

Utility Cost Test

The Utility Cost test compares the cost to the utility to implement a program to the cost that are 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.

Total Resource Cost Test

The Total Resource Cost ("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.

Ratepayer Impact Measure Test

The Ratepayer Impact Measure ("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 ratepayers 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 ratepayers, including non-participants.

Societal Test

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 ratepayers. The Company does not currently use the Societal test to determine the benefits of DSM programs, as the Virginia SCC's Rules Governing Cost/Benefit Measures for Demand-Side Management Programs, 20 VAC 5-304-10 *et seq.*, do not require an analysis of the Societal Test when evaluating 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 – FUTURE PROGRAMS NON-COINCIDENTAL PEAK SAVINGS (kW) (System-Level)

Programs	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
In-Home Energy Display Program	0	0	610	2,250	4,910	8,050	11,380	11,670	11,980	12,120	12,270	12,420	12,570	12,720	12,870	13,020
Residential Duct Testing & Sealing Program	0	0	400	1,490	3,220	5,240	7,350	7,440	7,540	7,630	7,730	7,820	7,910	8,010	8,100	8,200
Residential Energy Audit Program	0	0	340	1,140	2,140	3,070	4,010	4,060	4,110	4,160	4,210	4,260	4,310	4,360	4,410	4,460
Commercial Duct Testing & Sealing Program	0	0	1,140	4,180	9,040	14,700	20,640	20,900	21,160	21,420	21,680	21,940	22,200	22,460	22,720	22,990
Commercial Energy Audit Program	0	0	1,090	4,020	8,720	14,200	19,970	20,300	20,550	20,810	21,060	21,310	21,570	21,820	22,070	22,330
Commercial HVAC Tune-Up Program	0	0	1,570	5,400	11,510	18,640	26,100	26,430	26,760	27,090	27,420	27,750	28,080	28,410	28,740	29,070

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

Programs	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
In-Home Energy Display Program	0	0	610	2,240	4,880	8,000	11,310	11,610	11,900	12,050	12,200	12,350	12,500	12,650	12,790	12,940
Residential Duct Testing & Sealing Program	0	0	360	1,340	2,900	4,710	6,610	6,690	6,780	6,860	6,950	7,030	7,120	7,200	7,280	7,370
Residential Energy Audit Program	0	0	270	680	1,330	1,900	2,490	2,520	2,550	2,580	2,610	2,640	2,670	2,710	2,740	2,770
Commercial Duct Testing & Sealing Program	0	0	970	3,560	7,680	12,500	17,540	17,760	17,990	18,210	18,430	18,650	18,870	19,090	19,320	19,540
Commercial Energy Audit Program	0	0	870	3,210	6,960	11,340	15,950	16,210	16,420	16,620	16,820	17,020	17,230	17,430	17,630	17,830
Commercial HVAC Tune-Up Program	0	0	1,060	3,630	7,750	12,550	17,580	17,800	18,030	18,250	18,470	18,690	18,910	19,140	19,360	19,580
Totals	0	0	4,140	14,660	31,500	51,000	71,480	72,590	73,670	74,570	75,480	76,380	77,300	78,220	79,120	80,030

APPENDIX 5G – FUTURE PROGRAMS ENERGYSAVINGS
(MWh) (System-Level)

Programs	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
In-Home Energy Display Program	0	0	1,788	6,575	14,323	23,475	33,200	34,058	34,937	35,373	35,808	36,244	36,679	37,114	37,550	37,985
Residential Duct Testing & Sealing Program	0	0	587	2,160	4,676	7,604	10,674	10,811	10,947	11,083	11,219	11,356	11,492	11,628	11,765	11,901
Residential Energy Audit Program	0	0	921	2,428	4,183	6,006	7,844	7,943	8,042	8,141	8,241	8,340	8,439	8,538	8,637	8,736
Commercial Duct Testing & Sealing Program	0	0	4,149	15,225	32,827	53,399	74,951	76,061	76,845	77,792	78,739	79,858	80,633	81,580	82,528	83,654
Commercial Energy Audit Program	0	0	4,919	18,172	39,422	64,207	90,301	91,807	92,953	94,098	95,244	96,390	97,536	98,681	99,827	100,973
Commercial HVAC Tune-Up Program	0	0	1,812	6,232	13,290	21,513	30,131	30,523	30,892	31,273	31,654	32,046	32,415	32,796	33,177	33,570
Totals	0	0	14,176	50,792	108,720	176,204	247,101	251,203	254,617	257,761	260,905	264,233	267,194	270,339	273,483	276,819

APPENDIX 5H – FUTURE PROGRAM PENETRATION
(System-Level)

Programs	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
In-Home Energy Display Program	0	0	1,690	6,216	13,540	22,192	31,387	32,197	33,029	33,440	33,852	34,264	34,675	35,087	35,498	35,910
Residential Duct Testing & Sealing Program	0	0	1,329	4,890	10,586	17,217	24,167	24,476	24,784	25,093	25,402	25,710	26,019	26,327	26,636	26,945
Residential Energy Audit Program	0	0	3,413	8,992	15,494	22,244	29,052	29,419	29,786	30,153	30,520	30,887	31,254	31,622	31,989	32,356
Commercial Duct Testing & Sealing Program	0	0	136	499	1,078	1,754	2,462	2,493	2,524	2,555	2,587	2,618	2,649	2,680	2,711	2,742
Commercial Energy Audit Program	0	0	166	615	1,333	2,171	3,054	3,104	3,143	3,182	3,221	3,259	3,298	3,337	3,376	3,414
Commercial HVAC Tune-Up Program	0	0	336	1,156	2,467	3,993	5,592	5,663	5,733	5,804	5,875	5,945	6,016	6,086	6,157	6,228

APPENDIX 5I – 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 2014	VA

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APPENDIX 5J – LIST OF PLANNED TRANSMISSION LINES

Line Terminal	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Remington CT – Gainesville	230	[redacted]	Apr 2012	VA
Hayes – Yorktown	230		May 2012	VA
Arlington- Radnor Heights-Ballston UG Line	230		May 2012	VA
Uprate 500 kV Line # 555 Dooms – Lexington	500		May 2012	VA
Chancellor 2nd 500-115 kV Transformer	500/115		May 2013	VA
Uprate Line #575 Ladysmith – North Anna	500		June 2013	VA
Harrisonburg – Merck	230		May 2014	VA
Midlothian – Chesterfield	230		May 2016	VA
Clark – Idylwood	230		May 2016	VA
Bristers – Possum Point	500		May 2016	VA
Skiffs Creek 500 -230 kV Switching Substation	500/230		May 2016	VA
Bristers – Garrisonville	230		June 2016	VA
Hopewell – Poe	230		June 2017	VA
Rebuild Line #551 Mt Storm – Doubs	500		June 2018	VA
Uprate Line #566 Lexington – Cloverdale	500		Nov 2018	VA

APPENDIX 6A – RENEWABLE RESOURCES

Company Name: Virginia Electric and Power Company **Schedule 11**

RENEWABLE RESOURCE GENERATION (GWh)

Resource Type (1)	Unit Name	C.O.D.(2)	Build/ (3) Purchase	Life/ (4) Duration	Size MW (5)	2006 (ACTUAL)	2007 (ACTUAL)	2008 (ACTUAL)	2009	2010 (PROJECTED)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Hydro																								
	Cushaw Hydro Unit	Apr-05	Build	60	2	19	15	13	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	Gaston Hydro	Feb-63	Build	60	225	240	225	157	296	296	296	296	296	296	29 6	296	296	296	296	29 6	296	296	296	296
	North Anna Hydro	Dec-87	Build	60	1	3	2	0.5	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Roanoke Rapids Hydro	Sep-55	Build	60	99	248	230	166	298	298	298	298	298	298	29 8	298	298	298	298	29 8	298	298	298	298
	BTM - Brasfield Dam	-	Purchase	-	3	11	9	9	22	22	22	22	18	0	0	0	0	0	0	0	0	0	0	0
	BTM - Columbia Mills	-	Purchase	-	0.3	2	1	2	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0
	BTM - Schoolfield Dam	-	Purchase	-	3	16	15	12	22	22	22	22	22	22	20	0	0	0	0	0	0	0	0	0
Sub-total					332	540	498	359	658	658	658	658	654	636	3 2	611	611	611	611	31 1	611	611	611	611
Biomass																								
	Altavista		Build	60	6	-	-	-	32	36	30	26	13	13	13	12	10	9	9	9	10	9	8	7
	Multitrade (Company-owned)	Jun-94	Build	60	83	470	438	488	411	573	539	447	581	625	630	635	635	631	628	664	663	665	663	668
	Virginia City (6)		Build	60	585	-	-	-	-	-	-	169	197	193	178	221	249	276	287	360	352	362	350	357
	BIOMASS UNIT:2016:297	2016	Build	60	50	-	-	-	-	-	-	-	-	-	-	241	407	408	403	400	398	399	397	402
	BIOMASS UNIT:2017:295	2017	Build	60	50	-	-	-	-	-	-	-	-	-	-	-	241	409	405	403	400	400	401	403
	BTM - Alexandria MSW	-	Purchase	-	20	184	184	181	171	171	171	171	171	171	17 1	171	171	171	171	17 1	171	171	15	0
	Ogden-Martin Fairfax	-	Purchase	-	92	617	611	589	680	752	747	701	731	732	32 0	0	0	0	0	0	0	0	0	0
Sub-total					886	1,271	1,233	1,258	1,294	1,532	1,487	1,515	1,692	1,734	1,312	1,281	1,712	1,904	1,903	2,007	1,994	2,007	1,835	1,837
Wind																								
	NEW ON-SHORE WIND :2017:100	2017	Build	25	5	-	-	-	-	-	-	-	-	-	-	-	105	105	105	106	105	105	105	106
	NEW ON-SHORE WIND :2017:97	2017	Build	25	6	-	-	-	-	-	-	-	-	-	-	-	132	132	132	132	132	132	132	132
	NEW ON-SHORE WIND :2017:98	2017	Build	25	6	-	-	-	-	-	-	-	-	-	-	-	132	132	132	132	132	132	132	132
	NEW ON-SHORE WIND :2017:99	2017	Build	25	8	-	-	-	-	-	-	-	-	-	-	-	158	158	158	158	158	158	158	158
Sub-total					26	0	0	0	0	0	0	0	0	0	0	0	526	526	526	52 8	526	526	526	528
Other																								
	BTM - Richmond Electric Generation	-	Purchase	-	3	9	8	9	25	25	25	25	17	0	0	0	0	0	0	0	0	0	0	0
Sub-total					3	9	8	9	25	25	25	25	17	0	0	0	0	0	0	0	0	0	0	0
Total Renewables					1,247	1,820	1,739	1,626	1,977	2,215	2,170	2,198	2,364	2,370	1,944	1,892	2,850	3,041	3,041	3,146	3,132	3,144	2,972	2,976

(1) Per definition of § 56-576 of the code of Virginia.

(2) Commercial operation date.

(3) Company built or purchased.

(4) Expected life of facility or duration of purchase contract in years.

(5) Net dependable capability.

(6) Duel 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
BIOMASS UNIT:2016:297	N/A	Base	Renewable	N/A	50	50
BIOMASS UNIT:2017:295	N/A	Base	Renewable	N/A	50	50
Combined Cycle 7FA :2017:296	N/A	Intermediate	Natural Gas-CC	N/A	640	662
Combined Cycle 7FA :2021:291	N/A	Intermediate	Natural Gas-CC	N/A	640	662
Combined Cycle 7FA :2022:290	N/A	Intermediate	Natural Gas-CC	N/A	640	662
Combined Cycle 7FA :2023:289	N/A	Intermediate	Natural Gas-CC	N/A	640	662
Combined Cycle 7FA :2024:288	N/A	Intermediate	Natural Gas-CC	N/A	640	662
NEW On-shore WIND :2017:100	N/A	Intermittent	Renewable	N/A	5	40
NEW ON-SHORE WIND :2017:97	N/A	Intermittent	Renewable	N/A	6	50
NEW ON-SHORE WIND :2017:98	N/A	Intermittent	Renewable	N/A	6	50
NEW ON-SHORE WIND :2017:99	N/A	Intermittent	Renewable	N/A	8	60
Simple Cycle 7FA:2016:298	N/A	Peak	Natural Gas-CT	N/A	340	395
Simple Cycle 7FA:2016:299	N/A	Peak	Natural Gas-CT	N/A	340	395
Simple Cycle 7FA:2019:293	N/A	Peak	Natural Gas-CT	N/A	340	395
Simple Cycle 7FA:2020:292	N/A	Peak	Natural Gas-CT	N/A	340	395

(1) Commercial Online Date

APPENDIX 6C – CAPACITY POSITION

Company Name: Virginia Electric and Power Company

Schedule 16

UTILITY CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)															
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Existing Capacity																			
Conventional	13,489	13,607	14,055	14,257	14,320	14,485	14,475	14,559	14,487	14,423	14,376	14,376	14,297	14,297	14,297	14,297	14,297	14,297	14,297
Renewable	2,063	2,116	2,155	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212
Total Existing Capacity	15,552	15,723	16,210	16,469	16,531	16,697	16,687	16,771	16,699	16,635	16,588	16,588	16,509	16,509	16,509	16,509	16,509	16,509	16,509
Planned Under Construction																			
Conventional				0	0	590	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175
Renewable				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Construction Capacity				0	0	590	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175
Planned Under Development																			
Conventional				0	0	0	0	0	0	640	640	640	1,913	1,913	1,913	1,913	1,913	1,913	1,913
Renewable				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Development Capacity				0	0	0	0	0	0	640	640	640	1,913	1,913	1,913	1,913	1,913	1,913	1,913
Potential (Expected) New Capacity																			
Conventional				0	0	0	0	0	0	0	680	1,320	1,320	1,660	2,000	2,640	3,280	3,920	4,560
Renewable				0	0	0	0	0	0	0	50	126	126	126	126	126	126	126	126
Total Potential New Capacity				0	0	0	0	0	0	0	730	1,446	1,446	1,786	2,126	2,766	3,406	4,046	4,686
Other (NUG)	1,966	1,966	1,749	1,776	1,776	1,776	1,776	1,776	1,776	1,232	1,232	427	434	267	222	0	0	0	0
Other (BTM)[1]	110	110	111	158	158	158	155	152	147	143	141	141	141	141	141	141	141	121	121
Unforced Availability	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
Net Generation Capacity	17,628	17,799	18,070	18,403	18,466	19,221	19,793	19,874	19,797	19,826	20,506	20,417	21,618	21,791	22,086	22,504	23,144	23,764	24,404
Existing DSM Reductions																			
Demand Response																			
Conservation/Efficiency																			
Total Existing DSM Reductions[2]	21	23	22	22	21	19	17	16	15	15	15	15	15	15	15	15	15	15	15
Proposed & Future DSM Reductions																			
Demand Response				0	0	0	91	273	369	435	495	551	595	627	654	677	692	705	716
Energy Efficiency[3]				0	0	0	31	106	179	202	205	208	210	213	215	218	220	222	225
Total DSM Reductions				0	0	0	121	379	548	637	700	759	805	840	869	894	912	928	941
Total Demand-Side Reductions	21	23	22	22	21	19	138	395	563	652	715	774	820	855	884	909	927	943	956
Net Generation & Demand-side	17,628	17,799	18,070	18,403	18,466	19,221	19,915	20,254	20,345	20,463	21,206	21,175	22,424	22,631	22,956	23,398	24,056	24,692	25,345
Capacity Sale[4]				0	0	0	0	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200
Capacity Purchase[4]				1,963	1,779	1,355	1,578	504	1,008	1,172	851	1,299	353	597	904	930	721	525	214
Capacity Adjustment[4]				-541	-347	-225	-263	0	0	0	0	0	0	0	0	0	0	0	0
Capacity Requirement or PJM Capacity Obligation	19,063	19,435	18,826	19,826	19,898	20,351	21,199	20,451	20,974	21,233	21,653	22,067	22,367	22,815	23,445	23,911	24,357	24,794	25,135
Net Utility Capacity Position	0	0	0	1,963	1,779	1,355	1,578	304	808	972	651	1,099	153	397	704	730	521	325	14

(1) The Company does not carry reserves on BTM
(2) Existing DSM programs are included in the load forecast
(3) Efficiency programs are not part of the Company's calculation of capacity
(4) Capacity Sale, Purchase & Adjustments are used for modeling purposes

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APPENDIX 6D – CONSTRUCTION FORECAST

Company Name: Virginia Electric and Power Company

Schedule 17

CONSTRUCTION FORECAST (Thousand Dollars)

(PROJECTED)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
I. New Traditional Generating Facilities																
a. Construction Expenditure (Not AFUDC)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
b. AFUDC[1]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
c. Annual Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
d. Cumulative Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
II. New Renewable Generating Facilities																
a. Construction Expenditure (Not AFUDC)	0	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]	0	0	0	0	0	0	0
b. AFUDC[1]	0	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]	0	0	0	0	0	0	0
c. Annual Total	0	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]	0	0	0	0	0	0	0
d. Cumulative Total	0	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
III. Other Facilities																
a. Transmission[2]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
b. Distribution[2]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
c. Energy Efficiency & Peak Shaving	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
d. Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
e. AFUDC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
f. Annual Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
g. Cumulative Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IV. Total Construction Expenditures																
a. Annual	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
b. Cumulative	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
V. % of Funds for Total Construction Provided from External Financing	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) Does not include Construction Work in Progress.

(2) 2014 through 2024 projected based on CPI growth.

Confidential Information Redacted

APPENDIX 6E – CAPACITY POSITION

Company Name: Virginia Electric and Power Company

Schedule 4

POWER SUPPLY DATA

	(ACTUAL)			(PROJECTED)															
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
I. Capability (MW)																			
1. Summer																			
a. Installed Net Dependable Capacity [1]	15,552	15,723	16,210	16,469	16,531	17,287	17,862	17,946	17,874	18,450	19,133	19,849	21,043	21,383	21,723	22,363	23,003	23,643	24,283
b. Positive Interchange Commitments [2]	2,076	2,076	1,860	1,935	1,935	1,935	1,932	1,929	1,923	1,376	1,373	568	575	408	363	141	141	121	121
c. Capability in Cold Reserve/ Reserve Shutdown Status [1]	63	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Demand Response - Existing	21	23	22	22	21	19	17	16	15	15	15	15	15	15	15	15	15	15	15
e. Demand Response - Proposed				0	0	0	91	273	369	435	495	551	595	627	654	677	692	705	716
f. Capacity Sale				0	0	0	0	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200
g. Capacity Purchase				1,963	1,779	1,355	1,578	504	1,008	1,172	851	1,299	353	597	904	930	721	525	214
h. Capacity Adjustment				-541	-347	-225	-263	0	0	0	0	0	0	0	0	0	0	0	0
i. Total Net Summer Capability	17,712	17,822	18,092	19,826	19,898	20,351	21,199	20,451	20,974	21,233	21,653	22,067	22,367	22,815	23,445	23,911	24,357	24,794	25,135
2. Winter																			
a. Installed Net Dependable Capacity [1]				19,866	20,061	20,777	21,475	21,705	21,705	22,362	22,898	23,708	24,449	24,844	25,155	25,795	26,346	27,008	27,670
b. Positive Interchange Commitments [2]				1,963	1,779	1,355	1,578	504	1,008	1,172	851	1,299	353	597	904	930	721	525	214
c. Capability in Cold Reserve/ Reserve Shutdown Status [1]	63	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Demand-Side and Response				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Total Net Winter Capability				21,830	21,840	22,132	23,053	22,209	22,713	23,535	23,750	25,008	24,802	25,441	26,060	26,725	27,067	27,532	27,884

(1) Net Seasonable Capability.

(2) To include firm commitments for the receipt of specified blocks of power (i.e., unit power, limited term, diversity exchange, cogeneration, small power production, etc.)