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**PUBLIC VERSION**

May 1, 2017

VIA HAND DELIVERY

Joel H. Peck, Clerk
Document Control Center
State Corporation Commission
1300 E. Main Street, Tyler Bldg., 1st Fl.
Richmond, VA 23219

*Commonwealth of Virginia ex rel. State Corporation Commission,*
*In re: Virginia Electric and Power Company's Integrated Resource Plan*
*filing pursuant to Va. Code § 56-597 et seq.*
Case No. PUR-2017-00051

Dear Mr. Peck:

Please find enclosed for filing in the above-captioned proceeding, an unbound original and one (1) bound copy of the Public version of the Integrated Resource Plan for 2017 ("2017 Plan") of Virginia Electric and Power Company filed pursuant to § 56-597 *et seq*. of the Code of Virginia as amended by Senate Bill 1349 ("SB 1349"), the Commission's December 23, 2008 Order Establishing Guidelines for Developing Integrated Resource Plans issued in Case No. PUE-2008-00099 ("Order Establishing Guidelines"), and the Integrated Resource Planning guidelines ("Guidelines") established therein. As required by the Commission's December 30, 2015 Final Order issued in Case No. PUE-2015-00035 ("2015 Plan Order"), a reference index identifying sections of the 2017 Plan that comply with the Guidelines and the bulleted requirements of recent Plan Orders is enclosed herein.

The Company is contemporaneously filing under seal with the Commission under separate cover a Confidential version of the 2017 Plan. A Motion for Entry of a Protective Order is also being filed under separate cover in this proceeding.

Also enclosed in this filing is a cover letter from Robert M. Blue, President and CEO of Virginia Electric and Power Company, which provides an overview of the Company's 2017 Plan.

Pursuant to Section E of the Guidelines, also enclosed herein is a copy of the Company's proposed notice in this proceeding. In accordance with that same section of the Guidelines, the Company is sending under separate cover to the Commission Staff, Division of Energy Regulation, a hard copy of the Confidential version of the 2017 Plan and an electronic disk containing the Confidential version of the 2017 Plan results presented in tabular format using an Excel spreadsheet format.

Finally, as directed by Ordering Paragraph (3) of the Order Establishing Guidelines, the third enactment clauses in Chapters 476 and 603 of the 2008 Virginia Acts of Assembly, and SB 1349, the Company is providing a copy of the **Public** version of its 2017 Plan to members of the General Assembly under separate cover and as specified therein.

Please do not hesitate to contact me if you have any questions in regard to this filing.

Very truly yours,

Vishwa B. Link

Enclosures

cc: William H. Chambliss, Esq. (cover letter only)
C. Meade Browder, Jr., Esq.
Lisa S. Booth, Esq. (cover letter only)

**Robert M Blue**
President and Chief Executive Officer
Dominion Virginia Power

*An operating segment of*
**Dominion Resources, Inc.**
120 Tredegar Street, Richmond, VA 23219

dom.com



May 1, 2017

Joel H. Peck, Clerk
Virginia State Corporation Commission
C/o Document Control Center
1300 East Main Street
Richmond, VA 23219

Re: Case No. PUR-2017-00051

Dear Mr. Peck:

Virginia Electric and Power Company ("Dominion" or the "Company") is pleased to submit to the Virginia State Corporation Commission ("Commission) its 2017 Integrated Resource Plan (the "2017 Plan" or "Plan") for the planning period of 2018-2032. The Plan is submitted in accordance with §56-599 of the Code of Virginia. Simultaneously, the Plan is being filed as an update in North Carolina with the North Carolina Utilities Commission ("NCUC"). This filing is in accordance with §62-2 of the North Carolina General Statutes and Rule R8-60 of the Rules and Regulations of the NCUC.

As did its 2015 and 2016 predecessors, the 2017 Plan recognizes the extreme uncertainty facing the electric utility industry today, particularly regarding regulation of power station carbon dioxide ("$CO_2$") emissions. The U.S. Supreme Court's February 2016 stay of implementation of the federal Clean Power Plan ("CPP") issued by the U.S. Environmental Protection Agency ("EPA") remains in place pending resolution of a federal court appeal. In March 2017, President Donald J. Trump also ordered the EPA to begin the process of reviewing the CPP and determining "as soon as practicable" whether to revise the final rule or withdraw it. On April 4, 2017, in response to the executive order, the EPA issued a notice that it was initiating a review of the CPP, which could lead to proceedings to revise or rescind the rule. Also, a work group created by an executive order from Virginia Governor Terry McAuliffe continues to work toward its May 31, 2017 deadline of developing recommendations for state action to reduce $CO_2$ emissions to levels similar to those mandated by the CPP.

Facing this high level of uncertainty, the 2017 Plan, as did the 2015 and 2016 Plans, presents no recommended path, or "Preferred Plan," for meeting our customers' future energy needs. Instead, it presents a range of options representing plausible paths forward under a variety of scenarios, ranging from the absence of carbon dioxide regulations – a situation considered unlikely by the Company – to full implementation of the strictest compliance scenarios incorporated in the CPP. These "Alternative Plans" are discussed in detail in the 2017 Plan.

**Major Focuses of the 2017 Plan**

Despite this uncertainty, the 2017 Plan reflects several major judgments and decisions made by the Company regarding the future of its generating fleet and the best interests of its customers. These judgments are reflected in the Alternative Plans presented by the Company.

- Regardless of the final disposition of the CPP, the Company believes some form of carbon regulation is virtually assured in the future.

- The Company is committed to making the transition to a generation portfolio with lower emission rates. This transition has been underway for some time as the Company has recently added lower-emissions natural gas units and facilities powered by renewable energy to its fleet. Dominion's 2017 Plan will continue moving the Company forward to ensure its customers and the entire Commonwealth of Virginia as well as the Company's North Carolina service territory can efficiently move toward a cleaner energy future while maintaining diverse, reliable and affordable sources of electricity.

- Solar energy will play a major role in meeting the energy needs of Dominion customers in the future. Solar technology is now cost-competitive with other more traditional forms of generation. The installed cost of utility-scale solar photovoltaic (PV) generation has declined by approximately 24 percent since the issuance of the 2016 Plan one year ago. As a result, large amounts of solar PV resources are included in each of the Alternative Plans because of their optimal economics in addition to their zero-emissions characteristics. In fact, all of the Alternative Plans call for the addition of at least 3,200 megawatts (MW) of additional solar capacity to the Company's generation fleet by 2032 and at least 5,280 MW of additional solar capacity by the conclusion of a longer, 25-year study period concluding in 2042. This solar development builds on a solid foundation. The Company has already added 56 MW of solar capacity to its fleet in Virginia, and has also built or is developing other solar facilities serving the needs of specific governmental and large business customers. Additionally, the Company anticipates signing by 2022 long-term contracts with 990 MW of solar facilities built by non-utility generators in Virginia and northeastern North Carolina.

- Other forms of low or no emissions generation will also be important to assuring that Dominion's customers have the energy they need in future decades. For example, all of the Alternative Plans call for the Company to seek additional 20-year license extensions for its existing nuclear units in Virginia, including Surry 1 and 2 and North Anna 1 and 2. Additionally, all of the plans continue the Company's assessment of zero-emissions wind technology through construction of the Virginia Offshore Wind Technology Assessment Project (VOWTAP), a test bed facility off the Virginia coast using two wind turbines with a combined capacity of 12 MW. The Alternative Plans call for VOWTAP to be operational by 2021. Dominion will also work to preserve other options to ensure it transitions smoothly to a cleaner energy future, such as continued assessment of offshore wind, energy storage mechanisms including pumped storage, and new nuclear generation. Additionally, Dominion will continue to evaluate options for cost-effective demand-side management programs, including initiatives designed to reduce peak demand and lower overall energy usage. Consumer education programs sponsored by the Company also will play a significant role in helping customers conserve energy and use it wisely.

- Finally, on the technical front, the Company recognizes that it must take steps toward modernizing the electric grid at both the transmission and distribution levels to develop a more dynamic system better equipped to respond to the growth of utility-scale solar facilities, as well as the expected proliferation of smaller, widely dispersed solar generating units. These trends are also discussed in the 2017 Plan.

**Alternative Plans – Paths Forward Examined by the Company**

While there is a high level of uncertainty surrounding the CPP and carbon regulation in general, the Company believes it is important that its planning process continue to include a thorough evaluation of options for complying with the federal CPP rule. In fact, this Commission, in its Final Order on the 2016 Plan, directed that the Company's 2017 Plan include scenarios modeled on compliance options offered to the states by the federal rule. Additionally, Dominion considers that the CPP compliance options provide a reasonable proxy for the analysis of likely future regulation of carbon emissions, regardless of the ultimate fate of current federal rule.

Based on these considerations and recent directives from this Commission, the Company presents a series of eight Alternative Plans. They are based primarily on differing assumptions for power station $CO_2$ emissions regulations, ranging from the unlikely prospect of no regulation to full implementation of the CPP's strictest compliance scenarios.

The plans are described briefly below in two sections. One deals with a plan that fails to comply with the CPP. The second describes seven plans that comply with differing scenarios offered to the states by the CPP for meeting its carbon reduction mandates. Consistent with directives in the Commission's Final Order on the 2016 Plan, four of the CPP-compliant Alternative Plans were modeled on the assumption that the Company would achieve compliance on its own, with no need to purchase either emission rate credits (ERCs) or carbon allowances. Also following the Commission's directives, three of the CPP-compliant plans were modeled on the assumption that the Company would use ERC or allowance purchases to assist with compliance. Dominion expects markets for ERCs or allowances to mature and favors compliance strategies that include trading in these instruments.

**Non-Compliant Plan**

- Plan A: No CPP. The Alternative Plan is based on a future without any new limits on power station carbon dioxide emissions, a future the Company considers unlikely.[1] It does, however, comply with the Commission's directive in its 2016 Final Order for development of a least-cost base plan not compliant with the CPP.

**CPP-Compliant Plans**

- Plan $B^{NT}$: Intensity-Based Dual Rate (No Trading). The plan is based on a CPP compliance scenario limiting generating unit carbon intensity (the average amount of $CO_2$ released for each megawatt-hour [MWH] of electricity produced). Separate standards are set for fossil fuel-powered steam generating units (1,305 lbs of $CO_2$/MWH by 2030) and for combined-cycle

[1] The Company's new integrated combined cycle facilities have stringent $CO_2$ limits which will continue to apply.

natural gas-powered units (771 lbs of $CO_2$/MWH by 2030). The plan assumes that the Company will not acquire ERCs from the market to help comply with the standards.

- Plan $C^{T}$: Intensity-Based Dual Rate (Trading). The plan also follows the intensity-based CPP scenario described in Plan $B^{NT}$ but assumes the Company will use the ERC market to help achieve compliance.

- Plan $D^{NT}$: Mass-Based Existing Units (No Trading). This Alternative Plan is based on the CPP compliance scenario that limits total annual $CO_2$ emissions from a state's existing fossil fuel-powered generation fleet. In Virginia's case, the annual limit is approximately 27.43 million short tons of $CO_2$ by 2030. The plan assumes that the company will not procure carbon allowances from the market to help with compliance.

- Plan $E^{T}$: Mass-Based Existing Units (Trading). The plan is also based on the CPP compliance pathway that limits total annual state $CO_2$ emissions from existing fossil-fueled generators. It assumes Dominion will use the carbon allowance markets to assist with compliance.

- Plan $F^{NT}$: Mass-Based All Units (No Trading). This Alternative Plan meets another possible CPP compliance scenario by capping total annual $CO_2$ emissions both from a state's existing fossil fuel-powered fleet and new units that may be added in the future. In Virginia's case, the annual limit by 2030 is approximately 27.83 million short tons of $CO_2$. The plan assumes Dominion will not use the carbon allowance markets to assist with compliance.

- Plan $G^{T}$: Mass-Based All Units (Trading). The plan is also designed to meet the CPP compliance requirements capping total annual $CO_2$ emissions from all of a state's fossil fuel-powered units, including those now in existence and those built in the future. The plan assumes Dominion will use the carbon allowance markets to achieve compliance.

- Plan $H^{NT}$: New Nuclear (No Trading). The plan also meets the CPP compliance requirements capping total annual $CO_2$ emissions from all of a state's fossil fuel-powered units, including those now in existence and those built in the future. Additionally, it assumes the company will not use the carbon allowance markets to assist in compliance. Plan $H^{NT}$: New Nuclear is the only Alternative Plan that includes construction of a third nuclear reactor at the company's North Anna Power Station. North Anna 3 would add 1,452 MW of base load, zero-emission capacity to the company's generating fleet. Plan $H^{NT}$ calls for the unit to be operational by 2030. (It must be emphasized that Dominion has made no final decision on construction of the unit and will not do so until the reactor receives a combined operating license [COL] from the U.S. Nuclear Regulatory Commission.)

**Common Elements of Alternative Plans**

While the eight Alternative Plans differ in many respects, they also have significant common elements, with a strong focus on maintaining a diversified generating fleet with lower emission rates through the use of renewable resources, natural gas and nuclear energy. All capacity numbers refer to nameplate ratings, the theoretical maximum output of the unit under optimal conditions. Major common elements through the 15-year planning period of 2018-2032 include:

- Development of solar PV capacity totaling approximately 3,200 MW by 2032.
- The addition of 990 MW of solar PV capacity owned by non-utility generators (NUGs) in northeastern North Carolina and Virginia under long-term contracts with the Company, with the NUG capacity to be added by 2022.
- Development of the 12 MW Virginia Offshore Wind Technology Advancement Project (VOWTAP), testing two wind turbines at a site off the coast of Virginia Beach, as early as 2021.
- Completion of Greensville County Power Station, a natural gas-powered combined cycle facility capable of producing approximately 1,585 MW and now under construction in Greensville County, Va., by 2019. (The Company expects construction to be completed in late 2018.)
- The addition of approximately 1,374 MW of new natural gas-powered combustion turbine (CT) units by 2032.
- Implementation of demand-side management programs, both already approved by and currently proposed to this Commission, capable of reducing system peak demand by approximately 426 MW and annual energy consumption by 1,221 gigawatt-hours (GWH) by 2032. This represents a 29 percent increase in peak demand reduction and a 62 percent increase in annual energy savings over the levels proposed in the 2016 Plan.
- Additional 20-year relicensing for all four company-owned nuclear units in Virginia, Surry 1 and 2 and North Anna 1 and 2, with the Surry units relicensed by 2033 and 2034 and the North Anna units relicensed by 2038 and 2040, respectively.

**Additional Generation Retirements in CPP-Compliant Alternative Plans**

The seven CPP-compliant Alternative Plans call for potential additional closures of fossil-fueled generating units.

- All seven plans include the potential closure of Yorktown Unit 3, a 790-MW oil-fired facility, by 2022, and coal-fired Chesterfield Units 3 and 4, with a combined capacity of 261 MW, also by 2022.

- Plans $F^{NT}$: Mass-Based All Units and $H^{NT}$: New Nuclear also include the potential retirement of coal-fired Mecklenburg Units 1 and 2, with a combined capacity of 138 MW, and Clover Units 1 and 2, with a combined capacity of 439 MW, by 2025.

**Additional Generation in Alternative Plans**

The eight Alternative Plans, including the one non-compliant and seven CPP-compliant plans, also call for specific generation additions during the 15-year planning period beyond those common to all of the scenarios. All of the generation additions specific to individual Alternative Plans utilize zero or low emissions technology, including natural gas, solar, and nuclear energy.

For example, four of the plans (Plan $B^{NT}$: Intensity-Based Dual Rate, $C^{T}$: Intensity-Based Dual Rate, $D^{NT}$: Mass-Based Existing Units and $E^{T}$: Mass-Based Existing Units) call for an additional natural gas-powered combined cycle facility, with a capacity of 1,591 MW, by 2025.

Other generation additions, beyond those included in all eight Alternative Plans, are described below.

- Plan A: No CPP calls for an additional 458 MW of CT capacity and 160 MW of solar capacity.
- Plan $B^{NT}$: Intensity-Based Dual Rate includes an additional 160 MW of solar capacity.
- Plan $C^{T}$: Intensity-Based Dual Rate models an additional 80 MW of solar capacity.
- Plan $D^{NT}$: Mass-Based Existing Units includes an additional 80 MW of solar capacity.
- Plan $E^{T}$: Mass-Based Existing Units calls for an additional 80 MW of solar capacity.
- Plan $F^{NT}$: Mass-Based All Units models an additional 2,290 MW of CT capacity and 80 MW of solar capacity.
- Plan $G^{T}$: Mass-Based All Units calls for an additional 1,832 MW of CT capacity and 160 MW of solar capacity.
- Plan $H^{NT}$: New Nuclear models an additional 916 MW of CT capacity and 160 MW of solar capacity. Significantly, the plan also includes a new nuclear unit, North Anna 3, adding 1,452 MW of new nuclear capacity to the Company's generating fleet by 2030.

**Cost and Rate Impact of Alternative Plans**

The Company's analysis indicates that all seven CPP-compliant plans would require significant investments by Dominion and impose significant costs on it and its customers, leading to higher customer rates. However, the costs and rate impacts of the CPP-compliant scenarios vary significantly.

The net present value (NPV) in 2017 dollars of the additional costs imposed by the CPP-compliant Alternative Plans, above those that would otherwise be incurred in the absence of carbon regulation, ranges from a low of $2.3 billion for Plan $C^{T}$: Intensity-Based Dual Rate to a high of $14.8 billion for Plan $H^{NT}$: New Nuclear. These incremental costs would be incurred during the period from 2018 through 2042.

Similarly, the rate impacts of the CPP-compliant Alternative Plans vary widely. Plan $C^{T}$: Intensity-Based Dual Rate has the lowest rate impact, increasing the typical monthly residential bill for 1,000 kWh of usage by 1.6 percent by 2030. Customers would see the largest bill increase through implementation of $H^{NT}$: New Nuclear. Under that scenario, the typical monthly residential bill would be 22.0 percent higher by 2030 than it would be in the absence of carbon regulation. The other five CPP-compliant Alternative Plans are projected to have rate impacts ranging from 1.8 percent to 4.0 percent by 2030.

**Transitioning to a Lower Emissions Future**

The 2017 Plan recognizes that the Company and the Commonwealth of Virginia are making the transition to a lower emissions future, including lower rates of carbon emissions. Amid these challenges, Dominion remains committed to its longstanding goals of environmentally responsible operations; maintenance of a diverse, balanced generation fleet avoiding over-reliance on a single fuel type; and providing reliable and affordable energy for its customers. These goals guided development of the 2017 Plan and will guide its development of integrated resource plans in the future.

Sincerely,

Robert M. Blue

NOTICE TO THE PUBLIC
OF A PROCEEDING TO CONSIDER
THE INTEGRATED RESOURCE PLAN
OF VIRGINIA ELECTRIC AND POWER COMPANY
UNDER § 56-597 OF THE CODE OF VIRGINIA
CASE NO. PUR-2017-00051

On May 1, 2017, Virginia Electric and Power Company ("Company"), submitted to the State Corporation Commission ("Commission") its Integrated Resource Plan ("IRP") pursuant to § 56-597 *et seq*. of the Code of Virginia ("Va. Code") as amended by Senate Bill 1349. An IRP, as defined by Va. Code § 56-597, is a document developed by an electric utility that provides a forecast of its load obligations and a plan to meet those obligations by supply-side and demand-side resources over the ensuing 15 years to promote reasonable prices, reliable service, energy independence, and environmental responsibility. Pursuant to Va. Code § 56-599 E, the Commission will analyze the Company's IRP and make a determination as to whether the Company's IRP is reasonable and in the public interest.

The Commission entered an Order for Notice and Comment ("Notice Order") that, among other things, directed the Company to provide notice to the public and offered interested persons an opportunity to comment and/or request a hearing on the Company's IRP filing.

A copy of the public version of the Company's IRP may be obtained, at no charge, by requesting it in writing from Jennifer D. Valaika, Esquire, McGuireWoods LLP, Gateway Plaza, 800 East Canal Street, Richmond, Virginia 23219. Copies of the public version of the IRP and related documents are also available for review in the Commission's Document Control Center, located on the first floor of the Tyler Building, 1300 East Main Street, Richmond, Virginia, between the hours of 8:15 a.m. and 5:00 p.m., Monday through Friday, excluding holidays. Interested persons may also download unofficial copies from the Commission's website: http://www.scc.virginia.gov/case.

On or before [date], interested persons may file written comments concerning the issues in this case with Joel H. Peck, Clerk, State Corporation Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218-2118. Interested persons desiring to submit comments electronically may do so by following the instructions found on the Commission's website: http://www.scc.virginia.gov/case. Comments shall refer to Case No. PUR-2017-00051.

On or before [date], interested persons may request that the Commission convene a hearing on the Company's IRP by filing a request for a hearing at the address set forth above. Requests for hearing must include: (i) a precise statement of the filing party's interest in the proceeding; (ii) a statement of the specific action sought to the extent then known; (iii) a statement of the legal basis for such action; and (iv) a precise statement why a hearing should be conducted in this matter.

Any interested person may participate as a respondent in this proceeding by filing on or before [date], an original and fifteen (15) copies of a notice of participation with the Clerk of the Commission at the address set forth above and shall simultaneously serve a copy of the notice of participation on counsel to the Company at the address set forth above. Pursuant to 5 VAC 5-20-80 of the Commission's Rules of Practice and Procedure, any notice of participation shall set forth: (i) a precise statement of the interest of the respondent; (ii) a statement of the specific action sought to the extent known; and (iii) the factual and legal basis for the action. Interested persons shall refer in all filed papers to Case No. PUR-2017-00051.

VIRGINIA ELECTRIC AND POWER COMPANY

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# Virginia Electric and Power Company
## 2017 Integrated Resource Plan – Reference Index

| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **2016 Plan Final Order** | | |
| **Case No. PUE-2016-00049 Final Order at 7** | **2017 Integrated Resource Plan** Reference Index | Dominion shall continue to comply with all requirements directed in prior IRP orders, including the requirement to include an index that identifies the specific location(s) within the IRP that complies with each such requirement. |
| **Case No. PUE-2016-00049 Final Order at 4-5** | **Section 1.3.2** SCC's 2016 Plan Final Order<br>**Section 1.4** 2017 Plan<br>**Section 6.4** Alternative Plans | We direct the Company to model and present scenarios … updating the data and assumptions as appropriate … [including], at a minimum, the following:<br>(1) Least-cost base plan (non-compliant with the CPP); |
| **Case No. PUE-2016-00049 Final Order at 4-5** | **Section 1.3.2** SCC's 2016 Plan Final Order<br>**Section 1.4** 2017 Plan<br>**Section 6.4** Alternative Plans | (2) Least-cost CPP-compliant intensity-based plan (regional and island approaches"); |
| **Case No. PUE-2016-00049 Final Order at 4-5** | **Section 1.3.2** SCC's 2016 Plan Final Order<br>**Section 1.4** 2017 Plan<br>**Section 6.4** Alternative Plans | (3) Least-cost CPP-compliant mass-based plan (regional and island approaches); |

Virginia Electric and Power Company
2017 Integrated Resource Plan – Reference Index

| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **Case No. PUE-2016-00049 Final Order at 4-5** | **Section 1.3.2** SCC's 2016 Plan Final Order<br>**Section 1.4** 2017 Plan<br>**Section 6.4** Alternative Plans | (4) Federal implementation plan; and |
| **Case No. PUE-2016-00049 Final Order at 4-5** | **Section 1.3.2** SCC's 2016 Plan Final Order<br>**Section 1.4** 2017 Plan<br>**Section 6.4** Alternative Plans | (5) Company-preferred plan, if any. |
| **Case No. PUE-2016-00049 Final Order at 5** | **Section 1.4** 2017 Plan<br>**Section 6.4** Alternative Plans | Dominion shall run these scenarios without capping the amount of third-party, energy and capacity market purchases or sales that the model would select to achieve a least-cost plan for the compliance and non-compliance scenarios. |
| **Case No. PUE-2016-00049 Final Order at 6** | As applicable | Until the uncertainty regarding CPP compliance is resolved and the details of a final SIP are known, including the role and amount of demand side management ("DSM") such a plan may require, it serves no purpose to conduct additional studies as part of upcoming IRPs that will continue to present hypothetical compliance plans. |
| **Case No. PUE-2016-00049 Final Order at 6** | As applicable | In the future, however, should a SIP specifically require DSM as part of compliance, at that time it will be appropriate to consider, along with all other compliance options, whether and to what extent various forms of alternative rate design could play a role in CPP compliance. |

Virginia Electric and Power Company
2017 Integrated Resource Plan – Reference Index

| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **2015 Plan Final Order** | | |
| **Case No. PUE-2015-00035 Final Order at 18** | **2017 Integrated Resource Plan** Reference Index | Finally, in future IRPs, Dominion shall include an index that identifies the specific location(s) within the IRP filing that complies with each bulleted requirement in this Final Order. |
| **Case No. PUE-2015-00035 Final Order at 9** | **2016 Integrated Resource Plan** Legal Memorandum<br>**Section 5.3** Generation Under Development | • Pursuant to what authority does Dominion believe that the costs it plans to incur for North Anna 3 before receiving a CPCN or RAC are recoverable from its customers? |
| **Case No. PUE-2015-00035 Final Order at 9** | **Section 5.3** Generation Under Development | • Is there a dollar limit on how much Dominion intends to spend on North Anna 3 before applying to this Commission for a CPCN and/or RAC? |
| **Case No. PUE-2015-00035 Final Order at 9** | **Section 5.3** Generation Under Development | • Without a guarantee of cost recovery, what is the limit on the amount of costs Dominion can incur, prior to obtaining a CPCN, without negatively affecting (i) the Company's fiscal soundness, and (ii) the Company's cost of capital? |
| **Case No. PUE-2015-00035 Final Order at 9** | **Section 5.3** Generation Under Development | • Why are expenditures continuing to be made? Solely for NRC approval? Why in the Company's view is it necessary to spend at projected rates, specifically when the Company has not decided to proceed and does not have Commission approval? |
| **Case No. PUE-2015-00035 Final Order at 10** | **Section 6.9** Miscellaneous Analysis | • update the timing analysis that it performed in this proceeding, and, in that timing analysis, quantify the trade-off between operating cost risks that may be increased and the cost savings that may be realized by delaying the construction of North Anna 3 |
| **Case No. PUE-2015-00035 Final Order at 10** | **Section 5.2** Levelized Busbar Costs<br>**Chapter 7** Short-Term Action Plan | • continue to investigate the feasibility and cost of extending the operating licenses for Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2 |

Virginia Electric and Power Company
2017 Integrated Resource Plan – Reference Index

| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **Case No. PUE-2015-00035 Final Order at 10-11** | **Section 5.2**<br>Levelized Busbar Costs<br><br>**Section 6.4**<br>Alternative Plans<br><br>**Appendix 3Y**<br>Letter of Intent for Nuclear License Extension for Surry Power Station Units 1 and 2<br><br>**Appendix 5F**<br>Cost Estimates for Nuclear License Extensions | • prepare a report for its upcoming IRP filing on the status of the license extension process, which shall include, but is not limited to, a discussion of communications between the Company and the United States Nuclear Regulatory Commission concerning the operating license extensions, updated cost estimates of the license renewals, a timetable showing key dates in the renewal process, and the results of Strategist® model runs to determine the net present value of utility costs where it is assumed that the operating licenses for all of the nuclear units are extended for 20 years |
| **Case No. PUE-2015-00035 Final Order at 11** | **Section 6.10**<br>2017 Plan | • model and provide an optimal (least-cost, basecase) plan for meeting the electricity needs of its service territory over the planning time frame |
| **Case No. PUE-2015-00035 Final Order at 11** | **2016 Integrated Resource Plan**<br>Legal Memorandum<br><br>**Section 6.4**<br>Alternative Plans<br><br>**Section 6.5**<br>Alternative Plans NPV Comparison<br><br>**Section 6.6**<br>Rate Impact Analysis<br><br>**Section 6.7**<br>Comprehensive Risk Analysis | • model and provide multiple plans that are each compliant with the Clean Power Plan, under both a mass-based approach and an intensity-based approach (including a least-cost compliant plan where the Strategist® model is allowed to choose the least-cost path given the emission constraints imposed by the Clean Power Plan); provide a detailed analysis of the impact of each plan in terms of all costs, including, but not limited to, capital, programmatic and financing; provide the impact of each plan on the electricity rates paid by Dominion's customers; and identify whether any aspect of any plan would require changes to existing Virginia law |

Virginia Electric and Power Company
2017 Integrated Resource Plan – Reference Index

| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **Case No. PUE-2015-00035 Final Order at 12** | **2016 Integrated Resource Plan**<br>Legal Memorandum<br><br>**Section 1.1**<br>Integrated Resource Plan Overview<br><br>**Section 1.3.1**<br>EPA's Clean Power Plan<br><br>**Section 1.3.2**<br>SCC's 2016 Plan Final Order<br><br>**Section 3.1.3**<br>Changes to Existing Generation<br><br>**Section 6.4**<br>Alternative Plans<br><br>**Section 6.7**<br>Comprehensive Risk Analysis | • analyze the final federal implementation plan, should the final federal implementation plan be published before May 1, 2016, or, if no final federal implementation plan has been published by this time, analyze the proposed federal implementation plan; provide a detailed analysis of the impact of the proposed or final plan in terms of all costs, including, but not limited to, capital, programmatic and financing; provide the impact of the proposed or final plan on the electricity rates paid by Dominion's customers; and identify whether any aspect of the proposed or final plan would require changes to existing Virginia law |
| **Case No. PUE-2015-00035 Final Order at 12** | **Section 3.1.3**<br>Changes to Existing Generation<br><br>**2016 Integrated Resource Plan**<br>Chapter 3<br>Section 3.1.3 | • provide a detailed description of leakage and the treatment of new units under differing compliance regimes |

Virginia Electric and Power Company
2017 Integrated Resource Plan – Reference Index

| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **Case No. PUE-2015-00035 Final Order at 12** | **Section 1.3.1**<br>EPA's Clean Power Plan<br><br>**Section 3.1.3**<br>Changes to Existing Generation<br><br>**Section 6.4**<br>Alternative Plans<br><br>**Section 6.10**<br>2017 Plan<br><br>**2016 Integrated Resource Plan**<br>Chapter 3<br>Section 3.1.3 | • examine the differing impacts of the Virginia-specific targets versus source subcategory specific rates under an intensity-based approach |
| **Case No. PUE-2015-00035 Final Order at 12** | **Section 3.1.3**<br>Changes to Existing Generation<br><br>**2016 Integrated Resource Plan**<br>Chapter 3<br>Section 3.1.3 | • examine the potential for early action emission rate credits and allowances that may be available for qualified renewable energy or demand-side energy efficiency measures |
| **Case No. PUE-2015-00035 Final Order at 12** | **Section 5.3**<br>Generation Under Development<br><br>**Section 6.4**<br>Alternative Plans<br><br>**Section 6.5**<br>Alternative Plans NPV Comparison | • analyze the treatment of a new nuclear unit under differing compliance approaches, including an assessment of the cost implications of a nuclear-based plan and the optimal timing of adding a nuclear unit under both an intensity-based approach and a mass-based approach |

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| **Case No. PUE-2015-00035 Final Order at 12** | **Section 1.4**<br>2017 Plan<br>**Section 3.1.3**<br>Changes to Existing Generation<br>**Section 4.4**<br>Commodity Price Assumptions<br>**Section 6.4**<br>Alternative Plans<br>**2016 Integrated Resource Plan**<br>Chapter 3<br>Section 3.1.3 | • as recommended by MAREC, examine the cost benefits of trading emissions allowances or emissions reductions credits, or acquiring renewable resources from inside and outside of Virginia |
| **Case No. PUE-2015-00035 Final Order at 13** | **Section 1.3.1**<br>EPA's Clean Power Plan<br>**Section 6.4**<br>Alternative Plans<br>**Section 6.10**<br>2017 Plan<br>**Chapter 7**<br>Short-Term Action Plan | • identify a long-term plan recommendation that reflects the EPA's final version of the Clean Power Plan |
| **Case No. PUE-2015-00035 Final Order at 13** | **Section 6.7**<br>Comprehensive Risk Analysis. | • continue to evaluate the risks associated with plans that the Company prepares |
| **Case No. PUE-2015-00035 Final Order at 13** | **Section 6.7**<br>Comprehensive Risk Analysis | • include discount rate risk as a criterion in the Company's risk analysis |
| **Case No. PUE-2015-00035 Final Order at 13** | **Section 6.7**<br>Comprehensive Risk Analysis<br>**Section 6.7.4**<br>Identification of Levels of Natural Gas Generation with Excessive Cost Risks | • specifically identify the levels of natural gas-fired generation where operating cost risks may become excessive or provide a detailed explanation as to why such a calculation cannot be made |

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| **Case No. PUE-2015-00035 Final Order at 13** | **Section 6.7** Comprehensive Risk Analysis<br>**Section 6.7.5** Operating Cost Risk Assessment | • analyze ways to mitigate operating cost risk associated with natural gas-fired generation, including, but not limited to, long-term supply contracts that lock in a stable price, long-term investment in gas reserves, securing long-term firm transportation, and on-site liquefied natural gas storage |
| **Case No. PUE-2015-00035 Final Order at 14** | **2016 Plan Final Order** N/A | • analyze the cost of mitigating risks associated with the share of natural-gas fired generation that is equivalent to the amount the Company expects would be displaced by the construction and operation of North Anna 3 |
| **Case No. PUE-2015-00035 Final Order at 15** | **2016 Plan Final Order** N/A | • continue to report on a residential rate design alternative that includes a flat winter generation rate, an increased inclining summer generation rate, and no changes to distribution rates |
| **Case No. PUE-2015-00035 Final Order at 15** | **2016 Plan Final Order** N/A | • continue to report on a residential rate design alternative that includes an increased differential between summer and winter rates for residential customers above the 800 kilowatt-hour block and no change to distribution rates |
| **Case No. PUE-2015-00035 Final Order at 15** | **2016 Plan Final Order** N/A | • continue to report on alternative GS-1 rate designs |
| **Case No. PUE-2015-00035 Final Order at 15** | **2016 Plan Final Order** N/A | • expand its analysis of alternative rate designs to other non-residential rate classes |
| **Case No. PUE-2015-00035 Final Order at 15** | **2016 Plan Final Order** N/A | • investigate an alternative rate design for RACs that includes a summer rate with an inclining block rate component combined with a flat winter rate |
| **Case No. PUE-2015-00035 Final Order at 15** | **2016 Plan Final Order** N/A | • analyze whether maintaining the existing rate structure is in the best interests of residential customers |

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| **Case No. PUE-2015-00035 Final Order at 15** | **2016 Plan Final Order**<br>N/A | • evaluate options for variable pricing models that could incent customers to shift consumption away from peak times to reduce costs and emissions |
| **Case No. PUE-2015-00035 Final Order at 16** | **Section 5.1.4**<br>Assessment of Supply-Side Resource Alternatives | • include a more detailed analysis of market alternatives, especially third-party purchases that may provide long-term price stability, and includes, but is not limited to, wind and solar resources |
| **Case No. PUE-2015-00035 Final Order at 16** | **Section 5.1**<br>Future Supply-Side Resources | • examine wind and solar purchases at prices (including prices available through long-term purchase power agreements) and in quantities that are being seen in the market at the time the Company prepares its IRP filings |
| **Case No. PUE-2015-00035 Final Order at 16** | **Section 3.1.2**<br>Existing Renewable Resources<br><br>**Section 5.1**<br>Future Supply-Side Resources | • provide a comparison of the cost of purchasing power from wind and solar resources from third-party vendors versus self-build options, including off-shore and on-shore wind, with this comparison including information from a variety of third-party vendors |
| **Case No. PUE-2015-00035 Final Order at 17** | **Section 5.1.2.1**<br>Solar PV Integration Cost | • develop a plan for identifying, quantifying, and mitigating cost and integration issues associated with greater reliance on solar photovoltaic generation |
| **2013 Plan Final Order** | | |
| **Case No. PUE-2013-00088 Final Order at 4** | **Section 6.7**<br>Comprehensive Risk Analysis<br><br>**Section 6.7.4**<br>Identification of Levels of Natural Gas Generation with Excessive Cost Risks | In its 2015 IRP filing, Dominion Virginia Power shall include an analysis of the trade-off between operating cost risk and project development cost risk associated with the Base Plan and the Fuel Diversity Plan. In developing this analysis, the Company shall identify the levels of natural gas-fired generation where operating cost risks may become excessive. |
| **Case No. PUE-2013-00088 Final Order at 5** | **Section 5.3**<br>Generation Under Development<br><br>**Section 6.5**<br>Alternative Plans NPV Comparison<br><br>**Section 6.9**<br>Miscellaneous Analysis | As several parties have noted, there are significant costs associated with the construction of a new nuclear facility. Given these significant costs, the Commission directs the Company to conduct an optimum timing analysis for North Anna 3 in its next IRP. This timing analysis should examine the impact of delaying the construction of North Anna 3 from the 2025 date the Company proposed in this IRP and should take into consideration the trade-off between operating cost risks that may be increased and the cost savings that may be realized by delaying the construction of North Anna 3. |

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| **Case No. PUE-2013-00088 Final Order at 5** | **Section 5.2**<br>Levelized Busbar Costs | Further, several parties have suggested that given the high costs of constructing a nuclear unit today, Dominion Virginia Power should investigate the feasibility and cost of extending the lives and operating licenses of the four existing nuclear units that are currently scheduled to be retired. The Commission directs the Company to include the results of such an investigation in its next IRP filing. As part of this investigation, the Company should compare the cost of constructing North Anna 3 to the cost of renewing the licenses of the four existing nuclear units, and should also compare the cost of retiring the four existing nuclear units to the cost of renewing the licenses for those units. |
| **Case No. PUE-2013-00088 Final Order at 5-6** | **Section 5.2**<br>Levelized Busbar Costs<br>**Appendix 3Y**<br>Letter of Intent for Nuclear License Extension for Surry Power Station Units 1 and 2 | The Company shall also provide status updates on any discussions it engages in with the United States Nuclear Regulatory Commission on a possible extension for the operating licenses for Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2, in its future IRP and IRP update filings. |
| **Case No. PUE-2013-00088 Final Order at 6** | **2016 Plan Final Order**<br>N/A | In its next IRP, Dominion Virginia Power shall continue to model and refine alternative rate design proposals, including alternative rate designs for customer classes in addition to the residential class. The Company shall also specifically examine the appropriateness of its residential winter declining block rate and present other potential rate design alternatives for the residential winter declining block rate. Finally, the Company shall analyze how alternative rate designs may impact demand and the Company's resource planning process. |
| **Case No. PUE-2013-00088 Final Order at 6-7** | **Section 5.1**<br>Future Supply-Side Resources<br>**Section 5.1.4**<br>Assessment of Supply-Side Resource Alternatives | While the Company may submit its preferred models and plans, we find that future IRP filings should not be so limited. Accordingly, Dominion Virginia Power's future IRP filings shall include a more detailed analysis of market alterative, especially third-party purchases that may provide long-term price stability. The Company's analysis of market alterative shall also include, but not be limited to, wind and solar resources, and this analysis should examine wind and solar purchases at prices (including prices available through long-term purchase power agreements) and in quantities that are being seen in the market at the time the Company prepares its IRP filings. In particular, Dominion shall provide a comparison of the cost of purchasing power from wind and solar resources from third-party vendors versus self-build options, including off-shore and on-shore wind. |

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| **Case No. PUE-2013-00088 Final Order at 7-8** | **Section 1.1**<br>Integrated Resource Plan Overview<br><br>**Section 1.3.1**<br>EPA's Clean Power Plan<br><br>**Section 6.4**<br>Alternative Plans<br><br>**Section 6.65**<br>Alternative Plans NPV Comparison<br><br>**Section 6.6**<br>Rate Impact Analysis<br><br>**Section 6.10**<br>2017 Plan | Given the potential future impacts of the proposed rule, the Commission finds that Dominion Virginia Power's future planning should take into account the requirements of the Clean Power Plan as necessary. |
| **Case No. PUE-2013-00088 Final Order at 8** | **Section 5.5.4**<br>Assessment of Overall Demand-Side Options | Next, the Commission finds that in future IRP filings, Dominion Virginia Power should compare the cost of its demand-side management proposals to the cost of new generating resource alternatives. Specifically, Staff has suggested that it would be informative to compare the Company's expected demand-side management costs per megawatt hour saved to its expected supply side costs per megawatt hour. We agree and direct the Company to evaluate demand-side management alternatives using this methodology. |
| **Case No. PUE-2013-00088 Final Order at 8** | **Section 6.1**<br>IRP Process<br><br>**Section 6.7**<br>Comprehensive Risk Analysis | Further, we direct Dominion Virginia Power to include a broad band of prices used in future forecasting assumptions, such as forecasting assumptions related to fuel prices, effluent prices, market prices and renewable energy credit costs, in order to continue to set reasonable boundaries around the modeling assumptions, and to continue to refine the specific assumptions and sensitivity adjustments of its modeling data in future IRP filings. |
| **2011 Plan Final Order** | | |
| **Case No. PUE-2011-00092 Final Order at 3-4** | **Section 5.2**<br>Levelized Busbar Costs<br><br>**Section 6.5**<br>Alternative Plans NPV Comparison | Thus, Dominion's future IRP filings also shall include models where North Anna 3 (if included in subsequent IRPs) competes against other resource options. |

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| **Case No. PUE-2011-00092 Final Order at 4** | **Section 5.1** Future Supply-Side Resources<br>**Section 5.2** Levelized Busbar Costs<br>**Appendix 5A** Tabular Results of Busbar<br>**Appendix 5B** Busbar Assumptions | A decision to prohibit the construction of any type of power plant, coal-fired or otherwise, in Virginia is a policy decision for the General Assembly. Accordingly, Dominion's future IRP filings shall include consideration of non-carbon capture sequestration capable coal resources (as new construction and through the purchase of existing facilities) relative to other technologies included in its busbar screening process. In sum, both coal and nuclear options should be considered against the full panoply of conventional, renewable, and other resource alternatives. |
| **Case No. PUE-2011-00092 Final Order at 4-5** | **Section 5.1** Future Supply-Side Resources<br>**Section 5.1.4** Assessment of Supply-Side Resource Alternatives | We also believe that Dominion should adequately consider third-party market alternatives as capacity resources. We do not conclude, however, that Dominion should be required to perform independent market tests as part of the IRP because, as noted by Consumer Counsel, "the IRP is a planning document, and is not a commitment to pursue any particular investment." Rather, we find that market alternatives are appropriate for consideration in cases where Dominion seeks a certificate of public convenience and necessity for specific investments. Indeed, the Commission has previously explained that third-party alternatives, including purchased power and new construction, "would likely be relevant evidence in an application proceeding [for a self-build option for new generation]." |
| **Case No. PUE-2011-00092 Final Order at 6** | **2016 Plan Final Order** N/A | In future IRPs, rate design options should be modeled by the Company, for example, to analyze how alternative rate designs may impact demand and the plans to meet demand, particularly given Dominion's "commitment to meeting the Commonwealth's [10%] energy reduction goals." |

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| **Guidelines** | | |
| **Guidelines (A)** | **Section 4.2**<br>PJM Capacity Planning Process & Reserve Requirements<br><br>**Chapter 6**<br>Development of the Integrated Resource Plan | The purpose of these guidelines is to implement the provisions of §§ 56-597, 56-598 and 56-599 of the Code of Virginia with respect to integrated resource planning ("IRP") by the electric utilities in the Commonwealth. In order to understand the basis for the utility's plan, the IRP filing shall include a narrative summary detailing the underlying assumptions reflected in its forecast as further described in the guidelines. To better follow the utility's planning process, the narrative shall include a description of the utility's rationale for the selection of any particular generation addition or demand-side management program to fulfill its forecasted need. Such description should include the utility's evaluation of its purchase options and cost/benefit analyses for each resource option to confirm and justify each resource option it has chosen. Such narrative shall also describe the planning process including timelines and appropriate reviews and/or approvals of the utility's plan. For members of PJM Interconnection, LLC ("PJM"), the narrative should describe how the IRP incorporates the PJM planning and implementation processes and how it will satisfy PJM load obligations.These guidelines also include sample schedules to supplement this narrative discussion and assist the utilities in developing a tabulation of the utility's forecast for at least a 15-year period and identify the projected supply-side or demand-side resource additions and solutions to adequately and reliably meet the electricity needs of the Commonwealth. This tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the same period. These guidelines also direct that all IRP filings include information to comparably evaluate various supply-side technologies and demand-side programs and technologies on an equivalent basis as more fully described below in Section F (7). The Commission may revise or supplement the sample schedules as needed or warranted. |
| **Guidelines (C) (1)** | **Section 2.4**<br>Summer & Winter Peak Demand & Annual Energy<br><br>**Appendix 2I**<br>Projected Summer & Winter Peak Load & Energy Forecast for Plan $C^T$: Intensity-Based Dual Rate<br><br>**Appendix 2J**<br>Required Reserve Margin for Plan $C^T$: Intensity-Based Dual Rate | 1. Forecast. A three-year historical record and a 15-year forecast of the utility's native load requirements, the utility's PJM load obligations if appropriate, and other system capacity or firm energy obligations for each peak season along with the supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads, and the reserve margin thus produced. |

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| **Guidelines (C) (2)** | **Section 5.2**<br>Levelized Busbar Costs<br><br>**Chapter 6**<br>Development of the Integrated Resource Plan | 2. Option analyses. A comprehensive analysis of all existing and new resource options (supply- and demand-side), including costs, benefits, risks, uncertainties, reliability, and customer acceptance where appropriate, considered and chosen by the utility for satisfaction of native load requirements and other system obligations necessary to provide reliable electric utility service, at the lowest reasonable cost, over the planning period. |
| **Guidelines (C) (2) (a)** | **Section 3.1.7**<br>Wholesale & Purchased Power<br><br>**Section 5.1.4**<br>Assessment of Supply-Side Resource Alternatives | a. Purchased Power - assess the potential costs and benefits of purchasing power from wholesale power suppliers and power marketers to supply it with needed capacity and describe in detail any decision to purchase electricity from the wholesale power market. |
| **Guidelines (C) (2) (b)** | **Section 5.1**<br>Future Supply-Side Resources | b. Supply-side Energy Resources - assess the potential costs and benefits of reasonably available traditional and alternative supply-side energy resource options, including, but not limited to technologies such as, nuclear, pulverized coal, clean coal, circulating fluidized bed, wood, combined cycle, integrated gasification combined cycle, and combustion turbine, as well as renewable energy resources such as those derived from sunlight, wind, falling water, sustainable biomass, energy from waste, municipal solid waste, wave motion, tides, and geothermal power. |
| **Guidelines (C) (2) (c)** | **Section 3.2**<br>Demand-Side Resources<br><br>**Section 5.5**<br>Future DSM Initiatives<br><br>**Section 6.1**<br>IRP Process | c. Demand-side Options - assess the potential costs and benefits of programs that promote demand-side management. For purposes of these guidelines, peak reduction and demand response programs and energy efficiency and conservation programs will collectively be referred to as demand-side options. |
| **Guidelines (C) (2) (d)** | **Chapter 5**<br>Future Resources<br><br>**Chapter 6**<br>Development of the Integrated Resource Plan | d. Evaluation of Resource Options - analyze potential resource options and combinations of resource options to serve system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction or implementation costs, transmission and distribution costs, environmental impacts and compliance costs. |

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| **Guidelines (C) (3)** | As applicable | 3. Data availability. To the extent the information requested is not currently available or is not applicable, the utility will clearly note and explain this in the appropriate location in the plan, narrative, or schedule. |
| **Guidelines (D) (1)** | **Section 2.2**<br>History & Forecast by Customer Class & Assumptions<br><br>**Section 4.2**<br>PJM Capacity Planning Process & Reserve Requirements | 1. Discussion regarding the forecasted peak load obligation and energy requirements. PJM members should also discuss the relationship of the utility's expected non-coincident peak and its expected PJM related load obligations. |
| **Guidelines (D) (2)** | **Section 3.2**<br>Demand-Side Resources<br><br>**Section 4.3**<br>Renewable Energy<br><br>**Section 5.5**<br>Future DSM Initiatives | 2. Discussion regarding company goals and plans in response to directives of Chapters 23 and 24 of Title 56 of the Code of Virginia, including compliance with energy efficiency, energy conservation, demand-side and response programs, and the provision of electricity from renewable energy resources. |
| **Guidelines (D) (3)** | **Chapter 4**<br>Planning Assumptions<br><br>**Section 6.1**<br>IRP Process | 3. Discussion regarding the complete planning process, including timelines, assumptions, reviews, approvals, etc., of the company's plans. For PJM members, the discussion should also describe how the IRP integrates into the complete planning process of PJM. |
| **Guidelines (D) (4)** | **Section 2.1**<br>Forecast Methods<br><br>**Section 2.2**<br>History & Forecast by Customer Class & Assumptions | 4. Discussion of the critical input assumptions to determine the load forecast and expected changes in load growth including factors such as energy conservation, efficiency, load management, demand response, variations in customer class sizes, expected levels of economic activity, variations in fuel prices and appliance inventories, etc. |
| **Guidelines (D) (5)** | **Section 5.5**<br>Future DSM Initiatives<br><br>**Chapter 6**<br>Development of the Integrated Resource Plan | 5. Discussion regarding cost/benefit analyses and the results of such factors on this plan, including the methodology used to consider equal or comparable treatment afforded both the demand-side options and supply-side resources. |

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| **Guidelines (D) (6)** | **Section 3.1.3**<br>Changes to Existing Generation<br><br>**Section 3.1.4**<br>Generation Retirements & Blackstart<br><br>**Section 3.1.5**<br>Generation Under Construction<br><br>**Appendix 3I**<br>Planned Changes to Existing Generation Units<br><br>**Appendix 3J**<br>Potential Unit Retirements<br><br>**Appendix 3K**<br>Generation Under Construction | 6. Planned changes in operating characteristics such as unit retirements, unit uprates or derates, changes in unit availabilities, changes in capacity resource mix, changes in fuel supplies or transport, emissions compliance, unit performance, etc. |
| **Guidelines (D) (7)** | **Section 6.10**<br>2017 Plan<br><br>**Section 6.11**<br>Conclusion<br><br>**Chapter 7**<br>Short-Term Action Plan | 7. Discussion regarding the effectiveness of the utility's IRP to meet its load obligations with supply-side and demand-side resources to enable the utility to provide reliable service at reasonable prices over the long term. |

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| **Guidelines (E)** | **Chapter 7**<br>Short-Term Action Plan | By September 1, 2009, and every two years thereafter, each utility shall file with the Commission its then current integrated resource plan, which shall include all information required by these guidelines for the ensuing 15-year planning period along with the prior three-year historical period. The process and analyses shall be described in a narrative discussion and the results presented in tabular format using an EXCEL spreadsheet format, similar to the attached sample schedules, and be provided in both printed and electronic media. For those utilities that operate as part of a multi-state integrated power system, the schedules should be submitted for both the individual company and the generation planning pool of which the utility is a member. The top line stating the company name should indicate that the data reflects the individual utility company or the total system. For partial ownership of any facility, please provide the percent ownership and footnote accordingly. Each filing shall include a five-year action plan that discusses those specific actions currently being taken by the utility to implement the options or activities chosen as appropriate per the IRP. If a utility considers certain information in its IRP to be proprietary or confidential, the utility may so designate, file separately and request such treatment in accordance with the Commission's Rules of Practice and Procedures. Additionally, by September 1 of each year in which a plan is not required, each utility shall file a narrative summary describing any significant event necessitating a major revision to the most recently filed IRP, including adjustments to the type and size of resources identified. If the utility provides a total system IRP in another jurisdiction by September 1 of the year in which a plan is not required, filing the total system IRP from the other jurisdiction will suffice for purposes of this section. As § 56-599 E requires the giving of notice and an opportunity to be heard, each utility shall also include a copy of its proposed notice to be used to afford such an opportunity. |
| **Guidelines (F) (1)** | **Section 2.1**<br>Forecast Methods | 1. Forecast of Load. The forecast shall include descriptions of the methods, models, and assumptions used by the utility to prepare its forecasts of its loads, requirements associated with the utility's PJM load obligation (MW) if appropriate, the utility's peak load (MW) and energy sales (MWh) and the variables used in the models and shall include, at a minimum, the following: |
| **Guidelines (F) (1) (a)** | **Section 2.2**<br>History & Forecast by Customer Class & Assumptions<br><br>**Appendix 2A**<br>Total Sales by Customer Class<br><br>**Appendix 2B**<br>Virginia Sales by Customer Class<br><br>**Appendix 2C**<br>North Carolina Sales by Customer Class | a. The most recent three-year history and 15-year forecast of energy sales (kWh) by each customer class |

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| **Guidelines (F) (1) (b)** | **Section 2.4**<br>Summer & Winter Peak Demand & Annual Energy<br><br>**Appendix 2I**<br>Projected Summer & Winter Peak Load & Energy Forecast for Plan $C^T$: Intensity-Based Dual Rate<br><br>**Appendix 2J**<br>Required Reserve Margin for Plan $C^T$: Intensity-Based Dual Rate | b. The most recent three-year history and 15-year forecast of the utility's peak load and the expected load obligation to satisfy PJM's coincident peak forecast if appropriate, and the utility's coincident peak load and associated noncoincident peak load for summer and winter seasons of each year (prior to any DSM), annual energy forecasts, and resultant reserve margins. During the forecast period, the tabulation shall also indicate the projected effects of incremental demand-side options on the forecasted annual energy and peak loads |
| **Guidelines (F) (1) (c)** | **Chapter 5**<br>Future Resources<br><br>**Section 6.10**<br>2017 Plan | c. Where future resources are required, a description and associated characteristics of the option that the utility proposes to use to address the forecasted need |
| **Guidelines (F) (2) (a) (i)** | **Section 3.1.1**<br>Existing Generation<br><br>**Appendix 3A**<br>Existing Generation Units in Service | 2. Supply-side Resources. The forecast shall provide data for its existing and planned electric generating facilities (including planned additions and retirements and rating changes, as well as firm purchase contracts, including cogeneration and small power production) and a narrative description of the driver(s) underlying such anticipated changes such as expected environmental compliance, carbon restrictions, technology enhancements, etc.:<br>a. Existing Generation. For existing units in service:<br>i. Type of fuel(s) used |
| **Guidelines (F) (2) (a) (ii)** | **Appendix 3A**<br>Existing Generation Units in Service | ii. Type of unit (e.g., base, intermediate, or peaking) |
| **Guidelines (F) (2) (a) (iii)** | **Section 3.1.1**<br>Existing Generation<br><br>**Appendix 3A**<br>Existing Generation Units in Service | iii. Location of each existing unit |

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| **Guidelines (F) (2) (a) (iv)** | **Appendix 3A**<br>Existing Generation Units in Service | iv. Commercial Operation Date |
| **Guidelines (F) (2) (a) (v)** | **Section 3.1.1**<br>Existing Generation<br><br>**Appendix 3A**<br>Existing Generation Units in Service | v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW)) |
| **Guidelines (F) (2) (a) (vi)** | **Section 3.1.4**<br>Generation Retirements & Blackstart<br><br>**Appendix 3J**<br>Potential Unit Retirements | vi. Units to be placed in reserve shutdown or retired from service with expected date of shutdown or retirement and an economic analysis supporting the planned retirement or shutdown dates |
| **Guidelines (F) (2) (a) (vii)** | **Section 3.1.3**<br>Changes to Existing Generation<br><br>**Section 5.2**<br>Levelized Busbar Costs<br><br>**Appendix 3I**<br>Planned Changes to Existing Generation Units | vii. Units with specific plans for life extension, refurbishment, fuel conversion, modification or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, expected return to service date, capacity rating upon return to service, a general description of work to be performed as well as an economic analysis supporting such plans for existing units |
| **Guidelines (F) (2) (a) (viii)** | **Section 3.1.3**<br>Changes to Existing Generation<br><br>**Appendix 3I**<br>Planned Changes to Existing Generation Units | viii. Major capital improvements such as the addition of scrubbers, shall be evaluated through the IRP analysis to assess whether such improvements are cost justified when compared to other alternatives, including retirement and replacement of such resources |

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| **Guidelines (F) (2) (a) (ix)** | **Section 3.1.3**<br>Changes to Existing Generation<br><br>**Appendix 3I**<br>Planned Changes to Existing Generation Units | ix. Other changes to existing generating units that are expected to increase or decrease generation capability of such units. |
| **Guidelines (F) (2) (b)** | **Section 5.1**<br>Future Supply-Side Resources | b. Assessment of Supply-side Resources. Include the current overall assessment of existing and potential traditional and alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its mostrecent IRP or annual report. |
| **Guidelines (F) (2) (b) (i)** | **Section 6.10**<br>2017 Plan<br><br>**Appendix 6A**<br>Renewable Resources<br><br>**Appendix 6B**<br>Potential Supply-Side Resources<br><br>**Appendix 6C**<br>Summer Capacity Position for Plan $C^T$: Intensity-Based Dual Rate<br><br>**Appendix 6D**<br>Construction Forecast for Plan $C^T$: Intensity-Based Dual Rate<br><br>**Appendix 6E**<br>Capacity Position for Plan $C^T$: Intensity-Based Dual Rate | i. For the currently operational or potential future supply-side energy resources included, provide information on the capacity and energy available or projected to be available from the resource and associated costs. The utility shall also provide this information for any actual or potential supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance. |
| **Guidelines (F) (2) (b) (ii)** | **Section 5.1.4**<br>Assessment of Supply-Side Resource Alternatives | ii. For supply-side energy resources evaluated but rejected, a description of the resource; the potential capacity and energy associated with the resource; estimated costs and the reasons for the rejection of the resource. |

| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **Guidelines (F) (2) (c) (i)** | **Section 3.1.5**<br>Generation Under Construction<br><br>**Appendix 3K**<br>Generation Under Construction | c. Planned Generation Additions. A list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition:<br>i. Type of conventional or alternative facility and fuel(s) used |
| **Guidelines (F) (2) (c) (ii)** | **Section 3.1.5**<br>Generation Under Construction<br><br>**Appendix 3K**<br>Generation Under Construction | ii. Type of unit (e .g . baseload, intermediate, peaking) |
| **Guidelines (F) (2) (c) (iii)** | **Section 3.1.5**<br>Generation Under Construction<br><br>**Appendix 3K**<br>Generation Under Construction | iii. Location of each planned unit, including description of locational benefits identified by PJM and/or the utility |
| **Guidelines (F) (2) (c) (iv)** | **Section 3.1.5**<br>Generation Under Construction<br><br>**Appendix 3K**<br>Generation Under Construction | iv. Expected Commercial Operation Date |
| **Guidelines (F) (2) (c) (v)** | **Section 3.1.5**<br>Generation Under Construction<br><br>**Appendix 3K**<br>Generation Under Construction | v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW)) |
| **Guidelines (F) (2) (c) (vi)** | **Section 3.1.5**<br>Generation Under Construction | vi. Summaries of the analyses supporting such new generation additions, including its type of fuel and designation as base, intermediate, or peaking capacity |

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| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **Guidelines (F) (2) (c) (vii)** | **Section 3.1.5**<br>Generation Under Construction<br>**Section 5.2**<br>Levelized Busbar Costs<br>**Appendix 3K**<br>Generation Under Construction<br>**Appendix 5B**<br>Busbar Assumptions | vii. Estimated cost of planned unit additions to compare with demand-side options |
| **Guidelines (F) (2) (d)** | **Section 3.1.6**<br>Non-Utility Generation<br>**Appendix 3B**<br>Other Generation Units | d. Non-Utility Generation. A separate list of all non-utility electric generating facilities included in the IRP, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and contractual capacity (including any contract dispatch conditions or limitations), and the contractual start and expiration dates. The utility shall also indicate which facilities are included in their total supply of resources |
| **Guidelines (F) (3)** | **Section 4.6.1**<br>Regional Transmission Planning & System Adequacy<br>**Section 6.10**<br>2017 Plan<br>**Appendix 6C**<br>Summer Capacity Position for Plan $C^T$: Intensity-Based Dual Rate | 3. Capacity Position. Provide a narrative discussion and tabulation reflecting the capacity position of the utility in relation to satisfying PJM's load obligation, similar to Schedule 16 of the attached schedules. |
| **Guidelines (F) (4)** | **Section 3.1.7**<br>Wholesale & Purchased Power<br>**Appendix 3L**<br>Wholesale Power Sales Contracts | 4. Wholesale Contracts for the Purchase and Sale of Power. A list of firm wholesale purchased power and sales contracts reflected in the plan, including the primary fuel type, designation as base, intermediate, or peaking capacity, contract capacity, location, commencement and expiration dates, and volume. |

| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **Guidelines (F) (5)** | **Section 3.2**<br>Demand-Side Resources<br><br>**Section 5.5**<br>Future DSM Initiatives<br><br>**Appendix 5E**<br>DSM Programs Energy Savings for Plan $C^T$: Intensity-Based Dual Rate<br><br>**Appendix 3S**<br>Proposed Programs Non-Coincidental Peak Savings for Plan $C^T$: Intensity-Based Dual Rate<br><br>**Appendix 3T**<br>Proposed Programs Coincidental Peak Savings for Plan $C^T$: Intensity-Based Dual Rate<br><br>**Appendix 3U**<br>Proposed Programs Energy Savings for Plan $C^T$: Intensity-Based Dual Rate<br><br>**Appendix 3V**<br>Proposed Programs Penetrations for Plan $C^T$: Intensity-Based Dual Rate | 5. Demand-side Options. Provide the results of its overall assessment of existing and potential demand-side option programs, including a descriptive summary of each analysis performed or used by the utility in its assessment and any changes to the methods and assumptions employed since its last IRP. Such descriptive summary, and corresponding schedules, shall clearly identify the total impact of each DSM program. |

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| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **Guidelines (F) (6)** | **Section 3.3.3**<br>Transmission Projects Under Construction<br><br>**Section 4.6**<br>Transmission Planning<br><br>**Section 5.5.4**<br>Assessment of Overall Demand-Side Options<br><br>**Chapter 6**<br>Development of the Integrated Resource Plan<br><br>**Appendix 3W**<br>Generation Interconnection Projects Under Construction<br><br>**Appendix 3X**<br>List of Transmission Lines Under Construction | 6. Evaluation of Resource Options. Provide a description and a summary of the results of the utility's analyses of potential resource options and combinations of resource options performed by it pursuant to these guidelines to determine its integrated resource plan. IRP filings should identify and include forecasted transmission interconnection and enhancement costs associated with specific resources evaluated in conjunction with the analysis of resource options. |
| **Guidelines (F) (7)** | **Section 5.2**<br>Levelized Busbar Costs<br><br>**Appendix 5A**<br>Tabular Results of Busbar<br><br>**Appendix 5B**<br>Busbar Assumptions | 7. Comparative Costs of Options. Provide detailed information on levelized busbar costs, annual revenue requirements or equivalent methodology for various supply-side options and demand-side options to permit comparison of such resources on equitable footing. Such data should be tabulated and at a minimum, reflect the resource's heat rate, variable and fixed operating maintenance costs, expected service life, overnight construction costs, fixed charged rate, and the basis of escalation for each component. |
| **Schedule 1** | **Appendix 2I**<br>Projected Summer & Winter Peak Load & Energy Forecast for Plan $C^T$: Intensity-Based Dual Rate | Peak load and energy forecast |
| **Schedule 2** | **Appendix 3G**<br>Energy Generation by Type for Plan $C^T$: Intensity-Based Dual Rate | Generation output |

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| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **Schedule 3** | **Appendix 3H** Energy Generation by Type for Plan $C^T$: Intensity-Based Dual Rate | System output mix |
| **Schedule 4** | **Appendix 6E** Capacity Position for Plan $C^T$: Intensity-Based Dual Rate | Seasonal capability |
| **Schedule 5** | **Appendix 2G** Zonal Summer and Winter Peak Demand | Seasonal load |
| **Schedule 6** | **Appendix 2J** Required Reserve Margin for Plan $C^T$: Intensity-Based Dual Rate | Reserve margin |
| **Schedule 7** | **Appendix 3F** Existing Capacity for Plan $C^T$: Intensity-Based Dual Rate | Installed capacity |
| **Schedule 8** | **Appendix 3C** Equivalent Availability Factor for Plan $C^T$: Intensity-Based Dual Rate | Equivalent Availability Factor |
| **Schedule 9** | **Appendix 3D** Net Capacity Factor for Plan $C^T$: Intensity-Based Dual Rate | Net capacity factor |
| **Schedule 10** | **Appendix 3E** Heat Rates for Plan $C^T$: Intensity-Based Dual Rate | Average Heat Rate |
| **Schedule 11** | **Appendix 6A** Renewable Resources for Plan $C^T$: Intensity-Based Dual Rate | Renewable resources |
| **Schedule 12** | **Appendix 5E** DSM Program Energy Savings for Plan $C^T$: Intensity-Based Dual Rate | DSM Programs |

| ORDER/GUIDELINE | IRP SECTION | REQUIREMENT |
|---|---|---|
| **Schedule 13a** | **Appendix 3I** Planned Changes to Existing Generation Units | Unit size uprate and derate |
| **Schedule 13b** | **Appendix 3I** Planned Changes to Existing Generation Units | |
| **Schedule 14a** | **Appendix 3A** Existing Generation Units in Service | Existing unit performance data |
| **Schedule 14b** | **Appendix 3B** Other Generation Units | |
| **Schedule 15a** | **Appendix 3K** Generation Under Construction | Planned unit performance data |
| **Schedule 15b** | **Appendix 6B** Potential Supply-Side Resources for Plan $C^T$: Intensity-Based Dual Rate | |
| **Schedule 15c** | **Appendix 5C** Planned Generation under Development | |
| **Schedule 16** | **Appendix 6C** Summer Capacity Position for Plan $C^T$: Intensity-Based Dual Rate | Utility capacity position |
| **Schedule 17** | **Appendix 6D** Construction Forecast for Plan $C^T$: Intensity-Based Dual Rate | Construction forecast |
| **Schedule 18** | **Appendix 4B** Delivered Fuel Data for Plan $C^T$: Intensity-Based Dual Rate | Fuel data |

parta



# Virginia Electric and Power Company's Report of Its Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

PUBLIC VERSION

Case No. PUR-2017-00051
Docket No. E-100, Sub 147

Filed: May 1, 2017

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APPENDIX

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# LIST OF ACRONYMS

| Acronym | Meaning |
|---|---|
| 2016 Plan | 2016 Integrated Resource Plan |
| 2017 Plan | 2017 Integrated Resource Plan |
| AC | Alternating Current |
| ACP | Atlantic Coast Pipeline |
| AMI | Advanced Metering Infrastructure |
| BTMG | Behind-the-Meter Generation |
| Btu | British Thermal Unit |
| CAGR | Compound Annual Growth Rate |
| CAPP | Central Appalachian |
| CC | Combined-Cycle |
| CCR | Coal Combustion Residuals |
| CCS | Carbon Capture and Sequestration |
| CFB | Circulating Fluidized Bed |
| $CO_2$ | Carbon Dioxide |
| COD | Commercial Operation Date |
| COL | Combined Operating License |
| Company | Virginia Electric and Power Company |
| CPCN | Certificate of Public Convenience and Necessity |
| CPP | Clean Power Plan, Rule 111(d) |
| CSAPR | Cross-State Air Pollution Rule |
| CSP | Concentrating Solar Power |
| CT | Combustion Turbine |
| CWA | Clean Water Act |
| DC | Direct Current |
| DEQ | Virginia Department of Environmental Quality |
| DER | Distributed Energy Resource(s) |
| DG | Distributed Generation |
| DOE | U.S. Department of Energy |
| DOM LSE | Dominion Load Serving Entity |
| DOM Zone | Dominion Zone within the PJM Interconnection, L.L.C. Regional Transmission Organization |
| DSM | Demand-Side Management |
| EGU | Electric Generating Unit(s) |
| EIA | U.S. Energy Information Administration |
| EM&V | Evaluation, Measurement, and Verification |
| EPA | U.S. Environmental Protection Agency |
| EPC | Engineering, Procurement, and Construction |
| EPRI | Electric Power Research Institute |
| ERC | Emission Rate Credit(s) |
| ESBWR | Economic Simplified Boiling Water Reactor |
| EV | Electric Vehicle |
| FERC | Federal Energy Regulatory Commission |
| FIP | Federal Implementation Plan |
| GDP | Gross Domestic Product |
| GEH | GE-Hitachi Nuclear Energy Americas LLC |
| GHG | Greenhouse Gas |
| GSP | Gross State Product |
| GWh | Gigawatt Hour(s) |
| Hg | Mercury |
| HVAC | Heating, Ventilating, and Air Conditioning |
| IDR | Interval Data Recorder |
| 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 |
| LMP | Locational Marginal Pricing |

| Acronym | Meaning |
|---|---|
| LOLE | Loss of Load Expectation |
| LSE | Load Serving Entity |
| MATS | Mercury and Air Toxics Standards |
| MMBTU | Million British Thermal Unit(s) |
| MMCF | Million Cubic Feet |
| MW | Megawatt(s) |
| MWh | Megawatt Hour(s) |
| NAAQS | National Ambient Air Quality Standards |
| NCGS | North Carolina General Statute |
| NCUC | North Carolina Utilities Commission |
| NERC | North American Electric Reliability Corporation |
| NGCC | Natural Gas Combined Cycle |
| $NO_x$ | Nitrogen Oxide |
| NODA | Notice of Data Availability |
| NPV | Net Present Value |
| NRC | Nuclear Regulatory Commission |
| NREL | The National Renewable Energy Laboratory |
| NSPS | New Source Performance Standards |
| NUG | Non-Utility Generation or Non-Utility Generator |
| O&M | Operation and Maintenance |
| OEM | Original Equipment Manufacturers |
| PC | Pulverized Coal |
| PHEV | Plug-in Hybrid Electric Vehicle |
| PJM | PJM Interconnection, L.L.C. |
| Plan | 2017 Integrated Resource Plan |
| PPA | Power Purchase Agreement |
| PTC | Production Tax Credit |
| PURPA | Public Utility Regulatory Policies Act of 1978 |
| PV | Photovoltaic |
| RACT | Reasonable Available Control Technology |
| REC | Renewable Energy Certificate(s) |
| REPS | Renewable Energy and Energy Efficiency Portfolio Standard (NC) |
| RFC | Reliability First Corporation |
| RFP | Request for Proposal |
| 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 |
| SCPC | Super Critical Pulverized Coal |
| SCR | Selective Catalytic Reduction |
| SG | Standby Generation |
| SIP | State Implementation Plan |
| SMR | Small Modular Reactors |
| SNCR | Selective Non-Catalytic Reduction |
| $SO_2$ | Sulfur Dioxide |
| SPP | Solar Partnership Program |
| SRP | Stakeholder Review Process |
| STAP | Short-Term Action Plan |
| TRC | Total Resource Cost |
| Va. Code | Code of Virginia |
| VCHEC | Virginia City Hybrid Energy Center |
| VOW | Virginia Offshore Wind Coalition |
| VOWDA | Virginia Offshore Wind Development Authority |
| VOWTAP | Virginia Offshore Wind Technology Advancement Project |
| WACC | Weighted Average Cost of Capital |
| WEA | Wind Energy Area |

# CHAPTER 1 – EXECUTIVE SUMMARY

## 1.1 INTEGRATED RESOURCE PLAN OVERVIEW

Virginia Electric and Power Company (the "Company") hereby files its 2017 Integrated Resource Plan ("2017 Plan") with the Virginia State Corporation Commission ("SCC") in accordance with § 56-599 of the Code of Virginia (or "Va. Code") and the SCC's guidelines issued on December 23, 2008. The Plan is also filed as an update with the North Carolina Utilities Commission ("NCUC") in accordance with § 62-2 of the North Carolina General Statutes ("NCGS") and Rule R8-60 of NCUC's Rules and Regulations.

The 2017 Plan was prepared for the Dominion Load Serving Entity ("DOM LSE") and represents the Company's service territories in the Commonwealth of Virginia and the State of North Carolina, which are part of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization ("RTO"). Subject to provisions of Virginia and North Carolina law, the Company prepares an integrated resource plan (generally, "Plan") for filing in each jurisdiction every year. On April 29, 2016, the Company filed its 2016 Plan with the SCC (Case No. PUE-2016-00049) and with the NCUC (Docket No. E-100, Sub 147). On December 14, 2016, the SCC issued its Final Order finding the 2016 Plan ("2016 Plan Final Order") reasonable and in the public interest for the specific and limited purpose of filing the planning document as mandated by Va. Code § 56-597 *et seq*. The Company's 2016 Plan remains pending before the NCUC.

The Company is committed to address concerns and/or requirements identified by the SCC or NCUC in prior relevant orders that continue to be applicable, as well as new or proposed provisions of state and federal law. Notably, the Plan continues to evaluate compliance with the greenhouse gas ("GHG") regulations promulgated by the U.S. Environmental Protection Agency ("EPA") on October 23, 2015, known as the Clean Power Plan ("CPP") or 111(d) Rule. Implementation of the CPP was stayed by the order of the U.S. Supreme Court on February 9, 2016 ("Stay Order"), and the CPP is currently before the U.S. Circuit Court of Appeals for the District of Columbia for judicial review.

Delayed implementation and enforcement of the CPP resulting from the Stay Order has significantly increased uncertainty from both a substantive and timing perspective. That uncertainty has been compounded by the recent change in federal administration. On March 28, 2017, President Trump issued an Executive Order directing the administrator of the EPA to begin the process of reviewing the CPP, and if appropriate, as soon as practicable, revise, or rescind the rule.[1]

[1] The March 28th Executive Order also directed the EPA to undertake a similar review of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed EGUs or the "111(b) rule," as well as the Federal Plan proposed for federal implementation of the CPP in states that failed to submit compliant state plans. See https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1.

On April 3 and 4, 2017, in response to the Executive Order, the EPA issued notices announcing that it was withdrawing the proposed Federal Implementation Plan ("FIP"), proposed Model Trading Rules, proposed design elements for the Clean Energy Incentive Program, as well as initiating a review of the entire CPP and the 111(b) rules.[2] However, since the CPP is part of existing federal regulation and its precise fate is still uncertain, it remains important that the Company's planning process include thorough evaluation of the likely future regulation of power station carbon dioxide ("$CO_2$") emissions. The CPP compliance options provide a reasonable proxy for that analysis. Further, this approach is consistent with the SCC's directive in its 2016 Plan Final Order that the Company should evaluate a range of CPP compliance pathways, acknowledging that the CPP "continues to be a significant planning consideration for Dominion and other electric utilities" (2016 Plan Final Order, page 3) even in light of the Stay Order and other challenges to the rule. Regardless of the final disposition of the CPP, the Company believes that future regulation will require it to address carbon and carbon emissions in some form beyond what is required today.

The Company's objective in the 2017 Plan is to identify a mix of resources necessary to meet its customers' projected energy and capacity needs in an efficient and reliable manner at the lowest reasonable cost, while considering future uncertainties. The Company's options for meeting these future needs are: i) supply-side resources, ii) demand-side resources, and iii) market purchases. A balanced approach, which includes the consideration of options for maintaining and enhancing rate stability, energy independence, economic development, as well as input from stakeholders, will help the Company meet growing demand while protecting customers from a variety of potential negative impacts and challenges.

Given the uncertainties of the CPP and the need to plan for a variety of contingencies, the 2017 Plan, like its predecessors, presents a range of alternatives representing plausible paths forward for the Company to meet the future energy needs of its customers. Specifically, the Company presents eight different alternative plans (collectively, the "Alternative Plans") designed to meet customers' needs in a future with or without the CPP. The Alternative Plans are based on a variety of CPP compliance approaches and other factors in a changing and challenging regulatory environment.

The Company primarily used the PLEXOS model ("PLEXOS"), a utility modeling and resource optimization tool, to develop this 2017 Plan over the 25-year period, beginning in 2018 and continuing through 2042 ("Study Period"), using 2017 as the base year. The 2017 Plan is based on the Company's current assumptions regarding load growth, commodity price projections, economic conditions, environmental regulations, construction and equipment costs, Demand-Side Management ("DSM") programs, and many other regulatory and market developments that may occur during the Study Period.

The Company's comprehensive planning process requires it to consider any significant emerging policy, market, or technical developments that could impact its operations and, in turn, its customers. On the market front, these developments include solar photovoltaic ("PV") technology,

[2] See https://www.gpo.gov/fdsys/pkg/FR-2017-04-04/pdf/2017-06522.pdf, https://www.gpo.gov/fdsys/pkg/FR-2017-04-04/pdf/2017-06519.pdf, and https://www.gpo.gov/fdsys/pkg/FR-2017-04-03/pdf/2017-06518.pdf.

which is currently cost-competitive with other more traditional forms of generation, such as combined-cycle ("CC") natural gas. The 2017 Plan includes a considerable amount of solar resources, as reflected in each of the Alternative Plans. This is due to their optimal economics, low or zero emission characteristics, and the fact that the installed cost of solar PV generation has decreased by approximately 24% between the filing of the 2016 Plan and the 2017 Plan. The Alternative Plans call for solar additions ranging from 5,280 megawatt ("MW") (nameplate) to 5,760 MW (nameplate) during the 25-year Study Period. Within the shorter 15-year period of 2018 to 2032 (the "Planning Period"), the Alternative Plans call for solar additions ranging from 3,200 MW (nameplate) to 3,360 MW (nameplate).

The 2017 Plan includes for modeling purposes "utility-scale" solar facilities that are assumed to be between 20 MW and 80 MW in size and predominately interconnected to the Company's transmission network. In reality, solar PV can be a collection of different-sized facilities ranging from 5 kilowatts ("kW") up to 100 MW, which may be interconnected along the Company's transmission network or may be rooftop facilities interconnected to the Company's distribution network. The Company must now prepare for a future in which solar PV generation can become a major contributor to the Company's overall energy mix.

On the technical front, the Company must take steps to plan for the modernization of its electric power grid, at both the distribution and transmission levels, to create a more dynamic system that is better able to respond to the growth of utility-scale solar facilities, as well as the proliferation of smaller, widely-dispersed solar generation facilities. That preparation includes a plan to create a more flexible electric power grid that will accommodate the highly variable output associated with solar PV and other intermittent forms of generation, while still maintaining reliability. To that end, the 2017 Plan includes a new section (Section 5.1.3) that identifies, at a high level, the steps the Company believes are necessary to transform its existing transmission and distribution network into a more modern grid system that will adequately accommodate the integration of large volumes of solar PV generation while maintaining reliability.

Included in this 2017 Plan are sections on load forecasting (Chapter 2), existing resources and resources currently under development (Chapter 3), planning assumptions (Chapter 4), and future resources, including grid modernization (Chapter 5). Additionally, there is a section describing the development of the Plan (Chapter 6), which defines the integrated resource planning ("IRP") process, and outlines alternative plans that were compared by weighing the costs of those plans and further compared by using a comprehensive risk analysis; and a Portfolio Evaluation Scorecard (or "Scorecard") process. This analysis allowed the Company to examine the Alternative Plans given significant industry uncertainties, such as environmental regulations, commodity and construction prices, and resource mix. The Scorecard provides a quantitative and qualitative measurement system to assess the different alternatives, using criteria that include Total Cost, Portfolio Risk, and Capital Investment Concentration. Finally, a Short-Term Action Plan (or "STAP") (Chapter 7) is included, which discusses the Company's specific actions currently underway to support the 2017 Plan over the next five years (2018 – 2022). The Company maintains that the STAP represents the short-term path forward which will best meet the energy and capacity needs of its customers at the lowest reasonable cost over the next five years, with due quantification, consideration, and analysis of future risks and uncertainties facing the industry, the Company, and its customers.

The Company's balanced approach to develop its Plan also includes input from stakeholders. In 2010, the Company initiated its Stakeholder Review Process ("SRP") in Virginia. The SRP serves as a forum for the Company to inform stakeholders from across the service territory about the IRP process; to provide more specific information about the Company's planning process, including IRP and DSM initiatives; and to receive stakeholder input. The Company coordinates with interested parties in sharing DSM program Evaluation, Measurement and Verification ("EM&V") results and developing future DSM program proposals, pursuant to an SCC directive. The Company is committed to continue the SRP and expects the next SRP meeting involving stakeholders across its service territory to occur after the filing of this 2017 Plan.

Finally, the Company notes that inclusion of a project or resource in any given year's integrated resource plan is not a commitment to construct, implement, or a request for approval of any particular project. Conversely, not including a specific project in a given year's plan does not preclude the Company from including that project in subsequent regulatory filings. Rather, an integrated resource plan is a long-term planning document based on current market information and projections and should be viewed in that context.

## 1.2 COMPANY DESCRIPTION

Headquartered in Richmond, Virginia, the Company currently serves approximately 2.5 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company's supply-side portfolio consists of 20,302 MW of generation capacity, including approximately 749 MW of fossil-fueled and renewable non-utility generation ("NUG") resources, approximately 6,600 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV, and approximately 57,000 miles of distribution lines at voltages ranging from 4 kV to 46 kV in Virginia, North Carolina, and West Virginia. The Company is a member of PJM, the operator of the wholesale electric grid in the Mid-Atlantic region of the United States.

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

## 1.3 2017 INTEGRATED RESOURCE PLANNING PROCESS

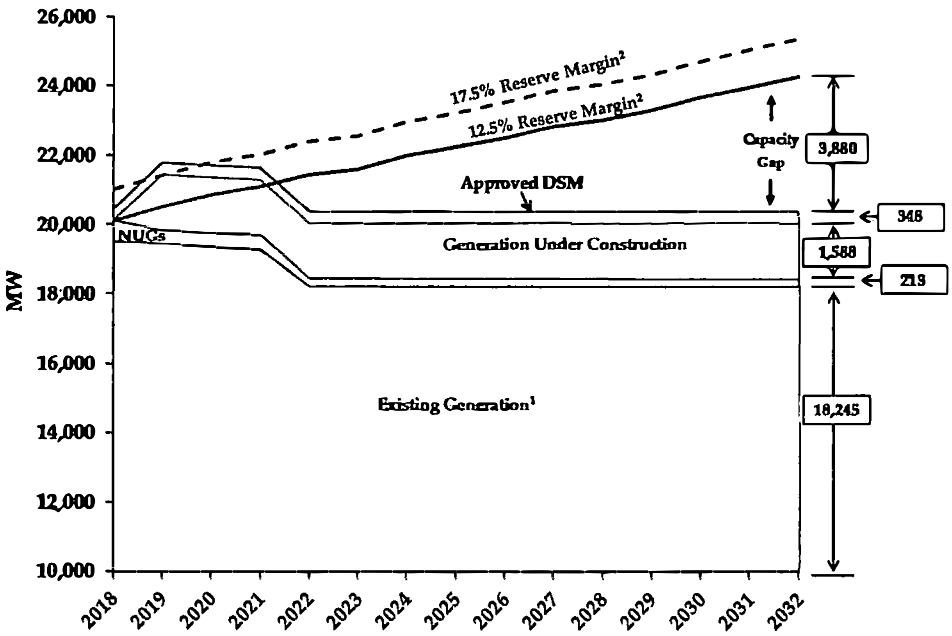
In order to meet future customer needs at the lowest reasonable cost while maintaining reliability and flexibility, the Company must take into consideration the uncertainties and risks associated with the energy industry. Uncertainties assessed in this 2017 Plan include:

- load growth in the Company's service territory;
- effective, anticipated, and stayed EPA regulations concerning air, water, and solid waste constituents (as shown in Figure 3.1.3.2), including the CPP;
- fuel prices;
- cost and performance of energy technologies;
- renewable energy requirements including integration of intermittent renewable generation;
- current and future DSM; and

- retirement of Company-owned generation units.

The Company developed this 2017 Plan based on its evaluation of various supply- and demand-side alternatives and in consideration of acceptable levels of risk that maintain the option to develop a diverse mix of resources for the benefit of its customers. Various planning groups throughout the Company provided input and insight into evaluating all viable options, including existing generation, DSM programs, and new (both traditional and alternative) resources to meet the growing demand in the Company's service territory. The IRP process began with the development of the Company's long-term load forecast, which indicates that over the Planning Period (2018 – 2032), the DOM LSE is expected to experience annual increases of 1.3% in both future peak and energy requirements. Collectively, these elements assisted in determining updated capacity and energy requirements as illustrated in Figures 1.3.1 and 1.3.2.

**Figure 1.3.1 - Current Company Capacity Position (2018 - 2032)**

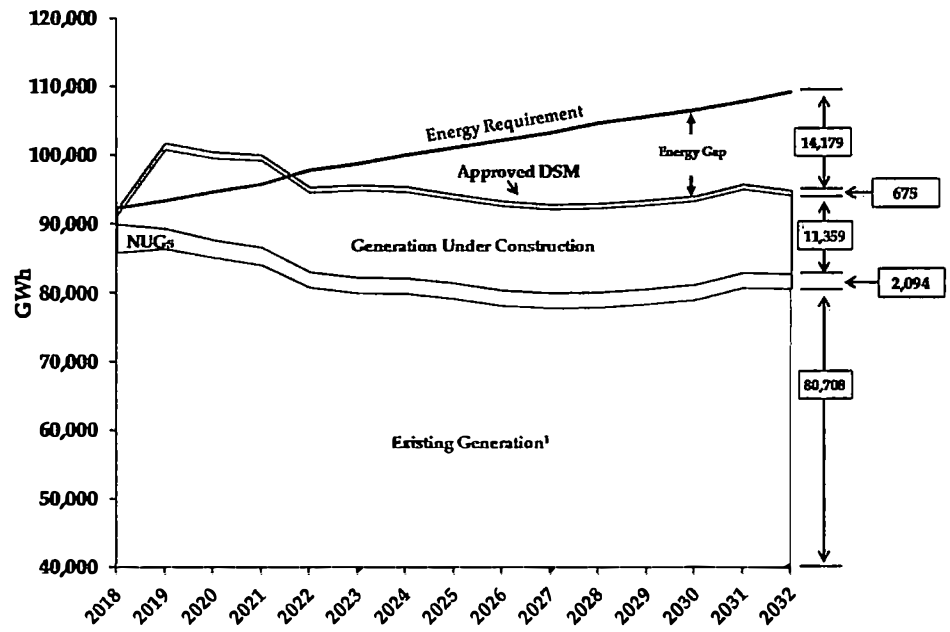



Note: The values in the boxes represent total capacity in 2032.

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

2) See Section 4.2.2.

**Figure 1.3.2 - Current Company Energy Position (2018 - 2032)**




Note: The values in the boxes represent total energy in 2032.

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

### 1.3.1 EPA's CLEAN POWER PLAN

The importance of lower carbon emitting generation was reinforced on October 23, 2015, with the EPA's promulgation of its final GHG regulations. These regulations, known as the Clean Power Plan (also referred to as CPP or 111(d) Rule), would significantly reduce carbon emissions from electric generating units ("EGUs") by mandating reductions in carbon emissions. The CPP offers each state two sets of options to achieve compliance and originally included a FIP associated with each set. On April 3, 2017, the EPA issued a notice withdrawing the proposed FIP.[3] These options include Rate-Based programs designed to reduce overall generating fleet $CO_2$ intensity (i.e., the rate of $CO_2$ emissions as determined by dividing the pounds of $CO_2$ emitted by each megawatt-hour ("MWh") of electricity produced), referred to hereinafter as Intensity-Based programs. The options also include Mass-Based programs designed to reduce total annual fleet $CO_2$ emissions based on tonnage.[4] The CPP, as issued, required each state to submit a state implementation plan ("SIP") to the EPA detailing how it will meet its individual state targets no later than September 6, 2018.

With the Stay Order remaining in place, and the recent change in federal administration, many states, including Virginia, West Virginia and North Carolina, have deferred CPP compliance planning given the high level of uncertainty associated with the rule. West Virginia is challenging

[3] See https://www.gpo.gov/fdsys/pkg/FR-2017-04-03/pdf/2017-06518.pdf.

[4] Although the CPP's enforceability and legal effectiveness have been stayed by the Supreme Court, for purposes of this 2017 Plan, the Company will discuss the provisions of the CPP as if the rules are enforceable and in effect both from a substantive and implementation timeframe standpoint, as a reasonable proxy for analysis of a low carbon future.

the CPP in Court. North Carolina has withdrawn its earlier challenge to the CPP, noting that its challenge no longer represented the state's goal of investing in cleaner energy, but is not formally pursuing development of a SIP at this time. In Virginia, under an Executive Order issued by the Governor in June 2016, the Secretary of Natural Resources has convened a work group charged with recommending concrete steps to reduce carbon pollution from Virginia's power plants. This could include measures aimed at achieving $CO_2$ reduction levels similar to those mandated by the CPP, among other options. The work group is to submit a report with recommendations to the Governor by May 31, 2017. In addition, on April 17, 2017, the Virginia Department of Environmental Quality ("DEQ") issued a notice seeking public comment on a petition it received from a member of the public requesting that the State Air Pollution Control Board direct DEQ to promulgate regulations to reduce $CO_2$ emissions from power plants in Virginia by 30% from 2015 levels by 2030.[5]

Based on the Company's review of the CPP, for each of the two options (i.e., Intensity-Based and Mass-Based) for compliance, there are three sub-options, resulting in a total of six possible options for state compliance. They are as follows:

Intensity-Based Programs

- Intensity-Based Dual Rate Program: An Intensity-Based $CO_2$ program that requires each existing: a) fossil fuel-fired electric steam generating unit to achieve an intensity target of 1,305 lbs of $CO_2$ per MWh by 2030 and beyond; and b) natural gas combined-cycle ("NGCC") unit to achieve an intensity target of 771 lbs of $CO_2$ per MWh by 2030, and beyond. These standards, which are based on national $CO_2$ performance rates, are consistent for any state that opts for this program.
- Intensity-Based State Average Program: An Intensity-Based $CO_2$ program that requires all existing fossil fuel-fired generation units in the state to collectively achieve a portfolio average intensity target by 2030, and beyond. In Virginia, that average intensity is 934 lbs of $CO_2$ per MWh by 2030, and beyond. The 2030 and beyond targets for West Virginia and North Carolina are 1,305 lbs of $CO_2$ per MWh and 1,136 lbs of $CO_2$ per MWh, respectively.
- A Unique State Intensity-Based Program: A unique state Intensity-Based program designed so that the ultimate state level intensity target does not exceed those targets described in the two Intensity-Based programs set forth above.

Mass-Based Programs

- Mass-Based Existing Units Program: A Mass-Based program that limits the total $CO_2$ emissions from a state's existing fleet of fossil fuel-fired generating units. In Virginia, this limit is 27,433,111 short tons of $CO_2$ in 2030 and beyond. The corresponding limits for West Virginia and North Carolina, in 2030 and beyond, are 51,325,342 short tons of $CO_2$ and 51,266,234 short tons of $CO_2$, respectively.
- Mass-Based All Units Program: A Mass-Based program that limits the total $CO_2$ emissions from both the existing fleet of fossil-fuel fired generating units and all new generation units

[5] See http://register.dls.virginia.gov/issue.aspx?voliss=33:17&type=4.

in the future. In Virginia, this limit is 27,830,174 short tons of $CO_2$ by 2030. The corresponding limits for West Virginia and North Carolina, in 2030 and beyond, are 51,857,307 short tons of $CO_2$ and 51,876,856 short tons of $CO_2$, respectively.

- Unique State Mass-Based Program: A unique state Mass-Based approach limiting total $CO_2$ emissions.

While it remains uncertain what, if any, form the CPP will ultimately take, the Company anticipates that the Unique State Intensity-Based and Mass-Based Programs identified above are unlikely choices for the states in which the Company's generation fleet is located. This is partly due to the time constraints for states to implement programs and partly due to the restrictions that a unique state program would impose on operating flexibility and compliance coordination among states. In addition, the Company further anticipates that an Intensity-Based State Average Program would be an unlikely choice for Virginia, West Virginia, or North Carolina given this type of program is not considered "trading ready" by the EPA and thus diminishes the likelihood of emission rate credits ("ERCs") trading under this type of program. Therefore, the 2017 Plan assesses the remaining three programs that would likely be implemented in Virginia, West Virginia, and North Carolina, if the CPP were to remain in its present form. Per the CPP, compliance for each of the three programs would begin in 2022, and includes interim $CO_2$ targets that must be achieved prior to the final targets in 2030 and beyond. Figures 1.3.1.1 through 1.3.1.3 identify these interim targets per program per state.

**Figure 1.3.1.1 - CPP Implementation Options - Virginia**

| | Intensity-Based Program Existing Units (lbs/Net MWh) | | Mass-Based Program (short tons) | |
|---|---|---|---|---|
| | Dual Rate (EGU specific) | | | |
| | Steam | NGCC | Emissions Cap Existing Units Only | Emissions Cap Existing and New Units |
| 2012 Baseline | | | 27,365,439 | |
| Interim Step 1 Period 2022 - 2024 | 1,671 | 877 | 31,290,209 | 31,474,885 |
| Interim Step 2 Period 2025 - 2027 | 1,500 | 817 | 28,990,999 | 29,614,008 |
| Interim Step 3 Period 2028 - 2029 | 1,380 | 784 | 27,898,475 | 28,487,101 |
| Final Goal 2030 and Beyond | 1,305 | 771 | 27,433,111 | 27,830,174 |

**Figure 1.3.1.2 - CPP Implementation Options - West Virginia**

| | Intensity-Based Program Existing Units (lbs/Net MWh) | | Mass-Based Program (short tons) | |
|---|---|---|---|---|
| | Dual Rate (EGU specific) | | | |
| | Steam | NGCC | Emissions Cap Existing Units Only | Emissions Cap Existing and New Units |
| 2012 Baseline | | | 72,318,917 | |
| Interim Step 1 Period 2022 - 2024 | 1,671 | 877 | 62,557,024 | 62,804,443 |
| Interim Step 2 Period 2025 - 2027 | 1,500 | 817 | 56,762,771 | 57,597,448 |
| Interim Step 3 Period 2028 - 2029 | 1,380 | 784 | 53,352,666 | 54,141,279 |
| Final Goal 2030 and Beyond | 1,305 | 771 | 51,325,342 | 51,857,307 |

**Figure 1.3.1.3 - CPP Implementation Options - North Carolina**

| | Intensity-Based Program Existing Units (lbs/Net MWh) | | Mass-Based Program (short tons) | |
|---|---|---|---|---|
| | Dual Rate (EGU specific) | | Emissions Cap | Emissions Cap |
| | Steam | NGCC | Existing Units Only | Existing and New Units |
| 2012 Baseline | | | 58,566,353 | |
| Interim Step 1 Period 2022 - 2024 | 1,671 | 877 | 60,975,831 | 61,259,834 |
| Interim Step 2 Period 2025 - 2027 | 1,500 | 817 | 55,749,239 | 56,707,332 |
| Interim Step 3 Period 2028 - 2029 | 1,380 | 784 | 52,856,495 | 53,761,714 |
| Final Goal 2030 and Beyond | 1,305 | 771 | 51,266,234 | 51,876,856 |

Reflecting this uncertainty and the need to plan for a variety of contingencies, the Company presents in this 2017 Plan, eight different Alternative Plans designed to meet the needs of its customers in a future with or without the CPP. To assess a future without the CPP, the 2017 Plan includes an alternative designed using least-cost planning techniques and assuming no additional carbon regulation is implemented through the CPP, other legislation, or rules. This alternative is identified as "Plan A: No CPP" or "Plan A." Seven additional Plans are designed to be compliant with the CPP as set forth in the 2016 Plan Final Order ("CPP-Compliant Plans"). All utilize one of the three program options likely to be implemented in the Commonwealth of Virginia, where the bulk of the Company's generation assets are located.

### 1.3.2 SCC's 2016 PLAN FINAL ORDER

As mentioned above, the SCC's 2016 Plan Final Order found, in part, the 2016 Plan to be in the public interest for the specific and limited purpose of filing the planning document. The SCC went on to state:

> While some parties and members of the public participating in this case have suggested that the uncertainty regarding the CPP has diminished, the CPP is currently stayed by the Supreme Court of the United States. Even if the CPP is upheld, it could be several years before a final State Implementation Plan is approved. Until such time, an IRP can only present scenarios that are based on compliance assumptions, rather than the specific requirements of compliance. The only exception is a least-cost base plan, which is not designed to comply with the CPP, and can be more readily determined by modeling.
>
> For next year's IRP filing, we direct the Company to model and present scenarios similar to those included in the current IRP, updating the data and assumptions as appropriate. These scenarios shall include, at a minimum, the following:
>
> 1) Least-cost base plan (non-compliant with the CPP);
> 2) Least-cost CPP-compliant intensity-based plan (regional and island approaches);

3) Least-cost CPP-compliant mass-based plan (regional and island approaches);
4) Federal implementation plan;[6] and
5) Company-preferred plan, if any.

Dominion shall run these scenarios without capping the amount of third-party, energy and capacity market purchases or sales that the model would select to achieve a least-cost plan for the compliance and non-compliance scenarios.[7]

## 1.4 2017 PLAN

Since the issuance of the Company's 2016 Plan, little if any federal regulatory progress has been achieved with respect to the CPP. As such, the exact nature of future $CO_2$ regulation of the U.S. electric sector remains highly uncertain, even though the Company believes some form of $CO_2$ regulation is virtually assured in the future. Therefore, at this time and as was the case in the 2015 and 2016 Plans, the Company is unable to identify a "Preferred Plan" or a recommended path forward beyond the STAP. Rather, in compliance with the 2016 Plan Final Order, the Company is presenting the Alternative Plans that are described below. The Company believes the Alternative Plans represent plausible future paths for meeting the future electric needs of its customers while responding to the regulatory requirements associated with the 2016 Plan Final Order.

All of the Alternative Plans were designed using least-cost planning techniques and are as follows:

- Plan A: No CPP: This Alternative Plan anticipates a future without any new regulations or restrictions on $CO_2$ emissions. Plan A selects significant levels of solar PV generation, as it is currently cost competitive with other traditional generation technologies as described above.

Should the CPP ultimately be upheld as promulgated, and consistent with the SCC's 2016 Plan Final Order, the 2017 Plan includes CPP-Compliant Plans that comply with the three programs that may be adopted by the Commonwealth of Virginia. These three programs are: i) an Intensity-Based Dual Rate Program; ii) a Mass-Based Existing Units Program; or iii) a Mass-Based All Units Program. Also consistent with the 2016 Plan Final Order, each of these programs is modeled under two different scenarios. Scenario 1 assumes that the Company does not use the $CO_2$ allowance or ERC markets to comply with the CPP, but, rather, complies solely through generation portfolio modifications and/or market purchases of capacity and energy. In other words, $CO_2$ emissions from the Company's applicable generating units cannot exceed the actual limits set forth by the CPP. Scenario 2 assumes the Company utilizes the $CO_2$ allowance or ERC markets to comply with the CPP. In Scenario 2, the Company's applicable generating units can exceed the $CO_2$ limits set forth by the CPP, but are subject to additional $CO_2$ allowance or ERC costs. The Alternative Plans modeled without the trading scenario (Scenario 1) are denoted with a superscript $^{NT}$ (no $CO_2$ trading); Alternative Plans that are modeled with the $CO_2$ trading scenario (Scenario 2) are denoted with a superscript $^{T}$ ($CO_2$ trading). Consistent with the 2016 Plan Final Order, neither scenario contains market purchases of capacity and energy that exceed the 5,200 MW physical electric

[6] The Company noted previously that the FIP has been withdrawn.

[7] 2016 Plan Final Order at 4-5 (internal citations omitted).

transmission import/export limits associated with the Company's service territory. The CPP-Compliant Plans within each scenario are summarized in Figure 1.4.1.

**Figure 1.4.1 - CPP-Compliant Plan Scenarios**

| Scenario 1: No $CO_2$ Trading | | | |
|---|---|---|---|
| Plan $B^{NT}$:<br>Intensity-Based<br>Dual Rate<br>("Plan $B^{NT}$" or "Plan B") | Plan $D^{NT}$:<br>Mass-Based<br>Existing Units<br>("Plan $D^{NT}$" or "Plan D") | Plan $F^{NT}$:<br>Mass-Based<br>All Units<br>("Plan $F^{NT}$" or "Plan F") | Plan $H^{NT}$:<br>New Nuclear<br>("Plan $H^{NT}$" or "Plan H") |

| Scenario 2: $CO_2$ Trading | | |
|---|---|---|
| Plan $C^T$:<br>Intensity-Based<br>Dual Rate<br>("Plan $C^T$" or "Plan C") | Plan $E^T$:<br>Mass-Based<br>Existing Units<br>("Plan $E^T$" or "Plan E") | Plan $G^T$:<br>Mass-Based<br>All Units<br>("Plan $G^T$" or "Plan G") |

Alternative Plans in Scenario 1 ($B^{NT}$, $D^{NT}$, $F^{NT}$, and $H^{NT}$) were designed using least-cost analytical methods given the constraints of the CPP state compliance program options that had the highest likelihood of adoption by the Commonwealth of Virginia. Further, each of these four CPP-Compliant Plans were designed in accordance with the final CPP, with the intent that the Company would achieve CPP compliance independently, with no need to rely on purchasing $CO_2$ allowances or ERCs. While these four Alternative Plans were developed with the assumption that the Company would achieve CPP compliance via generation portfolio design, the Company expects markets for ERCs and $CO_2$ allowances to evolve and favors CPP programs that encourage trading of ERCs and/or $CO_2$ allowances. Trading provides a clear market price signal, which is the most efficient means of emission mitigation. Also, trading offers flexibility in the event of years with unit outages or non-normal weather. However, planning for significant $CO_2$ trading or importing power to meet rigid $CO_2$ targets is not the course the Company believes is appropriate given the high uncertainty with $CO_2$ pricing and availability. Rather, a balanced approach considering both generating assets (renewables, DSM, and nuclear) and trading is prudent.

Alternative Plans in Scenario 2 ($C^T$, $E^T$, and $G^T$) were designed using least-cost analytical methods given the constraints of the CPP state compliance program options that have the highest likelihood of adoption by the Commonwealth of Virginia. These Alternative Plans, however, were designed assuming the Company could freely trade $CO_2$ allowances of ERCs in order to comply with the CPP.

As was stated in the 2016 Plan and based on this analysis, should the CPP be upheld in its current form, the Company believes that the adoption of a CPP compliance program option that is consistent with an Intensity-Based Dual Rate Program (Plans $B^{NT}$ and $C^T$) offers the most cost-effective and flexible option for achieving compliance in the Commonwealth of Virginia. This flexibility associated with an Intensity-Based Dual Rate Program directly corresponds to the quantity of renewable resources, energy efficiency, or resources purchased within or outside the Commonwealth. The availability of these resources needs to be contrasted against Mass-Based programs which, by definition, dictate adherence to hard caps on $CO_2$ emissions that limit the compliance options available to the Commonwealth, which in all likelihood will further increase cost and rate volatility for customers.

Going forward, the Company will continue to analyze both the operational implications and challenges of meeting carbon restrictions, adding renewable generation, as well as options for keeping existing generation, including coal units operational, when doing so is in the best interest of customers, the Commonwealth, and in compliance with federal and state laws and regulations. The Company will also continue to work to maintain its long-standing service tradition of providing competitive rates, a diverse mix of generation, and reliable service. The Company continues to believe that these three factors are closely interrelated.

As mentioned above, to assess the uncertainty and risks associated with external market and environmental factors, the Company developed the Alternative Plans representing plausible future paths the Company could follow to meet the future electric power needs of its customers. There are several elements common to all of the Alternative Plans. Each Alternative Plan includes at least 5,200 MW (nameplate) of new solar generation within the Study Period (2018 – 2042), with at least 3,200 MW (nameplate) of new solar capacity being added by the end of the Planning Period (2032).

The Alternative Plans also include the Virginia Offshore Wind Technology Advancement Project ("VOWTAP"), 12 MW (nameplate), as early as 2021; 990 MW (nameplate) of Virginia and North Carolina solar generation from NUGs either currently or expected to be under long-term contracts to the Company; 56 MW (nameplate) of solar generation already in service from Company-owned utility-scale facilities located in Virginia; and Greensville County Power Station, 1,585 MW, which is currently under construction and planned to enter commercial operations by 2019. Lastly, the Alternative Plans include 7.7 MW (nameplate) (8 MW Direct Current ("DC")) from the Company's Solar Partnership Program ("SPP"). The SPP initiative installs Company-owned solar arrays on rooftops and other spaces rented from customers at sites throughout the service area.

The Alternative Plans also assume that all of the Company's existing nuclear generation will receive 20-year license extensions that lengthen their useful lives beyond the Study Period. The license extensions for Surry Units 1 and 2 are included in 2033 and 2034, respectively, as well as the license extensions for North Anna Units 1 and 2 in 2038 and 2040, respectively.

The Alternative Plans are discussed further below and are summarized in Figure 1.4.2.

## Figure 1.4.2 - 2017 Alternative Plans

| Year | Plan A: No CPP | Plan B[NT]: Intensity-Based Dual Rate | Plan C[1]: Intensity-Based Dual Rate | Plan D[NT]: Mass-Based Existing Units | Plan E[1]: Mass-Based Existing Units | Plan F[NT]: Mass-Based All Units | Plan G[1]: Mass-Based All Units | Plan H[NT]: New Nuclear |
|---|---|---|---|---|---|---|---|---|
| | | Compliant with Clean Power Plan | | | | | | |
| Approved and Proposed DSM: 426 MW, 1,221 GWh by 2032 | | | | | | | | |
| 2018 | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] |
| 2019 | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR |
| 2020 | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) |
| 2021 | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) |
| 2022 | SLR (240 MW) | SLR (240 MW)<br>CH 3-4[3], YT3[3] | SLR (240 MW)<br>CH 3-4[3], YT3[3] | SLR (240 MW)<br>CH 3-4[3], YT3[3] | SLR (240 MW)<br>CH 3-4[3], YT3[3] | CT<br>SLR (240 MW)<br>CH 3-4[3], YT3[3] | CT<br>SLR (240 MW)<br>CH 3-4[3], YT3[3] | CT<br>SLR (240 MW)<br>CH 3-4[3], YT3[3] |
| 2023 | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (160 MW) | SLR (240 MW) | CT<br>SLR (160 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) |
| 2024 | CT<br>SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) |
| 2025 | SLR (240 MW) | 3x1 CC<br>SLR (240 MW) | 3x1 CC<br>SLR (240 MW) | 3x1 CC<br>SLR (240 MW) | 3x1 CC<br>SLR (240 MW) | CT<br>SLR (240 MW)<br>MB 1-2[4], CL 1-2[4] | SLR (240 MW) | SLR (240 MW)<br>MB 1-2[4], CL 1-2[4] |
| 2026 | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) |
| 2027 | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | CT<br>SLR (160 MW) | SLR (240 MW) | SLR (240 MW) |
| 2028 | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) |
| 2029 | CT<br>SLR (240 MW) | SLR (240 MW) | CT<br>SLR (160 MW) | CT<br>SLR (240 MW) | CT<br>SLR (160 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | SLR (240 MW) |
| 2030 | SLR (240 MW) | CT<br>SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | NA3<br>SLR (240 MW) |
| 2031 | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | SLR (240 MW) | SLR (240 MW) |
| 2032 | SLR (240 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) |

Key: CC: Combined-Cycle; CH: Chesterfield Power Station; CL: Clover Power Station; CT: Combustion Turbine (2 units); Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; NA3: North Anna 3; PP5: Possum Point Unit 5; SLR: Generic Solar; SLR NUG: Solar NUG; SNCR: Selective Non-Catalytic Reduction; SPP: Solar Partnership Program; VOWTAP: Virginia Offshore Wind Technology Advancement Project; YT: Yorktown Unit.

Note: 1) Solar NUGs include 950 MW of NC solar NUGs and 40 MW of VA solar NUGs by 2022.
2) SPP started in 2014 and continues through 2017.
3) The potential retirements of Chesterfield Units 3 & 4 and Yorktown Unit 3 are modeled in all CPP-Compliant Plans.
4) The potential retirements of Clover Units 1 & 2 and Mecklenburg Units 1 & 2 are modeled in Plan F[NT] and Plan H[NT].

## Common elements of the Alternative Plans

The following are common to the Alternative Plans through the Planning Period:

- **Demand-Side Resources:**
  - approved DSM programs reaching approximately 348 MW by 2032;
  - proposed DSM programs reaching approximately 78 MW by 2032;
- **Generation under Construction:**
  - Greensville County Power Station, approximately 1,585 MW of natural gas-fired CC capacity by 2019;
  - SPP, consisting of 7.7 MW (nameplate) of capacity of solar distributed generation (or "DG") installed by the end of 2017;
- **Generation under Development:**
  - VOWTAP, approximately 12 MW (nameplate) as early as 2021;
- **Potential Generation:**
  - three combustion turbine ("CT")[8] plants totaling approximately 1,374 MW by 2032;
  - solar PV generation totaling approximately 3,200 MW (nameplate) by 2032;
- **NUGs:**
  - 950 MW (nameplate) of North Carolina solar NUGs by 2022;
  - 40 MW (nameplate) of Virginia solar NUGs by 2017;
- **Retrofit:**
  - Possum Point Power Station Unit 5, retrofitted with Select Non-Catalytic Reduction ("SNCR") by 2019;
- **Extensions:**
  - Surry Units 1 and 2, license extensions of 20 years by 2033 and 2034; and
  - North Anna Units 1 and 2, license extensions of 20 years by 2038 and 2040.

In addition to the supply-side/DSM initiatives that are common to all Alternative Plans, the CPP-Compliant Plans model the potential retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW) and Yorktown Unit 3 (790 MW) in 2022. Additional resources and retirements included in the Alternative Plans are described below:

- **Generation Under Development:**
  - Plan $H^{NT}$: New Nuclear includes 1,452 MW of nuclear generation.

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

- **Potential Generation:**
  - Plan A: No CPP includes one CT plant of approximately 458 MW and an additional 160 MW (nameplate) of solar by 2032 (totaling 5,600 MW (nameplate) by 2042);
  - Plan B$^{NT}$: Intensity-Based Dual Rate includes one 3x1 CC unit of approximately 1,591 MW and an additional 160 MW (nameplate) of solar by 2032 (totaling 5,760 MW (nameplate) by 2042);
  - Plan C$^{T}$: Intensity-Based Dual Rate includes one 3x1 CC unit of approximately 1,591 MW, and an additional 80 MW (nameplate) of solar by 2032 (totaling 5,680 MW (nameplate) by 2042);
  - Plan D$^{NT}$: Mass-Based Existing Units includes one 3x1 CC unit of approximately 1,591 MW and an additional 80 MW (nameplate) of solar by 2032 (totaling 5,680 MW (nameplate) by 2042);
  - Plan E$^{T}$: Mass-Based Existing Units includes one 3x1 CC unit of approximately 1,591 MW and an additional 80 MW (nameplate) of solar by 2032 (totaling 5,280 MW (nameplate) by 2042);
  - Plan F$^{NT}$: Mass-Based All Units includes five CT plants of 2,290 MW by 2032 and 5,280 MW (nameplate) of solar by 2042;
  - Plan G$^{T}$: Mass-Based All Units includes four CT plants of 1,832 MW and an additional 160 MW (nameplate) of solar by 2032 (totaling 5,680 MW (nameplate) by 2042); and
  - Plan H$^{NT}$: New Nuclear includes two CT plants of 916 MW and an additional 160 MW (nameplate) of solar by 2032 (totaling 5,760 MW (nameplate) by 2042).
- **Retirements:**
  - Plan F$^{NT}$: Mass-Based All Units includes the potential retirements of Mecklenburg Units 1 (69 MW) and 2 (69 MW) and Clover Units 1 (220 MW) and 2 (219 MW) by 2025; and
  - Plan H$^{NT}$: New Nuclear includes the potential retirements of Mecklenburg Units 1 (69 MW) and 2 (69 MW) and Clover Units 1 (220 MW) and 2 (219 MW) by 2025.

Figure 1.4.3 illustrates the renewable resources included in the Alternative Plans over the Study Period (2018 - 2042).

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## Figure 1.4.3 - Renewable Resources in the Alternative Plans through the Study Period

| Resource | Nameplate MW | Plan A: No CPP | Compliant with the Clean Power Plan | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Plan B$^{NT}$: Intensity-Based Dual Rate | Plan C$^{T}$: Intensity-Based Dual Rate | Plan D$^{NT}$: Mass-Based Existing Units | Plan E$^{T}$: Mass-Based Existing Units | Plan F$^{NT}$: Mass-Based All Units | Plan G$^{T}$: Mass-Based All Units | Plan H$^{NT}$: New Nuclear |
| Existing Resources[1] | 610 | x | x | x | x | x | x | x | x |
| VCHEC Biomass | 61 | x | x | x | x | x | x | x | x |
| SPP | 8 | x | x | x | x | x | x | x | x |
| Solar NUGs[2] | 990 | x | x | x | x | x | x | x | x |
| VOWTAP | 12 | x | x | x | x | x | x | x | x |
| Solar PV | Varies | 5,600 | 5,760 | 5,680 | 5,680 | 5,280 | 5,280 | 5,680 | 5,760 |

Note: 1) Existing Resources include hydro, biomass (excluding VCHEC), and solar.
2) Solar NUGs include forecasted VA and NC solar NUGs through 2022.

To meet the projected demand of electric customers and annual reserve requirements throughout the Planning Period, the Company has identified additional resources utilizing a balanced mix of supply- and demand-side resources and market purchases to fill the capacity gap shown in Figure 1.3.1. These resources are illustrated in Appendix 1A for all Alternative Plans.

The 2017 Plan balances the Company's commitment to operate in an environmentally-responsible manner with its obligation to provide reliable and reasonably-priced electric service. The Company has established a strong track record of environmental protection and stewardship and has spent more than $1.8 billion since 1998 to make environmental improvements to its generation fleet. These improvements have already reduced emissions by 81% for nitrogen oxide ("$NO_x$"), 95% for mercury ("Hg"), and 96% for sulfur dioxide ("$SO_2$") from 2000 levels.

Since numerous EPA regulations are effective, anticipated, stayed, or under EPA review (as further shown in Figure 3.1.3.2), the Company continuously evaluates various alternatives with respect to its existing units. Coal-fired and/or oil-fired units that have limited environmental controls are considered at-risk units. Environmental compliance offers three options for such units: i) retrofit with additional environmental control reduction equipment, ii) repower (including co-fire), or iii) retire the unit.

The generators listed as potential retirements in each of the Alternative Plans are currently being examined for repowering and co-firing. The preliminary results of this analysis are discussed in Section 6.9.

The generators listed below should be considered as tentative for retirement only. The Company's final decisions regarding any unit retirement will be made at a future date once all analysis has been completed. For purposes of this 2017 Plan, the assumptions regarding generation unit retrofit, repower, and retire are as follows:

### Retrofit

- 786 MW of heavy oil-fired generation retrofitted with new SNCR controls at Possum Point Unit 5 by 2019 (all Alternative Plans).

### Repower

- No units selected for repower at this time.

### Retire

- 790 MW of oil-fired generation at Yorktown Unit 3, to be potentially retired in 2022 (all CPP-Compliant Plans);
- 261 MW of coal-fired generation at Chesterfield Units 3 and 4, to be potentially retired in 2022 (all CPP-Compliant Plans); and
- 138 MW of coal-fired generation at Mecklenburg Units 1 and 2 and 439 MW of coal-fired generation at Clover Units 1 and 2, to be potentially retired by 2025 (in Plan $F^{NT}$ and Plan $H^{NT}$).

While the Planning Period is a 15-year outlook, the Company is mindful of the scheduled license expirations of Company-owned nuclear units: Surry Unit 1 (838 MW) and Surry Unit 2 (838 MW) in 2032 and 2033, respectively, and North Anna Unit 1 (838 MW) and North Anna Unit 2 (834 MW) in 2038 and 2040, respectively. At the current time, the Company believes it will be able to obtain license extensions on all four nuclear units at a reasonable cost; therefore, it has included the extensions in all Alternative Plans.

While not definitively choosing one plan or a combination of plans beyond the STAP, the Company remains committed to pursue the development of resources that meets the needs of customers discussed in the STAP, while supporting the fuel diversity needed to minimize risks associated with changing market conditions, industry regulations, and customer preferences.

# CHAPTER 2 – LOAD FORECAST

## 2.1 FORECAST METHODS

The Company uses two econometric models with an end-use orientation to forecast sales, energy, and peak demand. The first is a customer class level model ("sales model") and the second is an hourly load system level model ("system model"). The models used to produce the Company's load forecast have been developed, enhanced, and re-estimated annually for over 20 years, but have remained substantially consistent year-over-year.

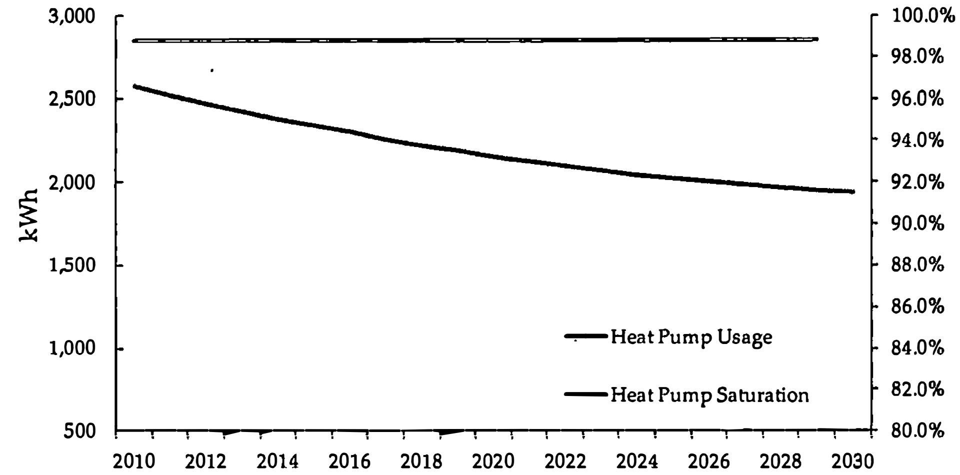
The sales model incorporates separate monthly sales equations for residential, commercial, industrial, public authority, street and traffic lighting, and wholesale customers, as well as other Load Serving Entities ("LSEs") in the Dominion Zone ("DOM Zone"), all of which are in the PJM RTO. The monthly sales equations are specified in a manner that produces estimates of heating load, cooling load, and non-weather sensitive load.

Variables included in each of the class monthly sales equations are as follows:

- **Residential Sales equation:** Income, electric prices, unemployment rate, number of customers, appliance saturations, appliance efficiencies, building permits, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Commercial Sales equation:** Virginia Gross State Product ("GSP"), electric prices, natural gas prices, number of customers, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Industrial Sales equation:** Employment in manufacturing, electric prices, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Public Authorities Sales equation:** Employment for Public Authority, number of customers, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Street and Traffic Lighting Sales equation:** Number of residential customers and calendar month variables to capture seasonal impacts.
- **Wholesale Customers and Other LSEs Sales equations:** A measure of non-weather sensitive load derived from the residential equation, heating and air-conditioning appliance stocks, number of days in the month, weather, and calendar month variables to capture seasonal and other effects.

The Residential Sales Model also includes an algorithm that dynamically adjusts forecasted appliance saturation and usage based on historical trends. These historical trends are determined through appliance data collected through surveys from the Company's residential customers. Figure 2.1.1 shows historical and forecasted saturation and usage data of a residential heat pump (cooling).

**Figure 2.1.1 - Residential Heat Pump (Cooling) Saturation and Usage**




The most recent residential customer appliance survey was completed in 2016. One noteworthy item from the results of that survey is with respect to residential lighting. Between the time of the 2013 appliance survey and the 2016 appliance survey, a significant change was observed in the penetration of light emitting diode ("LED") lighting amongst the Company's residential customers. In order to account for this new lighting trend, the Company modified its Residential Sales Model in a manner that will dynamically reduce forecasts of residential lighting load as more and more LED lighting penetrates the Company's customer base. The residential lighting saturation and usage used in the load forecast for the 2017 Plan is shown in Figures 2.1.2 and 2.1.3, respectively. The lighting saturation trajectory is included in the Company's 2017 load forecast.

**Figure 2.1.2 - Residential Lighting Saturation**

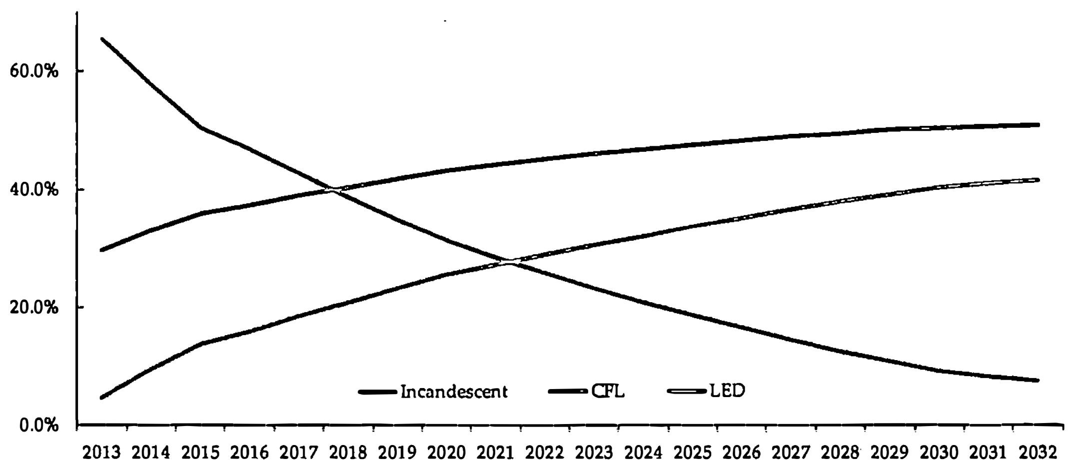
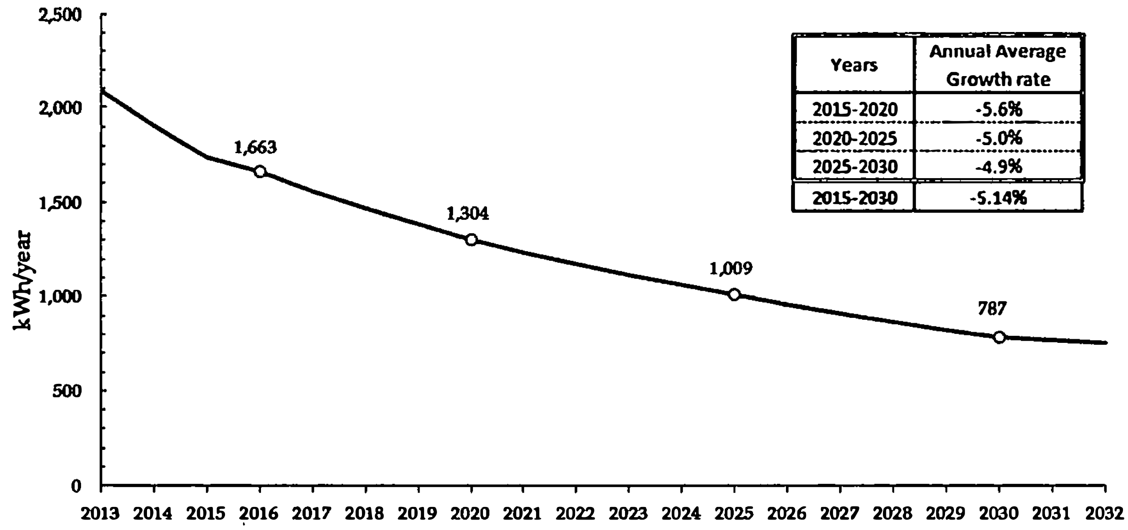


**Figure 2.1.3 - Residential Lighting Usage**




The Company's second model, the system model, utilizes hourly DOM Zone load data and is estimated in one stage. The DOM Zone load is modeled as a function of detailed specification of weather involving interactions between both current and lagged values of temperature, humidity, wind speed, sky cover, and precipitation for five weather stations in order to capture heating load and cooling load.

In addition to the two weather variables, the model uses estimates of non-weather sensitive load derived from the sales model and residential heating and cooling appliance stocks as explanatory variables. The equation also compensates for customer class proportions of total load acquired from the sales model. The hourly model also uses calendar month variables to capture time of day, day of week, holiday, other seasonal effects and unusual events such as hurricanes. Separate equations are estimated for each hour of the day.

Hourly loads for wholesale customers and other LSEs within the DOM Zone are also modeled as a function of the DOM Zone load since they face similar weather and economic activity. LSE peak and energy is based on a monthly 10-year average percentage. These percentages are then applied to the forecasted zonal peak and energy to calculate LSE peak and energy. The DOM LSE load is derived by subtracting the other LSEs from the DOM Zone load. DOM LSE load and firm contractual obligations are used as the total load obligation for the purpose of this 2017 Plan.

Forecasts are produced by simulating the model over actual weather data from the past 30 years along with projected economic conditions. Sales estimates from the sales model and energy output estimates from the system model are compared and reconciled appropriately in the development of the final sales, energy, and peak demand forecast that is utilized in this 2017 Plan.

## 2.2 HISTORY & FORECAST BY CUSTOMER CLASS & ASSUMPTIONS

The Company is typically a summer peaking system; however, during the winter period of both 2014 and 2015, all-time DOM Zone peaks were set at 19,785 MW and 21,651 MW respectively. The historical DOM Zone summer peak growth rate has averaged about 1.2% annually over 2002 - 2016. The annual average energy growth rate over the same period is approximately 1.0%. Historical DOM Zone peak load and annual energy output along with a 15-year forecast are shown in Figures 2.2.1 and 2.2.2. Figure 2.2.1 also reflects the actual winter peak demand. DOM LSE peak and energy requirements are both estimated to grow annually at approximately 1.3% throughout the Planning Period. Additionally, a 10-year history and 15-year forecast of sales and customer count at the system level, as well as a breakdown at Virginia and North Carolina levels are provided in Appendices 2A to 2F. Appendix 2G provides a summary of the summer and winter peaks used in the development of this 2017 Plan. Finally, the three-year historical load and 15-year projected load for wholesale customers are provided in Appendix 3L.

**Figure 2.2.1 - DOM Zone Peak Load**

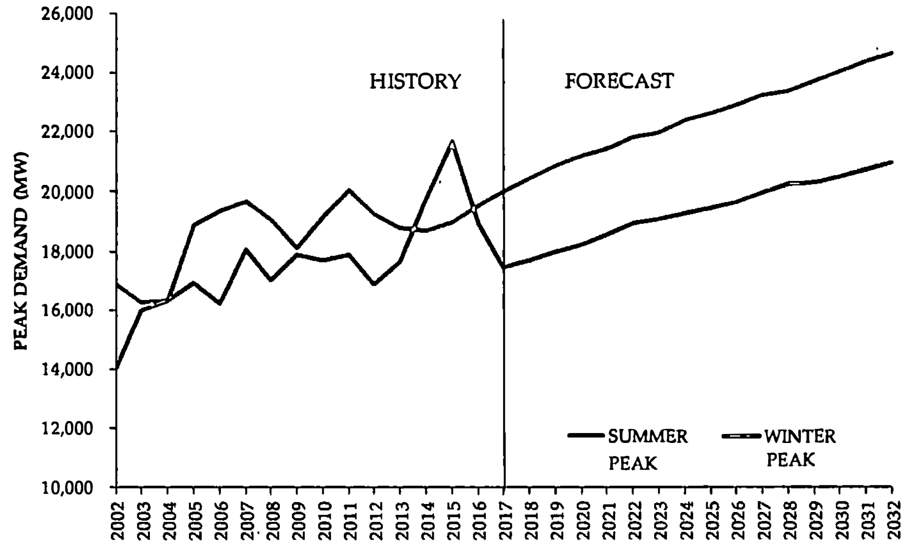



**Figure 2.2.2 - DOM Zone Annual Energy**

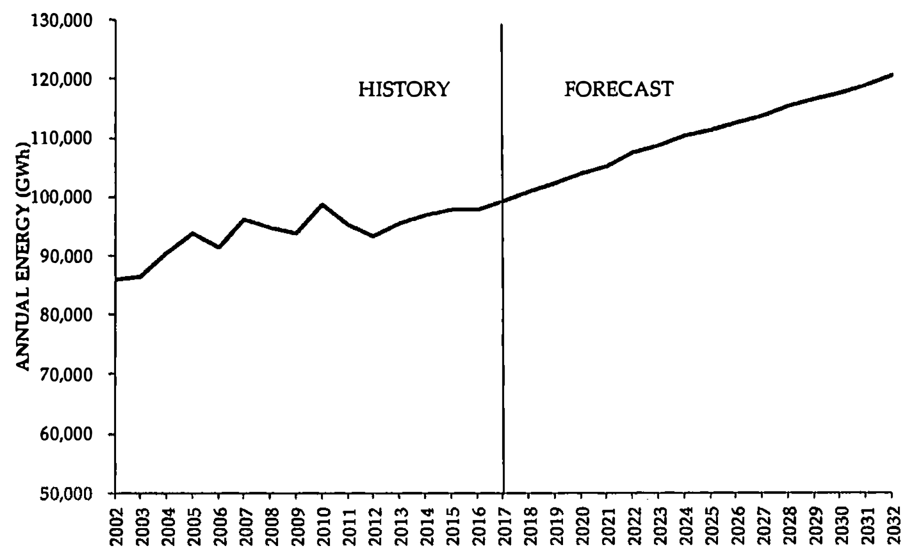


Figure 2.2.3 summarizes the final forecast of energy sales and peak load over the next 15 years. The Company's wholesale and retail customer energy sales are estimated to grow at annual rates of approximately 1.2% and 1.3%, respectively, over the Planning Period. Historical and projected growth rates can diverge for a number of reasons, including weather and economic conditions.

**Figure 2.2.3 - Summary of the Energy Sales & Peak Load Forecast**

| | 2017 | 2032 | Compound Annual Growth Rate (%) 2017 - 2032 |
|---|---|---|---|
| DOMINION LSE | | | |
| TOTAL ENERGY SALES (GWh) | 83,413 | 101,613 | 1.3% |
| Retail | 81,624 | 99,472 | 1.3% |
| Residential | 30,742 | 35,585 | 1.0% |
| Commercial | 31,884 | 44,240 | 2.2% |
| Industrial | 8,494 | 7,530 | -0.8% |
| Public Authorities | 10,207 | 11,765 | 1.0% |
| Street and Traffic Lighting | 297 | 352 | 1.1% |
| Wholesale (Resale) | 1,789 | 2,141 | 1.2% |
| SEASONAL PEAK (MW) | | | |
| Summer | 17,501 | 21,581 | 1.4% |
| Winter | 15,044 | 18,027 | 1.2% |
| ENERGY OUTPUT (GWh) | 86,940 | 105,562 | 1.3% |
| | | | |
| DOMINION ZONE | | | |
| SEASONAL PEAK (MW) | | | |
| Summer | 20,014 | 24,681 | 1.4% |
| Winter | 17,478 | 20,945 | 1.2% |
| | | | |
| ENERGY OUTPUT (GWh) | 99,258 | 120,518 | 1.3% |

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

Figures 2.2.4 and 2.2.5 provide a comparison of DOM Zone summer peak load and energy forecasts included in the 2016 Plan, 2017 Plan, and PJM's load forecast for the DOM Zone from its 2016 and 2017 Load Forecast Reports[9].

[9] See http://www.pjm.com/~/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx and http://www.pjm.com/~/media/library/reports-notices/load-forecast/2016-load-report.ashx.

**Figure 2.2.4 - DOM Zone Peak Load Comparison**

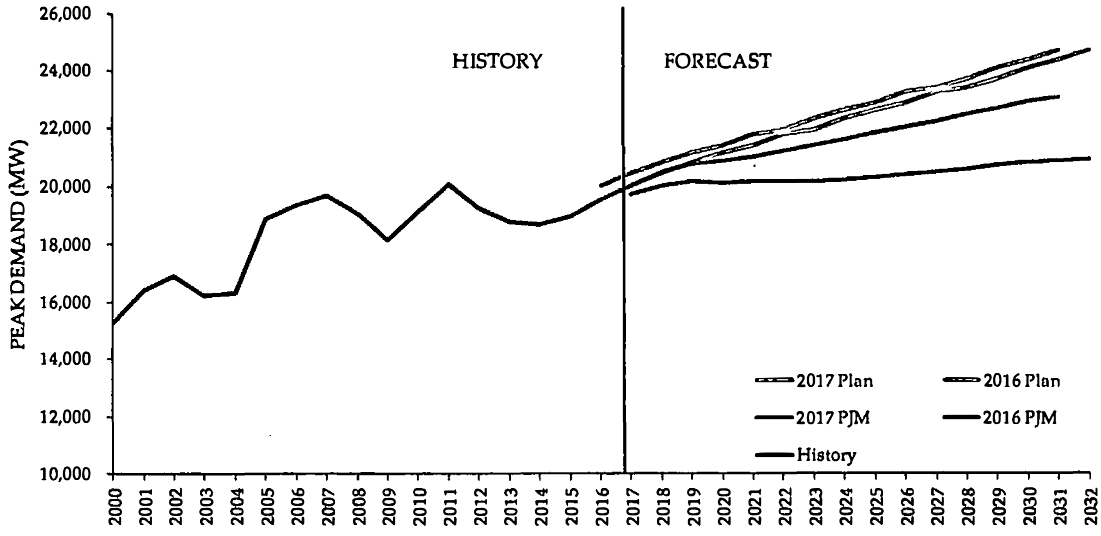
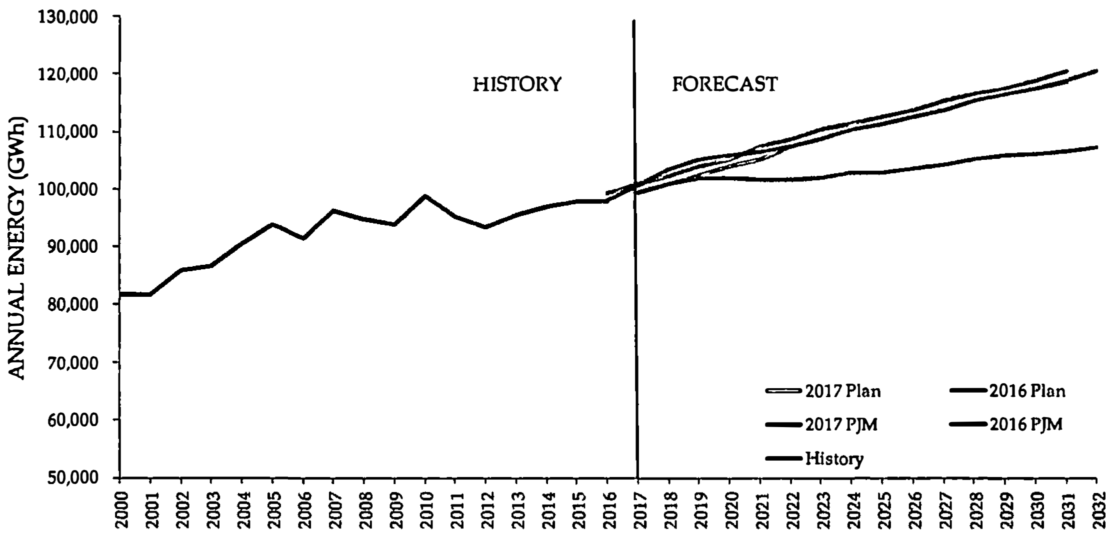



**Figure 2.2.5 - DOM Zone Annual Energy Comparison**




The economic and demographic assumptions that were used in the Company's load forecast models were supplied by Moody's Economy.com, prepared in October 2016, and are included as Appendix 2K. Figure 2.2.6 summarizes the economic variables used to develop the sales and peak load forecasts used in this 2017 Plan.

## Figure 2.2.6 - Major Assumptions for the Energy Sales & Peak Demand Model

| | 2017 | 2032 | Compound Annual Growth Rate (%) 2017 - 2032 |
|---|---|---|---|
| DEMOGRAPHIC: | | | |
| Customers (000) | | | |
| Residential | 2,297 | 2,683 | 1.04% |
| Commercial | 243 | 278 | 0.90% |
| Population (000) | 8,509 | 9,439 | 0.69% |
| | | | |
| ECONOMIC: | | | |
| Employment (000) | | | |
| State & Local Government | 539 | 611 | 0.83% |
| Manufacturing | 228 | 195 | -1.06% |
| Government | 719 | 793 | 0.66% |
| | | | |
| Income ($) | | | |
| Per Capita Real disposable | 42,980 | 54,697 | 1.62% |
| | | | |
| Price Index | | | |
| Consumer Price (1982-84=100) | 245 | 348 | 2.35% |
| | | | |
| VA Gross State Product | 459 | 622 | 2.04% |

The forecast for the Virginia economy is a key driver in the Company's energy sales and load forecasts. Like most states, the Virginia economy was adversely impacted by the recession of 2007 - 2009. However, the Virginia economy was also negatively impacted by federal government budget cuts of 2013 that resulted from the sequestration. The latter event further adversely affected Virginia due to its dependency on federal government spending, particularly in the area of defense. In spite of these economic hurdles, the Virginia economy continued to grow at an annual average real Gross Domestic Product ("GDP") growth rate of approximately 0.8% during 2008 - 2015. Furthermore, during that same time period, Virginia's annual unemployment rate averaged approximately 2% below the national rate. As of December 2016, the seasonally-adjusted unemployment rate in Virginia approached 4.1%, approximately 0.7% below the national unemployment rate. Based on the input data provided by Moody's Analytics, the Virginia economy is expected to rebound considerably within the Planning Period. This is reflected in their projection of the Virginia GSP. Their projection has a compound annual growth rate ("CAGR") of 2.04%. In addition, Virginia per capita disposable income is projected to increase at a CAGR of 1.62%.

As stated above, the Virginia economy is expected to rebound considerably within the Planning Period. For example, in February 2017, President Trump proposed an increase of approximately 10% in the level of military spending. Given Virginia's large military footprint, approval of this budget should benefit the Virginia economy. The Commonwealth has also been aggressive in its economic development efforts, a major priority for Virginia state government and the current Governor.

Residential housing starts and associated new homes are major contributors to electric sales growth in the Company's service territory. The sector saw significant year-over-year declines in the construction of new homes from 2006 through 2010, but began showing increased growth beginning in 2012. According to Moody's Analytics, Virginia is expected to show significant improvement in housing starts in 2017, which is reflected as new customers in the load forecast.

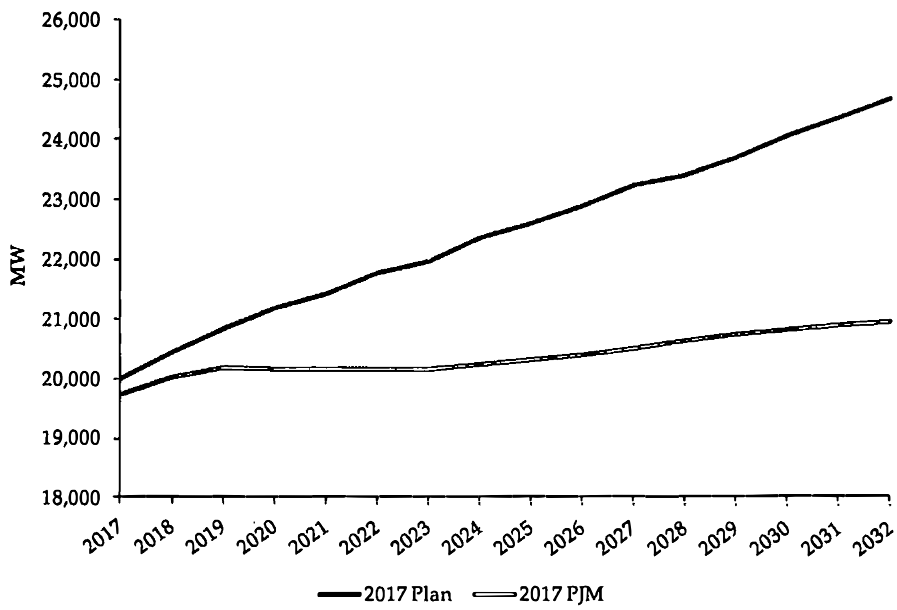
Another driver of energy sales in the Company's service territory is new and existing data centers. The Company has seen significant interest in data centers locating in Virginia because of its proximity to fiber optic networks as well as low-cost, reliable power sources.

Further, after the Atlantic Coast Pipeline ("ACP") is completed, new industrial, commercial, and residential load growth is expected to materialize as additional low-cost natural gas is made available to the region.

## 2.3 COMPARISON WITH PJM'S 2017 PEAK DEMAND FORECAST FOR THE DOM ZONE

Since 2015, PJM has implemented numerous revisions to its load forecasting process that have resulted in a decrease of approximately 1,918 MW of peak demand for all years for the DOM Zone. In 2016, PJM's peak demand forecast for the DOM Zone was below that of the Company's for the first time. PJM's DOM Zone 2017 peak demand forecast is also approximately 1,251 MW less than its 2016 forecast and once again is lower than the Company's internal DOM Zone peak demand forecast. Figure 2.3.1 compares the Company's peak demand forecast for the DOM Zone against PJM's 2017 peak demand forecast.

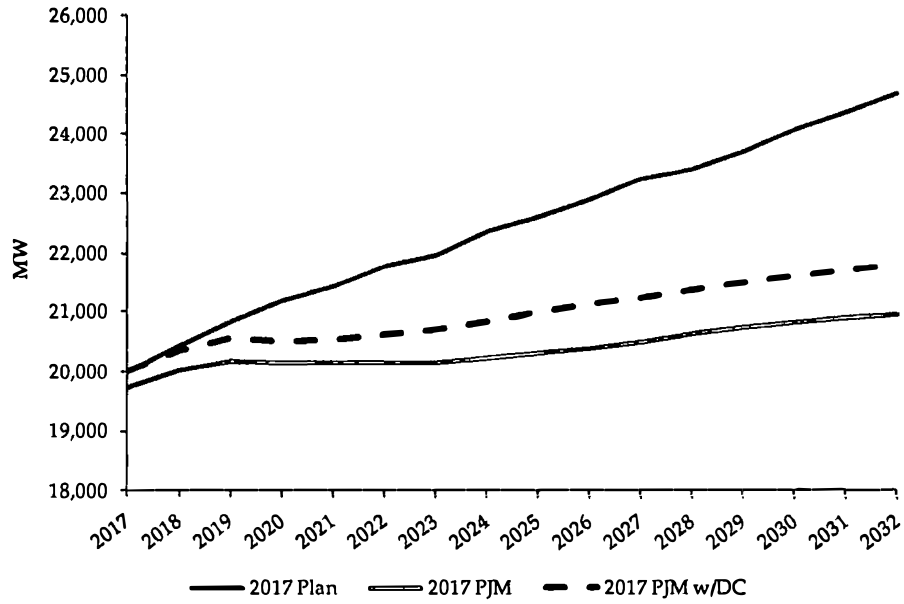
**Figure 2.3.1 - 2017 DOM Zone Peak Demand Forecast**




To understand the differences in PJM's peak demand forecasting process versus those of the Company, the 2017 Plan includes a series of graphs that identify four key differences between the two methods.

First in its 2017 peak demand forecast, PJM has eliminated new data center growth in the DOM Zone beginning in 2021 – in other words, it excluded incremental data center growth beyond what is captured in historic trends. This is a significant change from PJM's 2016 peak demand forecast, which included new data center growth continuing for the balance of the forecast. In comparison, the Company utilizes historical trend data center load coupled with interconnect data from new and existing data center customers to forecast data center growth within its service territory. Over the longer term, the Company relies on data center forecasts that are included in a 2015 study prepared for the Company by Quanta Technology, LLC, entitled "Dominion Northern Virginia Load Forecast." Figure 2.3.2 compares the Company's DOM Zone peak demand forecast included in this 2017 Plan against PJM's 2017 DOM Zone peak demand forecast when adjusted for data center growth consistent with the Company's approach.

**Figure 2.3.2 - 2017 DOM Zone Peak Demand Forecast Adjusted for Data Center Growth**

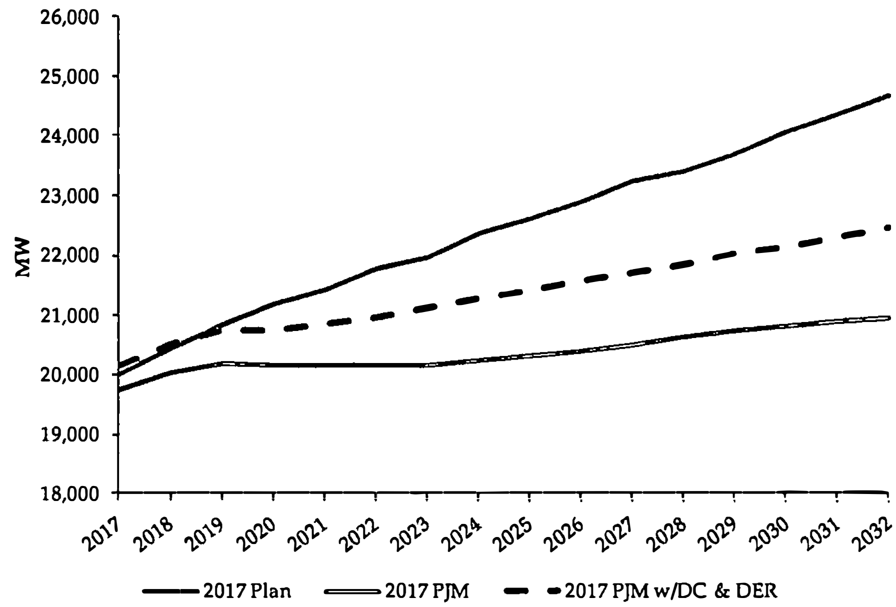



The second load adjustment practice utilized by PJM is with respect to solar PV facilities connected to the distribution grid ("Distributed Energy Resources" or "DERs"). Beginning in 2016, PJM initiated a practice within its load forecasting process which reduces the zonal peak demand and energy forecasts by a level commensurate with known and forecasted solar PV DER facilities. In its 2017 load forecast, PJM forecast that approximately 490 MW (nameplate) of DER is in the DOM Zone in 2017, which increases to approximately 2,000 MW (nameplate) by 2030. After proper adjustment for dependability, PJM subtracts these values from its peak demand and energy forecasts for the DOM Zone. However, by netting out the actual and forecasted values of DER, the actual or true load is masked. As a result, the generation and transmission systems needed to support the true load could be underestimated should these DER facilities underperform during critical system conditions. This issue was discussed in a recent study by the North American Electric Reliability Corporation ("NERC"), dated February 2017 and entitled "Distributed Energy Resources –

Connection Modeling and Reliability Considerations."[10] In that study, NERC advises that continued growth of DERs could impact power flows between the transmission and distribution system to a point that may conflict with NERC system performance criteria. NERC goes on to state:

DERs should not be netted with load but modeled in an aggregate and/or equivalent way to reflect their dynamic characteristics and steady-state output. In general, netting DERs with load should be avoided. Figure 2.3.3 further modifies PJM's 2017 peak demand forecast for the DOM Zone by adding back DERs.

**Figure 2.3.3 - 2017 DOM Zone Peak Demand Forecast Adjusted for Data Center Growth and DERs**




Third, in its 2017 DOM Zone peak demand forecast, PJM includes a forecast of appliance saturation and efficiencies as published in the U.S. Energy Information Administration's ("EIA") 2016 Annual Energy Outlook for the South Atlantic Census Region. This region is comprised of Delaware, Maryland, Virginia, West Virginia, North Carolina, South Carolina, Georgia, Florida, and the District of Columbia. These forecasts differ from those of the Company in that the Company relies on appliance saturation and efficiency data acquired from its own customer surveys, the most recent of which occurred during 2016. The Company uses this historical customer survey data to develop forecasts of both appliance saturation and corresponding appliance efficiency gains, which are then incorporated into the Company's load forecasting process. As a further adjustment to PJM's load forecast, the Company incorporated its customer appliance saturation and efficiency forecasts into PJM's modeling framework. The result is shown in Figure 2.3.4, which further closes the gap between PJM's 2017 DOM Zone peak demand forecast and the Company's DOM Zone peak demand forecast used in this 2017 Plan.

[10] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

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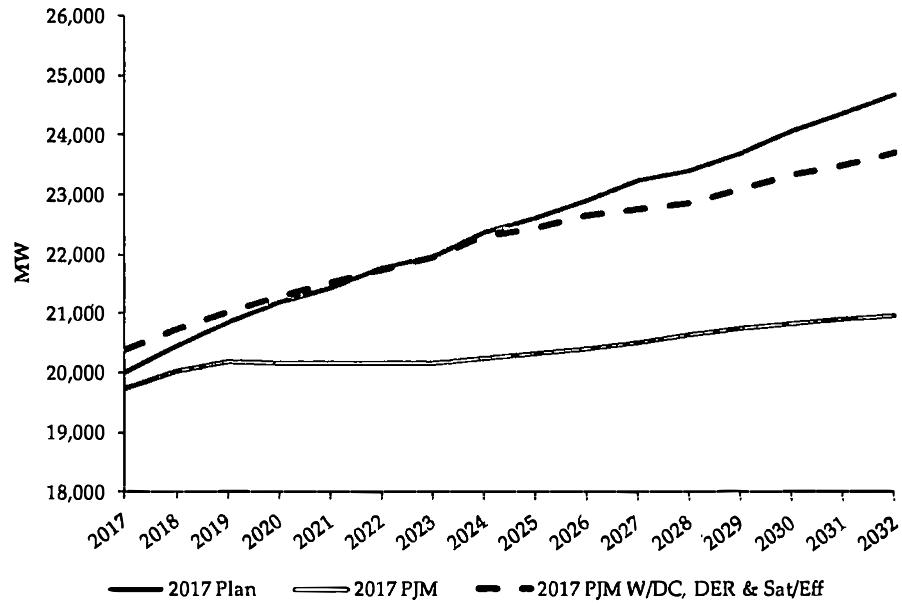
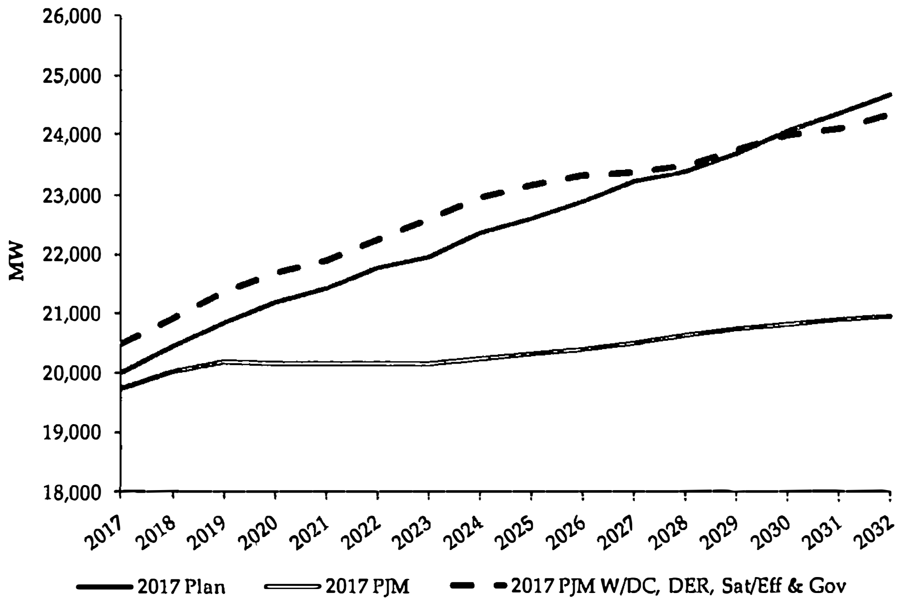
**Figure 2.3.4 - 2017 DOM Zone Peak Demand Forecast Adjusted for Data Center Growth, DERs, Saturation, and Efficiencies**




The fourth adjustment relates to electricity sales to local, state, and federal governments, which have historically comprised approximately 13% of total Company sales. This sector, known as the "Public Authority," is specifically accounted for within the Company's load forecasting process along with the residential, commercial, industrial, street and traffic lighting, and wholesale sectors. PJM, however, makes no such distinction in their load forecasting process. Rather, PJM assumes only three customer sectors: residential, commercial, and industrial. As a final adjustment to PJM's 2017 DOM Zone load forecast, the Company incorporated the Public Authority Sector explanatory variables identical to those used by the Company into PJM's load forecasting framework. Further, the same Moody's Analytics forecasts of these variables were used within the PJM modeling framework. The final result is shown in Figure 2.3.5.

**Figure 2.3.5 - 2017 DOM Zone Peak Demand Forecast Adjusted for Data Center Growth, DERs, Saturation, Efficiencies, and Public Authority**




As shown in Figure 2.3.5, it is clear that the forecasted gap between PJM's 2017 DOM Zone peak demand forecast and the Company's DOM Zone peak demand forecast has been closed as a result of the adjustments described above. The Company maintains that these adjustments are reasonable in that they are based on actual customer data or, in the case of DERs, a difference in reliability policy.

## 2.4 SUMMER & WINTER PEAK DEMAND & ANNUAL ENERGY

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

## 2.5 ECONOMIC DEVELOPMENT RATES

As of March 1, 2017, the Company has seven customers in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 86 MW. There are no customers in Virginia under a self-generation deferral rate.

As of March 1, 2017, the Company has one customer in North Carolina receiving service under economic development rates with approximately 13 MW of load. There are no customers in North Carolina under a self-generation deferral rate.

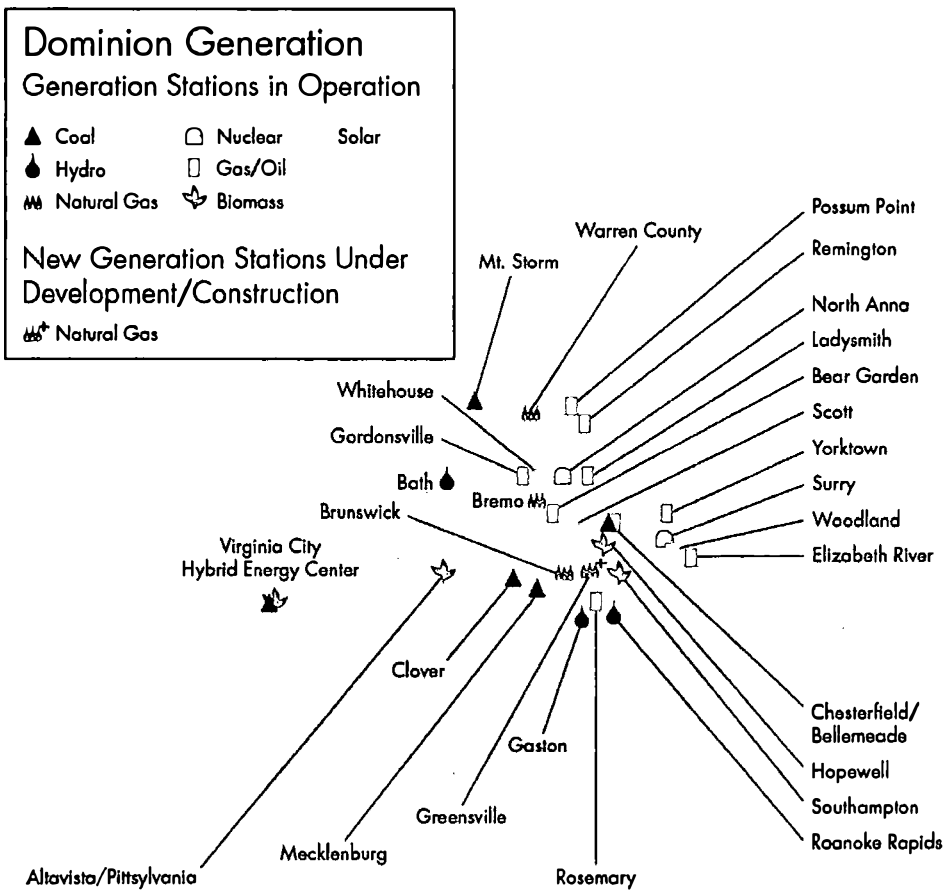
# CHAPTER 3 – EXISTING & PROPOSED RESOURCES

## 3.1 SUPPLY-SIDE RESOURCES

### 3.1.1 EXISTING GENERATION

The Company's existing generating resources are located at multiple sites distributed throughout its service territory, as shown in Figure 3.1.1.1. This diverse fleet of 100 generation units includes four nuclear, 12 coal, four natural gas-steam, 10 CCs, 41 CTs, four biomass, two heavy oil, six pumped storage, 14 hydro units, and three solar units with a total summer capacity of approximately 19,602 MW.[11] The Company's continued operational goal is to manage this fleet in a manner that provides reliable, cost-effective service under varying conditions.

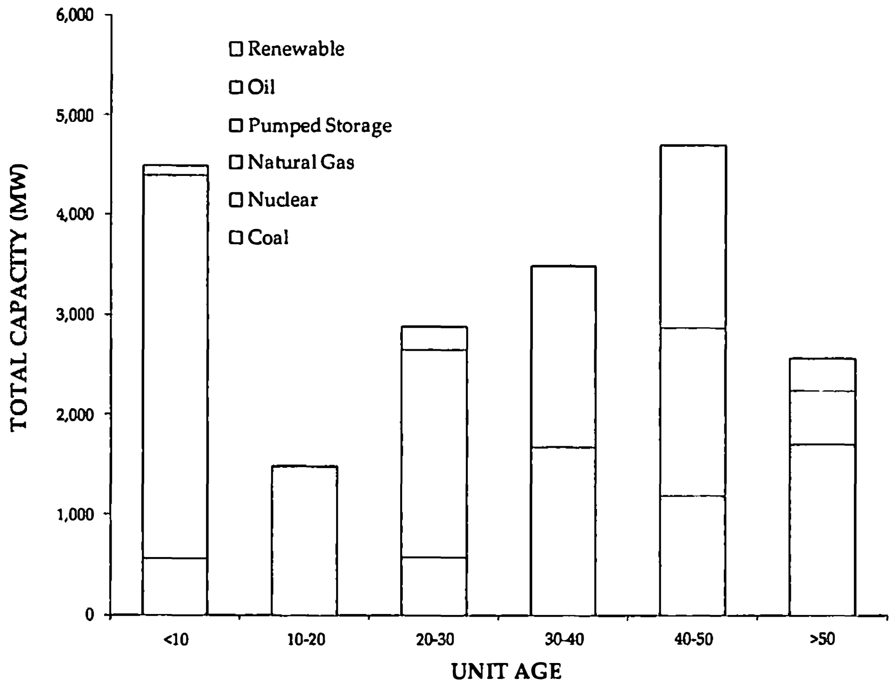
**Figure 3.1.1.1 – Virginia Electric and Power Company Generation Resources**




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

The Company owns a variety of generation resources that operate using a diverse set of fuels. The largest proportion of the Company's generation resources has operated for 40 to 50 years, followed closely by a large number of units that have operated for less than 10 years, and units that have operated for 30 to 40 years. Figure 3.1.1.2 shows the demographics of the entire existing generation fleet.

**Figure 3.1.1.2 - Generation Fleet Demographics**




Note: Renewable resources constitute biomass, wind, solar, and hydro units.

Figure 3.1.1.3 illustrates that the Company's existing generation fleet is comprised of a mix of generation resources with varying operating characteristics and fueling requirements. The Company also has contracted 749 MW of fossil-burning and renewable NUGs, which provide firm capacity as well as associated energy and ancillary services to meet the Company's load requirements. Appendix 3B lists all of the NUGs in the 2017 Plan. The Company's planning process strives to maintain a diverse portfolio of capacity and energy resources to meet its customers' needs.

## Figure 3.1.1.3 - 2017 Capacity Resource Mix by Unit Type

| Generation Resource Type | Net Summer Capacity[1] (MW) | Percentage (%) |
|---|---|---|
| Coal | 4,043 | 19.9% |
| Nuclear | 3,349 | 16.5% |
| Natural Gas | 7,923 | 39.0% |
| Pumped Storage | 1,808 | 8.9% |
| Oil | 1,822 | 9.0% |
| Renewable | 608 | 3.0% |
| NUG - Coal | 627 | 3.1% |
| NUG - Natural Gas Turbine | - | 0.0% |
| NUG - Solar | 122 | 0.6% |
| NUG Contracted | 749 | 3.7% |
| Company Owned | 19,553 | 96.3% |
| Company Owned and NUG Contracted | 20,302 | 100.0% |
| Purchases | - | 0.0% |
| Total | 20,302 | 100.0% |

Note: 1) Represents firm capacity towards reserve margin.

Due to differences in the operating and fuel costs of various types of units and PJM system conditions, the Company's energy mix is not equivalent to its capacity mix. The Company's generation fleet is economically dispatched by PJM within its larger footprint, ensuring that customers in the Company's service territory receive the benefit from all resources in the PJM power pool regardless of whether the source of electricity is Company-owned, contracted, or third-party units. PJM dispatches resources within the DOM Zone from the lowest cost units to the highest cost units, while maintaining its mandated reliability standards. Figures 3.1.1.4 and 3.1.1.5 provide the Company's 2016 actual capacity and energy mix.

Figure 3.1.1.4 - 2016 Actual Capacity Mix

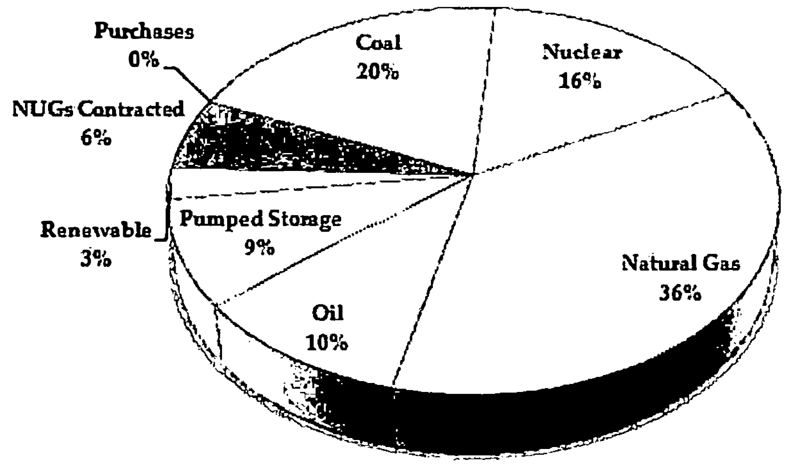
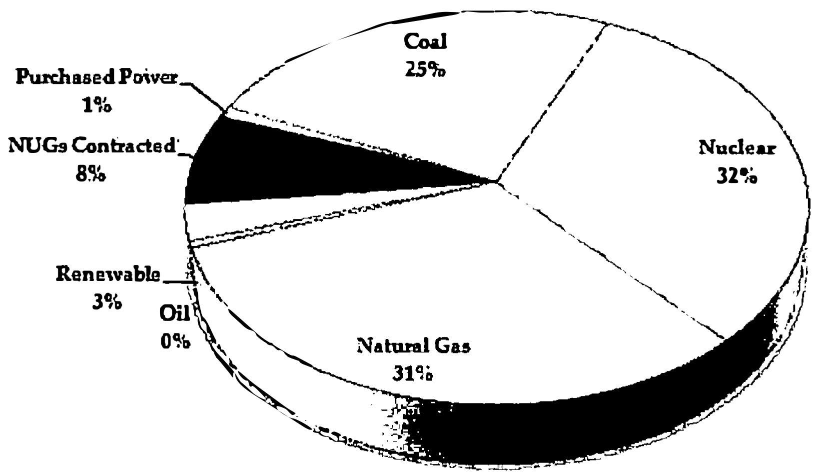



Figure 3.1.1.5 - 2016 Actual Energy Mix




Note: Pumped storage is not shown because it is net negative to the Company's 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, by fuel class, and NUGs. Appendices 3G and 3H provide energy generation by type as well as the system output mix. Appendix 3B provides a listing of other generation units including NUGs, behind-the-meter generation ("BTMG"), and customer-owned generation units.

### 3.1.2 EXISTING RENEWABLE RESOURCES

The Company currently owns and operates 657 MW of renewable resources, including approximately 236 MW of biomass generating facilities. The Virginia City Hybrid Energy Center ("VCHEC") (610 MW) is expected to consume renewable biomass fuel of up to 6.5% (40 MW) in 2017 and gradually increase that level to 10% (61 MW) by 2021. The Company also owns and operates four hydro facilities: Gaston Hydro Station (220 MW), Roanoke Rapids Hydro Station (95 MW), Cushaw Hydro Station (2 MW), and North Anna Hydro Station (1 MW). Additionally, the Company owns and operates three solar units totaling 56 MW (nameplate) in Virginia, as well as the aforementioned SPP (7.7 MW nameplate).

## Renewable Energy Rates and Programs

The Company has implemented various rates and programs to increase the availability of renewable options, as summarized in Figure 3.1.2.1.

### Figure 3.1.2.1 - Renewable Rates & Programs

| Renewable Programs | Supplier | | | Customer Group | | | | Size Limitations | |
|---|---|---|---|---|---|---|---|---|---|
| | Company-Owned | Participant-Owned | Third-Party Owned | Residential | Small Commercial | Large Commercial | Industrial | Individual | Aggregate |
| Solar Partnership Program | X | - | - | - | X | X | X | 500 kW - 2 MW | 30 MW |
| Solar Purchase Program | - | X | - | X | X | - | - | Res: ≤20 kW<br>Non-Res: ≤50 kW | 3 MW |
| Green Power Program | - | - | X | X | X | X | X | None | None |
| Third-Party PPA Pilot | - | - | X | X | X | X | X | 1 kW - 1 MW | 50 MW |
| Net Metering | - | X | - | X | X | X | X | Res: 20 kW<br>Non-Res: 1 MW | 1% of Adjusted Peak Load for Prior Year |
| Agricultural Net Metering | - | X | - | - | X | X | X | ≤500 kW | Within Net Metering Cap |

Note: Eligibility and participation subject to individual program parameters.

## Solar Partnership Program

The SPP is a demonstration program in which the Company is authorized to construct and operate up to 30 MW (DC) of Company-owned solar DG facilities on leased commercial and industrial customer property and in community settings. This is intended as a five-year demonstration program to study the benefits and impacts of solar DG on targeted distribution circuits. Current installed capacity of the program is 5.2 MW. More information can be found on the SCC website under Case No. PUE-2011-00117 and on the Company's website: https://www.dom.com/large-business/renewable-energy-programs/solar-partnership-program.

## Solar Purchase Program

The Solar Purchase Program facilitates customer-owned solar DG as an alternative to net metering. Under this program, the Company purchases energy output, including all environmental attributes and associated renewable energy certificates ("RECs") from participants at a premium rate under Rate Schedule SP, a voluntary experimental rate, for a period of five years. The Company's Green Power Program® directly supports the Solar Purchase Program through the purchase and retirement of produced solar RECs. There are approximately 140 participants with an installed capacity of 1.7 MW. More information can be found on the SCC website under Case No. PUE-2012-00064 and on the Company's website: https://www.dom.com/home-and-small-business/ways-to-save/renewable-energy-programs/solar-purchase-program.

part 3





### Green Power Program®

The Company's Green Power Program® allows customers to promote renewable energy by purchasing, through the Company, RECs in discrete blocks equal to 100% of their usage or a portion of their usage. The Company purchases and retires RECs on behalf of participants. There are approximately 24,000 customers participating in this program. More information can be found on the SCC website under Case No. PUE-2008-00044 and on the Company's website: https://www.dom.com/home-and-small-business/ways-to-save/renewable-energy-programs/dominion-green-power.

### Renewable Energy (Third-Party PPA) Pilot

The Renewable Energy Pilot Program allows qualified customers to enter into a Power Purchase Agreement ("PPA") with a third-party renewable energy supplier. The energy supplied must come from a wind or solar generator located on the customer's premise. Eight customers are participating with a total installed capacity of approximately 1.2 MW. More information can be found on the SCC website under Case No. PUE-2013-00045 and on the Company's website: https://www.dom.com/large-business/renewable-energy-programs/renewable-energy-pilot-program.

### Net Metering

Net Metering allows for eligible customer generators producing renewable generation to offset their own electricity usage consistent with Va. Code § 56-594 and SCC regulations governing net metering in the Virginia Administrative Code (20 VAC 5-315-10 *et seq.*) and on the Company's website: https://www.dom.com/home-and-small-business/ways-to-save/renewable-energy-programs/net-metering. There are approximately 2,170 net metering customer-generators with a total installed capacity of approximately 17.4 MW.

### Agricultural Net Metering

Agricultural Net Metering allows agricultural customers to net meter across multiple accounts on contiguous property. More information can be found on the SCC website under Case No. PUE-2014-00003 and on the Company's website: https://www.dom.com/home-and-small-business/ways-to-save/renewable-energy-programs/agricultural-net-metering.

## 3.1.3 CHANGES TO EXISTING GENERATION

The Company is fully committed to meeting its customers' energy needs in a manner consistent with a clean environment and supports the establishment of a comprehensive national energy and environmental policy that balances the country's needs for reliable and affordable energy with reasonable minimization of environmental impacts. Cognizant of the effective and anticipated EPA regulations concerning air, water, and solid waste constituents (see Figure 3.1.3.2), the Company continuously evaluates various options with respect to its existing fleet.

As a result, the Company has a balanced portfolio of generating units, including low-emission nuclear, highly-efficient and clean-burning natural gas, solar, and hydro. As to the Company's coal generators, the majority of the generators are equipped with $SO_2$ and $NO_x$ controls; however, the remaining small coal-fired units are without sufficient emission controls to comply with effective and anticipated regulatory requirements. The Company's coal-fired units at Chesterfield, Mt. Storm, Clover, Mecklenburg, and VCHEC have flue gas desulfurization environmental controls for $SO_2$ emissions. The Company's coal-fired generation at Chesterfield (Units 4, 5, and 6), Mt. Storm, Clover, and VCHEC have selective catalytic reduction ("SCR") or SNCR technology to control $NO_x$ emissions. The Company's biomass units at Pittsylvania, Altavista, Hopewell, and Southampton operate SNCRs to reduce $NO_x$. In addition, the Company's NGCC units at Bellemeade, Bear Garden, Gordonsville, Possum Point, Warren County, and Brunswick have SCRs. The Company is installing SNCR $NO_x$ controls on Possum Point Unit 5 to meet Reasonable Available Control Technology ("RACT") requirements that the Company expects will be operational in 2019.

### Uprates and Derates

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

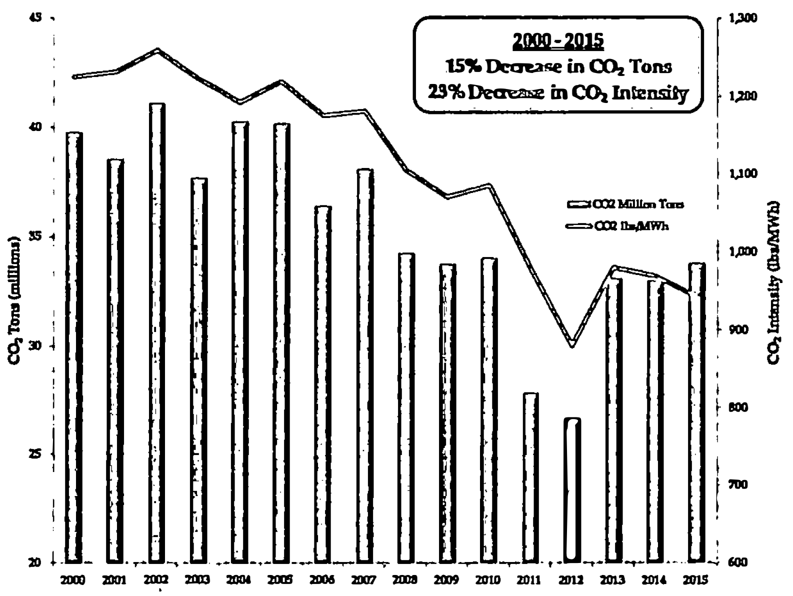
Bear Garden Power Station is a 2x1 CC that was completed in the summer of 2011. A turbine uprate is planned to be completed in May 2017, which will increase summer capacity from 590 MW to 616 MW.

The Company continues to evaluate opportunities for existing unit uprates as a cost-effective means of increasing generating capacity and improving system reliability. Appendix 3I provides a list of historical and planned uprates and derates to the Company's existing generation fleet.

### Environmental Performance

The Company has reduced emissions of $CO_2$ from its generation fleet over the last decade as reflected in Figure 3.1.3.1.

**Figure 3.1.3.1 – Virginia Electric and Power Company $CO_2$ Reductions**



Similarly, the Company has reduced emissions of GHGs, including $CO_2$, through retiring certain at-risk units and building additional efficient and lower-emitting power generating sources.

## EPA Regulations

There are a significant number of final, proposed, stayed, and anticipated EPA regulations that will affect certain units in the Company's current fleet of generation resources. As shown in Figure 3.1.3.2, these regulations are designed to regulate air, solid waste, water, and wildlife constituents.

### Figure 3.1.3.2 - EPA Regulations

| Constituent | | Key Regulation | Final Rule | Compliance |
|---|---|---|---|---|
| AIR | Hg/HAPS | Mercury & Air Toxics Standards[1] (MATS) | 12/16/2011 | 4/16/2017 |
| | $SO_2$ | CSAPR[2] | 2011 | 2015/2017 |
| | | $SO_2$ NAAQS | 6/2/2010 | 2018 |
| | NOx | 2008 Ozone Standard (75 ppb) | 5/2012 | 2017 |
| | | 2015 Ozone Standard (70 ppb) | 10/1/2015 | 2018 - 2019 |
| | | CSAPR[3] | 2011 | 2015/2017 |
| | $CO_2$ | GHG Tailoring Rule | 5/2010 | 2011 |
| | | EGU NSPS (New) | 10/2015 | Retro to 1/8/2014 |
| | | EGU NSPS (Modified and Reconstructed) | 10/2015 | 10/23/2015 |
| | | Clean Power Plan (CPP)[4] | 10/2015 | 2022/2030 |
| | | Federal $CO_2$ Program (Alternative to CPP) | Uncertain | 2023 |
| WASTE | Ash | CCR's | 4/17/2015 | 2017 - 2019 |
| WATER | Water 316b | 316(b) Impingement & Entrainment[5,6] | 5/19/2014 | 2016 - 2027 |
| | Water ELG | Effluent Limitation Guidelines[7] | 9/30/2015 | 2021 - 2022 |
| WILDLIFE | Threatened & Endangered | Atlantic Sturgeon Endangered Species Listing | 1/2012 | TBD[8] |
| | | Atlantic Sturgeon Critical Habitat Listing | 2017 (expected) | TBD |

Key: Constituent: Hg: Mercury; HAPS: Hazardous Air Pollutants; $SO_2$: Sulfur Dioxide; NOx: Nitrogen Oxide; $CO_2$: Carbon Dioxide; GHG: Greenhouse Gas; Water 316b: Clean Water Act § 316(b) Cooling Water Intake Structures;

Regulation: MATS: Mercury & Air Toxics Standards; CPP: Clean Power Plan; CSAPR: Cross-State Air Pollution Rule; $SO_2$ NAAQS: Sulfur Dioxide National Ambient Air Quality Standards; Ozone Std Rev PPB: Ozone Standard Review Parts per Billion; EGU NSPS: Electric Generating Units New Source Performance Standard.

Note: 1) CEC 1-4 retired in December 2014. YT 1-2 have ceased operation on April 15, 2017.

2) $SO_2$ allowances decreased by 50% beginning in 2017. Retired units retain CSAPR allowances for four years. System is expected to have sufficient $SO_2$ allowances.

3) CSAPR ozone season NOx allowances reduced by ~22% beginning in 2017 with limits imposed on use of banked Phase I allowances (~3.5:1). Retired units retail CSAPR allowances for four years. System is expected to have sufficient annual $NO_x$ allowances.

4) Rule sets interim targets (2022 - 2024; 2025 - 2027; 2028 - 2029) in addition to 2030 targets. Rule also sets "equivalent" statewide Intensity-Based and Mass-Based interim and 2030 targets. Rule currently stayed by the Supreme Court and under review by the EPA.

5) Rule would not apply to Mt. Storm under the assumption that the plant's man-made lake does not qualify as a "water of the U.S."

6) 316(b) studies will be due with discharge permit applications beginning in mid-2018. Installation of 316(b) technology requirements will be based on compliance schedules put into discharge permits.

7) Rule does not apply to simple-cycle CTs or biomass units. The EPA has indicated its intent to reconsider the rule and issue an administrative stay of the compliance dates in the rule.

8) ITP is expected in the spring of 2017 with details on compliance schedule, study scope and required mitigation.

**Revised Ozone National Ambient Air Quality Standards**

In May 2008, the EPA revised the ozone National Ambient Air Quality Standard ("NAAQS") from 80 ppb to 75 ppb. Subsequently, in October 2015, the EPA issued a final rule further tightening the ozone standard from 75 ppb to 70 ppb. States will have until late 2020 or early 2021 to develop plans to address the new standard. In November 2016, the DEQ determined that the installation and operation of SNCR technology to control $NO_x$ emissions on Possum Point Unit 5 is needed to meet RACT requirements under the 2008 Ozone NAAQS SIP. The Company anticipates that the SNCR at Possum Point Unit 5, expected to be operational in 2019, will also meet RACT requirements under the new 2015 Ozone NAAQS. At this time, no other power generating units are expected to be impacted by the new standard. In April 2017, the EPA verbally announced its intent to review its decision to tighten the standard from 75 to 70 ppb, but, to date, has not published an official notice initiating that process.

**Cross-State Air Pollution Rule**

In October 2016, the EPA published final revisions to the Cross-State Air Pollution Rule ("CSAPR") that substantially reduces the CSAPR Phase II ozone season $NO_x$ emission caps in 22 states, including Virginia and West Virginia, which take effect beginning with the 2017 ozone season. The reductions in state caps will in turn reduce, by approximately 22% overall, the number of allowances the Company's EGUs will receive under the CSAPR Phase II ozone season $NO_x$ program. In addition, the EPA will discount the use of banked Phase I allowances for compliance in Phase II by applying a surrender ratio that the EPA anticipates will be approximately 3.5:1. At this time, the Company does not anticipate the need for any additional $NO_x$ controls to be installed on any units to meet these requirements.

In January 2016, the EPA issued a Notice of Data Availability ("NODA") providing information on emission inventories, including EGUs. Additionally, the NODA provides air quality modeling projections to assist states in developing SIPs based on an evaluation of whether additional reductions in emissions of $NO_x$ and/or volatile organic compounds beyond measures already in place or planned are needed to address interstate transport under the Clean Air Act's "good neighbor" provisions as it pertains to the 2015 ozone NAAQS, which are due in October 2018. Although the NODA itself does not do so, this information may be used by the EPA should the agency pursue a regional transport rulemaking requiring additional $NO_x$ emission reductions from EGUs as a backstop to address ozone transport under the 2015 ozone NAAQS for states that fail to submit SIPs. At this time, the Company has not planned for any additional $NO_x$ controls given the uncertainty of future regulatory action to further address ozone transport.

**Coal Ash Regulations**

In April 2015, the EPA's final rule regulating the management of coal combustion residuals ("CCRs") stored in impoundments (ash ponds) and landfills was published in the Federal Register. This final rule regulates CCR landfills, existing ash ponds that still receive and manage CCRs, and inactive ash ponds that do not receive, but still store CCRs. The Company currently owns ash ponds and CCR landfills subject to the CCR final rule at eight different facilities. The final rule required the Company to retrofit or close all of its inactive and existing ash ponds over a certain period of time, as well as to perform required monitoring, corrective action, and post-closure care activities as necessary.

In addition, a new Virginia law, Senate Bill 1398, which comes into effect on July 1st, requires additional assessments be completed by the Company to further evaluate alternatives for the closure of ash ponds at four locations. These assessments will include an evaluation of the feasibility of excavation of the ponds, recycling of ash from the ponds, groundwater and surface water conditions, as well as corrective actions and safety aspects of the closure options. The Company is engaging a third-party to complete the assessment, and will work to conduct individual assessments of the ash ponds at Bremo Bluff, Chesapeake, Chesterfield, and Possum Point Power Stations. The assessments are due to be completed by December 1, 2017, which is consistent with the timeframe for complying with the EPA's CCR rule. The Company is in the process of complying with all federal and state requirements.

### Clean Water Intake Regulations

In October 2014, final regulations became effective under Section 316(b) of the Clean Water Act ("CWA"), which govern existing facilities that employ a cooling water intake structure and have flow levels exceeding a minimum threshold. The rule establishes a national standard for impingement based on seven compliance options. The EPA has delegated entrainment technology decisions to state environmental regulators. State environmental regulators will make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost/benefit test and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two million gallons per day. The Company has 11 facilities that may be subject to these regulations, and anticipates that it will have to install impingement control technologies at many of these stations that have once-through cooling systems. Currently, the Company is evaluating the need and/or potential for entrainment controls under the final regulations as these decisions will be made on a case-by-case basis by the state regulatory agency after a thorough review of detailed biological, technology, cost, and benefit studies. Any new technology requirements will likely be incorporated in discharge permits issued beginning in 2018, and will be installed in accordance with schedules established in those permits. The costs for these additional control technologies could be significant.

### Clean Power Plan Overview

As discussed in Chapter 1, a high level of uncertainty remains regarding the future of the CPP. For a complete overview of the CPP rules, see Chapter 3 of the Company's 2016 Plan.[12]

## 3.1.4 GENERATION RETIREMENTS & BLACKSTART

### Retirements

Based on the current and anticipated environmental regulations along with current market conditions, the 2017 Plan includes the following impacts to the Company's existing generating resources in terms of retirements. On April 16, 2016, the EPA granted permission, through an Administrative Order, to operate the Yorktown Units 1 (159 MW) and 2 (164 MW), until April 15,

[12] As required by the 2015 Plan Final Order, Chapter 3 of the 2016 Plan, and in particular Section 3.1.3, Changes to Existing Generation, includes a discussion of (i) leakage and the treatment of new units under differing compliance regimes; (ii) the differing impacts of the Virginia-specific targets versus source subcategory specific rates under an intensity-based approach; (iii) the potential for early action emission rate credits and allowances that may be available for qualified renewable energy or demand-side energy efficiency measures; and (iv) the cost benefits of trading emissions allowances or emissions reductions credits, or acquiring renewable resources from inside and outside of Virginia.

2017 under certain limitations consistent with the federal Mercury and Air Toxics Standards ("MATS") rule. Upon expiration of the EPA Administrative Order on April 15, 2017, the Yorktown coal-fired units ceased operations to comply with the MATS rule.

Currently under evaluation are the potential retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW), as well as Yorktown Unit 3 (790 MW), all modeled for retirement by 2022 (all CPP-Compliant Plans). Also under evaluation are the potential retirements of Clover Units 1 (220 MW) and 2 (219 MW), and Mecklenburg Units 1 (69 MW) and 2 (69 MW), all modeled for retirement in 2025 (Plans $F^{NT}$ and $H^{NT}$). Appendix 3J lists the planned and potential retirements included in the 2017 Plan.

Also, Figure 6.9.1 reflects the results of a retirement, co-fire, and repower analysis that was conducted by the Company regarding the Company's coal and heavy oil fired units. This analysis is included in this 2017 Plan as a result of a request by the SCC Staff during the 2016 Plan regulatory proceedings.

**Blackstart**

Blackstart generators are generating units that are able to start without an outside electrical supply or are able to remain operating at reduced levels when automatically disconnected from the grid. NERC Reliability Standard EOP-005-2 requires the RTO to have a plan that allows for restoring its system following a complete shutdown (i.e., blackout). As the RTO, PJM performs an analysis to verify all requirements are met and coordinates this analysis with the Company in its role as the Transmission Owner. The Company and other PJM members have and continue to work with PJM to implement a RTO-wide strategy for procuring blackstart resources. This strategy ensures a resilient and robust ability to meet blackstart and restoration requirements. It is described in detail in Section 10 of PJM Manual 14D – Generator Operational Requirements. PJM will issue an RTO-wide Request for Proposal ("RFP") for blackstart generation every five years, which will be open to all existing and potential new blackstart units on a voluntary basis. Resources are selected based upon the individual needs of each transmission zone. The first five-year selection process was initiated in 2013 and resulted in blackstart solutions totaling 286 MW in the DOM Zone. Two solutions became effective on June 1, 2015. The first was for 50 MW and the second was for 85 MW. The third solution (151 MW) became effective on June 1, 2016. Blackstart solutions from the subsequent five-year selection processes will be effective on April 1, 2018. For incremental changes in resource needs or availability that may arise between the five-year solicitations, the strategy includes an incremental RFP process.

### 3.1.5 GENERATION UNDER CONSTRUCTION

Pursuant to Chapter 771 of the 2011 Virginia Acts of Assembly (House Bill 1686), the SCC granted the Company in November 2012 a "blanket" certificate of public convenience and necessity ("CPCN") to construct and operate the SPP, up to 24 MW alternating current ("AC") (30 MW DC) of Company-owned solar DG facilities at selected large commercial and industrial customer locations dispersed throughout its Virginia service territory. Currently, the Company has installed and/or has under development 7.7 MW (nameplate) of solar generation at various customer locations throughout its Virginia service territory.

The Greensville Power Station's (1,585 MW CC) CPCN was approved by the SCC on March 29, 2016. The unit is currently under construction and is expected to be online by 2019.

Figure 3.1.5.1 and Appendix 3K provide a summary of the generation under construction included in the Alternative Plans along with the forecasted in-service date and summer/winter capacity.

**Figure 3.1.5.1 - Generation under Construction**

| Forecasted COD[1] | Unit Name | Location | Primary Fuel | Unit Type | Capacity (Net MW) | | |
|---|---|---|---|---|---|---|---|
| | | | | | Nameplate | Summer[2] | Winter[2] |
| 2017 | SPP | VA | Solar | Intermittent | 8 | 2 | 2 |
| 2019 | Greensville County Power Station | VA | Natural Gas | Intermediate/Baseload | 1,585 | 1,585 | 1,710 |

Note: 1) Commercial Operation Date.
2) Firm capacity.

### 3.1.6 NON-UTILITY GENERATION

A portion of the Company's load and energy requirement is supplemented with contracted NUGs and market purchases. The Company has existing contracts with fossil-burning and renewable NUGs for capacity of 749 MW (firm capacity), which includes approximately 354 MW (nameplate) of solar PV NUGs that have achieved commercial operation. These NUGs are all considered firm generating capacity resources and are included in the 2017 Plan as supply-side resources.

Each of the NUGs listed as a capacity resource in Appendix 3B, including solar NUGs, are under contract to supply capacity and energy to the Company. NUG units are obligated to provide firm generating capacity and energy at the contracted terms during the life of the contract. The firm generating capacity from NUGs is included as a resource in meeting the reserve requirements.

For modeling purposes, the Company assumed that its NUG capacity will be available as a firm generating capacity resource in accordance with current contractual terms. These NUG units also provide energy to the Company according to their contractual arrangements. At the expiration of these NUG contracts, these units will no longer be modeled as a firm generating capacity resource. The Company assumed that NUGs or any other non-Company owned resource without a contract with the Company are available to the Company at market prices; therefore, the Company's optimization model may select these resources in lieu of other Company-owned/sponsored supply- or demand-side resources should the market economics dictate. Although this is a reasonable planning assumption, parties may elect to enter into future bilateral contracts on mutually agreeable terms. For potential bilateral contracts not known at this time, the market price is the best proxy to use for planning purposes.

Additionally, the Company is currently working with a number of potential solar qualifying facilities. The Alternative Plans include a total of 950 MW (nameplate) of North Carolina solar NUGs by 2022, which includes 506 MW (nameplate) of PPAs that have been signed as of March 2017. The Company is continually evaluating NUG opportunities as they arise to determine if they are beneficial to customers.

### 3.1.7 WHOLESALE & PURCHASED POWER

**Wholesale Power Sales**

The Company currently provides full requirement wholesale power sales to three entities, which are included in the Company's load forecast. These entities are Craig Botetourt Electric Cooperative, the Virginia Municipal Electric Association No.1, and the Town of Windsor in North Carolina. Additionally, the Company has partial requirement contracts to supply the supplemental power needs of the North Carolina Electric Membership Cooperative. Appendix 3L provides a listing of wholesale power sales contracts with parties with whom the Company has either committed, or expects to sell power during the Planning Period.

**Purchased Power**

Except for the NUG contracts discussed in Section 3.1.6, the Company does not have any bilateral contractual obligations with wholesale power suppliers or power marketers. As a member of PJM, the Company has the option to buy capacity through the Reliability Pricing Model ("RPM") auction ("RPM auction") process to satisfy its RPM requirements. The Company has satisfied its capacity obligation from the RPM market through May 31, 2020.

**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. The unit descriptions are provided in Appendix 3B.

## 3.2 DEMAND-SIDE RESOURCES

The Commonwealth of Virginia has a public policy goal set forth in the 2007 Electric Utility Re-regulation Act of reducing the consumption of electric energy by retail customers by 2022 by an amount equal to 10% of the amount of electric energy consumed by retail customers in Virginia in 2006. The Company has expressed its commitment to helping Virginia reach this goal through the implementation of cost-effective DSM programs. Related to and consistent with the goal, DSM programs are an important part of the Company's portfolio available to meet customers' growing need for electricity along with supply-side resources.

The Company generally defines DSM as all activities or programs undertaken to influence the amount and timing of electricity use. Demand-side resources encourage the more efficient use of existing resources and delay or eliminate the need for new supply-side infrastructure. The Company's DSM programs are designed to provide customers the opportunity to manage or reduce their electricity usage.

In this 2017 Plan, four categories of DSM programs are addressed: i) those approved by the SCC and NCUC; ii) those filed with the SCC for approval; iii) those programs that are under consideration but have not been fully evaluated and may be potential DSM resources; and iv) those programs currently rejected from further consideration at this time. The Company's Programs have been designed and evaluated using a system-level analysis. Figure 3.2.1 provides a graphical representation of the approved, proposed, under consideration, and rejected programs described in Chapters 3 and 5.

# Figure 3.2.1 - DSM Tariffs & Programs

| Tariff | Status (VA / NC) |
|---|---|
| Standby Generator Tariff | Approved / Approved |
| Curtailable Service Tariff | |
| **Program** | **Status (VA / NC)** |
| Air Conditioner Cycling Program | Approved / Approved |
| Residential Low Income Program | Completed / Completed |
| Residential Lighting Program | |
| Commercial Lighting Program | Closed / Closed |
| Commercial HVAC Upgrade | |
| Non-Residential Distributed Generation Program | Extension Under Consideration / Rejected |
| Non-Residential Energy Audit Program | Completed / Completed |
| Non-Residential Duct Testing and Sealing Program | |
| Residential Bundle Program | |
| Residential Home Energy Check-Up Program | |
| Residential Duct Sealing Program | |
| Residential Heat Pump Tune Up Program | |
| Residential Heat Pump Upgrade Program | Extension Under Consideration / Suspended |
| Non-Residential Window Film Program | Approved / Approved |
| Non-Residential Lighting Systems & Controls Program | |
| Non-Residential Heating and Cooling Efficiency Program | |
| Income and Age Qualifying Home Improvement Program | |
| Residential Appliance Recycling Program | Approved / No Plans |
| Small Business Improvement Program | Approved / Approved |
| Residential Lighting Program (NC only) | Approved (NC only) |
| Residential Home Energy Assessment | Proposed / Future |
| Non-Residential Prescriptive Program | |
| Non-Residential Re-commissioning Program | Under Consideration / Under Consideration |
| Non-Residential Compressed Air System Program | |
| Non-Residential HVAC Tune-Up Program | Rejected or Currently Not Under Consideration |
| Energy Management System Program | |
| ENERGY STAR® New Homes Program | |
| Geo-Thermal Heat Pump Program | |
| Home Energy Comparison Program | |
| Home Performance with ENERGY STAR® Program | |
| In-Home Energy Display Program | |
| Premium Efficiency Motors Program | |
| Residential Refrigerator Turn-In Program | |
| Residential Solar Water Heating Program | |
| Residential Water Heater Cycling Program | |
| Residential Comprehensive Energy Audit Program | |
| Residential Radiant Barrier Program | |
| Residential Lighting (Phase II) Program | |
| Non-Residential Refrigeration Program | |
| Cool Roof Program | |
| Non-Residential Data Centers Program | |
| Non-Residential Curtailable Service Program | |
| Non-Residential Custom Incentive | |
| Enhanced Air Conditioner Direct Load Control Program | |
| Residential Programmable Thermostat Program | |
| Residential Controllable Thermostat Program | |
| Residential Retail LED Lighting Program | |
| Residential New Homes Program | |
| Voltage Conservation | |

### 3.2.1 DSM PROGRAM DEFINITIONS

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

- **Demand Response**: Measures aimed at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.
- **Energy Efficiency Program**: 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; 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; and iii) customer engagement programs that result in measurable and verifiable energy savings that lead to efficient use patterns and practices. 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 are authorized to install and operate such advanced metering technology and equipment on a customer's premises; however, nothing in Chapter 23 of Title 56 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 interconnection 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.

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

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

### 3.2.2 CURRENT DSM TARIFFS

The Company modeled existing DSM pricing tariffs over the Study Period, based on historical data from the Company's Customer Information System. These projections were modeled with diminishing returns assuming new DSM programs will offer more cost-effective choices in the future. No active DSM pricing tariffs have been discontinued since the Company's 2016 Plan.

#### STANDBY GENERATION

**Program Type:** Energy Efficiency - Demand Response
**Target Class:** Commercial & Industrial
**Participants:** 5 customers on Standby Generation in Virginia
**Capacity Available:** See Figure 3.2.2.1

The Company currently offers one DSM pricing tariff, the Standby Generation ("SG") rate schedule, in Virginia. This tariff provides incentive payments for dispatchable load reductions that can be called on by the Company when capacity is needed.

The SG rate schedule provides 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.

During a load reduction event, a customer receiving service under the SG rate schedule is required to transfer a contracted level of load to its dedicated on-site backup generator. Figure 3.2.2.1 provides estimated load response data for summer/winter 2016. Additional jurisdictional rate schedule information is available on the Company's website at www.dom.com.

**Figure 3.2.2.1 - Estimated Load Response Data**

| | Summer 2016 | | Winter 2016 | |
|---|---|---|---|---|
| Tariff | Number of Events | Estimated MW Reduction | Number of Events | Estimated MW Reduction |
| Standby Generation | 19 | 2 | 4 | 2 |

### 3.2.3 CURRENT & COMPLETED DSM PILOTS & DEMONSTRATIONS

#### Pilots

The Company has received SCC approval for implementation of DSM pilots that are described below.

**Dynamic Pricing Tariffs Pilot**

**State:** Virginia
**Target Class:** Residential and Non-Residential
**Pilot Type:** Peak-Shaving
**Pilot Duration:** Pilot launched on July 1, 2011
Enrollment closed on November 30, 2014
Pilot concludes July 31, 2017

### Description:

On September 30, 2010, the Company filed an application with the SCC (Case No. PUE-2010-00135) proposing to offer three experimental and voluntary dynamic pricing tariffs to prepare for a potential system-wide offering in the future. The filing was in response to the SCC's directive to the Company to establish a pilot program under which eligible customers volunteering to participate would be provided the ability to purchase electricity from the Company at dynamic rates. The Dynamic Pricing Pilot program was approved by the SCC's Order Establishing Pilot Program issued on April 8, 2011.

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

The Pilot is limited to 3,000 participants consisting of up to 2,000 residential customers taking service under experimental dynamic pricing tariff DP-R and 1,000 commercial/general customers taking service under dynamic pricing tariffs DP-1 and DP-2. Participation in the Pilot requires either an Advanced Metering Infrastructure ("AMI") meter or an existing Interval Data Recorder ("IDR") meter at the customer location. The meter records energy usage every 30 minutes, which enables the Company to offer pricing that varies based on the time of day. In addition, the pricing varies based on the season, the classification for the day, and the customer's demand. Therefore, the AMI or IDR meter coupled with the dynamic pricing schedules allows customers to manage their energy costs based on the time of day. Additional information regarding the Pilot is available at http://www.dom.com/smartprice.

### Status:

As of December 31, 2016, there were 511 customers taking service under the residential DP-R tariff; 58 customers taking service under the commercial DP-1 tariff; and 73 customers taking service under the commercial DP-2 tariff. On January 31, 2017, the Company filed for SCC approval to modify language in the Dynamic Pricing Tariffs to allow existing customers to remain on them after the July 31, 2017 conclusion of the Dynamic Pricing Pilot if they choose to do so. The matter is pending before the SCC.

**Electric Vehicle Pilot**

**State:** Virginia

**Target Class:** Residential

**Pilot Type:** Peak-Shaving

**Pilot Duration:** Enrollment began October 3, 2011 and concluded September 1, 2016
Pilot is scheduled to conclude November 30, 2018.

**Description:**

On January 31, 2011, the Company filed an application with the SCC (Case No. PUE-2011-00014) proposing a pilot program to offer experimental and voluntary electric vehicle ("EV") rate options to encourage residential customers who purchase or lease EVs to charge them during off-peak periods. The SCC approved the Pilot in July 2011. The Pilot program provides two rate options. One rate option, a "Whole House" rate, allows customers to apply the time-of-use rate to their entire service, including their premises and vehicle. The other rate option, an "EV Only" rate, allows customers to remain on the existing residential rate for their premises and subscribe to the time-of-use rate only for their vehicle. The program is limited to 1,500 residential customers, with up to 750 in each of the two experimental rates. Additional information regarding the Company's EV Pilot Program is available in the Company's application, in the SCC's Order Granting Approval, and at https://www.dom.com/electricvehicle.

**Status:**

As of December 31, 2016, 447 customers were enrolled on the whole-house EV rate and 160 customers were enrolled on the EV-only rate.

**AMI Upgrades**

**State:** Virginia and North Carolina

**Target Class:** All Classes

**Type:** Energy Efficiency

**Duration:** Ongoing

**Description:**

The Company continues to upgrade meters to AMI, which are referred to as smart meters.

**Status:**

As of December 2016, the Company has installed over 370,000 smart meters in areas throughout Virginia and North Carolina. The AMI meter upgrades are part of an ongoing project that will help the Company further evaluate the effectiveness of AMI meters in achieving voltage conservation, voltage stability, remotely turning off and on electric service, power outage, restoration detection and reporting, remote daily meter readings, distributed energy resource integration, and offering dynamic rates. AMI is critical for grid modernization as discussed in Section 5.1.3.

### 3.2.4 CURRENT CONSUMER EDUCATION PROGRAMS

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

**Customer Connection Newsletter**

**State:** Virginia and North Carolina

The Customer Connection newsletter contains news on topics such as DSM programs, how to save money and manage electric bills, helping the environment, service issues, and safety recommendations, in addition to many other relevant subjects. Articles from the most recent Customer Connection Newsletter are located on the Company's website at: https://www.dom.com/about-us/news-center/customer-newsletters.

**Twitter® and Facebook**

**State:** Virginia and North Carolina

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

**"Every Day"**

**State:** Virginia

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

**News Releases**

**State:** Virginia and North Carolina

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

### Online Energy Calculators

**State:** Virginia and North Carolina

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

### Community Outreach - Trade Shows, Exhibits, and Speaking Engagements

**State:** Virginia and North Carolina

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

For example, Project Plant It! is an educational community learning program available to students in the service areas where the Company conducts business. The program teaches students about the importance of trees and how to protect the environment through a variety of hands-on teaching tools such as a website with downloadable classroom lesson plans, instructional videos, and interactive games. To enhance the learning experience, Project Plant It! provides each enrolled student with a redbud tree seedling to plant at home or at school. The Company offers Project Plant It! free of charge and has distributed over 350,000 seedlings through the program since 2007.

### DSM Program Communications

The Company uses numerous methods to make customers aware of its DSM programs. These methods include direct mail, communications through contractor networks, e-mail, radio ads, social media, and outreach events.

## 3.2.5 APPROVED DSM PROGRAMS

On August 28, 2015, the Company filed for SCC approval (Case No. PUE-2015-00089) for one Residential Program and one Non-Residential Program. The two proposed Programs are the i) Residential Programmable Thermostat Program and ii) Small Business Improvement Program. In addition, the Company filed for an extension of the Air Conditioner Cycling Program. On April 19, 2016, the Commission issued its Final Order approving the Small Business Improvement Program and continuation of the AC Cycling Program for five years (subject to certain conditions) and denied the Residential Programmable Thermostat Program.

In North Carolina, in Docket No. E-22, Sub 538, the Company filed for NCUC approval of the Small Business Improvement Program. This is the same Program that was approved in Virginia in Case No. PUE-2015-00089. On October 26, 2016, the NCUC approved the new Program, which has been available to qualifying North Carolina customers since January 2017. In October 2016, in Docket No. E-22, Sub 539, the Company filed for NCUC approval of a North Carolina only Residential Retail LED Lighting Program. On December 20, 2016, the NCUC approved the new Program. The Program is being offered in the Company's North Carolina service territory for a period of two years beginning in 2017.

Appendix 3M provides program descriptions for the currently approved DSM programs. Included in the descriptions are the branded names used for customer communications and marketing plans that the Company is employing and plans to achieve each program's penetration goals. Appendices 3N, 3O, 3P and 3Q provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each approved program.

### 3.2.6 PROPOSED DSM PROGRAMS

On October 3, 2016, as part of Case No. PUE-2016-00111, the Company filed in Virginia for SCC approval of two bundled DSM Programs ("Phase VI DSM Programs"), one for residential customers and the other for its non-residential customers. The two proposed Programs are the i) Residential Home Energy Assessment Program; and ii) Non-Residential Prescriptive Program. The Residential Home Energy Assessment Program would serve as an update/replacement to the current DSM II Residential Home Energy Check-Up Program. The bundles are a combination of several programs that include multiple measures as requested by the Company's stakeholders. The Company intends to launch these programs by August 2017 pending SCC approval. Both Programs are classified as energy efficiency programs, as that classification is defined under Va. Code § 56-576.

In addition to the above two programs, the Company is requesting the extension of the Phase II Residential Heat Pump Upgrade and the Non-Residential Distributed Generation Programs. The SCC is expected to issue its Final Order by early June 2017.

Appendix 3R provides program descriptions for the proposed DSM programs. Appendices 3S, 3T, 3U and 3V provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations.

### 3.2.7 EVALUATION, MEASUREMENT & VERIFICATION

The Company has implemented EM&V plans to quantify the level of energy and demand savings for approved DSM programs in Virginia and North Carolina. As required by the SCC and NCUC, the Company provides annual EM&V reports that include: i) the actual EM&V data; ii) the cumulative results for each DSM program in comparison to forecasted annual projections; and iii) any recommendations or observations following the analysis of the EM&V data. These reports are filed annually with the SCC and NCUC and provide information through the prior calendar year. DNV GL (formerly DNV KEMA Energy & Sustainability), a third-party vendor, continues to be responsible for developing, executing, and reporting the EM&V results for the Company's currently-approved DSM programs.

## 3.3 TRANSMISSION RESOURCES

### 3.3.1 EXISTING TRANSMISSION RESOURCES

The Company has approximately 6,600 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.

### 3.3.2 EXISTING TRANSMISSION & DISTRIBUTION LINES

North Carolina Plan Addendum 2 contains the list of the Company's existing transmission and distribution lines from the most recently filed Federal Energy Regulatory Commission ("FERC") Form 1.

### 3.3.3 TRANSMISSION PROJECTS UNDER CONSTRUCTION

The Company currently has one transmission interconnection project under construction that can be found in Appendix 3W. A list of the Company's transmission lines and associated facilities that are under construction can be found in Appendix 3X.

# CHAPTER 4 – PLANNING ASSUMPTIONS

## 4.1 PLANNING ASSUMPTIONS INTRODUCTION

In this 2017 Plan, the Company relies upon a number of assumptions including requirements from PJM. This Chapter discusses these assumptions and requirements related to capacity needs, reserve requirements, renewable energy requirements, commodity price assumptions, and transmission assumptions. The Company updates its IRP assumptions annually to maintain a current view of relevant markets, the economy, and regulatory drivers.

### 4.1.1 CLEAN POWER PLAN ASSUMPTIONS

However unlikely, the primary assumption that the Company used for the CPP-Compliant Plans is that the CPP final rule goes into effect as promulgated. Further, Chapter 6 includes two different sets of CPP-Compliant Plans modeled under different scenarios. Scenario 1 is modeled under the assumption that the Company achieves CPP compliance primarily through generation portfolio modifications, not allowing for any $CO_2$ emissions above the CPP limits, while Scenario 2 is modeled under the assumption that the Company achieves CPP compliance through allowance and/or ERC trading. Unlike the 2016 Plan, neither scenario of CPP-Compliant Plans limits the levels of energy and capacity that can be purchased or sold into the PJM marketplace except for the physical electric transmission import/export limits associated with the Company's service territory. Also, CPP-Compliant Plans modeled under Scenario 1 assume that the run-time of the Company's Mt. Storm Power Station, located in West Virginia, is limited to a 40% capacity factor. This assumption is based on the Company's view that West Virginia: i) would elect a Mass-Based CPP compliance program; and ii) would allocate allowances to affected units in West Virginia using the methodology based on a unit's pro-rata share of the average 2010 – 2012 statewide generation as proposed in the model trading rule. The CPP-Compliant Plans modeled under Scenario 2 place no limitation on Mt. Storm's run time.

The Company also assumed that it would be allocated 70% of the total $CO_2$ allowances under the Mass-Based compliance options for Virginia. This is based on the Company's average share of the statewide total $CO_2$ emissions in the 2012 baseline year. Allowance set-asides were not incorporated in the Mass-Based plans because of uncertainty in whether or how they would be established and distributed. However, if set-asides are part of the Mass-Based plans, the Company believes it will earn approximately 70% of the set-aside allowances, which means the Company will continue to receive 70% of all Virginia allowances, to the extent allowances are distributed directly to affected generating units.

A key resource contributing towards CPP compliance that is utilized by the Company in this 2017 Plan is solar PV. As discussed in Chapter 5, current solar PV technology produces intermittent energy that is non-dispatchable and subject to sudden changes in generation output along with voltage inconsistencies. Therefore, integrating large volumes of solar PV into the Company's grid presents service reliability challenges that the Company continues to examine and study. In the Alternative Plans described in Chapter 6, a $159/kW fixed charge was phased into the cost of solar PV to function as an estimated charge for transmission and distribution integration costs. Further, a $2/MWh variable charge was added to the dispatch price of solar PV generation to address generation re-dispatch costs. A full description of the analysis conducted by the Company to estimate these costs is included in Chapter 5. It should be emphasized that, although more defined than the proxy costs included in the Company's previous Plans, the solar PV integration costs remain, at this time, high level estimates. Costs such as advanced communications and control systems, intelligent grid devices, energy storage devices, increased operating reserve costs, natural gas nomination revision costs, and increased equipment O&M costs (due to increased cycling) are not included in these integration cost estimates. The Company continues to assess all costs associated with intermittent generation integration and intends to include those results in future Plans.

## 4.2 PJM CAPACITY PLANNING PROCESS & RESERVE REQUIREMENTS

The Company participates in the PJM capacity planning process for short- and long-term capacity planning. A brief discussion of this process and the Company's participation in it is provided in the following subsections.

### 4.2.1 SHORT-TERM CAPACITY PLANNING PROCESS – RPM

As a PJM member, the Company is a signatory to PJM's Reliability Assurance Agreement, which obligates the Company to own or procure sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone through its annual load forecast and reserve margin guidelines. PJM then conducts a capacity auction through its Short-Term Capacity Planning Process (i.e., the RPM auction) for meeting these requirements three years into the future. This auction process determines the reserve margin and the capacity price for each zone for the delivery year that is three years in the future (e.g., 2017 auction procures capacity for the delivery year 2020/2021).

The Company, as a generation provider, bids its capacity resources, including owned and contracted generation and DSM programs, into this auction. As an LSE, the Company is obligated to obtain enough capacity to cover its PJM-determined capacity requirements either from the RPM auction, or through any bilateral trades. Figure 4.2.2.1 provides the Company's estimated 2017 - 2019 capacity positions and associated reserve margins based on PJM's 2017 Load Forecast and RPM auctions that have already been conducted.

### 4.2.2 LONG-TERM CAPACITY PLANNING PROCESS – RESERVE REQUIREMENTS

The Company uses PJM's reserve margin guidelines in conjunction with its own load forecast, as 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") equivalent to one day of outage in 10 years. PJM's 2016 Reserve Requirement Study[13] for delivery year 2020/2021, recommends using an installed reserve margin ("IRM") of 16.6% to satisfy the NERC/Reliability First Corporation ("RFC") Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment, and Documentation.

[13] PJM's current and historical reserve margins are available at http://www.pjm.com/~/media/committees-groups/subcommittees/raas/20160927/20160927-2016-pjm-reserve-requirement-study.ashx.

PJM develops reserve margin estimates for planning years (referred to as "delivery years" for RPM) rather than calendar years. Specifically, PJM's planning year occurs from June 1st to May 31st. Since the Company and PJM are both historically summer peaking entities, and since the summer period of PJM's planning year coincides with the calendar year summer period, calendar and planning year reserve requirement estimates are determined based on the identical summer time period. For example, the Company uses PJM's 2019/2020 delivery year assumptions for the 2019 calendar year in this 2017 Plan because both represent the expected peak load during the summer of 2019.

Two assumptions were made by the Company when applying the PJM reserve margin to the Company's modeling efforts. First, since PJM uses a shorter planning period than the Company, the Company used the most recent PJM Reserve Requirements Study and assumed the reserve margin value for delivery year 2020 and beyond would continue throughout the Study Period.

The second assumption pertains to the coincident factor between the DOM Zone coincidental and non-coincidental peak load. The Company is obligated to maintain a reserve margin for its portion of the PJM coincidental peak load. Since the Company's peak load (non-coincidental) has not historically occurred during the same hour as PJM's peak load (coincidental), a smaller reserve margin is needed to meet reliability targets and is based on a coincidence factor. To determine the coincidence factor used in this 2017 Plan, the Company used a four-year (2017 - 2020) average of the coincidence factor between the DOM Zone coincidental and non-coincidental peak load. The coincidence factor for the Company's load is approximately 96.47%, as calculated using PJM's 2017 Load Forecast. In 2021, applying the PJM IRM requirement of 16.6% with the Company's coincidence factor of 96.47% resulted in an effective reserve margin of 12.48%, as shown in Figure 4.2.2.1. This effective reserve margin was then used for each year for the remainder of the Study Period.

As a member of PJM, the Company participates in the annual RPM capacity market. PJM's RPM construct has historically resulted in a clearing reserve margin in excess of the planned reserve margin requirement. The average PJM RPM clearing reserve margin is 20.3% over the past five years.[14] Using the same analysis approach described above, this equates to an approximate 16.05% effective reserve requirement. With the RPM clearing capacity in excess of its target level, the Company has purchased reserves in excess of the 12.48% planning reserve margin, as reflected in Figure 4.2.2.1. Given this history, the figures in Appendix 1A display a second capacity requirement that includes an additional 5% reserve requirement target (17.48% reserve margin) that is commensurate with the upper bound where the RPM market has historically cleared; however, the Company's planning reserve margin minimum target remains at the 12.48% average clearing level. The upper bound reserve margin reflects the reserve margin that the Company may be required to meet in the future.

[14] See http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx.

**Figure 4.2.2.1 - Peak Load Forecast & Reserve Requirements**

| Year | PJM Installed Reserve Margin Requirements | DVP Effective Reserve Margin Requirements | Total System Summer Peak | Adjusted System Summer Peak | Reserve Requirement | Total Resource Requirement |
|---|---|---|---|---|---|---|
| | % | % | MW | MW | MW | MW |
| 2018 | 16.60% | 23.67% | 17,875 | 17,615 | 4,169 | 21,784 |
| 2019 | 16.70% | 23.54% | 18,230 | 17,928 | 4,220 | 22,148 |
| 2020 | 16.60% | 17.46% | 18,545 | 18,228 | 3,182 | 21,410 |
| 2021 | 16.60% | 12.48% | 18,747 | 18,421 | 2,299 | 20,719 |
| 2022 | 16.60% | 12.48% | 19,058 | 18,730 | 2,337 | 21,068 |
| 2023 | 16.60% | 12.48% | 19,200 | 18,871 | 2,355 | 21,226 |
| 2024 | 16.60% | 12.48% | 19,555 | 19,225 | 2,399 | 21,624 |
| 2025 | 16.60% | 12.48% | 19,768 | 19,439 | 2,426 | 21,864 |
| 2026 | 16.60% | 12.48% | 20,013 | 19,683 | 2,456 | 22,140 |
| 2027 | 16.60% | 12.48% | 20,317 | 19,987 | 2,494 | 22,482 |
| 2028 | 16.60% | 12.48% | 20,463 | 20,131 | 2,512 | 22,643 |
| 2029 | 16.60% | 12.48% | 20,718 | 20,384 | 2,544 | 22,928 |
| 2030 | 16.60% | 12.48% | 21,042 | 20,706 | 2,584 | 23,290 |
| 2031 | 16.60% | 12.48% | 21,310 | 20,973 | 2,617 | 23,591 |
| 2032 | 16.60% | 12.48% | 21,581 | 21,243 | 2,651 | 23,894 |

Note: Values include energy efficiency.

In Figure 4.2.2.1, the total resource requirement provides the total amount of peak capacity including the reserve margin used in this 2017 Plan. This represents the Company's total resource need that must be met through existing resources, construction of new resources, DSM programs, and market capacity purchases. Actual reserve margins in each year may vary based upon the outcome of the forward RPM auctions, revisions to the PJM RPM rules, and annually updated load and reserve requirements. Appendix 2I provides a summary of summer and winter peak load and energy forecast, while Appendix 2J provides a summary of projected PJM reserve margins for summer peak demand.

## 4.3 RENEWABLE ENERGY

### 4.3.1 VIRGINIA RPS

On May 18, 2010, the SCC issued its Final Order granting the Company's July 28, 2009 application to participate in Virginia's voluntary Renewable Energy Portfolio Standards ("RPS") program finding that "the Company has demonstrated that it has a reasonable expectation of achieving 12% of its base year electric energy sales from renewable energy sources during calendar year 2022, and 15% of its base year electric energy sales from renewable energy sources during calendar year 2025" (Case No. PUE-2009-00082, May 18, 2010 Final Order at 7). The RPS guidelines state that a certain percent of the Company's energy is to be obtained from renewable resources. The Company can meet Virginia's RPS program guidelines through the generation of renewable energy, purchase of renewable energy, purchase of RECs, or a combination of the three options. The Company achieved its 2015 Virginia RPS Goal. Figure 4.3.1.1 displays Virginia's RPS goals.

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### Figure 4.3.1.1 - Virginia RPS Goals

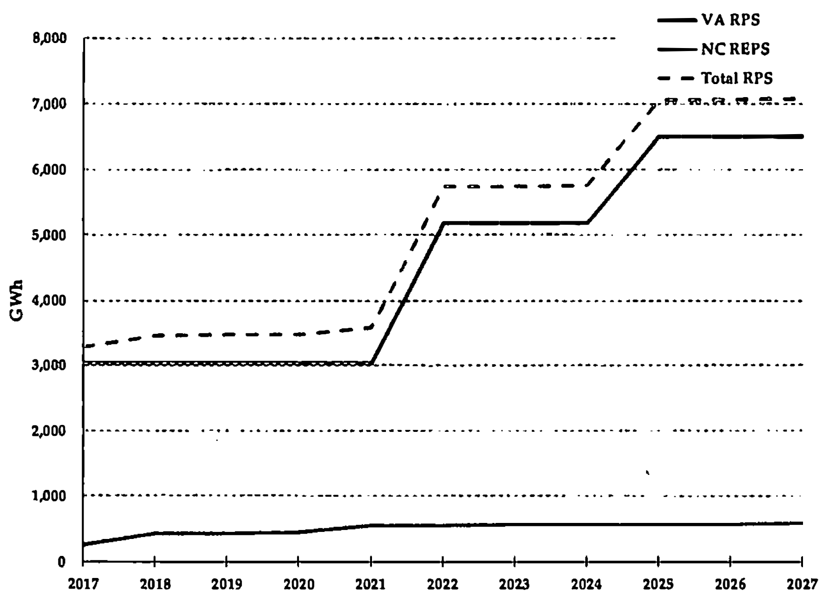
| Year | Percent of RPS | Annual GWh[1] |
|---|---|---|
| 2017-2021 | Average of 7% of Base Year Sales | 3,032 |
| 2022 | 12% of Base Year Sales | 5,198 |
| 2023-2024 | Average of 12% of Base Year Sales | 5,198 |
| 2025 | 15% of Base Year Sales | 6,497 |
| 2026-2027 | 15% of Base Year Sales | 6,497 |

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

The Company has included renewable resources as an option in PLEXOS, taking into consideration the economics and RPS requirements. If there are adequate supplies of waste wood available at the time, VCHEC is expected to provide up to 61 MW of renewable generation by 2021. The Company reiterates its intent to meet Virginia's RPS guidelines at a reasonable cost and in a prudent manner by: i) applying renewable energy from existing generating facilities including NUGs; ii) purchasing cost-effective RECs (including optimizing RECs produced by Company-owned generation when these higher priced RECs are sold into the market and less expensive RECs are purchased and applied to the Company's RPS goals); and iii) constructing new renewable resources when and where feasible.

The renewable energy requirements for Virginia and North Carolina and their totals are shown in Figure 4.3.1.2.

### Figure 4.3.1.2 - Renewable Energy Requirements



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### 4.3.2 NORTH CAROLINA REPS

NCGS § 62-133.8 requires the Company to comply with the state's Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") requirement. The REPS requirement can be met by generating renewable energy, energy efficiency measures (capped at 25% of the REPS requirements through 2020 and up to 40% thereafter), purchasing renewable energy, purchasing RECs, or a combination of options as permitted by NCGS § 62-133.8 (b) (2). The Company plans to meet a portion of the general REPS requirement using the approved energy efficiency programs discussed in Chapters 3 and 6 of this 2017 Plan. The Company achieved compliance with its 2015 North Carolina REPS general obligation by using approved North Carolina energy efficiency savings, banked RECs, and purchasing additional qualified RECs during 2015. In addition, the Company purchased sufficient RECs to comply with the solar and poultry waste set-aside requirements. However, on October 17, 2016, in response to the Joint Motion to Modify and Delay, the NCUC delayed the Company's 2016 swine waste set-aside requirement one year and delayed the poultry waste set-aside requirement increase for one year. More information regarding the Company's REPS compliance planning is available in its North Carolina REPS Compliance Plan filed in North Carolina with this 2017 Plan as North Carolina Plan Addendum 1. Figure 4.3.2.1 displays North Carolina's overall REPS requirement.

**Figure 4.3.2.1 - North Carolina Total REPS Requirement**

| Year | Percent of REPS | Annual GWh[1] |
|---|---|---|
| 2017 | 6% of 2016 DNCP Retail Sales | 257 |
| 2018 | 10% of 2017 DNCP Retail Sales | 431 |
| 2019 | 10% of 2018 DNCP Retail Sales | 435 |
| 2020 | 10% of 2019 DNCP Retail Sales | 438 |
| 2021 | 12.5% of 2020 DNCP Retail Sales | 552 |
| 2022 | 12.5% of 2021 DNCP Retail Sales | 557 |
| 2023 | 12.5% of 2022 DNCP Retail Sales | 561 |
| 2024 | 12.5% of 2023 DNCP Retail Sales | 566 |
| 2025 | 12.5% of 2024 DNCP Retail Sales | 570 |
| 2026 | 12.5% of 2025 DNCP Retail Sales | 575 |
| 2027 | 12.5% of 2026 DNCP Retail Sales | 579 |

Note: 1) Annual GWh is an estimate only based on the latest forecast sales. The Company intends to comply with the North Carolina REPS requirement, including the set-asides for energy derived from solar, poultry waste, and swine waste through the purchase of RECs and/or purchased energy, as applicable. The set-aside requirements represent approximately 0.03% of system load by 2024 and will not materially alter this 2017 Plan.

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

## Figure 4.3.2.2 - North Carolina Solar Requirement

| Year | Requirement Target (%) | Annual GWh[1] |
|---|---|---|
| 2017 | 0.14% of 2016 DNCP Retail Sales | 5.99 |
| 2018 | 0.20% of 2017 DNCP Retail Sales | 8.63 |
| 2019 | 0.20% of 2018 DNCP Retail Sales | 8.70 |
| 2020 | 0.20% of 2019 DNCP Retail Sales | 8.77 |
| 2021 | 0.20% of 2020 DNCP Retail Sales | 8.84 |
| 2022 | 0.20% of 2021 DNCP Retail Sales | 8.91 |
| 2023 | 0.20% of 2022 DNCP Retail Sales | 8.98 |
| 2024 | 0.20% of 2023 DNCP Retail Sales | 9.05 |
| 2025 | 0.20% of 2024 DNCP Retail Sales | 9.12 |
| 2026 | 0.20% of 2025 DNCP Retail Sales | 9.20 |
| 2027 | 0.20% of 2026 DNCP Retail Sales | 9.27 |

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

## Figure 4.3.2.3 - North Carolina Swine Waste Requirement

| Year | Target | Dominion Market Share (Est.) | Annual GWh[1] |
|---|---|---|---|
| 2017 | 0.07% of 2016 NC Retail Sales | 3.27% | 3.00 |
| 2018 | 0.07% of 2017 NC Retail Sales | 3.16% | 3.02 |
| 2019 | 0.14% of 2018 NC Retail Sales | 3.16% | 6.09 |
| 2020 | 0.14% of 2019 NC Retail Sales | 3.15% | 6.14 |
| 2021 | 0.14% of 2020 NC Retail Sales | 3.14% | 6.19 |
| 2022 | 0.20% of 2021 NC Retail Sales | 3.12% | 8.91 |
| 2023 | 0.20% of 2022 NC Retail Sales | 3.10% | 8.98 |
| 2024 | 0.20% of 2023 NC Retail Sales | 3.09% | 9.05 |
| 2025 | 0.20% of 2024 NC Retail Sales | 3.07% | 9.12 |
| 2026 | 0.20% of 2025 NC Retail Sales | 3.06% | 9.24 |
| 2027 | 0.20% of 2026 NC Retail Sales | 3.04% | 9.32 |

Note: 1) Annual GWh is an estimate based on the latest forecast sales.

**Figure 4.3.2.4 - North Carolina Poultry Waste Requirement**

| Year | Target[1] (GWh) | Dominion Market Share (Est.) | Annual GWh[1] |
|---|---|---|---|
| 2017 | 700 | 3.31% | 23.17 |
| 2018 | 900 | 3.31% | 29.79 |
| 2019 | 900 | 3.12% | 28.08 |
| 2020 | 900 | 3.12% | 28.08 |
| 2021 | 900 | 3.12% | 28.08 |
| 2022 | 900 | 3.07% | 27.63 |
| 2023 | 900 | 3.07% | 27.63 |
| 2024 | 900 | 3.07% | 27.63 |
| 2025 | 900 | 3.03% | 27.27 |
| 2026 | 900 | 3.03% | 27.27 |
| 2027 | 900 | 3.03% | 27.27 |

Note: 1) For purposes of this filing, the Poultry Waste Resource requirement is calculated as an aggregate target for NC electric suppliers distributed based on market share. On April 18, 2016, the NCUC established a procedure to allocate the poultry waste set-aside by averaging three years of historical retail sales and using the resulting load share ratio for the following three years.

## 4.4 COMMODITY PRICE ASSUMPTIONS

The Company utilizes a single source to provide multiple scenarios for the commodity price forecast to ensure consistency in methodologies and assumptions. The Company performed the analysis in this 2017 Plan using energy and commodity price forecasts provided by ICF, a global energy consulting firm, in all periods except the first 36 months of the Study Period. The forecasts used for natural gas, coal, and power prices rely on forward market prices as of September 29, 2016, 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 forecast used for capacity prices, $NO_x$, and $SO_2$ allowance prices are provided by ICF for all years forecasted within this 2017 Plan. The capacity prices are provided on a calendar year basis and reflect the results of the PJM RPM Base Residual Auction through the 2019/2020 delivery year, thereafter transitioning to the ICF capacity forecast beginning with the 2020/2021 delivery year.

Consistent with the 2016 Plan, the Company utilizes the No $CO_2$ Cost forecast to evaluate Plan A: No CPP and the CPP commodity forecast to evaluate the CPP-Compliant Plans as listed in Figure 6.4.1. The primary reason for utilizing this method is to allow the Company to evaluate the CPP-Compliant Plans using a commodity price forecast that reflects the CPP. Plan A assumes no new $CO_2$ laws or regulations and; therefore, it was evaluated using a commodity price forecast without the influence of $CO_2$ compliance requirements. In summary, the primary commodity price forecast used to analyze the CPP-Compliant Plans is the CPP commodity forecast while the No $CO_2$ commodity price forecast was used to evaluate Plan A.

### 4.4.1 CPP COMMODITY FORECAST

The CPP commodity forecast is utilized as the primary planning curve for evaluation in this 2017 Plan. The forecast was developed for the Company to specifically address the CPP, which is designed to control $CO_2$ emissions from existing fossil-fired generators with an interim target for 2022 - 2029 and final targets in 2030. The key assumptions on market structure and the use of an integrated, internally-consistent fundamentals-based modeling methodology remain consistent with those utilized in the prior years' commodity forecasts. With consideration to the inherent uncertainty as to the final outcome of the legal challenges, trading rules, and state specific compliance plans developed for the CPP, the modeling methods utilized state designations of Intensity-Based and Mass-Based programs developed by ICF. Very few states have indicated what approach they will take, therefore, ICF is not projecting the paths states would take, but is assessing the uncertainties with the understanding that it is unlikely that all states will choose the same or similar paths forward. The designations were based on a combination of factors including whether the state is a party to the CPP lawsuit, is a participant in an existing Mass-Based $CO_2$ program, engages in renewable development, and/or nuclear development. The states projected to settle on a Mass-Based program for existing units are assumed to participate in a nationwide trading program for $CO_2$ allowances. States projected to settle on an Intensity-Based program are generally large creators of ERCs. A list of the projected programs for each state is provided in Appendix 4A. The modeling results in the price forecasts for two $CO_2$ related commodities, a carbon allowance measured in $/ton and an ERC measured in $/MWh. States projected to pursue a Mass-Based program on existing units will be buyers or sellers of $CO_2$ allowances, and those states that pursue an Intensity-Based program will be buyers and sellers of ERCs. The CPP commodity price forecast used in the 2017 Plan assumed that Virginia adopts an Intensity-Based program as the state specific compliance plan.

The Company's evaluation of an Intensity-Based program in Virginia utilized ERC prices to represent the cost of carbon; for the evaluation of a Mass-Based program, the carbon cost is represented by a $CO_2$ allowance price. In the 2016 Plan, the ERC prices had a zero value. In the 2017 forecast, ERC prices have increased due to a change in assumptions regarding the election made by qualifying renewable generation in Mass-Based states that are contiguous to Intensity-Based states. In the 2016 forecast, the assumption was that a qualifying renewable, in a contiguous Mass-Based state would elect to receive ERCs, which would be available for use in states that elect an Intensity-Based program. The assumption in the 2017 forecast is that a qualifying renewable generator would forego the earning of an ERC in order to remain eligible for renewable set asides in the state in which they are located. The assumption change used in the 2017 forecast results increased ERC prices relative to the 2016 forecast.

The value of ERCs and $CO_2$ allowances is ultimately contingent on i) the type of compliance plan adopted by states and whether the states elect to pursue an Intensity-Based or Mass-Based approach to CPP compliance; ii) the notion that all ERCs/$CO_2$ allowances will be offered to the market; iii) the probability that there will be no changes to ERC eligibility; iv) the trading programs are developed including state participation; and v) the type and timing of future generation development. Given the uncertainty inherent to a program that is determined by the actions of others, the Company continues to evaluate plans that will be CPP-compliant without consistent reliance on market purchases of ERCs or $CO_2$ allowances along with plans that do rely on trading to meet CPP compliance.

A summary of the CPP commodity forecast for the 2017 Plan and the CPP forecast used in the 2016 Plan are provided below. As discussed earlier, the CPP commodity forecast is the primary planning curve for evaluating the CPP-Compliant Plans (Figure 6.4.1). The primary reason for this is to allow the Company to evaluate the CPP-Compliant Plans using a commodity price forecast that reflects the current guidelines of the CPP. Appendix 4B provides delivered fuel prices and primary fuel expense from the PLEXOS model output using the CPP commodity forecast. Figures 4.4.1.1 - 5 display the fuel price forecasts, while Figures 4.4.1.6 displays the forecasted price for $SO_2$ and $NO_x$ on a dollar per ton basis. Figure 4.4.1.7 displays $CO_2$ emissions allowances ($/ton) and ERC prices ($/MWh). Figures 4.4.1.8 - 9 present the forecasted market clearing peak power prices for the DOM Zone. The PJM RTO capacity price forecast is presented in Figure 4.4.1.10.

**Figure 4.4.1.1 - Fuel Price Forecasts - Natural Gas Henry Hub**

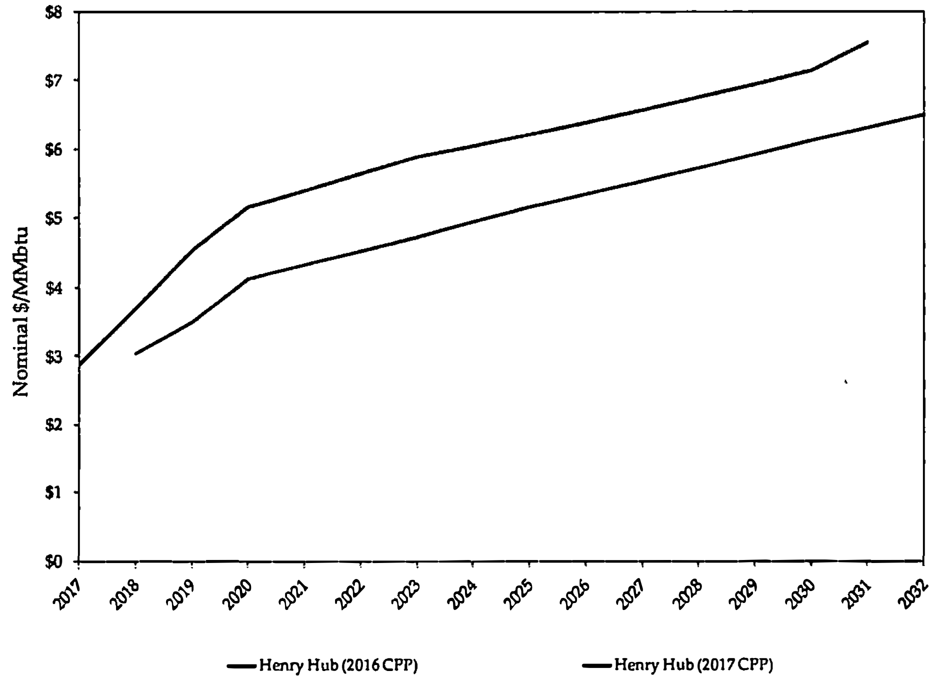

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Figure 4.4.1.2 - Fuel Price Forecasts - Natural Gas DOM Zone

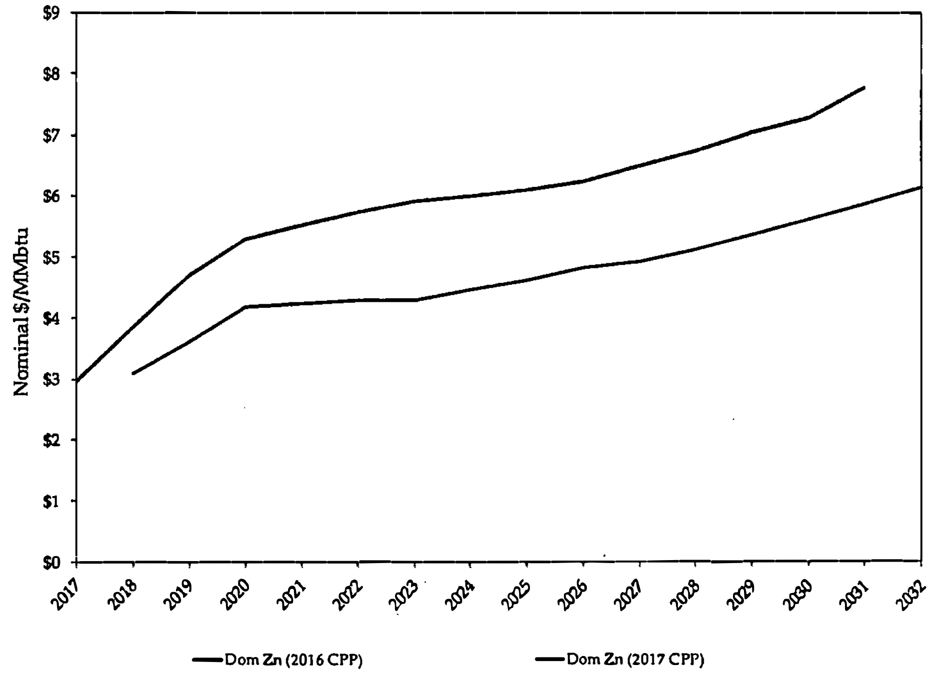
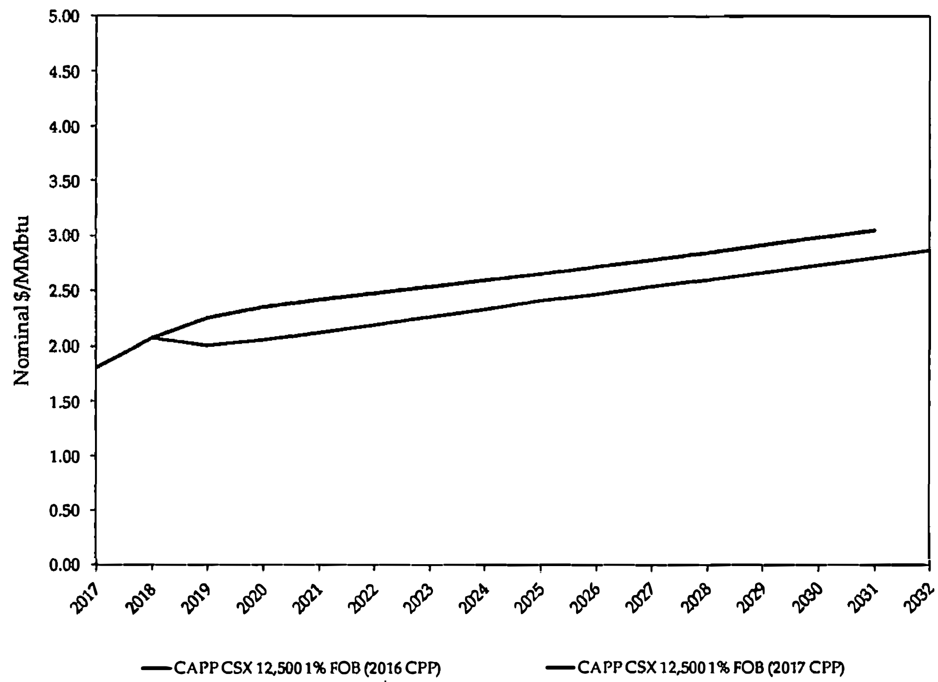
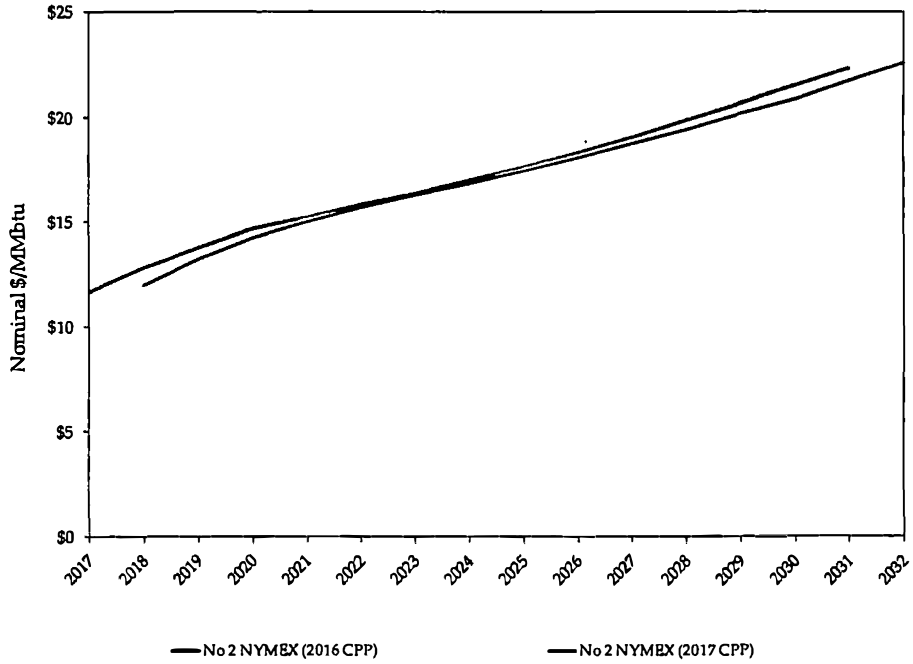



Figure 4.4.1.3 - Fuel Price Forecasts - Coal



## Figure 4.4.1.4 - Fuel Price Forecasts - #2 Oil




## Figure 4.4.1.5 - Price Forecasts – #6 Oil

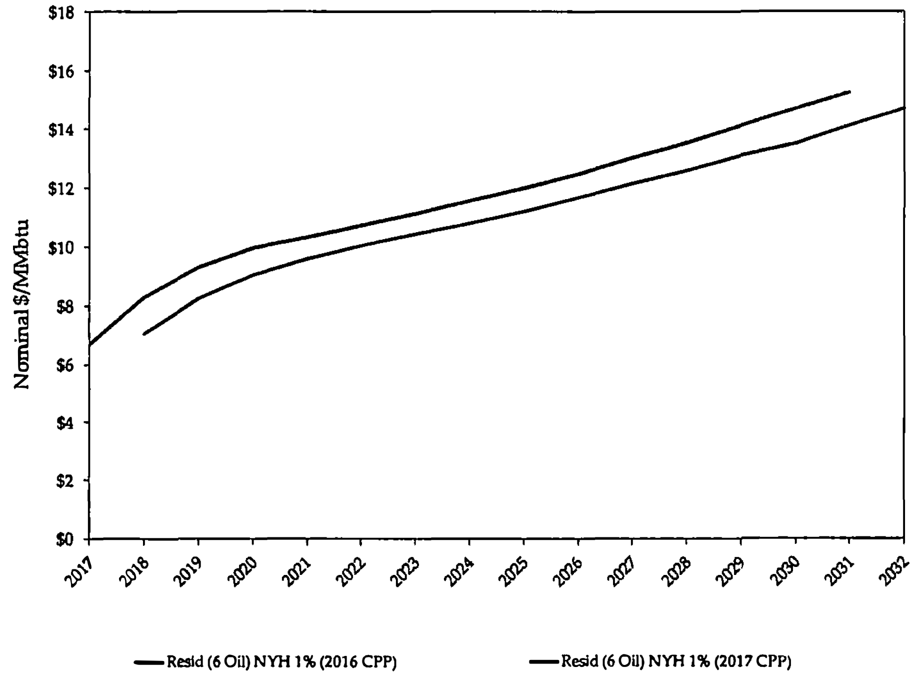


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Figure 4.4.1.6 - Price Forecasts – $SO_2$ & NOx

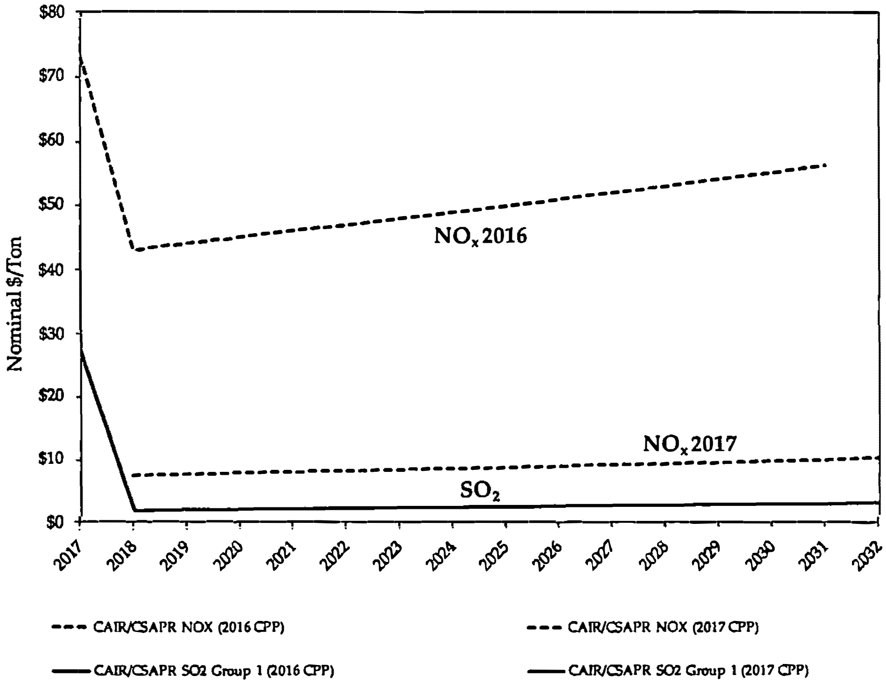
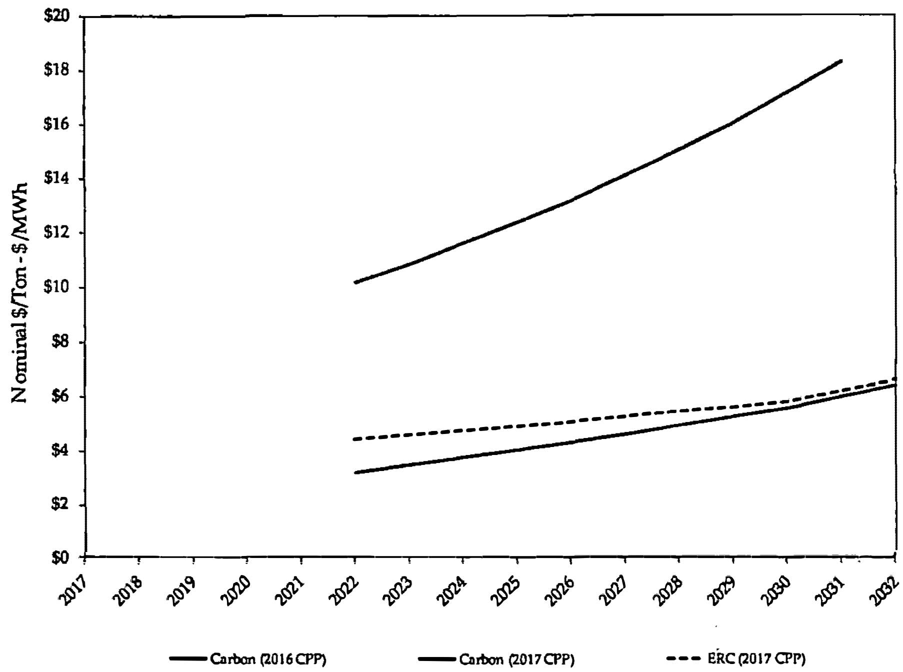
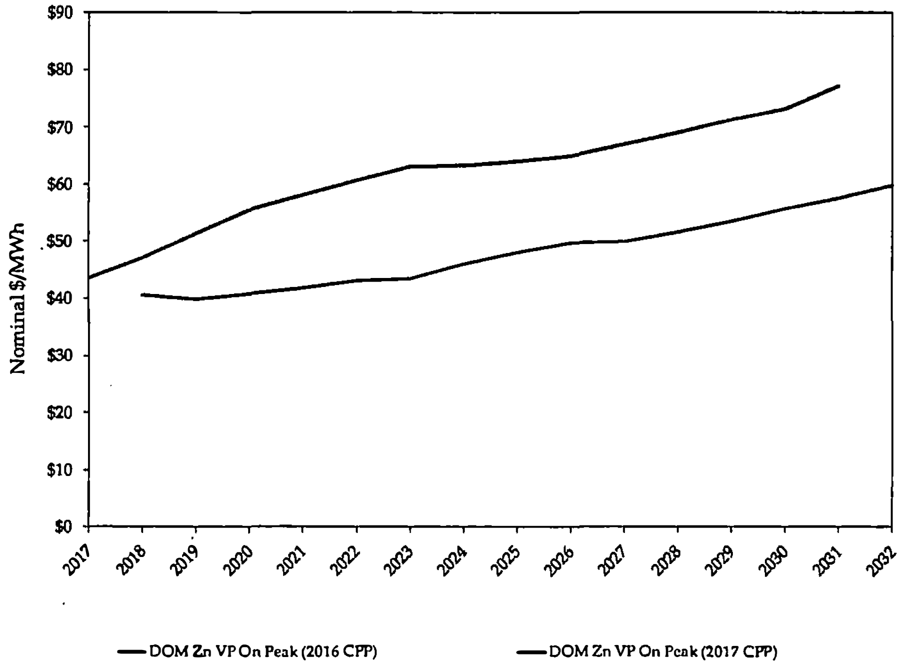



Figure 4.4.1.7 - Price Forecasts - $CO_2$




Note: The CPP commodity forecast used in the 2017 Plan includes both an ERC and $CO_2$ allowance price. The ERC forecast is in $/MWh and applies to states adopting an Intensity-Based compliance program. The $CO_2$ allowance price forecast is in $/ton and applies to states adopting a Mass-Based compliance program. In the 2016 Plan, ERCs were forecasted at $0/MWh because those states that were projected to adopt an Intensity-Based compliance program were projected to generate an abundance of ERCs.

## Figure 4.4.1.8 - Power Price Forecasts – On Peak




## Figure 4.4.1.9 - Power Price Forecasts – Off Peak

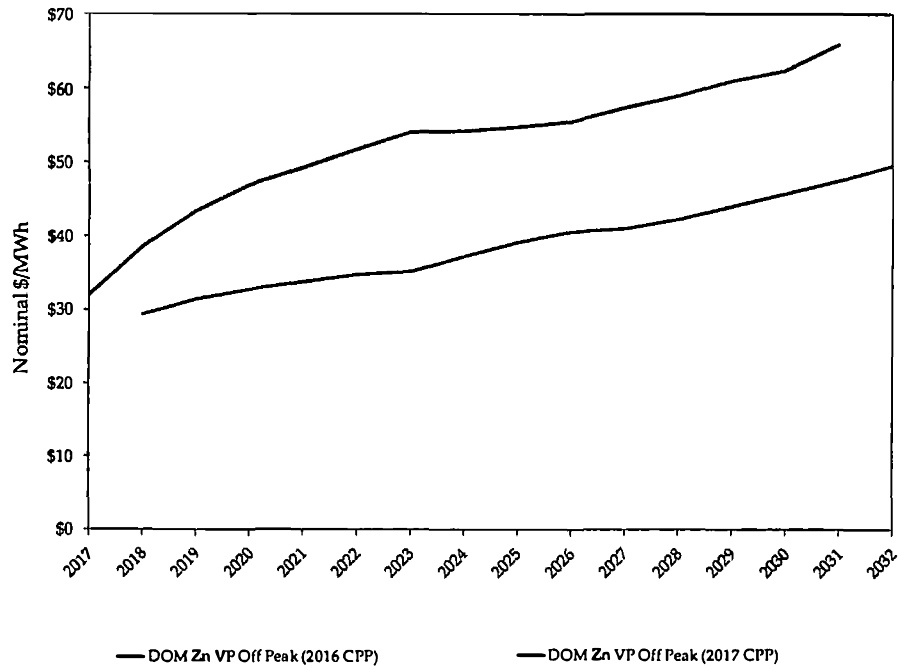
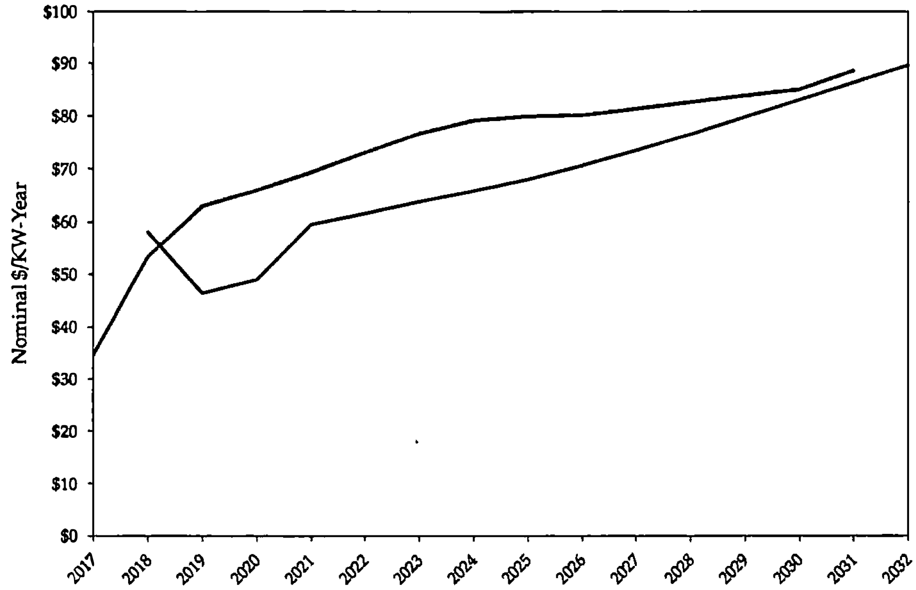


**Figure 4.4.1.10 - PJM RTO Capacity Price Forecasts**




The forecast of power and gas prices are lower this year than forecast in the 2016 Plan, primarily due to the continued decrease in cost and increase in volume of the shale gas resources. The lower load forecast also contributes to the decline in power and gas prices. Capacity prices are lower, reflecting lower costs and improved heat rates for new CCs. Figure 4.4.1.11 presents a comparison of average fuel, electric, and REC prices used in the 2016 Plan relative to those used in this 2017 Plan.

**Figure 4.4.1.11 - 2016 to 2017 Plan Fuel & Power Price Comparison**

| | Planning Period Comparison Average Value (Nominal $) | |
|---|---|---|
| Fuel Price | 2016 Plan CPP Commodity Forecast [3] | 2017 Plan CPP Commodity Forecast [3] |
| Henry Hub Natural Gas[1] ($/MMbtu) | 5.79 | 5.05 |
| DOM Zone Delivered Natural Gas[1] ($/MMbtu) | 5.85 | 4.71 |
| CAPP CSX: 12,500 1%S FOB ($/MMbtu) | 2.57 | 2.41 |
| No. 2 Oil ($/MMbtu) | 17.12 | 17.48 |
| 1% No. 6 Oil ($/MMbtu) | 11.55 | 11.22 |
| Electric and REC Prices | | |
| PJM-DOM On-Peak ($/MWh) | 61.96 | 48.05 |
| PJM-DOM Off-Peak ($/MWh) | 52.40 | 38.91 |
| PJM Tier 1 REC Prices ($/MWh) | 22.10 | 15.32 |
| RTO Capacity Prices[2] ($/KW-yr) | 73.17 | 68.79 |

Note: 1) DOM Zone natural gas price used in Plan analysis. Henry Hub prices are shown to provide market reference.
2) Capacity price represents actual clearing price from PJM Reliability Pricing Model. Base Residual Auction results through power year 2018/2019 for the 2016 Plan and 2019/2020 for the 2017 Plan.
3) 2016 Planning Period 2017 – 2031, 2017 Planning Period 2018 – 2032.

### 4.4.2 ALTERNATIVE SCENARIO COMMODITY PRICES

The Company utilizes the No $CO_2$ Cost forecast to evaluate Plan A. In this forecast, the cost associated with carbon emissions projected to commence in 2022 is removed from the CPP commodity forecast. The cost of $CO_2$ being removed has an effect of reducing natural gas prices by 1% from the CPP commodity forecast across the Planning Period due to reduced natural gas generation in the absence of a federal $CO_2$ program. DOM Zone peak energy prices are on average 5% lower than the CPP commodity forecast across the Planning Period due to lower natural gas prices and no $CO_2$ cost to pass through to power prices.

Appendix 4A provides the annual prices (nominal $) for the CPP commodity forecast and the No $CO_2$ Cost forecast. Figure 4.4.2.1 provides a comparison of the CPP commodity forecast and the No $CO_2$ Cost case.

**Figure 4.4.2.1 - 2017 Plan Fuel & Power Price Comparison**

| | 2018 - 2032 Average Value (Nominal $) | |
|---|---|---|
| Fuel Price | CPP Commodity Forecast | No $CO_2$ Cost Case |
| Henry Hub Natural Gas ($/MMbtu) | 5.05 | 5.01 |
| DOM Zone Delivered Natural Gas ($/MMbtu) | 4.71 | 4.67 |
| CAPP CSX: 12,500 1%S FOB ($/MMbtu) | 2.41 | 2.43 |
| No. 2 Oil ($/MMbtu) | 17.48 | 17.48 |
| 1% No. 6 Oil ($/MMbtu) | 11.22 | 11.22 |
| Electric and REC Prices | | |
| PJM-DOM On-Peak ($/MWh) | 48.05 | 45.59 |
| PJM-DOM Off-Peak ($/MWh) | 38.91 | 36.96 |
| PJM Tier 1 REC Prices ($/MWh) | 15.32 | 16.48 |
| RTO Capacity Prices ($/kW-yr) | 68.79 | 73.93 |

## 4.5 DEVELOPMENT OF DSM PROGRAM ASSUMPTIONS

The Company develops assumptions for new DSM programs by engaging vendors through a competitive bid process to submit proposals for candidate program design and implementation services. As part of the bid process, basic program design parameters and descriptions of candidate programs are requested. The Company generally prefers, to the extent practical, that the program design vendor is ultimately the same vendor that implements the program in order to maintain as much continuity as possible from design to implementation.

The DSM program design process includes evaluating programs as either a single measure, like the Residential Heat Pump Upgrade Program, or multi-measure, like the Small Business Improvement Program. For all measures in a program, the design vendor develops a baseline for a standard customer end-use technology. The baseline establishes the current energy usage for a particular appliance or customer end-use. Next, assumptions for a more efficient replacement measure or end-use are developed. The difference between the more efficient energy end-use and the standard end-use provides the incremental benefit that the Company and customer will achieve if the more efficient energy end-use is implemented.

The program design vendor's development of assumptions for a DSM program include determining cost estimates for the incremental customer investment in the more efficient technology, the incentive that the Company should pay the customer to encourage investment in the DSM measure, and the program cost the Company will likely incur to administer the program. In addition to the cost assumptions for the program, the program design vendor develops incremental demand and energy reductions associated with the program. This data is represented in the form of a load shape for energy efficiency programs which identifies the energy reductions by hour for each hour of the year (8,760 hour load shape).

The Company then uses the program assumptions developed by the program design vendor to perform cost/benefit tests for the programs. Programs that pass the Company's evaluation process are included in the Company's DSM portfolio, subject to appropriate regulatory approvals.

## 4.6 TRANSMISSION PLANNING

The Company's transmission planning process, system adequacy, transfer capabilities, and transmission interconnection process are described in the following subsections. As used in this 2017 Plan, electric transmission facilities can be generally defined as those operating at 69 kV and above that provide for the interchange of power within and outside of the Company's system.

### 4.6.1 REGIONAL TRANSMISSION PLANNING & SYSTEM ADEQUACY

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

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

The PJM RTEP covers the entire PJM control area and includes projects proposed by PJM, as well as projects proposed by the Company and other PJM members through internal planning processes. The PJM RTEP process includes both a five-year and a 15-year outlook.

The Company evaluates its ability to support expected customer growth through its internal transmission planning process. The results of this evaluation will indicate if any transmission improvements are needed, which the Company includes in the PJM RTEP process as appropriate and, if the need is confirmed, then the Company seeks approval from the appropriate regulatory body. Additionally, the Company performs seasonal operating studies to identify facilities in its transmission system that could be critical during the upcoming season. It is essential to maintain an adequate level of transfer capability between neighboring utilities to facilitate economic and emergency power flows, and the Company coordinates with other utilities to maintain adequate levels of transfer capability.

### 4.6.2 STATION SECURITY

As part of the Company's overall strategy to improve its transmission system resiliency and security, the Company is installing additional physical security measures at substations and switching stations in Virginia and North Carolina. The Company announced these plans publicly following the widely-reported April 2013 Metcalfe Substation incident in California.

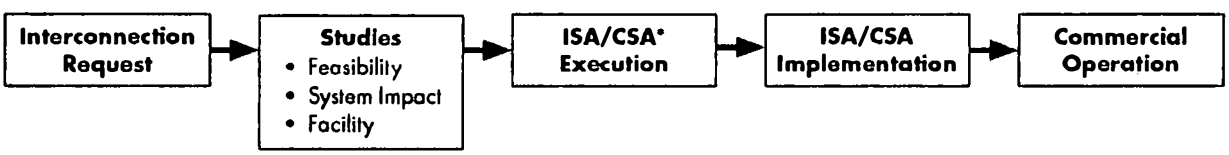
As one of the region's largest electricity suppliers, the Company proposed to spend up to $500 million by 2022 to increase the security for its transmission substations and other critical infrastructure against man-made physical threats and natural disasters, as well as purchase crucial equipment for major damage recovery. These new security facilities will be installed in accordance with recently approved NERC mandatory compliance standards. In addition, the Company has completed construction of its new System Operations Center, which will be operational in August 2017.

### 4.6.3 TRANSMISSION INTERCONNECTIONS

For any new generation proposed within the Company's transmission system, either by the Company or by other parties, the generation owner files an interconnection request with PJM. PJM, in conjunction with the Company, conducts feasibility studies, system impact studies, and facilities studies to determine the facilities required to interconnect the generation to the transmission system (Figure 4.6.3.1). These studies ensure deliverability of the generation into the PJM market. The scope of these studies is provided in the applicable sections of PJM manual 14A[15] and the Company's Facility Connection Requirements.[16]

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 4.6.3.1 - PJM Interconnection Request Process**




**Note: Projects may drop out of the queue at any time.**

* Interconnection Service Agreement/Construction Service Agreement

Source: PJM

[15] The PJM manual 14A is posted at http://www.pjm.com/~/media/documents/manuals/m14a.ashx.

[16] The Company's Facility Connection Requirements are posted at https://www.dom.com/library/domcom/pdfs/electric-transmission/facility-connection-requirements.pdf.

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

The Company also evaluates and analyzes transmission options for siting potential generation resources to offer flexibility and additional grid benefits. The Company conducts power flow studies and financial analysis to determine interconnection requirements for new supply-side resources.

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

The Promod IV® model enables the Company to integrate the transmission and generation system planning to: i) analyze the zonal and nodal level Locational Marginal Pricing ("LMP") impact of new resources and transmission facilities; ii) calculate the value of new facilities due to the alleviation of system constraints; and iii) perform transmission congestion analysis. The model is utilized to determine the most beneficial location for new supply-side resources in order to optimize the future need for both generation and transmission facilities, while providing reliable service to all customers. The Promod IV® model evaluates the impact of resources under development that are selected by the PLEXOS model. Specifically, this Promod IV® LMP analysis was conducted for the Brunswick County Power Station, as well as the Greensville County Power Station. In addition, the Promod IV® and Power System Simulator for Engineering were utilized to evaluate the impact of future generation retirements on the reliability of the DOM Zone transmission grid.

## 4.7 GAS SUPPLY, ADEQUACY, & RELIABILITY

In maintaining its diverse generating portfolio, the Company manages a balanced mix of fuels that includes fossil, nuclear, and renewable resources. Specifically, the Company's fleet includes units powered by natural gas, coal, petroleum, uranium, biomass (waste wood), water, and solar. This balanced and diversified fuel management approach supports the Company's efforts in meeting its customers' growing demand by responsibly and cost-effectively managing risk. By avoiding overreliance on any single fuel source, the Company protects its customers from rate volatility and other harms associated with shifting regulatory requirements, commodity price volatility, and reliability concerns.

### Electric Power and Natural Gas Interdependency

With a production shift from conventional to an expanded array of unconventional gas sources (such as shale) and relatively low commodity price forecasts, gas-fired generation continues to be a competitive choice for new capacity.

However, the electric grid's exposure to interruptions in natural gas fuel supply and delivery has increased with the generating capacity's growing dependence on a single fuel. Natural gas is largely delivered on a just-in-time basis, and vulnerabilities in gas supply and transportation must be sufficiently evaluated from a planning and reliability perspective. Mitigating strategies such as storage, firm fuel contracts, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, and overall fuel diversity all help to alleviate this risk.

There are two types of pipeline delivery service contracts, firm and interruptible service. Natural gas provided under a firm service contract is available to the customer at all times during the contract term and is not subject to a prior claim from another customer. For a firm service contract, the customer typically pays a facilities charge representing the customer's share of the capacity construction cost and a fixed monthly capacity reservation charge. Interruptible service contracts provide the customer with natural gas subject to the contractual rights of firm customers. The Company currently uses a combination of both firm and interruptible service to fuel its gas-fired generation fleet. As the percentage of natural gas use increases in terms of both energy and capacity, the Company intends to increase its use of firm transport capacity to help ensure reliability and price stability.

Pipeline deliverability can impact electrical system reliability. A physical disruption to a pipeline or compressor station can interrupt or reduce the flow pressure of gas supply to multiple EGUs at once. Electrical systems also have the ability to adversely impact pipeline reliability. The sudden loss of a large efficient generator can cause numerous smaller gas-fired CTs to be started in a short period of time. This sudden change in demand may cause drops in pipeline pressure that could reduce the quality of service to other pipeline customers, including other generators. Electric transmission system disturbances may also interrupt service to electric gas compressor stations, which can disrupt the fuel supply to electric generators.

As a result, the Company routinely assesses the gas-fueled reliability of its system. The results of these assessments show that current interruptions on any single pipeline are manageable, but as the Company and the electric industry shift to a heavier reliance on natural gas, additional actions are needed to ensure future reliability and rate stability. Additionally, equipping future gas-fired resources with backup fueling options may be needed to further enhance the reliability of the electric system.

### System Planning

In general, electric transmission service providers maintain, plan, design, and construct systems that meet federally-mandated NERC Reliability Standards and other requirements, and that are capable of serving forecasted customer demands and load growth. A well-designed electrical grid, with numerous points of interconnection and facilities designed to respond to contingency conditions, results in a flexible, robust electrical delivery system.

In contrast, pipelines generally are constructed to meet new load growth. FERC does not authorize new pipeline capacity unless customers have already committed to it via firm delivery contracts, and pipelines are prohibited from charging the cost of new capacity to their existing customer base. Thus, in order for a pipeline to add or expand facilities, existing or new customers must request additional firm service. The resulting new pipeline capacity closely matches the requirements of the new firm capacity request. If the firm customers accept all of the gas under their respective contracts, little or no excess pipeline capacity will be available for interruptible customers. This is a major difference between pipeline infrastructure construction and electric transmission system planning because the electric system is expanded to address current or projected system conditions and the costs are typically socialized across customers.

### Actions

The Company is aware of the risks associated with natural gas deliverability and has been proactive in mitigating these risks. For example, the Company continues to secure firm natural gas pipeline transportation service for all of the newer CC facilities, including the Bear Garden, Warren County, and Brunswick County Power Stations, as well as the Greensville County Power Station, which is currently under construction. Additionally, the Company maintains a portfolio of firm gas transportation to serve a portion of its remaining gas generation fleet.

### Atlantic Coast Pipeline

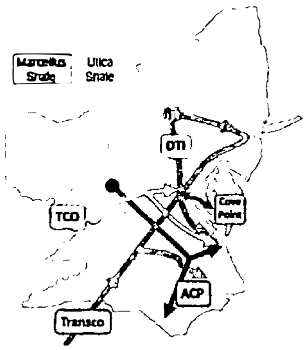
In August 2014, the Company executed a precedent agreement to secure firm transportation services on the ACP. This incremental capacity will support a portion of the natural gas needs for the existing power generation with enhanced fueling flexibility and reliability.

Currently, natural gas is primarily transported into the Company's service territory via four interstate pipelines:

- Transco: Transcontinental Gas Pipe Line;
- TCO: Columbia Gas Transmission;
- DTI: Dominion Transmission Inc.; and
- Cove Point Pipeline: Dominion Transmission Inc.

The ACP is a greenfield interstate pipeline that will provide access to competitively-priced, domestic natural gas supply for utility and industrial customers in Virginia and North Carolina and deliver those supplies to strategic points in the Company's service territory as early as November 2019. As shown in Figure 4.7.1, this geographically-diverse pipeline would also allow for future, lower-cost pipeline capacity expansions with limited environmental impact.

**Figure 4.7.1 - Map of Interstate Gas Pipelines**



# CHAPTER 5 – FUTURE RESOURCES

## 5.1 FUTURE SUPPLY-SIDE RESOURCES

The Company continues to monitor and gather information about potential and emerging generation technologies from a mix of internal and external sources. The Company's internal knowledge base spans various departments including, but not limited to, planning, financial analysis, construction, operations, and business development. The dispatchable and non-dispatchable resources examined in this 2017 Plan are defined and discussed in the following subsections.

### 5.1.1 DISPATCHABLE RESOURCES

**Aero-derivative Combustion Turbine**

Aero-derivative CT technology consists of a gas generator, which has been derived from an existing aircraft engine and used in an industrial application. Designed for a small footprint and low weight, it utilizes advanced materials for high efficiency, fast start-up times with little or no cyclic life penalty, and modular construction. They have been designed for quick removal and replacement, allowing for fast maintenance and greatly reduced downtimes, resulting in high unit availability and flexibility. These resources have the ability to react quickly from varying intermittent renewable resources, such as solar and wind to support bulk electric grid stability. This resource was considered for further analysis in the Company's busbar curve.

**Batteries**

Batteries serve a variety of purposes that make them attractive options to meet energy needs in both distributed and utility-scale applications. Batteries can be used to provide energy for the power station, blackstart, peak load shaving, frequency regulation services, or peak load shifting to off-peak periods. They vary in size, differ in performance characteristics, and are usable in different locations. Recently, batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar, onto the grid. Battery storage technology approximates dispatchability for these variable energy resources. The primary challenge facing battery systems is the cost. Other factors such as recharge times, variance in temperature, energy efficiency, and capacity degradation are also important considerations for utility-scale battery systems. This resource was not considered for further analysis in the Company's busbar curve.

**Biomass**

Biomass generation facilities rely on renewable fuel in their thermal generation process. In the Company's service territory, the renewable fuel primarily used is waste wood, which is carbon neutral. Greenfield biomass was considered for further analysis in the Company's busbar curve; however, it was found to be uneconomic. Generally, biomass generation facilities are geographically limited by access to a fuel source.

**Circulating Fluidized Bed**

Circulating Fluidized Bed ("CFB") combustion technology is a clean coal technology that has been operational for the past few decades and can consume a wide array of coal types and qualities, including low British thermal unit ("Btu") waste coal and wood products. The technology uses jets of air to suspend the fuel and results in a more complete chemical reaction allowing for efficient removal of many pollutants, such as $NO_x$ and $SO_2$. The preferred location for this technology is within the vicinity of large quantities of waste coal fields. The Company will continue to track this technology and its associated economics based on site and fuel resource availability. With strict standards on emissions from the EGU New Source Performance Standards ("NSPS") rule, this resource was not considered for further analysis in the Company's busbar curve, as these regulations effectively prevent permitting new coal units.

### Coal with Carbon Capture and Sequestration[17]

Coal generating technology is very mature with hundreds of plants in operation across the United States. Carbon Capture and Sequestration ("CCS") is a developing technology designed to collect and trap $CO_2$ underground. This technology can be combined with many thermal generation technologies to reduce atmospheric carbon emissions; however, it is generally proposed to be used with coal-burning facilities. The targets for new EGUs, as currently proposed under the EGU NSPS 111(b) rule, would require all new fossil fuel-fired electric generation resources to meet a strict limit for $CO_2$ emissions. To meet these standards, CCS technology is assumed to be required on all new coal, including supercritical pulverized coal ("SCPC") and integrated-gasification combined-cycle ("IGCC") technologies. Coal generation with CCS technology, however, is still under development and not commercially available. The Company will continue to track this technology and its associated economics. This resource was considered for further analysis in the Company's busbar curve.

### Fuel Cell

Fuel cells are electrochemical cells that convert chemical energy from fuel into electricity and heat. They are similar to batteries in their operation; but where batteries store energy in the components (a closed system), fuel cells consume their reactants. Although fuel cells are considered an alternative energy technology, they would only qualify as renewable in Virginia or North Carolina if powered by a renewable energy resource as defined by the respective state's statutes. This resource was considered for further analysis in the Company's busbar curve.

### Gas-Fired Combined-Cycle

A natural gas-fired CC plant combines a CT and a steam turbine plant into a single, highly-efficient power plant. The Company considered CCs, with heat recovery steam generators and supplemental firing capability, based on commercially-available advanced technology. This resource was considered for further analysis in the Company's busbar curve.

### Gas-Fired Combustion Turbine

Natural gas-fired CT technology has the lowest capital requirements ($/kW) of any resource considered; however, it has relatively high variable costs because of its low efficiency. This is a proven technology with cost information readily available. This resource was considered for further analysis in the Company's busbar curve.

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

### IGCC with CCS[18]

IGCC plants use a gasification system to produce synthetic natural gas from coal in order to fuel a CC. The gasification process produces a pressurized stream of $CO_2$ before combustion, which, as research suggests, provides some advantages in preparing the $CO_2$ for CCS systems. IGCC systems remove a greater proportion of other air effluents in comparison to traditional coal units. The Company will continue to follow this technology and its associated economics. This resource was considered for further analysis in the Company's busbar curve.

### Nuclear

With a need for clean, non-carbon emitting baseload power, and nuclear power's proven record of low operating costs, around the clock availability, and zero emissions, many electric utilities continue to examine new nuclear power units. The process for constructing a new nuclear unit remains time-consuming with various permits for design, location, and operation required by various government agencies. Recognizing the importance of nuclear power and its many environmental and economic benefits, the Company continues to develop an additional unit at North Anna. For further discussion of the Company's development of North Anna 3, see Section 5.3. This resource was considered for further analysis in the Company's busbar curve.

### Pumped Storage Hydroelectric Power

The Company is the operator and a 60% owner in the Bath County Pumped Storage Station, which is one of the world's largest pumped storage generation stations, with a net generating capacity of 3,003 MW. Due to their size, pumped storage facilities are best suited for centralized utility-scale applications. For recent advancements on pumped storage hydroelectric power, see Section 5.4 of this 2017 Plan. This resource was not considered for further analysis in the Company's busbar curve.

### Small Modular Reactors

Small Modular Reactors ("SMRs") are utility-scale nuclear units with electrical output of 300 MW or less. SMRs are manufactured almost entirely off-site in factories and delivered and installed on site in modules. The small power output of SMRs equates to higher electricity costs than a larger reactor, but the initial costs of building the plant are significantly reduced. An SMR entails underground placement of reactors and spent-fuel storage pools, a natural cooling feature that can continue to function in the absence of external power, and has more efficient containment and lessened proliferation concerns than standard nuclear units. SMRs are still in the early stages of development and permitting, and thus at this time are not considered a viable resource for the Company. The Company will continue to monitor the industry's ongoing research and development regarding this technology. This resource was not considered for further analysis in the Company's busbar curve.

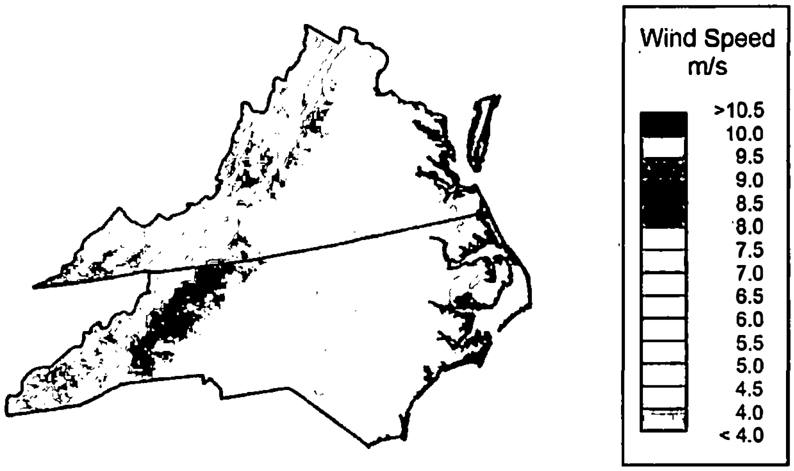
[18] The Company currently assumes that the captured carbon cannot be sold.

### 5.1.2 NON-DISPATCHABLE RESOURCES

**Onshore Wind**

Wind resources are one of the fastest growing resources in the United States. The Company has considered onshore wind resources as a means of meeting the RPS goals and REPS requirements, CPP requirements, and also as a cost-effective stand-alone resource. The suitability of this resource is highly dependent on locating an operating site that can achieve an acceptable capacity factor. Additionally, these facilities tend to operate at times that are non-coincidental with peak system conditions and therefore generally achieve a capacity contribution significantly lower than their nameplate ratings. There is limited land available in the Company's service territory because wind resources in the eastern portions of the United States are available in specialized locations, such as on mountain ridges. Figure 5.1.2.1 displays the onshore wind potential of Virginia and North Carolina. The Company continues to examine onshore wind and has identified three feasible sites for consideration as onshore wind facilities in the western part of Virginia on mountaintop locations. This resource was considered for further analysis in the Company's busbar curve.

**Figure 5.1.2.1 - Onshore Wind Resources**

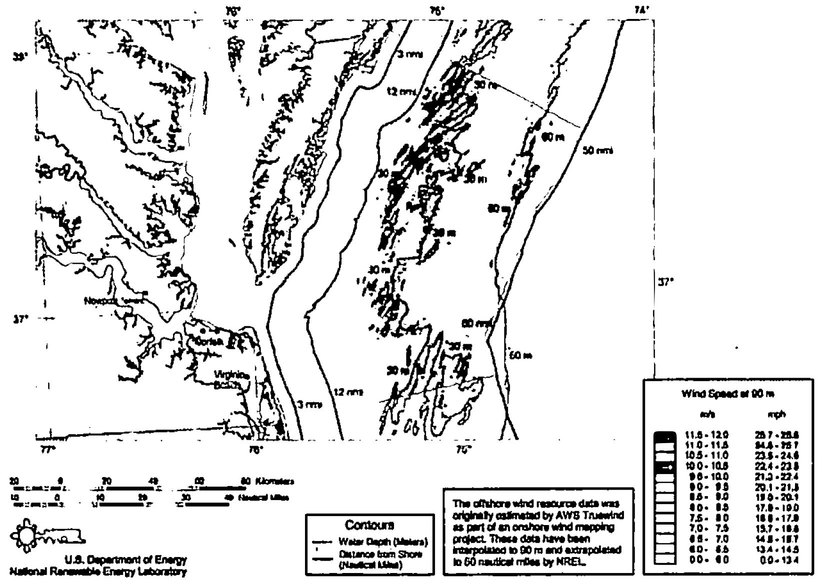



Source: National Renewable Energy Laboratory on May 1, 2017.

**Offshore Wind**

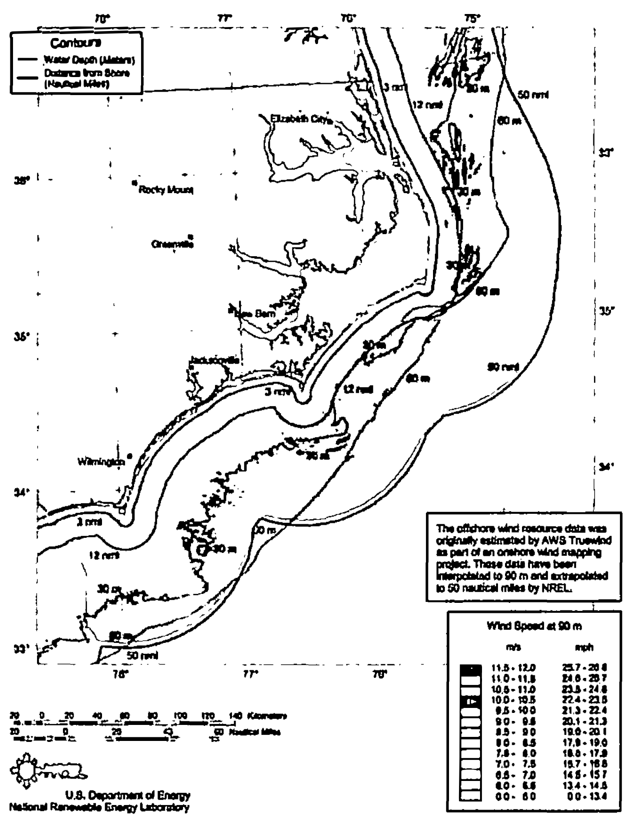
Offshore wind has the potential to provide a large, scalable renewable resource for Virginia. Figures 5.1.2.2 and 5.1.2.3 display the offshore wind potential of Virginia and North Carolina, respectively. Virginia has a unique offshore wind opportunity due to its shallow continental shelf extending approximately 40 miles off the coast, proximity to load centers, availability of local supply chain infrastructure, and world class port facilities. However, one challenge facing offshore wind development is its complex and costly installation and maintenance when compared to onshore wind. This resource was considered for further analysis in the Company's busbar curve.

## Figure 5.1.2.2 - Offshore Wind Resources - Virginia




Source: Retrieved from U.S. Department of Energy on May 1, 2017

## Figure 5.1.2.3 - Offshore Wind Resources - North Carolina




Source: Retrieved from U.S. Department of Energy on May 1, 2017.

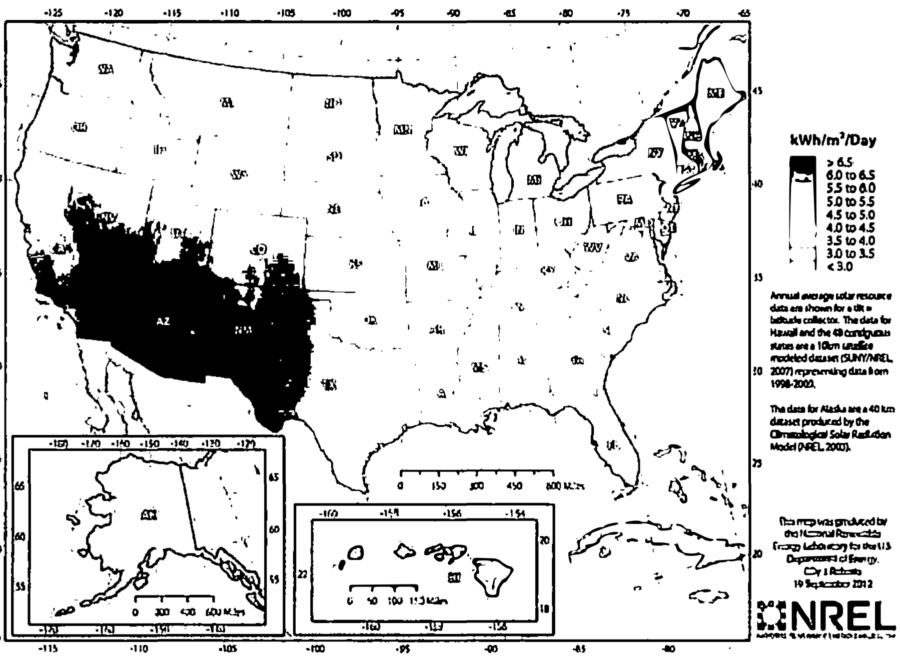
Part 4



### Solar PV & Concentrating Solar Power

Solar PV and Concentrating Solar Power ("CSP") are the two main types of solar technology used in electric power generation. Solar PV systems consist of interconnected PV cells that use semiconductor devices to convert sunlight into electricity. Solar PV technology is found in both large-scale and distributed systems and can be implemented where unobstructed access to sunlight is available. CSP systems utilize mirrors to reflect and concentrate sunlight onto receivers to convert solar energy into thermal energy that in turn produces electricity. CSP systems are generally used in large-scale solar plants and are mostly found in the southwestern area of the United States where solar resource potential is the highest. Figure 5.1.2.4 shows the solar PV resources for the United States.

**Figure 5.1.2.4 - Solar PV Resources of the United States**

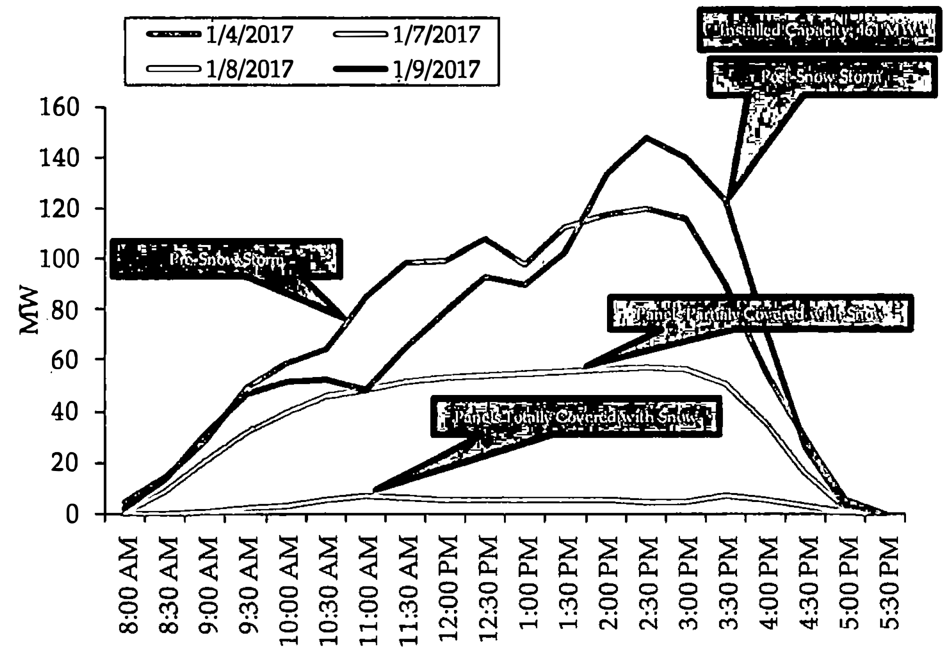



Source: National Renewable Energy Laboratory on May 1, 2017.

Solar PV technology was considered for further analysis in the Company's busbar curve, while CSP was not. The Company has considered both fixed-tilt and tracking PV technology. Also included in the Company's analysis is a fixed-tilt solar PV unit at a brownfield site (e.g., solar at an existing facility, solar tag at a new CC site). By installing solar at an existing generating facility, the output can be tied into the existing electrical infrastructure. The use of such a site would allow the Company to decrease the initial fixed cost of the resource, while the other characteristics of the unit stay the same. The Company currently has several solar PV facilities that achieved commercial operation in December 2016, including Scott 17 MW (nameplate), Whitehouse 20 MW (nameplate), and Woodland 19 MW (nameplate).

Solar generation is intermittent by nature, which fluctuates from hour-to-hour and in some cases from minute-to-minute. This type of generation volatility on a large scale could create distribution and/or transmission system instability. Figure 5.1.2.5 shows how a snowstorm affected the solar output over a series of peak winter days in January 2017. During the winter months, peaks tend to occur early in the morning or late in the afternoon. Figure 5.1.2.5 shows that a minimal amount of solar output was available to help serve peak load on these days. In order to mitigate this anomaly, other technologies will be needed, such as battery technology, quick start generation, voltage control technology, or pumped storage. Additionally, maintaining system reliability while integrating solar PV at scale will require extensions and upgrades of the Company's supervisory control and data acquisitions system both at the transmission and distribution level. The planning techniques and models currently used by the Company do not adequately assess the operational risk and cost that this type of generation could create, as further explained in Section 5.1.2.1.

**Figure 5.1.2.5 - Solar Output for NC & VA - Snow Cover**




### 5.1.2.1 SOLAR PV INTEGRATION COST

The electric service reliability issues associated with the integration of large volumes of solar PV has been well documented in prior Company Plans. To account for the cost of solar PV integration, the Company has utilized a "proxy cost" approach in prior Plans based on the cost of a new CT. In this 2017 Plan, the Company has refined its methods to estimate the solar PV integration costs as described below. It should be noted, however, that more work is required in order to fully assess the necessary grid modifications and associated costs. For example, this 2017 Plan includes an analysis of the cost to integrate 7,000 MW of solar PV that is interconnected at the most optimal sites along the Company's transmission network. It does not account for the same magnitude of solar PV located at less optimal locations. Limitations such as these are discussed at the end of this section.

#### Transmission Cost

In order to assess transmission integration costs, the Company performed a steady state power flow analysis where 7,000 MW of solar PV were interconnected to the Company's transmission grid.

Before the analysis could be performed, however, the Company first had to determine where the solar PV facilities would be located. This assessment was based on available land parcels in Virginia that were screened utilizing several criteria, including access to the Company's transmission grid and other land characteristics and costs. This data was then combined with solar irradiance data provided by National Renewable Energy Laboratory ("NREL") in order to assess the solar generation potential. From this screening process, 326 solar PV sites were identified that represented approximately 37 GW (nameplate) of solar PV generation. The resulting 326 sites were then further assessed to determine which sites were optimal from a system perspective, that is, which sites maximized solar PV MW injection into the system at the lowest possible cost. From this analysis, 115 sites were identified equating to 7,000 MW (nameplate) of solar PV capacity.

Next, using the PSS®E power flow model, the Company assessed the 115 sites under 2019 PJM summer peak demand conditions, while assuming maximum solar PV generation output (with reactive power support of +/- 0.95 PF), and also assuming displacement of generation from other Company-owned facilities. The results of this modeling identified several low voltage and thermal violations that required mitigation activities via physical enhancements to the Company's transmission system. The Company then assessed the cost of these enhancements which were added to other required interconnection costs. The sum total of these costs resulted in a fixed charge of $171.80/kW to integrate 7,000 MW (nameplate) of solar PV generation.

**Distribution Cost**

No new analytical work was performed by the Company with respect to solar PV facilities interconnected along the Company's distribution network. Rather, for purposes of this 2017 Plan, the Company utilized actual interconnection costs associated with solar PV facilities interconnected to the Company's distribution network. This integration cost was derived from the system impact studies performed using the Company's distribution network model under the state (Virginia and North Carolina) jurisdictional generation interconnection process. The average actual interconnection cost of these solar PV facilities is approximately $128.50/kW.

**Total Interconnection Cost**

Going forward, it is not reasonable to assume that 100% of future solar PV additions to the Company's system will be interconnected solely at the transmission level or distribution level. For purposes of this 2017 Plan, the Company assumed that 70% of all future solar PV additions would be interconnected along the Company's transmission network, while 30% would be interconnected at the distribution level. These weighting factors were selected based on current solar PV facilities interconnected to the Company's network, along with solar PV facilities to be located in the Company's service territory that are listed in the PJM and state interconnection queues. A 70/30 weight results in an average interconnection cost of $159.00/kW. As noted above, the interconnection cost for solar PV along the Company's transmission network ($171.80/kW) is based on 7,000 MW (nameplate) of solar PV generation. In the Company's judgment, however, it is unlikely that the same interconnection cost will be applicable for solar PV levels that are higher or lower than the 7,000 MW (nameplate) that was evaluated. Therefore, for purposes of this 2017 Plan, the Company used the following interconnection cost schedule for modeling various nameplate levels of solar PV.

**Figure 5.1.2.1.1 – Solar PV Interconnection Cost Schedule**

| From | Through | Interconnection Cost |
|---|---|---|
| 0 MW | 720 MW | $75.00/kW |
| 721 MW | 2,880 MW | $116.25/kW |
| 2,881 MW | No Limit | $159.00/kW |

### Generation Costs

Re-dispatch generation costs are defined in this 2017 Plan as additional costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. Historically, these types of events were driven by load variations due to actual weather that differs from what was forecasted for the period in question. For example, most power system operators assess the generation needs for a future period, typically next day, based on load forecasts and commit a series of generators to be available for operation in that period. These committed generators are expected to operate in an hour-to-hour sequence that minimizes total cost. Once within that period, however, load may vary from what was planned and the committed generators may operate in a less than optimal hour-to-hour sequence. The resulting additional costs, due to real time variability, are defined as re-dispatch costs.

As more and more intermittent generation like solar PV is added to the grid, additional uncertainty is added due to cloud cover and/or un-predicted changes in wind speed. In order to assess the resulting re-dispatch costs, the Company performed a simulation analysis to determine the impact on generation operations at varying levels of solar PV penetration. To establish base cases, a series of model runs were performed using generic solar generation profiles that are identical to those used in normal generation planning modeling exercises. Once the base cases were established, comparator model runs were performed that, in lieu of the generic solar generation profiles, include actual historic generation profiles from solar PV facilities currently interconnected to the Company's system. The total system cost results of the comparator cases were then evaluated against the base case model runs. The levelized cost differential between the comparator cases and the associated base cases resulted in an approximate re-dispatch cost of $2/MWh. This value was used as a variable cost adder for all solar PV generation evaluated in this 2017 Plan.

### Limitations of the Solar Integration Cost Analysis

While this 2017 Plan attempts to further refine solar PV integration costs, as described above, it is important to note that such costs are limited to the scope of the analysis conducted. For example, the transmission integration costs described above are specific to the solar PV site locations selected in the Company's analysis. If the solar PV site locations are different, then it is highly likely that the integration costs will also be different. The same applies at the distribution level. Furthermore, although the distribution integration costs described above are based on actual interconnection cost data, that data does not include distribution substation upgrade costs that may be necessary to support a high influx of solar PV integration at the distribution level. Nor does it include transmission upgrade cost to the extent solar PV generation at the distribution level back-feeds onto the transmission grid. From a generation perspective, the costs described above are only intended to assess re-dispatch costs. The costs associated with additional spinning reserve to support variable output from solar PV and the additional cost of machine wear and tear resulting from increased cycling have not yet been evaluated by the Company. Because of the current time constraints associated with the Plan filing schedule, the Company was not able to address all of these solar PV integration concerns in this 2017 Plan. The Company, however, continues to develop processes that will aid in the cost evaluation associated with solar PV integration. The results of these evaluations will be included in future Plans filed by the Company.

Another major assumption used by the Company in this 2017 Plan is that the majority (70%) of future solar PV facilities would be interconnected at the transmission level. The Company maintains that this assumption is reasonable given current available information, including the economies of scale associated with large solar PV facilities. If, however, solar PV costs continue to decline and given customer and society's preference for clean reliable energy, it is not unreasonable to expect that a large percentage of new solar PV facilities will be installed at or near customer homes and businesses or at other locations along the Company's distribution network. Given this plausible future outcome, the Company's distribution grid will require significant modification in order to maintain reliable service to its customers. As such, the Company has begun initial high level planning activities to assess what distribution modifications will be necessary to support the proliferation of distribution connected solar PV along with other DERs. A summary of this high level plan is reflected in Section 5.1.3.

Finally, for purposes of this 2017 Plan, the Company has placed an annual 240 MW (nameplate) limitation with respect to the level of solar PV generation that can achieve commercial operation in any given year. The Company's ability to develop and bring online multiple solar PV facilities annually is limited due to the schedules associated with land access, permitting, equipment procurement, and regulatory approvals.

### 5.1.3 GRID MODERNIZATION

The Company recognizes customer expectations are evolving and service reliability improvements will be required to maintain reliability, address resiliency, protect physical/cyber security, and improve the overall customer experience. The grid must adapt in order to meet such requirements.

A fundamental theme of this 2017 Plan is that utility-scale solar is currently cost competitive with other more traditional forms of generation. The anticipated proliferation of smaller-scale DERs includes renewable resources such as solar and wind. As costs continue to decline, it is not unreasonable to expect that the Company or its customers will continue to install solar or other DERs at their homes, businesses, or other locations along the Company's distribution network.

Like most of the industry, the Company's electric distribution system was designed for "one-way" delivery of energy to meet peak demand - from the generator, to the transmission network, then to the distribution network, and finally to the customer meter.

To the extent that DER proliferation and the adoption of EVs and battery storage continues, the Company must be prepared to meet a new paradigm that will require the Company, over the near future, to transform its existing electric delivery from its original one-way design to a modern two-way network capable of facilitating instantaneous energy injections and withdrawals at any point along the network while continuing to maintain the highest level of reliability while maintaining service levels that customers expect and deserve. The first step in this transformation process is a modernization of the distribution grid.

To that end, the Company has begun the initial planning associated with a transformational grid modernization effort. The modernized system would need to include elements such as i) "smart" or AMI meters; ii) improved communications network; iii) intelligent devices to monitor, predict and control the grid; iv) distribution substation automation; v) plans to replace aging infrastructure; vi) improvements to security; vii) methods to investigate new innovative technologies; and viii) an enhanced customer information platform to enable management of their energy usage.

Currently, at the generation and transmission level, the Company's electric system operators possess real-time visibility, communications, and control. Implementing a comprehensive program will not only improve and modernize the distribution grid, but make it adaptable to evolving technological changes. Ultimately this sophisticated system of communication and control will be similar to what system operators currently utilize at the generation and transmission levels.

In a future where potentially tens of thousands of DER devices are located at homes or businesses throughout Virginia, system operators will need the ability to monitor these devices in order to adjust the distribution network appropriately so that overall electric service reliability can be safely and efficiently maintained. In addition to ensuring reliability and accommodating integration of distributed generation into the grid, this modernization program will offer customers a new information platform and opportunities to manage their energy usage. The Company is assessing the details and costs associated with developing a future distribution grid modernization plan that is stronger, smarter, and greener than today's network. The Company intends to report those findings in future Plans.

### 5.1.4 ASSESSMENT OF SUPPLY-SIDE RESOURCE ALTERNATIVES

The process of selecting alternative resource types starts with the identification and review of the characteristics of available and emerging technologies, as well as any applicable statutory requirements. Next, the Company analyzes the current commercial status and market acceptance of the alternative resources. This analysis includes determining whether particular alternatives are feasible in the short- or long-term based on the availability of resources or fuel within the Company's service territory or PJM. The technology's ability to be dispatched is based on whether the resource was able to alter its output up or down in an economical fashion to balance the Company's constantly changing demand requirements. Further, this portion of the analysis requires consideration of the viability of the resource technologies available to the Company. This step identifies the risks that technology investment could create for the Company and its customers, such as site identification, development, infrastructure, and fuel procurement risks.

The feasibility of both conventional and alternative generation resources is considered in utility-grade projects based on capital and operating expenses including fuel, operation, and maintenance. Figure 5.1.4.1 summarizes the resource types that the Company reviewed as part of this IRP process. Those resources considered for further analysis in the busbar screening model are identified in the final column.

## Figure 5.1.4.1 - Alternative Supply-Side Resources

| Resource | Unit Type | Dispatchable | Primary Fuel | Busbar Resource |
|---|---|---|---|---|
| Aero-derivative CT | Peak | Yes | Natural Gas | Yes |
| Batteries | Peak | Yes | Varies | No |
| Biomass | Baseload | Yes | Renewable | Yes |
| CC 1x1 | Intermediate/Baseload | Yes | Natural Gas | Yes |
| CC 2x1 | Intermediate/Baseload | Yes | Natural Gas | Yes |
| CC 3x1 | Intermediate/Baseload | Yes | Natural Gas | Yes |
| CFB | Baseload | Yes | Coal | No |
| Coal (SCPC) w/ CCS | Intermediate | Yes | Coal | Yes |
| Coal (SCPC) w/o CCS | Baseload | Yes | Coal | No |
| CT | Peak | Yes | Natural Gas | Yes |
| Fuel Cell | Baseload | Yes | Natural Gas | Yes |
| Hydro Power | Intermittent | No | Renewable | No |
| IGCC CCS | Intermediate | Yes | Coal | Yes |
| IGCC w/o CCS | Baseload | Yes | Coal | No |
| Nuclear | Baseload | Yes | Uranium | Yes |
| Offshore Wind | Intermittent | No | Renewable | Yes |
| Onshore Wind | Intermittent | No | Renewable | Yes |
| Pumped Storage | Peak | Yes | Renewable | No |
| Solar PV | Intermittent | No | Renewable | Yes |
| Solar PV w/Aero-derivative CT | Peak | Yes | Renewable | Yes |
| SMR | Baseload | Yes | Uranium | No |

The resources not included as busbar resources for further analysis faced barriers such as the feasibility of the resource in the Company's service territory, the stage of technology development, and the availability of reasonable cost information. Although such resources were not considered in this 2017 Plan, the Company will continue monitoring all technologies that could best meet the energy needs of its customers.

### Third-Party Market Alternatives to Capacity Resources

### Solar

During the last two years, the Company has increased its engagement of third-party solar developers in both its Virginia and North Carolina service territory. On July 22, 2015, the Company issued an RFP for new utility-scale solar PV generating facilities, located in Virginia, which could achieve an online date of either 2016 or 2017. As a result of this RFP, the Company contracted with two developers for approximately 40 MW (nameplate) of solar. Since then, the developer of one of the 20 MW solar facilities failed to obtain a permit and terminated the PPA. The other PPA is on schedule to come online in the fourth quarter of 2017. During this same timeframe, the Company brought online three self-build solar facilities (Scott, Whitehouse and Woodland) totaling approximately 56 MW (nameplate).

In North Carolina, over the same period, the Company signed 73 PPAs totaling approximately 506 MW (nameplate) of new solar NUGs. Of these, 354 MW (nameplate) are from 51 solar projects that are currently in operation as of March 2017. The majority of these developers are Qualifying Facilities, contracting to sell capacity and energy at the Company's published North Carolina

Schedule 19 rates in accordance with the Public Utility Regulatory Policies Act ("PURPA"), as approved in Docket No. E-100, Sub 136 (2012), Docket No. E-100, Sub 140 (2014) and currently pending in Docket No. E-100, Sub 148 (2016).

### Wind

Since mid-2016, the Company has evaluated three offers representing approximately 648 MW (nameplate) of onshore wind third-party alternatives, one of which was located in Virginia. While these projects would be less expensive than the Company's self-build wind options (both onshore and offshore), they were not competitive against new solar or gas-fired generation and were not expected to contribute toward the Commonwealth meeting its CPP requirements at the time of evaluation and therefore were rejected. In addition, these out-of-territory wind projects generally include a considerable amount of congestion risk (because of either the location of the facility or the contractual delivery point), which reduces the overall economic value to customers.

### Other Third-Party Alternatives

Over the past two years, the Company has evaluated a number of opportunities to extend the terms of the current NUG contracts that have recently expired or will expire in the next several years. Many of these were evaluated through a formal RFP process, while others were evaluated through direct contact with the existing NUG owner. However, none were found to be cost-effective options for customers when compared to other options. Additionally, the Company has been in early discussions with a number of developers of other new third-party generation alternatives over the past year. However, none of these discussions have matured to the point of the Company receiving or being able to evaluate a firm PPA price offer.

## 5.2 LEVELIZED BUSBAR COSTS

The Company's busbar model was designed to estimate the levelized busbar costs of various technologies on an equivalent basis. The busbar results show the levelized cost of power generation at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. These comparisons include: fuel, heat rate, emissions, variable and fixed operation and maintenance ("O&M") costs, expected service life, and overnight construction costs. Figures 5.2.1 and 5.2.2 display summary results of the busbar model comparing the economics of the different technologies discussed in Sections 5.1.1 and 5.1.2. The results were separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources for the energy and capacity value they provide to customers. For example, dispatchable resources are able to generate when power prices are the highest, while non-dispatchable resources may not have the ability to do so. Furthermore, non-dispatchable resources typically receive less capacity value for meeting the Company's reserve margin requirements and may require additional technologies in order to assure grid stability.

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**Figure 5.2.1 - Dispatchable Levelized Busbar Costs (2022 COD)**

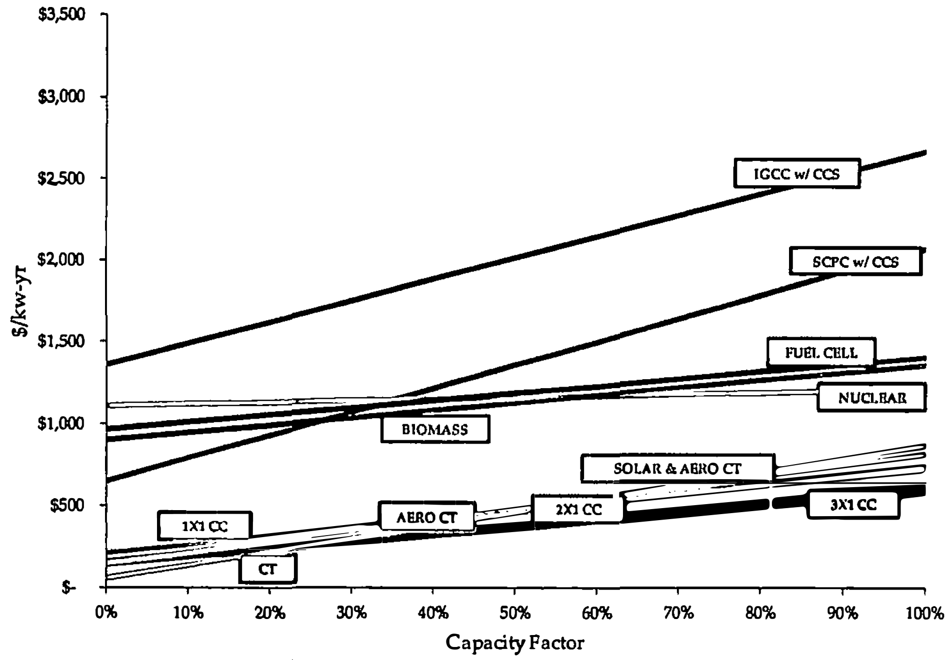
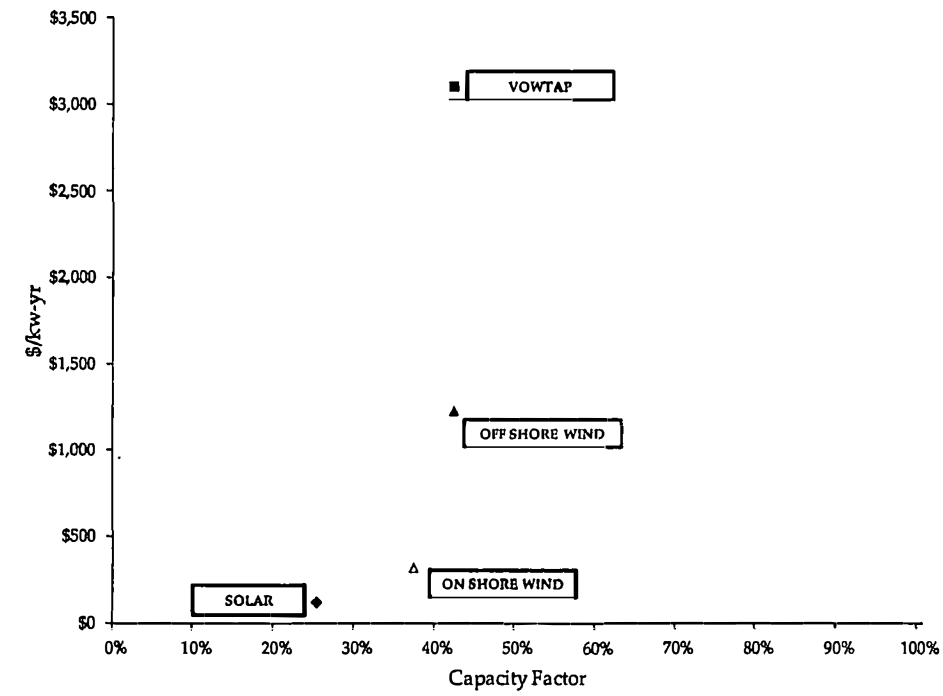



**Figure 5.2.2 - Non-Dispatchable Levelized Busbar Costs (2022 COD)**



Appendix 5A contains the tabular results of the screening level analysis. Appendix 5B displays the heat rates, fixed and variable operation expenses, maintenance expenses, expected service lives, and the estimated 2017 real dollar construction costs.

In Figure 5.2.1, the lowest values represent the lowest cost assets at the associated capacity factors along the x-axis. Therefore, one should look to the lowest curve (or combination of curves) when searching for the lowest cost combination of assets at operating capacity factors between 0% and 100%. Resources with busbar costs above the lowest combination of curves generally fail to move forward in a least-cost resource optimization. Higher cost generation, however, may be necessary to achieve other constraints like those required under the CPP. Figures 5.2.1 and 5.2.2 allow comparative evaluation of resource types. The cost curve at 0% capacity factor depicts the amount of invested total fixed cost of the unit. The slope of the unit's cost curve represents the variable cost of the unit, including fuel, emissions, and any REC or production tax credit ("PTC") value a given unit may receive.

As shown in Figure 5.2.1, CT technology is currently the most cost-effective option at capacity factors less than approximately 25% for meeting the Company's peaking requirements. Currently, the CC 3x1 technology is the most economical option for capacity factors greater than approximately 25%. Also, as depicted in Figure 5.2.2, solar PV is a competitive choice at capacity factors of approximately 25%.

Nuclear units have higher total life-cycle costs than a CC 3x1; however, they operate historically at higher capacity factors and have relatively more stable fuel costs and operating costs. Fuel also makes up a smaller component of a nuclear unit's overall operating costs than is the case with fossil fuel-fired units. New coal generation facilities without CCS technology will not meet the emission limitation included in the GHG NSPS rule for new EGUs, and as such, are not shown in Figure 5.2.1.

Wind and solar resources are non-dispatchable with intermittent production and lower dependable capacity ratings. Both resources produce less energy at peak demand periods, therefore more capacity would be required to maintain the same level of reliability. For example, onshore wind provides only 13% of its nameplate capacity as firm capacity that is available to meet the Company's PJM resource requirements as described in Chapter 4. Figure 5.2.2 displays the non-dispatchable resources that the Company considered in its busbar analysis. In addition, intermittent resources may require additional grid equipment and technology changes in order to maintain grid stability. The Company is routinely updating and evaluating the costs and availability of renewable resources, as discussed in Section 5.4.

Figure 5.2.3 identifies some basic capacity and energy differences between dispatchable resources and non-dispatchable resources. One additional factor to consider for solar installation is the amount of land required. For example, the installation of 1,000 MW of solar requires approximately 8,000 acres of land.

### Figure 5.2.3 - Comparison of Resources by Capacity and Annual Energy

| Resource Type | Nameplate Capacity (MW) | Estimated Firm Capacity (MW) | Estimated Capacity Factor (%) | Estimated Annual Energy (MWh) |
|---|---|---|---|---|
| Onshore Wind | 1,000 | 130 | 42% | 3,696,720 |
| Offshore Wind | 1,000 | 167 | 42% | 3,635,400 |
| Solar PV | 1,000 | 228 | 25% | 2,216,280 |
| Nuclear | 1,000 | 1,000 | 96% | 8,409,600 |
| Combined Cycle (3x1) | 1,000 | 1,000 | 70% | 6,132,000 |
| Combustion Turbine | 1,000 | 1,000 | 10% | 876,000 |

Note: 1) Solar PV firm capacity has 22.77% value through 35 years of operation.

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

### Extension of Nuclear Licensing

An application for a second license renewal is allowed during a nuclear plant's first period of extended operation - i.e., in the 40-60 years range of its service life. Surry Units 1 and 2 entered into that period in 2012 (Unit 1) and 2013 (Unit 2), however, North Anna Units 1 and 2 will not enter into that period until 2018 (Unit 1) and 2020 (Unit 2).

The Company informed the Nuclear Regulatory Commission ("NRC") in a letter dated November 5, 2015, attached as Appendix 3Y, of the intent to submit a second license renewal application for Surry Power Station Units 1 and 2. Under the current schedule, the Company intends to submit an application for the second renewed Operating Licenses in accordance with 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," by the end of the first quarter of 2019. The issuance of the renewed license would follow successful NRC safety and environmental reviews tentatively in the 2022 timeframe.

Although the Company has participated in public industry meetings during the last 12 months with other potential utility applicants in which second license renewal applications have been discussed with the NRC, there has been no additional correspondence between the Company and the NRC concerning any second license renewals.

NRC draft guidance on the requirements for a second license renewal was issued for public comment in December 2015. The industry, including the Company and interested stakeholders, has reviewed the guidance information to further understand the pre-decisional technical requirements and additional aging management program requirements. The nuclear industry, including the

Company, provided comments through the Nuclear Energy Institute in February 2016, which was the end of the public comment. The NRC is currently evaluating the industry and stakeholder comments. The approved second license renewal guidance documents are scheduled for issuance in mid-2017. Following the issuance of the final NRC guidance documents, the Company will begin finalizing the technical evaluation and additional aging management program requirements required to support the second license renewal application.

The cost estimates for the extension of the nuclear licenses for Surry Units 1 and 2, as well as North Anna Units 1 and 2 can be found in Appendix 5F.

## 5.3 GENERATION UNDER DEVELOPMENT

### North Anna 3

The Company is in the process of obtaining a Combined Operating License ("COL") from the NRC to support a new nuclear unit, North Anna 3, at its existing North Anna Power Station located in Louisa County in central Virginia. Based on the expected schedule for obtaining the COL from the NRC, allowing for the SCC certification and approval process, and the construction timeline for the facility, the earliest possible in-service date for North Anna 3 is September 2029, with capacity being available to meet the Company's 2030 summer peak. This in-service date has been delayed one-year from the 2016 Plan as the Company maintained lower expenditures under licensing only approach until carbon legislation becomes more certain.

The technology selection for North Anna 3 is the General Electric-Hitachi ("GEH") Economic Simplified Boiling Water Reactor ("ESBWR"). In March 2017, a major milestone was achieved when the NRC completed the uncontested mandatory hearing for the project which is the final step prior to the Commissioners' vote on issuance of the COL. Currently, the Company expects to receive the approved COL from the NRC by mid-2017.

Based on the uncertainties of future carbon regulation, including the CPP, the Company has determined it is prudent to focus its near-term efforts for North Anna 3 on the specific activities needed to secure the COL, which will provide a valuable option in the future for a baseload carbon-free generation resource, that requires minimal land use.

At the time of the issuance of the COL, the Company estimates that total expenditures associated with the development of North Anna 3 will be approximately $330 million (excluding AFUDC), which is net of the $302 million write-off applied to the capital development project and recovered through base rates as a result of Senate Bill 459, Virginia Acts of Assembly, 2014 Session, Chapter 541 (approved April 3, 2014; effective July 1, 2014) and as directed by the SCC's Final Order in the 2015 Biennial Review.[19]

[19] See also Section 5.3, Generation Under Development, of the 2016 Plan for additional discussion regarding why expenditures are continuing to be made and why, in the Company's view, it is necessary to spend at projected rates, specifically when the Company has not decided to proceed and does not have SCC approval, as required by the 2015 Plan Final Order.

The Company has not quantified any particular dollar limit that it intends to incur for North Anna 3 before seeking recovery.[20] Rather, the Company focuses on the reasonable and prudent development of any particular resource and achieving key developmental milestones related thereto. Once the Company secures the COL, the Company will determine whether and when it will apply to the SCC for cost recovery and/or a CPCN.

### Offshore Wind

The Company continues to pursue offshore wind development in a prudent manner for its customers and for the state's economic development. Offshore wind has the potential to provide a scalable renewable resource if it can be achieved at reasonable cost to customers. To help determine how this can be accomplished, the Company is involved in two active projects: 1) VOWTAP and 2) commercial development in the Virginia Wind Energy Area ("WEA"), both of which are located approximately 27 miles (approximately 24 nautical miles) off the coast of Virginia. A complete discussion of these efforts is included in Section 5.4.

Figure 5.3.1 and Appendix 5C provide the in-service dates and capacities for generation resources under development for the Alternative Plans.

**Figure 5.3.1 - Generation under Development[1]**

| Forecasted COD | Unit | Location | Primary Fuel | Unit Type | Nameplate Capacity (MW) | Capacity (Net MW) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Summer | Winter |
| 2021 | VOWTAP | VA | Wind | Intermittent | 12 | 2 | 2 |
| 2030 | North Anna 3 | VA | Nuclear | Baseload | 1,452 | 1,452 | 1,514 |

Notes: 1) All Generation under Development projects and capital expenditures are preliminary in nature and subject to regulatory and/or Board of Directors approval.

## 5.4 EMERGING AND RENEWABLE ENERGY TECHNOLOGY DEVELOPMENT

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

### Research and Development Initiatives – Virginia

Pursuant to Va. Code § 56-585.2, utilities that are participating in Virginia's RPS program are allowed to meet up to 20% of their annual RPS goals using RECs issued by the SCC for investments

[20] See Legal Memorandum of Virginia Electric and Power Company filed on April 29, 2016 in the 2016 Plan proceeding (Case No. PUE-2016-00049) addressing the question pursuant to what authority the Company believes that the costs it plans to incur for North Anna 3 before receiving a CPCN or RAC are recoverable from its customers, as required by the 2015 Plan Final Order; see also *Virginia Citizens Consumer Council, Petitioner v. Virginia Electric and Power Company, Defendant, For a declaratory judgment and an order requiring a filing pursuant to §§ 56-234.3 and 56-580 D of the Code of Virginia*, Case No. PUE-2016-00096, Final Order (Jan. 10, 2017). See also Section 5.3, Generation Under Development, of the 2016 Plan for additional discussion regarding the limit on the amount of costs the Company can incur, prior to obtaining a CPCN, without negatively affecting (i) the Company's fiscal soundness and (ii) the Company's cost of capital, as required by the 2015 Plan Final Order.

in renewable and alternative energy research and development activities. In addition to three projects completed in 2014, the Company is currently partnering with nine institutions of higher education on Virginia renewable energy research and development projects. The Company filed its third annual report in March 2016, analyzing the prior year's PJM REC prices and quantifying its qualified investments to facilitate the SCC's validation and issuance of RECs for Virginia renewable and alternative energy research and development projects.

In 2015, the Company accepted a grant from the U.S. Department of Energy ("DOE") for the purpose of funding the Virginia Solar Pathways Project. The project engages a core advisory team made up of a diverse group of representatives. The ultimate goal for this project is to develop a collaborative utility-administered solar strategy for the Commonwealth of Virginia. The process includes i) integrating existing solar programs with new options appropriate for Virginia's policy environment and broader economic development objectives; ii) promoting wider deployment of solar within a low rate environment; and iii) serves as a replicable model for use by other states with similar policy environments, including but not limited to the entire Southeast region. The Virginia Solar Pathways grant concludes in December 2017.

### Research and Development Initiatives – North Carolina

Pursuant to NCGS § 62-133.8(h), the Company completed construction of its microgrid demonstration project at its North Carolina Kitty Hawk District Office in July 2014. The microgrid project includes innovative distributed renewable generation and energy storage technologies. A microgrid, as defined by the DOE, is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid, allowing it to operate in grid-connected or island mode. The project includes four different types of micro-wind turbines, a solar PV array, and a lithium-ion battery integrated behind-the-meter with the existing on-site diesel generator and utility feed. In the third quarter of 2015, the Company integrated two small, residential-sized fuel cells in order to study the fuel cell's interaction with the on-site renewable energy technologies in a microgrid environment. The knowledge gained from this microgrid project will be used to further assess the best practice for integrating large amounts of intermittent generation (such as wind and solar PV) into the existing grid.

### Onshore Wind

The Company continues to pursue onshore wind development; however, there is a limited amount of onshore wind available within or near the Company's service territory. Only three feasible sites have been identified by the Company for consideration of onshore wind facilities. These sites are located in Virginia, on mountaintop locations.

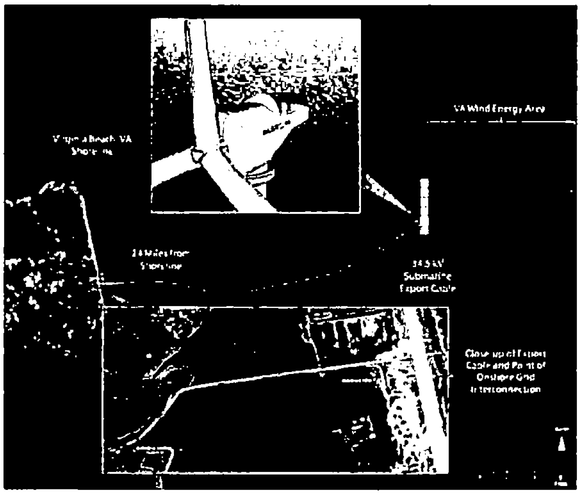
### Offshore Wind – Virginia

The Company is actively participating in offshore wind policy and innovative technology development in order to identify ways to advance offshore wind responsibly and cost-effectively. To that end, the Company is involved in the following select offshore wind policy and technology areas.

The Virginia General Assembly passed legislation in 2010 to create the Virginia Offshore Wind Development Authority ("VOWDA") to help facilitate offshore wind energy development in the Commonwealth. The Company continues to actively participate in VOWDA, as well as the Virginia Offshore Wind Coalition ("VOW"). The VOW is an organization comprised of developers, manufacturers, utilities, municipalities, businesses, and other parties interested in offshore wind. This group advocates on the behalf of offshore wind development before the Virginia General Assembly and with the Virginia delegation to the U.S. Congress.

Figure 5.4.1 illustrates the VOWTAP overview.

**Figure 5.4.1 – VOWTAP Overview**



In 2015, the Company announced a delay in the VOWTAP as it continued to work with stakeholders to find additional ways to reduce the cost and risks of this project. This delay was the result of significant increases in the estimated cost of the VOWTAP. The stakeholder process concluded the project was technically sound and an improved contract strategy could help lower the cost of installation. As a result of the stakeholder process, a second RFP for the VOWTAP project was issued; only this RFP was structured in a multi-contract manner (i.e., separate packages for marine supply, cable supply, fabrication, onshore electrical, etc.). This multi-consultant approach resulted in a lower overall bid cost of approximately $300 million.

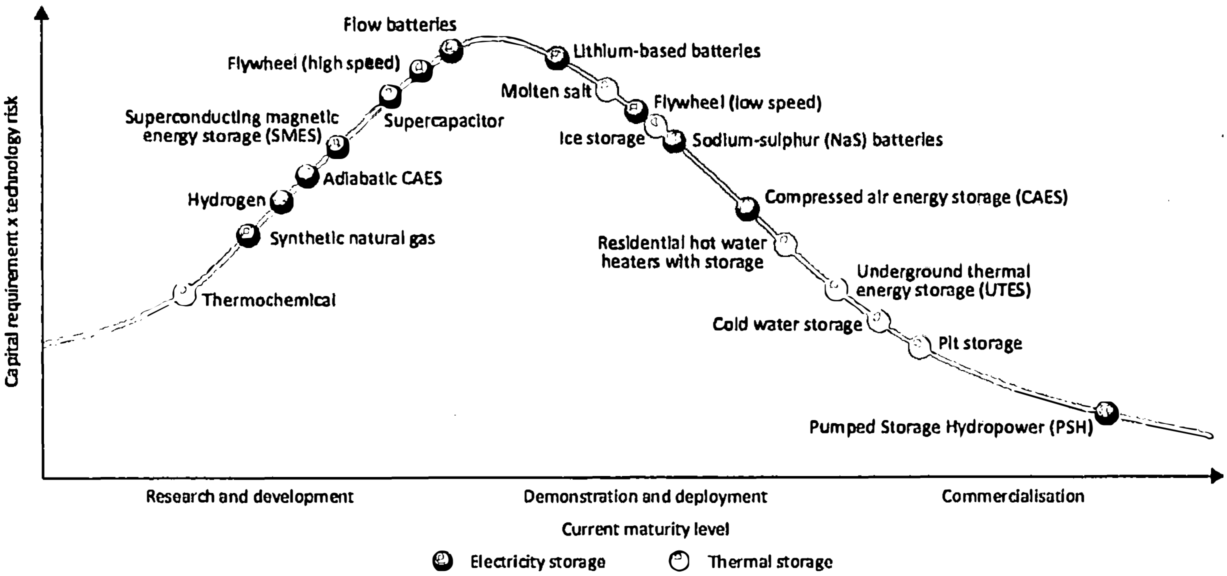
The Company remains committed to the development of all renewable and alternative energy provided the development of these technologies is commercially viable and at a reasonable cost. In the 2017 Plan, the Company estimates that the online date for VOWTAP could be as early as 2021.

### Energy Storage Technologies

There are several different types of energy storage technologies. Energy storage technologies include, but are not limited to, pumped storage hydroelectric power, superconducting magnetic energy storage, capacitors, compressed air energy storage, flywheels, and batteries. Cost considerations and technology maturity have restricted widespread deployment of most of these technologies, with the exception of pumped storage hydroelectric power and batteries.

Figure 5.4.2 is a graphical representation of the capital requirements, technology risks, and maturity of the various energy storage technologies. Pumped storage hydroelectric power is considered the most mature energy storage technology with relative low capital requirements and technology risks.

**Figure 5.4.2 - Capital Requirements, Technology Risks, and Maturity Level of Energy Storage Technologies**




Source: Decourt, B. and R. Debarre (2013), "Electricity storage", *Factbook*, Schlumberger Business Consulting Energy Institute, Paris France and Pak soy, H. (2013), "Thermal Energy Storage Today" presented at the IEA Energy Storage Technology Roadmap Stakeholder Engagement Workshop, Paris, France, 14 February.

There is also increasing interest in pumped storage hydroelectric power as a storage mechanism for the intermittent and highly variable output of EGUs powered by renewable energy such as solar and wind. For example, the 2017 session of the Virginia General Assembly passed Senate Bill 1418 supporting construction of "one or more pumped hydroelectric generation and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their power source and such facilities and associated resources are located in the coalfield region of the Commonwealth." The bill will become law, effective on July 1, 2017, after the General Assembly adopted the Governor's amendments to it on April 5, 2017.

Following the approval of SB 1418, the Company is in the early stages of conducting site selection studies for a potential pumped storage facility in the western part of the Commonwealth of Virginia. The Company acknowledges that pumped storage is a proven dispatchable technology that would complement the ongoing integration of renewable solar and wind resources.

Additionally, a July 2016 report by the DOE found that "significant potential exists for new pumped storage hydropower to meet grid flexibility needs and support increased integration of variable generation resources, such as wind and solar."[21] The report, entitled "Hydropower Vision: A New Chapter for America's 1st Renewable Electricity Source," found that "new advanced [pumped storage hydroelectric technology] with improved capabilities such as adjustable speed, closed-loop and modular designs can further facilitate integration of variable generation, such as wind and solar, due to its ability to provide grid flexibility, reserve capacity, and system inertia."[17] The report praised pumped storage as a "low-risk technology with a track record of high efficiency" and noted that such facilities have longer lifetimes and lower operating costs than other technologies being considered for facilitating grid integration of intermittent resources. However, the report cautioned that "better information on the role and value of grid storage" is needed by energy policymakers and recommended the development of tools that would lead to improved assessments of pumped storage as a means of supporting variable generation.[22]

In addition to pumped storage hydroelectric power, the Company has been monitoring recent advancements in other energy storage technologies, such as batteries and flywheels. These energy storage technologies can also be used to provide grid stability as more renewable generation sources are integrated into the grid. In addition to reducing the intermittency of wind and solar generation resources, batteries can shift power output from periods of low demand to periods of peak demand. This increases the dispatchability and flexibility of these resources. Recently, the Company installed a zinc-iron flow and an aqueous hybrid ion battery at a rooftop solar facility located at Randolph Macon College. These two small batteries are designed to test the extended capabilities of these new devices, and prove the potential benefits when integrated with existing solar generation.

### Electric Vehicle Initiatives

Various automotive original equipment manufacturers ("OEMs") have released EVs for sale to the public in the Company's service territory. The Chevrolet Volt, General Motor's first plug-in hybrid electric vehicle ("PHEV"), and the Nissan Leaf, an all-electric vehicle, became available for sale in the Company's Virginia service territory in 2011. Since that time, the Company has monitored the introduction of EV models from several other OEMs in its Virginia service territory. These include, but are not limited to, the Toyota Prius, the Ford Focus Electric and C-Max Hybrid Energi, the Tesla Roadster and Model S, and the Mitsubishi i-MIEV. While the overall penetration of EVs has been somewhat lower than anticipated, recent registration data from the Virginia Department of Motor Vehicles ("DMV") and IHS, Inc. (formerly Polk Automotive) demonstrates steady growth. The Company used data from the Virginia DMV, Electric Power Research Institute ("EPRI") and IHS, Inc. to develop a projection of system level EV and PHEV penetrations across its service territory to use in determining the load forecast used in this 2017 Plan.

## 5.5 FUTURE DSM INITIATIVES

The Company last conducted a DSM Potential study in 2013, with results illustrated in Figure 5.5.2. Since then, the Company conducted a new residential appliance saturation survey in 2016 with results shown in Figure 5.5.1. All else equal, the reduction in average energy use per household

[21] U.S. Department of Energy, "Hydropower Vision: A New Chapter for America's 1st Renewable Electricity Source," July 2016, p. 2. See https://energy.gov/eere/water/downloads/hydropower-vision-report-full-report.

[22] Ibid., p. 19.

would be expected to reduce the technical, economic, and achievable potential savings. Lower consumption means that there is less opportunity for energy savings. However, the "all else equal" caveat is an important one, as factors that change the economics of individual measures also affect potential, and possibly offset the impacts of consumption trends. Such factors include changes to avoided costs (which can change the cost effectiveness of a measure from a societal standpoint), rates (which can change the cost effectiveness of a measure from the customer standpoint), and measure costs (which affect both). The introduction of new technologies can also increase potential in the long run. On the other hand, codes and standards tend to reduce the achievable potential available to programs by improving the efficiency of baseline equipment or homes (society captures the savings, but through a separate avenue from efficiency programs).

### Figure 5.5.1 – Residential Energy Intensities (average kWh over all households)

| | Virginia (2013) | | | Virginia (2016) | | | Percent Change |
|---|---|---|---|---|---|---|---|
| kWh/household | Single Family | Multi-family | All Homes | Single Family | Multi-family | All Homes | All Homes |
| Base Split-System Air Conditioner | 1,557 | 621 | 1,398 | 1,346 | 666 | 1,230 | -12% |
| Base Early Replacement Split-System Air Conditioner | 325 | 130 | 292 | 470 | 122 | 411 | 41% |
| Base Heat Pump Cooling | 1,321 | 667 | 1,211 | 997 | 687 | 944 | -22% |
| Base Early Replacement Heat Pump Cooling | 201 | 120 | 187 | 203 | 49 | 177 | -5% |
| Base Room Air Conditioner | 91 | 35 | 81 | 54 | 55 | 54 | -33% |
| Base Early Replacement Room Air Conditioner | 17 | 3 | 15 | 4 | 0 | 3 | -80% |
| Base Dehumidifier | 17 | 8 | 15 | 287 | 38 | 245 | 1533% |
| Base Furnace Fans | 1,058 | 458 | 956 | 1,085 | 442 | 976 | 2% |
| Base Heat Pump Space Heating | 1,344 | 581 | 1,215 | 1,527 | 610 | 1,372 | 13% |
| Base Early Replacement Heat Pump Heating | 339 | 139 | 305 | 358 | 118 | 317 | 4% |
| Base Resistance Space Heating | 656 | 600 | 647 | 376 | 348 | 372 | -43% |
| Base High-Efficiency Incandescent Lighting, 0.5 hrs/day | 151 | 67 | 137 | 93 | 46 | 85 | -38% |
| Base High-Efficiency Incandescent Lighting, 2.5 hrs/day | 590 | 279 | 537 | 332 | 164 | 304 | -41% |
| Base High-Efficiency Incandescent Lighting, 6 hrs/day | 399 | 174 | 361 | 190 | 115 | 177 | -46% |
| Base Lighting 15 Watt CFL, 0.5 hrs/day | 20 | 9 | 18 | 17 | 10 | 16 | -11% |
| Base Lighting 15 Watt CFL, 2.5 hrs/day | 82 | 37 | 74 | 70 | 40 | 65 | -12% |
| Base Lighting 15 Watt CFL, 6 hrs/day | 54 | 25 | 49 | 46 | 27 | 43 | -12% |
| Base Lighting 9 Watt LED, 0.5 hrs/day | 1 | 1 | 1 | 3 | 3 | 3 | 200% |
| Base Lighting 9 Watt LED, 2.5 hrs/day | 10 | 6 | 10 | 24 | 17 | 23 | 130% |
| Base Lighting 9 Watt LED, 6 hrs/day | 10 | 5 | 9 | 23 | 8 | 20 | 122% |
| Base Specialty Incandescent Lighting, 0.5 hrs/day | 64 | 21 | 57 | 79 | 24 | 69 | 21% |
| Base Specialty Incandescent Lighting, 2.5 hrs/day | 266 | 85 | 236 | 323 | 98 | 285 | 21% |
| Base Specialty Incandescent Lighting, 6 hrs/day | 176 | 58 | 156 | 213 | 67 | 189 | 21% |
| Base Fluorescent Fixture 1.8 hrs/day | 442 | 135 | 390 | 442 | 121 | 388 | -1% |
| Base Refrigerator | 563 | 395 | 535 | 582 | 438 | 557 | 4% |
| Base Early Replacement Refrigerator | 80 | 54 | 75 | 200 | 126 | 187 | 149% |
| Base Second Refrigerator | 352 | 6 | 293 | 405 | 23 | 340 | 16% |
| Base Freezer | 334 | 52 | 286 | 150 | 63 | 136 | -52% |
| Base Early Replacement Freezer | 59 | 9 | 51 | 110 | 21 | 95 | 86% |
| Base Second Freezer | 18 | 0 | 15 | 14 | 0 | 11 | -27% |
| Base 40 gal. Water Heating | 1,569 | 1,441 | 1,547 | 920 | 261 | 808 | -48% |
| Base Early Replacement Water Heating | 277 | 254 | 273 | 1,071 | 1,176 | 1,089 | 299% |
| Base Clothes washer | 43 | 25 | 40 | 44 | 35 | 43 | 8% |
| Base Clothes Dryer | 600 | 469 | 578 | 691 | 570 | 670 | 16% |
| Base Dishwasher | 202 | 152 | 194 | 221 | 180 | 214 | 10% |
| Base Pool Pump | 158 | 0 | 131 | 45 | 0 | 37 | -72% |
| Base Plasma TV | 77 | 34 | 70 | 35 | 24 | 33 | -53% |
| Base LCD TV | 180 | 103 | 167 | 185 | 104 | 171 | 2% |
| Base CRT TV | 59 | 31 | 54 | 9 | 6 | 8 | -85% |
| Base Set-Top Box | 221 | 102 | 201 | 221 | 144 | 208 | 3% |
| Base DVD Player | 26 | 17 | 25 | 31 | 17 | 29 | 16% |
| Base Desktop PC | 241 | 128 | 222 | 274 | 107 | 245 | 10% |
| Base Laptop PC | 43 | 26 | 40 | 53 | 37 | 51 | 28% |
| Base Cooking | 528 | 451 | 515 | 659 | 617 | 652 | 27% |
| Base Miscellaneous | 600 | 500 | 583 | 600 | 500 | 583 | 0% |
| Whole House | 15,420 | 8,516 | 14,252 | 15,083 | 8,330 | 13,940 | -2% |

That being said, the 2013 DSM Potential Study identified the technical, economic, and achievable market potential of energy savings for all measures in the Company's residential and commercial sectors. The technical market potential reflects the upper limit of energy savings assuming anything that could be achieved is realized. Similarly, the economic potential reflects the upper limit of energy savings potential from all cost-effective measures. The achievable potential reflects a more realistic assessment of energy savings by considering what measures can be cost-effectively implemented through a future program. The result is a list of cost-effective measures that can ultimately be evaluated for use in future program designs and a high level estimate of the amount of energy and capacity savings still available in the Company's service territory. The achievable potential identified in the 2013 DSM Potential Study is shown in Figure 5.5.2.

**Figure 5.5.2 – 2017 Plan vs. DSM System Achievable Market Potential**

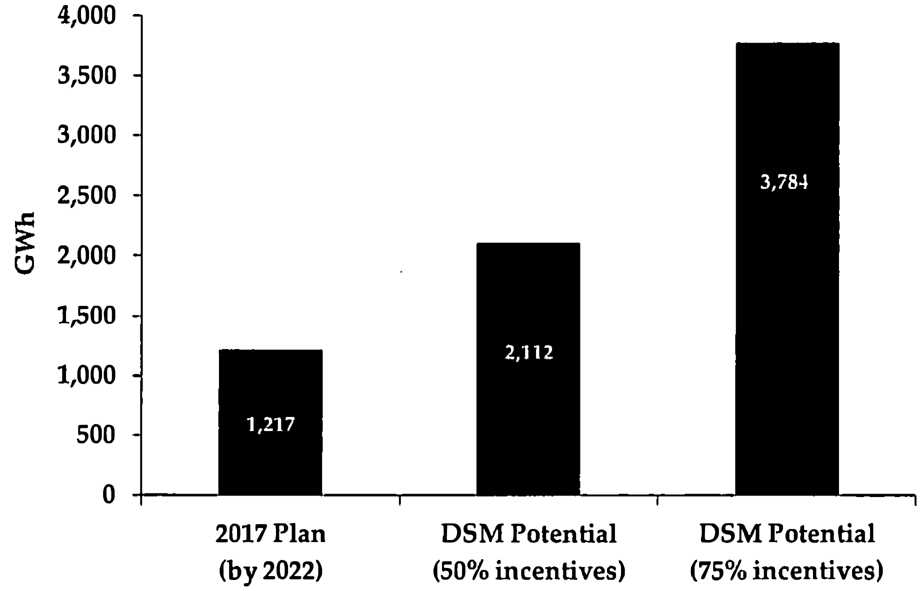
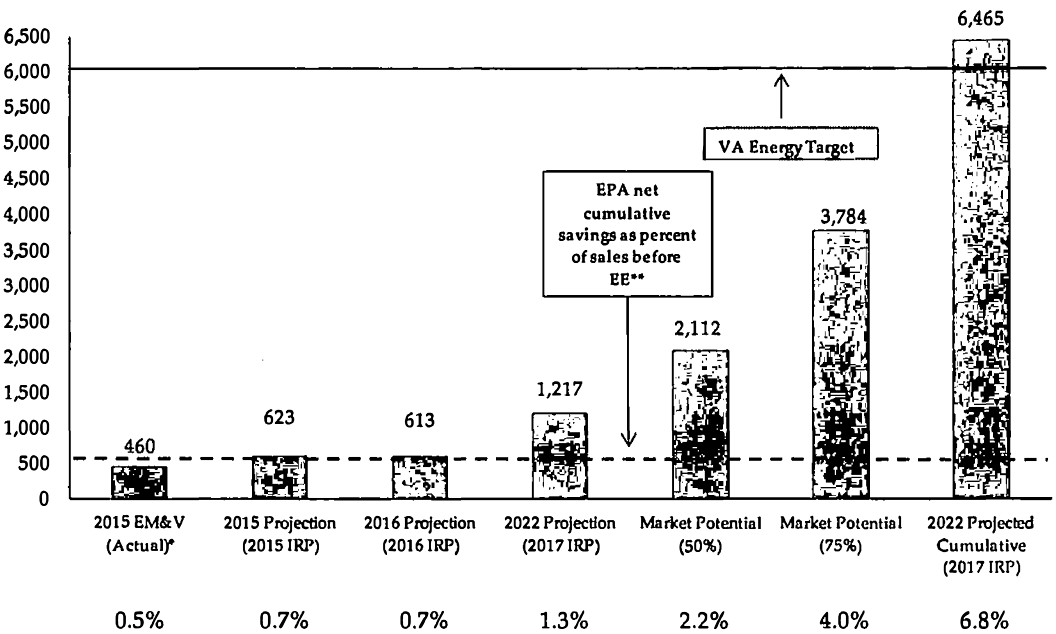



Figure 5.5.3 shows a comparison of the actual energy reductions for 2015 compared to the projected energy reductions for 2015. The actual energy reductions were 74% of the projected energy reductions for 2015. The energy reductions projected for 2022 in the 2016 Plan were 727 gigawatt hours ("GWhs"). This level of energy reduction represents 34% of the amount shown in the 2013 DSM Potential Study (50% incentive level) for 2022.

**Figure 5.5.3 – DSM Projections/Percent Sales (GWh)**




Note: *Actual energy savings are a function of SCC-approved program funding levels and measured energy savings/participation relative to program design projections.
**EPA Demand-Side Energy Efficiency Technical Support Document August 2015.
https://www.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents
"Data File: Demand-Side Energy Efficiency Appendix – Illustrative 7% Scenario.xlsx". Net Cumulative savings of 0.66% as percent of sales before EE.

A reasonable approach is to examine the projected energy reductions as a percent of energy sales. Those values are shown at the bottom of the graph for each of the energy reduction bars. Currently, the Company is producing actual energy reductions at a rate of about .5% of system energy sales. That is compared to a projected energy reduction of about .7% of sales in 2016. The projected energy reduction for the year 2022 is around 1.3% of sales. This level of energy reductions from DSM programs falls within a range of reasonable energy reductions. A reasonable range of energy reductions would lie in a band of .5% to 1% of sales on an incremental basis.

The Company will continue to evaluate new measures and re-evaluate existing programs for enhancements to reach this energy reduction level within the proposed range.

In October 2016, the Company issued an RFP for program design and implementation services for future programs. The RFP requested proposals for programs that may include measures identified in the DSM Potential Study, as well as other potential cost-effective measures based upon the current market trend. Responses from the RFP will be used to evaluate the feasibility and cost-effectiveness of proposed programs for customers in the Company's service territory.

In this 2017 Plan, there is a total reduction of 1,221 GWh by the end of the Planning Period. By 2022, there are 1,217 GWh of reductions included in this 2017 Plan. There are several drivers that will affect the Company's ability to meet the current level of projected GWh reductions, including the cost-effectiveness of the programs, SCC approval to implement new programs, continue existing programs, the final outcome of proposed environmental regulations, and customers' willingness to participate in the DSM programs.

### 5.5.1 STANDARD DSM TESTS

To evaluate DSM programs, the Company utilized four of the five standard tests from the California Standards Practice Manual. Based on SCC and NCUC findings and rulings in the Company's Virginia DSM proceedings (Case Nos. PUE-2009-00023, PUE-2009-00081, PUE-2010-00084, PUE-2011-00093, PUE-2012-00100, PUE-2013-00072, PUE-2014-00071, PUE-2015-00089, and PUE-2016-00111), and the North Carolina DSM proceedings (Docket No. E-22, Subs 463, 465, 466, 467, 468, 469, 495, 496, 497, 498, 499, 500, 507, 508, 509, 523, 524, 536, 538, and 539), the Company's future DSM programs are evaluated on both an individual and portfolio basis.

From the 2013 Plan going forward, the Company made changes to its DSM screening criteria in recognition of amendments to Va. Code § 56-576 enacted by the Virginia General Assembly in 2012 that a program "shall not be rejected based solely on the results of a single test." The Company has adjusted the requirement that the Total Resources Cost ("TRC") test score be 2.0 or better when the Ratepayer Impact Measure ("RIM") test is below 1.0 and the Utility Cost and Participant tests have passing scores. The Company will now consider including DSM programs that have passing scores (cost/benefit scores above 1.0) on the Participant, Utility Cost, and TRC tests.

Although the Company uses these criteria to assess DSM programs, there are circumstances that require the Company to deviate from the aforementioned criteria and evaluate certain programs that do not meet these criteria on an individual basis. These DSM programs serve important policy and public interest goals, such as that recognized by the SCC in Case No. PUE-2009-00081 and by the NCUC in Docket No. E-22, Sub 463 in approving the Company's Low Income Program, and more recently, the Company's Income & Age Qualifying Home Improvement Program (approved by the SCC in Case No. PUE-2014-00071 and NCUC in Docket No. E-22, Sub 523).

### 5.5.2 REJECTED DSM PROGRAMS

The Company did not reject any programs as part of the 2017 Plan process. A list of DSM rejected programs from prior IRP cycles is shown in Figure 5.5.2.1. Rejected programs may be re-evaluated and included in future DSM portfolios.

## Figure 5.5.2.1 - IRP Rejected DSM Programs

| Program |
|---|
| Non-Residential HVAC Tune-Up Program |
| Energy Management System Program |
| ENERGY STAR® New Homes Program |
| Geo-Thermal Heat Pump Program |
| Home Energy Comparison Program |
| Home Performance with ENERGY STAR® Program |
| In-Home Energy Display Program |
| Premium Efficiency Motors Program |
| Residential Refrigerator Turn-In Program |
| Residential Solar Water Heating Program |
| Residential Water Heater Cycling Program |
| Residential Comprehensive Energy Audit Program |
| Residential Radiant Barrier Program |
| Residential Lighting (Phase II) Program |
| Non-Residential Refrigeration Program |
| Cool Roof Program |
| Non-Residential Data Centers Program |
| Non-Residential Curtailable Service |
| Non-Residential Custom Incentive |
| Enhanced Air Conditioner Direct Load Control Program |
| Residential Programmable Thermostat Program |
| Residential Controllable Thermostat Program |
| Residential Retail LED Lighting Program |
| Residential New Homes Program |
| Voltage Conservation |

### 5.5.3 NEW CONSUMER EDUCATION PROGRAMS

Future promotion of DSM programs will be through methods that raise program awareness as currently conducted in Virginia and North Carolina.

### 5.5.4 ASSESSMENT OF OVERALL DEMAND-SIDE OPTIONS

Figure 5.5.4.1 represents approximately 1,221 GWh in energy savings from DSM programs at a system-level by 2032.

**Figure 5.5.4.1 - DSM Energy Reductions**

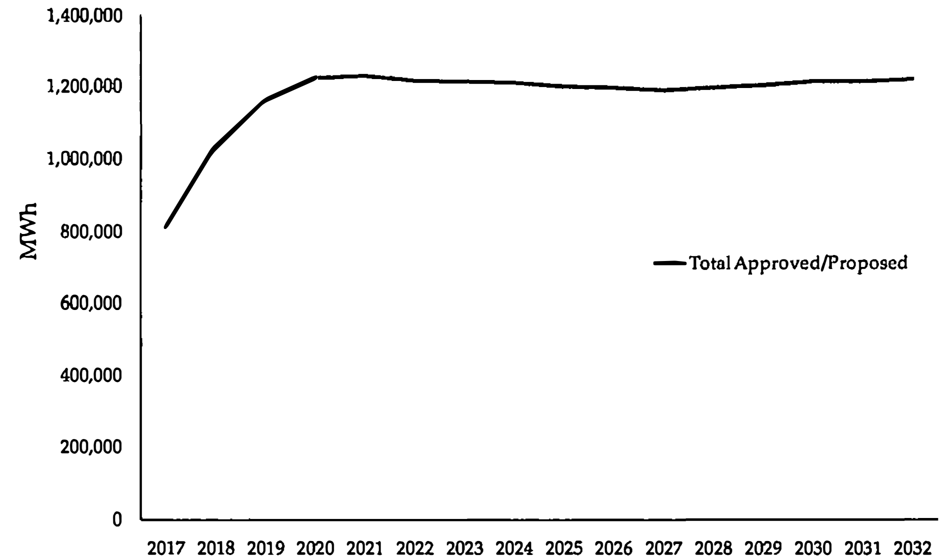
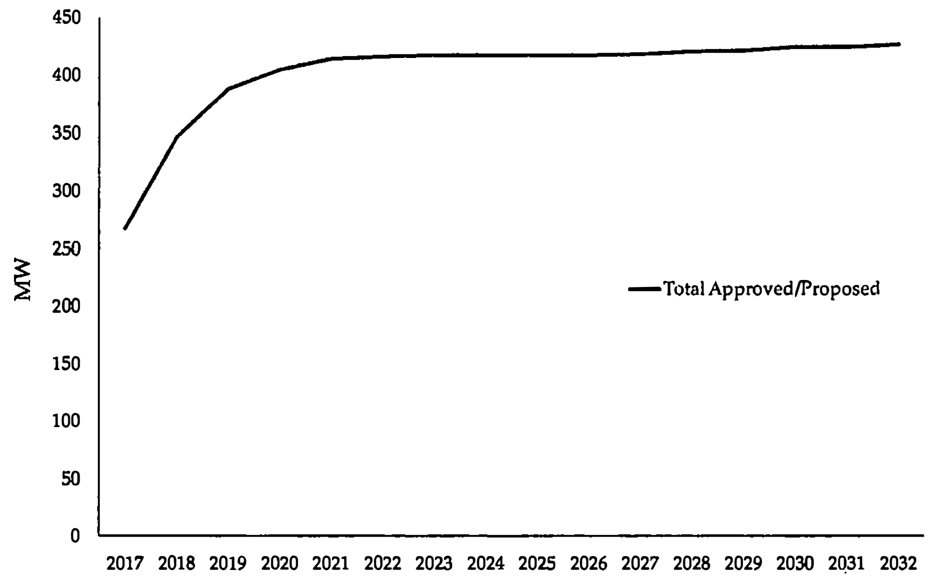



Figure 5.5.4.2 represents a system coincidental demand reduction of approximately 426 MW by 2032 from the DSM programs at a system-level.

**Figure 5.5.4.2 - DSM Demand Reductions**




The capacity reductions for the portfolio of DSM programs in this 2017 Plan are higher than the projections in the 2016 Plan. The total capacity reduction by the end of the Planning Period was 330 MW for the portfolio of DSM programs in the 2016 Plan and is 426 MW in this 2017 Plan. This represents approximately a 29% increase in demand reductions. The energy reduction for the DSM programs was 752 GWh in the 2016 Plan and is approximately 1,221 GWh in this 2017 Plan. This represents a 62% increase in energy reductions. The majority of the increase in energy from the 2016

Plan to the 2017 Plan is attributable to the proposed Non-Residential Prescriptive Program, which adds additional energy savings of 447 MWh in 2032.

### DSM Levelized Cost Comparison

As required by the SCC in its Final Order on the 2013 Plan issued on August 27, 2014 in Case No. PUE-2013-00088, the Company is providing a comparison of the cost of the Company's expected demand-side management costs relative to its expected supply-side costs. The costs are provided on a levelized cost per MWh basis for both supply- and demand-side options. The supply-side options' levelized costs are developed by determining the revenue requirements, which consist of the dispatch cost of each of the units and the revenue requirement associated with the capital cost recovery of the resource. The demand-side options' levelized cost is developed from the cost/benefit runs. The costs include the yearly program cash flow streams that incorporate program costs, customer incentives, and EM&V costs. The net present value ("NPV") of the cash flow stream is then levelized over the Planning Period using the Company's weighted average cost of capital. The costs for both types of resources are then sorted from lowest cost to highest cost and are shown in Figure 5.5.4.3.

**Figure 5.5.4.3 – Comparison of per MWh Costs of Selected Generation Resources**

| Comparison of per MWh Costs of Selected Generation Resources to Phase II through Phase V Programs Utility Cost Perspective | Cost ($/MWh) | |
|---|---|---|
| Non-Residential Heating and Cooling Efficiency Program | $ | 4.24 |
| Non-Residential Window Film Program | $ | 8.74 |
| Residential Appliance Recycling Program | $ | 17.01 |
| Non-Residential Lighting Systems and Controls Program | $ | 17.98 |
| Non-Residential Prescriptive Program | $ | 28.02 |
| Residential Heat Pump Upgrade Program | $ | 45.42 |
| Solar | $ | 51.73 |
| Small Business Improvement Program | $ | 62.20 |
| Residential Home Energy Assessment | $ | 68.25 |
| 3X1 CC | $ | 70.43 |
| 2X1 CC | $ | 74.80 |
| 1X1 CC | $ | 88.31 |
| Onshore Wind | $ | 99.19 |
| CT | $ | 125.93 |
| Aero CT | $ | 149.05 |
| Nuclear | $ | 149.45 |
| Biomass | $ | 166.92 |
| Fuel Cell | $ | 172.57 |
| Solar & Aero CT | $ | 200.77 |
| Income and Age Qualifying Home Improvement Program | $ | 281.29 |
| SCPC w/ CCS | $ | 309.76 |
| Offshore Wind | $ | 338.92 |
| IGCC w/ CCS | $ | 459.30 |
| VOWTAP | $ | 851.39 |

Note: The Company does not use levelized costs to screen DSM programs. DSM programs also produce benefits in the form of avoided supply-side capacity and energy cost that should be netted against DSM program cost. The DSM cost/benefit tests discussed in Section 5.5.1 are the appropriate way to evaluate DSM programs when comparing to equivalent supply-side options, and is the method the Company uses to screen DSM programs.

1) Values shown for these units reflect the Cost of Service method.

### 5.5.5 LOAD DURATION CURVES

The Company has provided load duration curves for the years 2018, 2022, and 2032 in Figures 5.5.5.1, 5.5.5.2, and 5.5.5.3.

**Figure 5.5.5.1 - Load Duration Curve 2018**

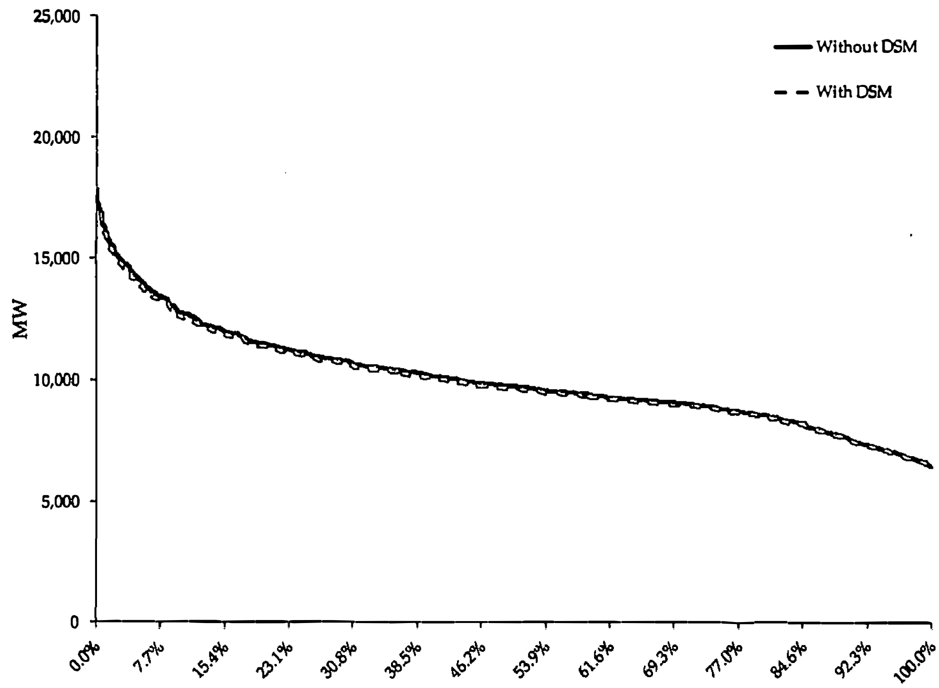



**Figure 5.5.5.2 - Load Duration Curve 2022**

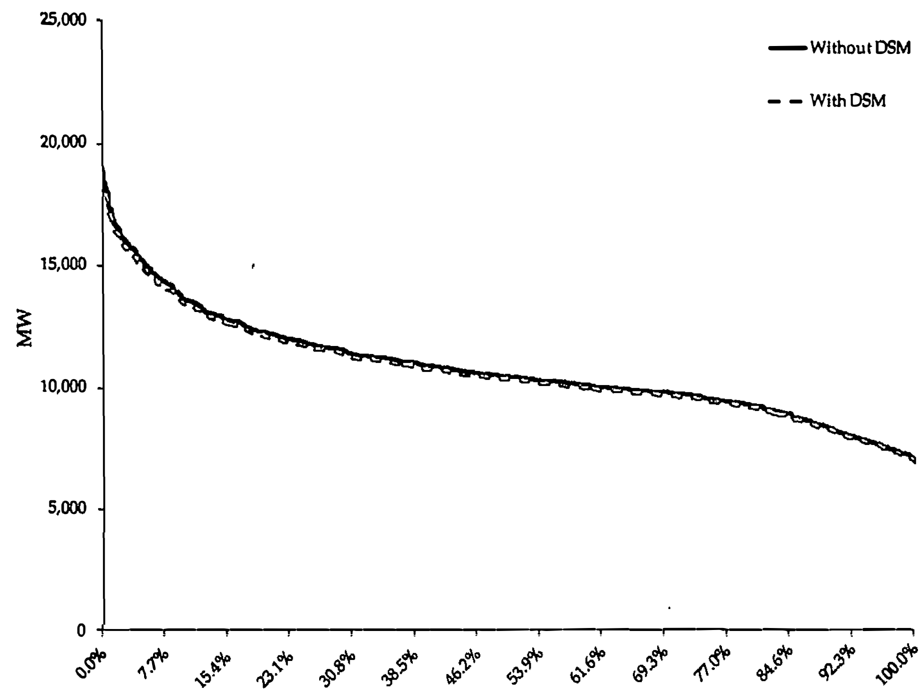
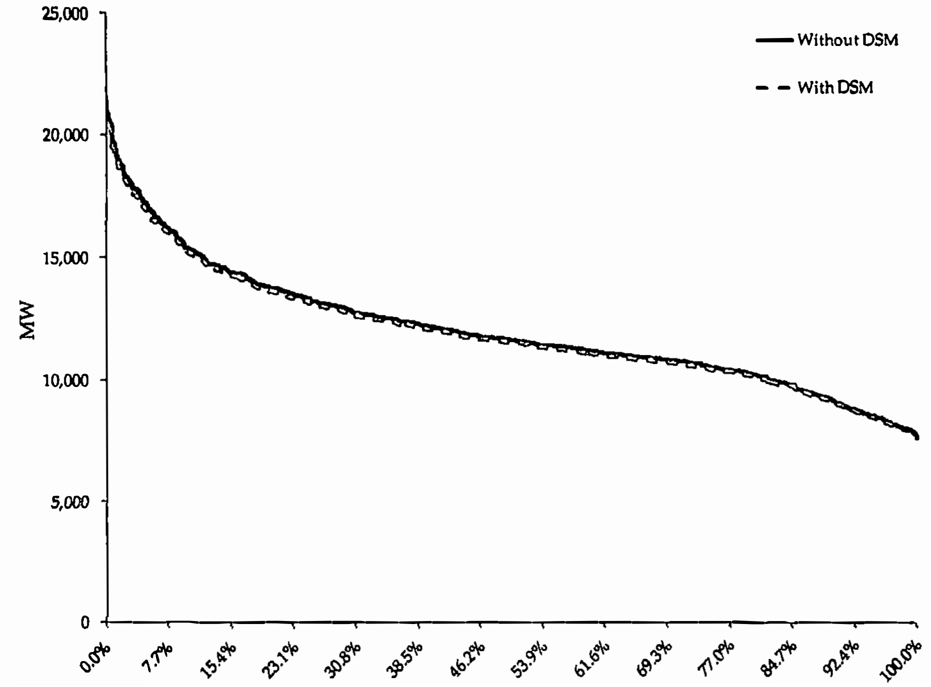


Figure 5.5.5.3 - Load Duration Curve 2032




## 5.6 FUTURE TRANSMISSION PROJECTS

Figure 7.3.1 provides a list of transmission lines that are planned to be constructed during the Planning Period.

# CHAPTER 6 – DEVELOPMENT OF THE INTEGRATED RESOURCE PLAN

## 6.1 IRP PROCESS

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

The IRP process begins with the development of a long-term annual peak and energy requirements forecast. Next, existing and approved supply- and demand-side resources are compared with expected load and reserve requirements. This comparison yields the Company's expected future capacity needs to maintain reliable service for its customers over the Study Period.

As described in Chapter 5, a feasibility screening, followed by a busbar screening curve analysis, are then conducted, to identify supply-side resources, and a cost/benefit screening is conducted to determine demand-side resources that could potentially fit into the Company's resource mix. These potential resources and their associated economics are next incorporated into the Company's planning model, PLEXOS. The PLEXOS model then optimizes the quantity, type, and timing of these new resources based on their economics to meet the Company's future energy and capacity requirements.

The next step is to develop a set of alternative plans, which represent plausible future paths considering the major drivers of future uncertainty. The Company develops these alternative plans in order to test different resource strategies against plausible scenarios that may occur given future market and regulatory uncertainty.

As a result of stakeholder input and consistent with the SCC's Final Order on the 2013 Plan issued in Case No. PUE-2013-00088 on August 27, 2014, the Company has included in this 2017 Plan a comprehensive risk analysis of the trade-off between operating cost risk and project development cost risk of each of the Alternative Plans, and has included a broadband of prices used in future forecasting assumptions, such as forecasting assumptions related to fuel prices, effluent prices, market prices, renewable energy credit costs, and construction costs. This analysis, which is described further in Section 6.7, attempts to quantify the fuel price, $CO_2$ emissions price, and construction cost risks represented in the Alternative Plans.

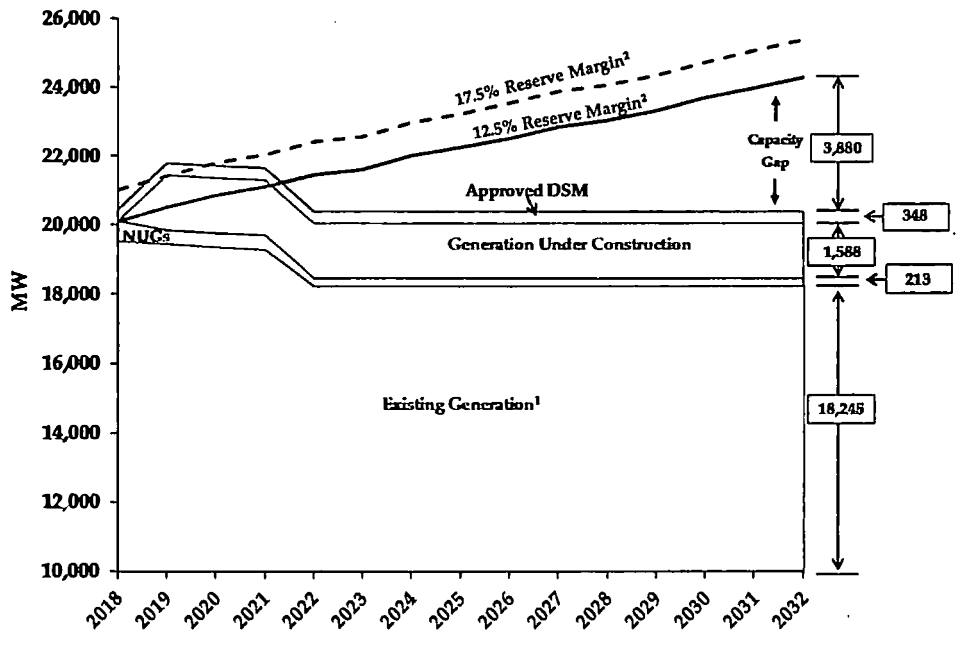
Finally, in order to summarize the results of the Company's overall analysis of the Alternative Plans, the Company developed a Portfolio Evaluation Scorecard. This Scorecard matrix combines the NPV cost results and the comprehensive risk analysis results along with a third evaluation criteria entitled Capital Investment Concentration.

The Scorecard has been applied to the Alternative Plans and the results are presented and discussed in Section 6.8. The results provided by the Scorecard analysis reflect several compliant and strategic paths that the Company maintains could best meet the energy and capacity needs of its customers at the lowest reasonable cost over the Planning Period, with due quantification, consideration and analysis of future risks and uncertainties facing the industry, the Company, and its customers.

## 6.2 CAPACITY & ENERGY NEEDS

As discussed in Chapter 2, over the Planning Period, the Company forecasted average annual growth rates of 1.3% in both peak and energy requirements for the DOM LSE. Chapter 3 presented the Company's existing supply- and demand-side resources, NUG contracts, generation retirements, and generation resources under construction. Figure 6.2.1 shows the Company's supply- and demand-side resources compared to the capacity requirement, including peak load and reserve margin. The area marked as "capacity gap" shows additional capacity resources that will be needed over the Planning Period in order to meet the capacity requirement. The Company plans to meet this capacity gap using a diverse combination of additional conventional and renewable generating capacity, DSM programs, and market purchases.

**Figure 6.2.1 - Current Company Capacity Position (2018 – 2032)**




Note: The values in the boxes represent total capacity in 2032.
1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.
2) See Section 4.2.2.

As indicated in Figure 6.2.1, the capacity gap at the end of the Planning Period is significant. The Planning Period capacity gap is expected to be approximately 3,880 MW. If this capacity deficit is not filled with additional resources, the reserve margin is expected to fall below the required 12.48% planning reserve margin (as shown in Figure 4.2.2.1) beginning in 2022 and continuing to decrease thereafter. Figure 6.2.2 displays actual reserve margins from 2018 to 2032.

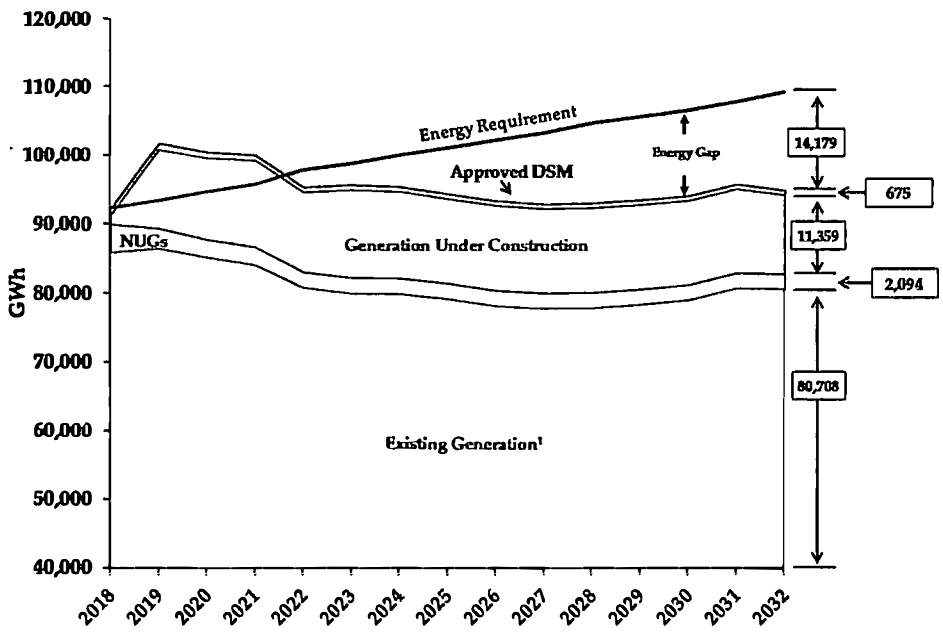
**Figure 6.2.2 - Actual Reserve Margin without New Resources**

| Year | Reserve Margin (%) |
|---|---|
| 2018 | 13.1% |
| 2019 | 18.1% |
| 2020 | 15.6% |
| 2021 | 14.1% |
| 2022 | 5.7% |
| 2023 | 4.9% |
| 2024 | 3.0% |
| 2025 | 1.9% |
| 2026 | 0.6% |
| 2027 | -0.9% |
| 2028 | -1.6% |
| 2029 | -2.8% |
| 2030 | -4.3% |
| 2031 | -5.5% |
| 2032 | -6.7% |

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

Figure 6.2.3 illustrates the amount of annual energy required by the Company after the dispatch of its existing resources. The Company's energy requirements increase significantly over time.

**Figure 6.2.3 - Current Company Energy Position (2018 – 2032)**




Note: The values in the boxes represent total energy in 2032.

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

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

## 6.3 MODELING PROCESSES & TECHNIQUES

The Company used a methodology that compares the costs of the Alternative Plans to evaluate the type and timing of resources that were included in those plans. The first step in the process was to construct a representation of the Company's current resource base. Then, future assumptions including, but not limited to, load, fuel prices, emissions costs, maintenance costs, and resource costs were used as inputs to PLEXOS. This analysis provided a set of future supply-side resources potentially available to the Company, along with their individual characteristics. The types of supply-side resources that are available to the PLEXOS model are shown in Figure 6.3.1.

**Figure 6.3.1 - Supply-Side Resources Available in PLEXOS**

| Dispatchable |
|---|
| Aero-derivative CT |
| Biomass |
| CC 1x1 |
| CC 2x1 |
| CC 3x1 |
| Coal w/CCS |
| CT |
| Fuel Cell |
| IGCC w/CCS |
| Nuclear (NA3) |
| **Non-Dispatchable** |
| Offshore Wind |
| Onshore Wind |
| Solar NUG |
| Solar PV |
| Solar Tag |
| VOWTAP |

Key: CC: Combined-Cycle; CT: Combustion Turbine (2 units); IGCC CCS: Integrated-Gasification Combined-Cycle with Carbon Capture and Sequestration; Coal CCS: Coal with Carbon Capture and Sequestration; Solar PV: Solar Photovoltaic; Solar Tag: Solar PV unit at a brownfield site; VOWTAP: Virginia Offshore Wind Technology Advancement Project.

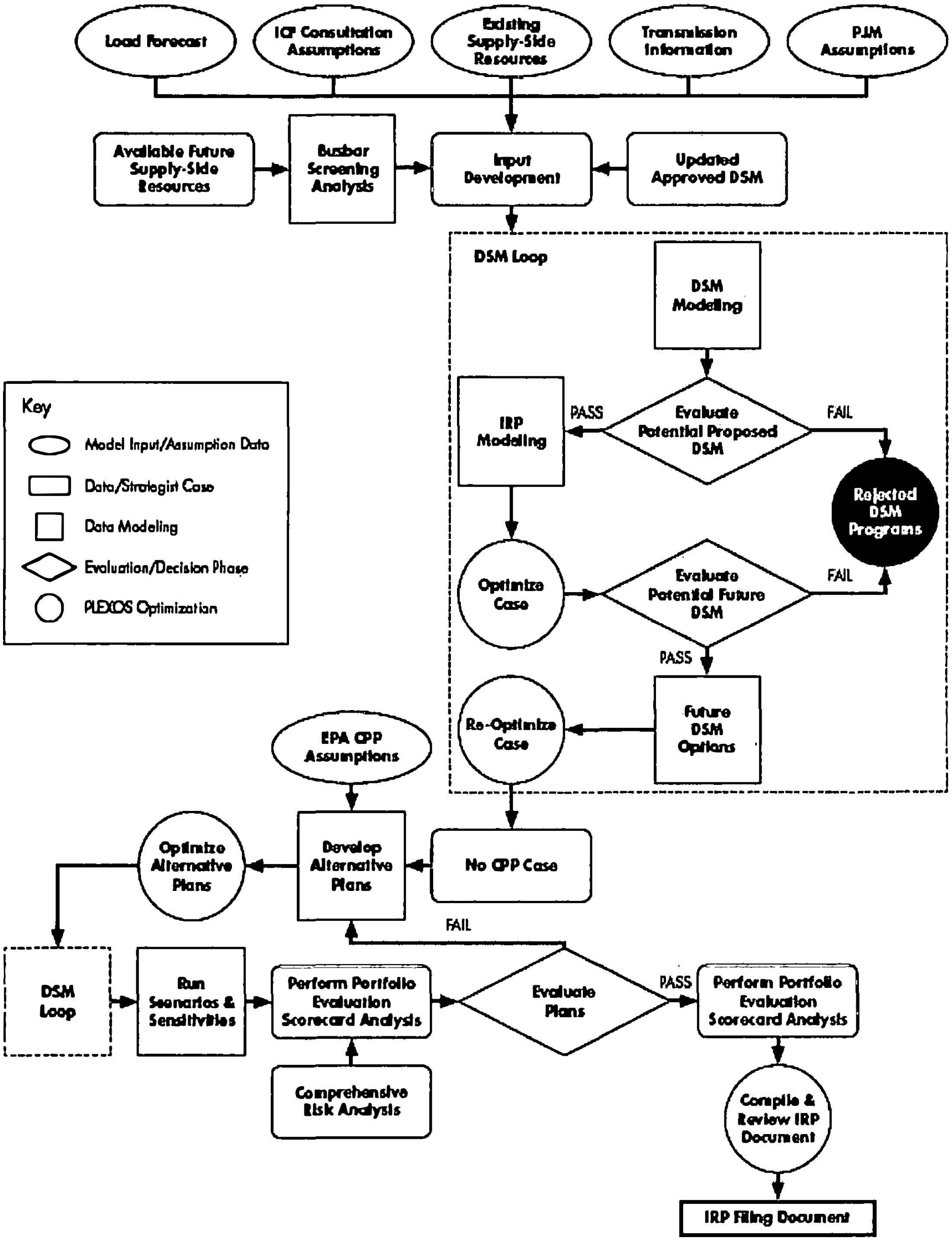
The Company continues to use Strategist to evaluate demand-side programs for cost effectiveness. The inputs into Strategist are consistent with those in PLEXOS for the 2017 Plan. PLEXOS does not have the ability to conduct cost/benefit evaluations for DSM within the model itself, leading to the need for the use of an additional model, tool, or process. For this reason, the Company has chosen to continue its use of Strategist for DSM evaluations using consistent data between the models.

As described in Chapter 5, the Company continues to evaluate the potential for new DSM programs or modifications to existing programs for possible filing in Virginia by October 2017. This may also lead to modifications or additions to the portfolio of DSM programs in North Carolina. Supply-side options, market purchases, and currently approved demand-side resource options were optimized to arrive at the Alternative Plans presented in this 2017 Plan. The level of DSM is the same in all of the Alternative Plans.

PLEXOS develops optimized resource plans based on the total NPV utility costs over the Study Period while simultaneously adhering to other market drivers, such as $CO_2$ targets set forth by the CPP. The NPV utility costs include the variable costs of all resources (including emissions and fuel), the cost of market purchases, and the fixed costs of future resources.

To create the Company's 2017 Plan, the Company developed the Alternative Plans representing plausible future paths, as described in Section 6.4. The Alternative Plans were also subjected to a comprehensive risk analysis to assess portfolio risks associated with fuel costs, $CO_2$ emission costs, load variations, and construction costs. In general, this analysis was used to quantify the value of fuel diversity. Finally, the results of all the analyses were summarized in the Portfolio Evaluation Scorecard, where each of the Alternative Plans was given a final score under various evaluation categories.

**Figure 6.3.2 - Plan Development Process**



## 6.4 ALTERNATIVE PLANS

The Company's analysis of the Alternative Plans is intended to represent plausible paths of future resource additions. The CPP-Compliant Plans presume the CPP will be implemented in accordance with the final CPP rule and the model trading rules as proposed in October 2015,[23] and are designed to ensure that the Company's Virginia-based generation fleet achieves compliance with three likely alternative programs that Virginia may choose under the CPP as described in Chapter 1. Each of the Alternative Plans were optimized using least-cost analytical techniques given the Intensity-Based or Mass-Based constraints associated with that alternative by using two scenarios (Scenarios 1 and 2) to meet the differing compliance approaches.

To the best of the Company's knowledge, Intensity- and Mass-Based programs represent the FIP. While, as noted earlier, the FIP has been withdrawn, Plan $B^{NT}$: Intensity-Based Dual Rate, Plan $C^{T}$: Intensity-Based Dual Rate, Plan $D^{NT}$: Mass-Based Existing Units and Plan $E^{T}$: Mass-Based Existing Units all are modeled under the FIP, consistent with the 2016 Plan Final Order.[24]

As described in Chapter 1, Scenario 1 assumes that the Company achieves CPP compliance through generation portfolio modifications with little, if any, purchases of $CO_2$ allowances or ERCs (Plan $B^{NT}$, Plan $D^{NT}$, Plan $F^{NT}$, and Plan $H^{NT}$ described below). Scenario 2 assumes the Company achieves CPP compliance through purchases of $CO_2$ allowances or ERCs (Plan $C^{T}$, Plan $E^{T}$, and Plan $G^{T}$ described below). It should be noted that in evaluating the Alternative Plans, no limitations were placed on market purchases of energy and capacity other than the 5,200 MW physical transmission interface limit associated with the Company's service territory. Further, all the Alternative Plans were optimized using the PLEXOS model except for Plan $H^{NT}$: New Nuclear, which included a user defined operations date for North Anna 3 of September 2029.

Figure 6.4.1 reflects the Alternative Plans in tabular format.

[23] As previously noted, on April 4, 2017, the EPA announced it is initiating a review of the CPP. On April 3, 2017, the EPA issued a notice officially withdrawing the proposed FIP and the model trading rules.

[24] See the Legal Memorandum of Virginia Electric and Power Company filed on April 29, 2016 in the 2016 Plan proceeding (Case No. PUE-2016-00049) regarding whether any aspect of any plan would require changes to existing Virginia law, as required by the 2015 Plan Final Order.

## Figure 6.4.1 – 2017 Alternative Plans

| Year | [illegible] | Plan $B^{NT}$: Intensity-Based Dual Rate | Plan $C^{I}$: Intensity-Based Dual Rate | Plan $D^{NT}$: Mass-Based Existing Units | Plan $E^{I}$: Mass-Based Existing Units | Plan $F^{NT}$: Mass-Based All Units | Plan $G^{I}$: Mass-Based All Units | Plan $H^{NT}$: New Nuclear |
|---|---|---|---|---|---|---|---|---|
| | | Compliant with Clean Power Plan | | | | | | |
| Approved and Proposed DSM: 426 MW, 1,221 GWh by 2032 | | | | | | | | |
| 2018 | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] | SLR NUG[1]<br>SPP[2] |
| 2019 | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR | Greensville<br>SLR (240 MW)<br>PP5 SNCR |
| 2020 | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) |
| 2021 | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) | VOWTAP<br>SLR (240 MW) |
| 2022 | SLR (240 MW) | SLR (240 MW)<br>CH 3-4[3], YT3[3] | SLR (240 MW)<br>CH 3-4[3], YT3[3] | SLR (240 MW)<br>CH 3-4[3], YT3[3] | SLR (240 MW)<br>CH 3-4[3], YT3[3] | CT<br>SLR (240 MW)<br>CH 3-4[3], YT3[3] | CT<br>SLR (240 MW)<br>CH 3-4[3], YT3[3] | CT<br>SLR (240 MW)<br>CH 3-4[3], YT3[3] |
| 2023 | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (160 MW) | SLR (240 MW) | CT<br>SLR (160 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) |
| 2024 | CT<br>SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) |
| 2025 | SLR (240 MW) | 3x1 CC<br>SLR (240 MW) | 3x1 CC<br>SLR (240 MW) | 3x1 CC<br>SLR (240 MW) | 3x1 CC<br>SLR (240 MW) | CT<br>SLR (240 MW)<br>MB 1-2[4], CL 1-2[4] | SLR (240 MW) | SLR (240 MW)<br>MB 1-2[4], CL 1-2[4] |
| 2026 | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) |
| 2027 | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | CT<br>SLR (160 MW) | SLR (240 MW) | SLR (240 MW) |
| 2028 | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) |
| 2029 | CT<br>SLR (240 MW) | SLR (240 MW) | CT<br>SLR (160 MW) | CT<br>SLR (240 MW) | CT<br>SLR (160 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | SLR (240 MW) |
| 2030 | SLR (240 MW) | CT<br>SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | NA3<br>SLR (240 MW) |
| 2031 | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) | SLR (240 MW) | SLR (240 MW) |
| 2032 | SLR (240 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | SLR (240 MW) | CT<br>SLR (240 MW) | CT<br>SLR (240 MW) |

Key: CC: Combined-Cycle; CH: Chesterfield Power Station; CL: Clover Power Station; CT: Combustion Turbine (2 units); Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; NA3: North Anna 3; PP5: Possum Point Unit 5; SLR: Generic Solar; SLR NUG: Solar NUG; SNCR: Selective Non-Catalytic Reduction; SPP: Solar Partnership Program; VOWTAP: Virginia Offshore Wind Technology Advancement Project; YT: Yorktown Unit.

Note: 1) Solar NUGs include 950 MW of NC solar NUGs and 40 MW of VA solar NUGs by 2022.

2) SPP started in 2014 and continues through 2017.

3) The potential retirements of Chesterfield Units 3 & 4 and Yorktown Unit 3 are modeled in all of the CPP-Compliant Plans.

4) The potential retirements of Clover Units 1 & 2 and Mecklenburg Units 1 & 2 are modeled in Plan $D^{NT}$ and Plan $H^{NT}$.

Along with the individual characteristics of the CPP-Compliant Plans, the Alternative Plans share a number of generation resource assumptions, including, but not limited to, the resources for which the Company has filed and/or has been granted CPCN approval from the SCC, or has publicly committed to pursuing, subject to SCC approval. These resources include Greensville County Power Station (1,585 MW), VOWTAP (12 MW nameplate), Virginia and North Carolina solar NUGs (990 MW nameplate), and the SPP (7.7 MW nameplate). In addition, all of the Alternative Plans assume 20-year license extensions of the Company's existing nuclear fleet at North Anna and Surry. The Alternative Plans also have the same level of approved and proposed DSM programs reaching 426 MW by the end of the Planning Period.

The CPP-Compliant Plans were designed using ICF's CPP commodity forecast. In addition to the supply- and demand-side resources listed above that are common to all of the Alternative Plans, the CPP-Compliant Plans also model the potential retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW) and Yorktown Unit 3 (790 MW) by 2022. Additional resources and retirements are included in the Alternative Plans below:

**Plan A: No CPP**

Plan A is based on the No $CO_2$ Cost scenario and is developed using least cost modeling methodology. Specifically, it selects:

- 1,832 MW of CT capacity; and
- 3,360 MW (nameplate) of solar.

**Plan $B^{NT}$: Intensity-Based Dual Rate**

Plan $B^{NT}$ represents an Intensity-Based $CO_2$ scenario that requires each existing: a) fossil-fueled steam unit to achieve an intensity target of 1,305 lbs of $CO_2$ per MWh by 2030, and beyond; and b) NGCC units to achieve an intensity target of 771 lbs of $CO_2$ per MWh by 2030, and beyond. This Alternative Plan was developed assuming that the Company achieves CPP compliance through portfolio modifications with no market purchase of ERCs. This Alternative Plan limits the generation at Mt. Storm to a 40% capacity factor. While, as noted earlier, the FIP has been withdrawn, to the best of the Company's knowledge, Intensity- and Mass-Based Existing Units programs represent a FIP. Plan $B^{NT}$ selects:

- 1,591 MW of 3x1 CC capacity;
- 1,374 MW of CT capacity; and
- 3,360 MW (nameplate) of solar.

**Plan $C^T$: Intensity-Based Dual Rate**

Plan $C^T$ uses the same ERC price as Plan $B^{NT}$, but allows for market purchases of ERCs to achieve CPP compliance. Additionally, Plan $C^T$ does not constrain the generation at Mt. Storm to meet the expected mass limit imposed on West Virginia generating units. While, as noted earlier, the FIP has been withdrawn, to the best of the Company's knowledge, Intensity- and Mass-Based Existing Units programs represent a FIP. Specifically, Plan $C^T$ selects:

- 1,591 MW of 3x1 CC capacity;
- 1,374 MW of CT capacity; and
- 3,280 MW (nameplate) of solar.

**Plan $D^{NT}$: Mass-Based Existing Units**

Plan $D^{NT}$ is a Mass-Based program that limits the total $CO_2$ emissions from the existing fleet of fossil-fired generating units. In Virginia, this limit is 27,433,111 short tons of $CO_2$ in 2030, and beyond. This Alternative Plan was developed assuming that the Company achieves CPP compliance through portfolio modifications with no market purchase of $CO_2$ allowances. This Alternative Plan limits the generation at Mt. Storm to a 40% capacity factor. While, as noted earlier, the FIP has been withdrawn, to the best of the Company's knowledge, Intensity- and Mass-Based Existing Units programs represent a FIP. Specifically, Plan $D^{NT}$ selects:

- 1,591 MW of 3x1 CC capacity;
- 1,374 MW of CT capacity; and
- 3,280 MW (nameplate) of solar.

**Plan $E^{T}$: Mass-Based Existing Units**

Plan $E^{T}$ uses the same allowance price as Plan $D^{NT}$, but allows for market purchases of $CO_2$ allowances to achieve CPP compliance. Additionally, Plan $E^{T}$ does not constrain the generation at Mt. Storm to meet the expected mass limit imposed on West Virginia generating units. While, as noted earlier, the FIP has been withdrawn, to the best of the Company's knowledge, Intensity- and Mass-Based Existing Units programs represent a FIP. Specifically, Plan $E^{T}$ selects:

- 1,591 MW of 3x1 CC capacity;
- 1,374 MW of CT capacity; and
- 3,280 MW (nameplate) of solar.

**Plan $F^{NT}$: Mass-Based All Units**

Plan $F^{NT}$ is a Mass-Based program that limits the total $CO_2$ emissions from both the existing fleet of fossil fuel-fired generating units and all new generation units in the future. In Virginia, this limit is 27,830,174 short tons of $CO_2$ in 2030, and beyond. This Alternative Plan was developed assuming that the Company achieves CPP compliance through portfolio modifications with no market purchase of $CO_2$ allowances. This Alternative Plan limits the generation at Mt. Storm to a 40% capacity factor. Specifically, Plan $F^{NT}$ selects:

- 3,664 MW of CT capacity;
- 3,200 MW (nameplate) of solar; and
- Potential retirement of Mecklenburg Units 1 (69 MW) and 2 (69 MW) and Clover Units 1 (220 MW) and 2 (219 MW) in 2025.

### Plan $G^{T}$: Mass-Based All Units

Plan $G^{T}$ uses the same allowance price as Plan $F^{NT}$, but allows for market purchases of $CO_2$ allowances to achieve CPP compliance. Additionally, Plan $G^{T}$ does not constrain the generation at Mt. Storm to meet the expected mass limit imposed on West Virginia generating units. Specifically, Plan $G^{T}$ selects:

- 3,206 MW of CT capacity; and
- 3,360 MW (nameplate) of solar.

### Plan $H^{NT}$: New Nuclear

Plan $H^{NT}$ is a Mass-Based program that limits the total $CO_2$ emissions from both the existing fleet of fossil fuel-fired generating units and all new generation units in the future, but also includes the construction and operation of North Anna 3 in 2030. This Alternative Plan was developed assuming that the Company achieves CPP compliance through portfolio modifications with no market purchase of $CO_2$ allowances. This Alternative Plan limits the generation at Mt. Storm to a 40% capacity factor. Specifically, Plan $H^{NT}$ selects:

- 2,290 MW of CT capacity;
- 3,360 MW (nameplate) of solar; and
- Potential retirement of Mecklenburg Units 1 (69 MW) and 2 (69 MW) and Clover Units 1 (220 MW) and 2 (219 MW) in 2025.

And includes:

- 1,452 MW of nuclear capacity (North Anna 3).

Figure 6.4.2 illustrates the renewable resources included in the Alternative Plans over the Study Period (2018 - 2042).

**Figure 6.4.2 – Renewable Resources in the Alternative Plans through the Study Period**

| Resource | Nameplate MW | Plan A: No CPP | Compliant with the Clean Power Plan | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Plan $B^{NT}$: Intensity-Based Dual Rate | Plan $C^{T}$: Intensity-Based Dual Rate | Plan $D^{NT}$: Mass-Based Existing Units | Plan $E^{T}$: Mass-Based Existing Units | Plan $F^{NT}$: Mass-Based All Units | Plan $G^{T}$: Mass-Based All Units | Plan $H^{NT}$: New Nuclear |
| Existing Resources[1] | 610 | x | x | x | x | x | x | x | x |
| VCHEC Biomass | 61 | x | x | x | x | x | x | x | x |
| SPP | 8 | x | x | x | x | x | x | x | x |
| Solar NUGs[2] | 990 | x | x | x | x | x | x | x | x |
| VOWTAP | 12 | x | x | x | x | x | x | x | x |
| Solar PV | Varies | 5,600 | 5,760 | 5,680 | 5,680 | 5,280 | 5,280 | 5,680 | 5,760 |

Note: 1) Existing Resources include hydro, biomass (excluding VCHEC), and solar.
2) Solar NUGs include forecasted VA and NC solar NUGs through 2022.

Figure 6.4.3 shows the total tons of $CO_2$ emitted for all generation resources including CTs, contracted NUGs, and purchases in each of the Alternative Plans through the Study Period. Figure 6.4.3 shows each of the Scenario 1 (no $CO_2$ trading) Plans compared against Plan A: No CPP. Figure 6.4.4 shows each of the Scenario 2 ($CO_2$ trading) Plans compared against Plan A. The $CO_2$ tons include emissions from all the Company's generating units, not just those that are bound under each applicable CPP compliance program. In other words, $CO_2$ emissions from units such as CTs, which are exempt under all CPP plans, are included.

Figure 6.4.3 shows that Plan B[NT]: Intensity-Based Dual Rate has total $CO_2$ emissions of 47 million tons by 2042, which is only a 2 million ton (4%) increase from the 2012 baseline values used by the EPA for CPP planning. Additionally, Plan H[NT]: New Nuclear has total $CO_2$ emissions of 42 million tons by 2042, which represents a 3 million ton (7%) decrease from the 2012 baseline values. This is in large part to the inclusion of North Anna 3 in Plan H[NT] as a zero-carbon baseload resource.

**Figure 6.4.3 – Total Customer $CO_2$ Impact for Scenario 1 (No $CO_2$ Trading) Plans**

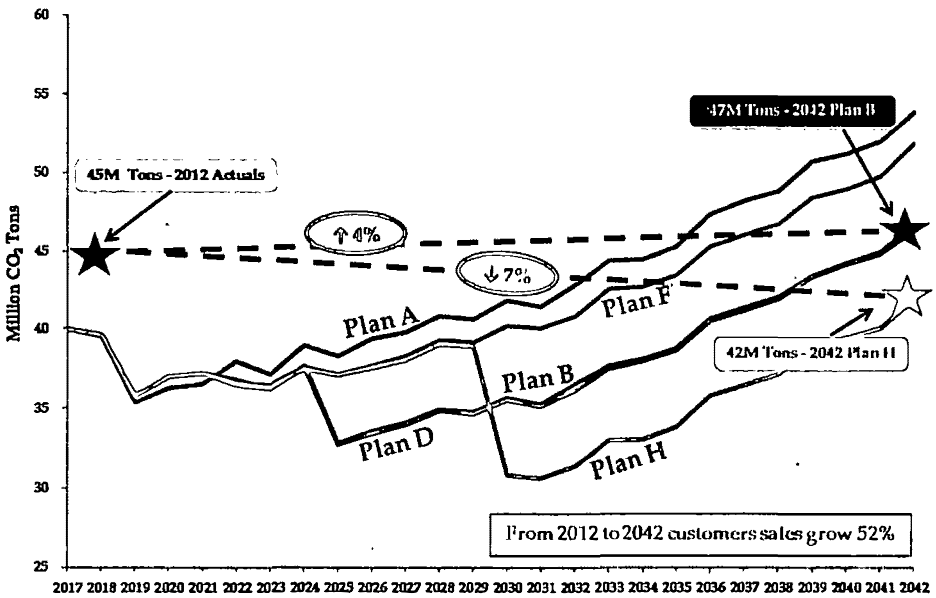
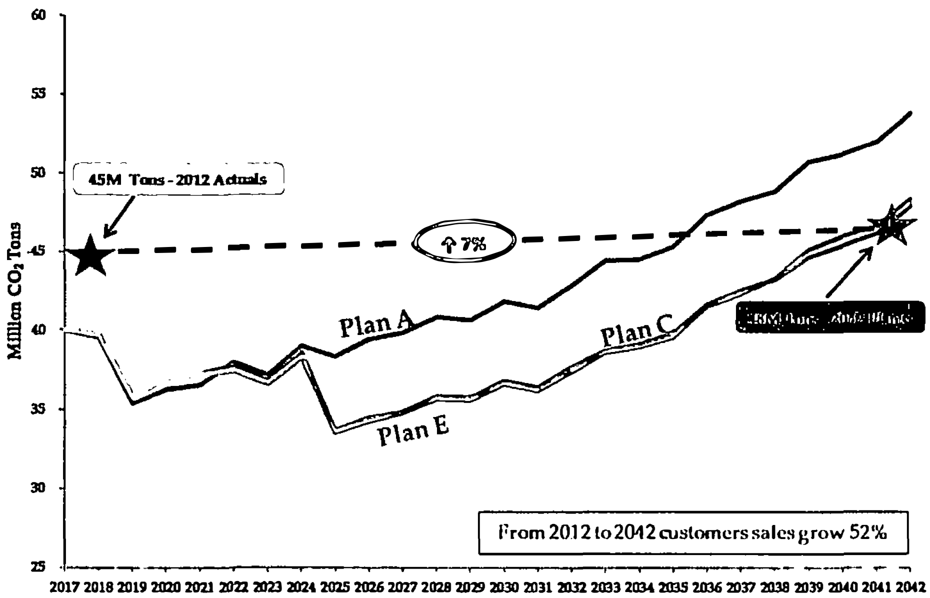



Figure 6.4.4 shows that Plan C[T]: Intensity-Based Dual Rate has total $CO_2$ emissions of 48 million tons by 2042, which is only a 3 million ton (7%) increase from the 2012 baseline values used by the EPA for CPP planning.

**Figure 6.4.4 – Total Customer $CO_2$ Impact for Scenario 2 ($CO_2$ Trading) Plans**




## 6.5 ALTERNATIVE PLANS NPV COMPARISON

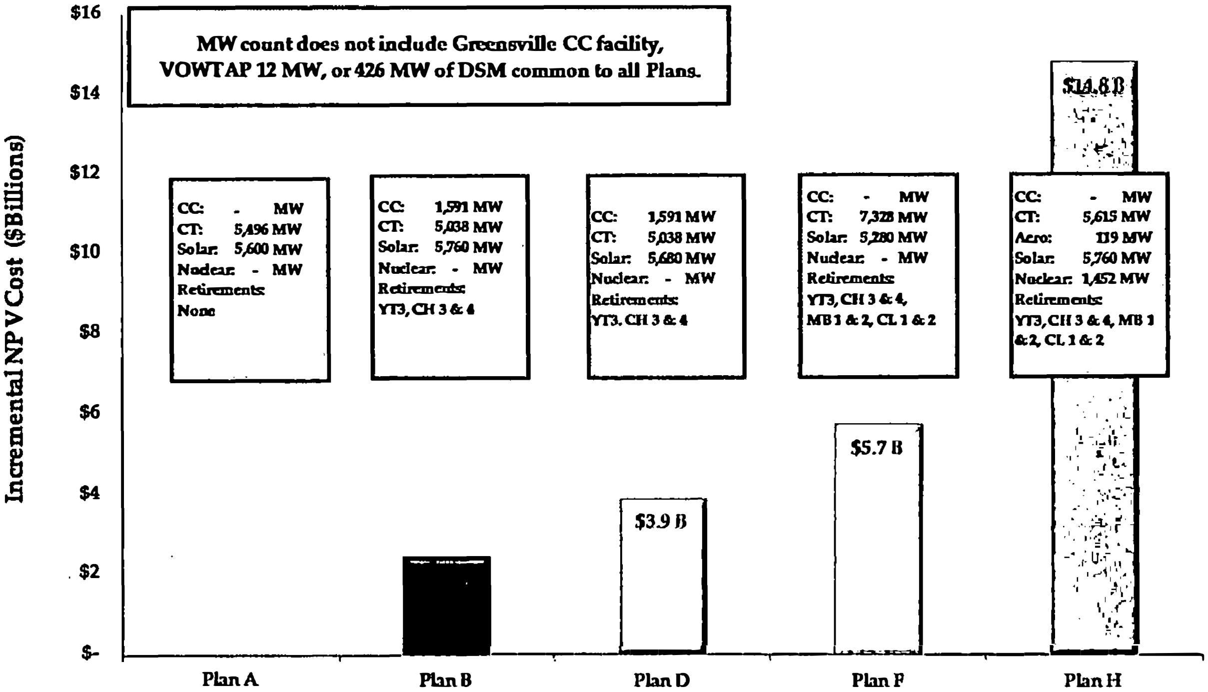
The Company evaluated the Alternative Plans using basecase assumptions to compare and contrast the NPV utility costs over the Study Period. Figure 6.5.1 illustrates the NPV CPP compliance cost for the Alternative Plans by showing the additional expenditures by the CPP-Compliant Plans over Plan A for the Study Period.

**Figure 6.5.1 – NPV CPP Compliance Cost of the Alternative Plans over Plan A**

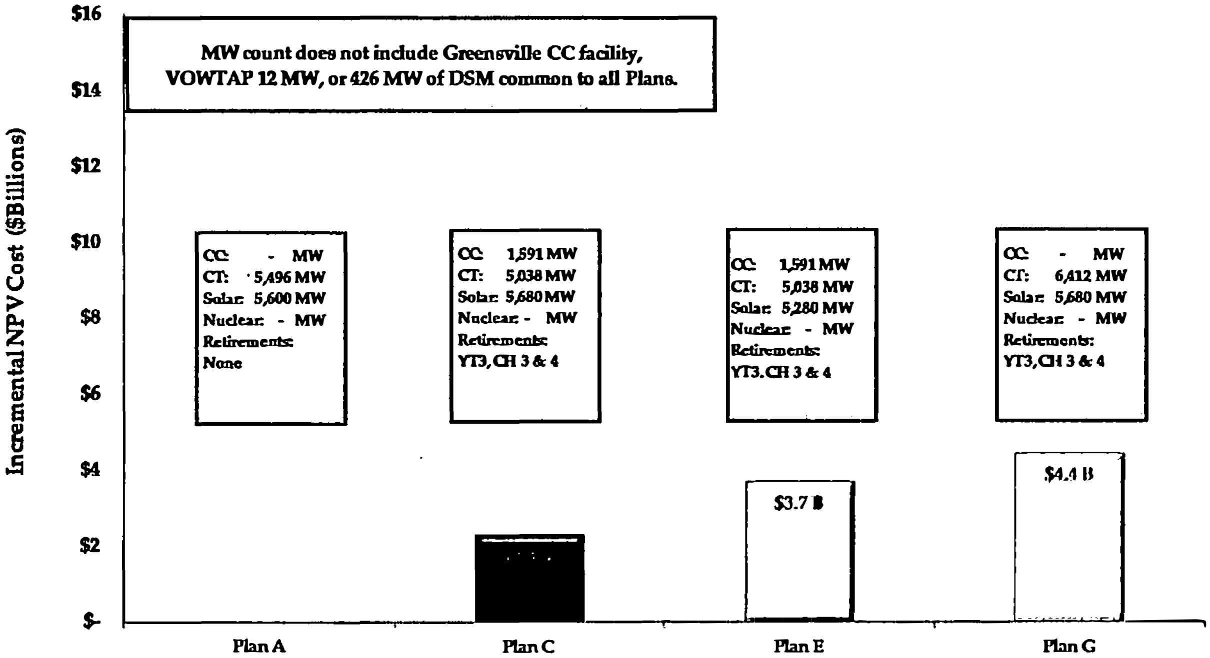
| | Subject to the EPA's Clean Power Plan | | | | | | |
|---|---|---|---|---|---|---|---|
| | Plan $B^{NT}$: Intensity-Based Dual Rate | Plan $C^{I}$: Intensity-Based Dual Rate | Plan $D^{NT}$: Mass-Based Existing Units | Plan $E^{I}$: Mass-Based Existing Units | Plan $F^{NT}$: Mass-Based All Units | Plan $G^{I}$: Mass-Based All Units | Plan $H^{NT}$: New Nuclear |
| NPV CPP Compliance Cost | $2.45B | $2.3B | $3.89B | $3.7B | $5.71B | $4.44B | $14.79B |

Figures 6.5.2 and 6.5.3 illustrate the incremental NPV CPP compliance cost for the Alternative Plans over Plan A for the Study Period for Scenario 1 (no $CO_2$ trading) and Scenario 2 ($CO_2$ trading), respectively.

## Figure 6.5.2 – Incremental NPV CPP Compliance Cost of the Alternative Plans (Scenario 1) over Plan A (2018 – 2042)




## Figure 6.5.3 – Incremental NPV CPP Compliance Cost of the Alternative Plans (Scenario 2) over Plan A (2018 – 2042)



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## 6.6 RATE IMPACT ANALYSIS

### 6.6.1 OVERVIEW

In its Final Order on the 2015 Plan (Case No. PUE-2015-00035), the SCC directed the Company to provide a calculation of the impact of each CPP program and the FIP on the electricity rates paid by the Company's customers. While, as noted earlier, the FIP has been withdrawn, to the best of the Company's knowledge, Intensity- and Mass-Based Existing Units programs represent a FIP.

### 6.6.2 ALTERNATIVE PLANS COMPARED TO PLAN A

The Company evaluated the residential rate impact of each CPP-Compliant Plan against Plan A. The results of this analysis are shown in Figures 6.6.2.1 and 6.6.2.2 which reflect both the dollar impact and percentage increase for a typical residential customer, using 1,000 kilowatt hour ("kWh") per month, each year starting in 2018 through 2042.

**Figure 6.6.2.1 – Monthly Rate Increase of Alternative Plans vs. Plan A ($)**

| | Increase Compared to Plan A: No $CO_2$ Limit ($) | | | | | | |
|---|---|---|---|---|---|---|---|
| | Plan $B^{NT}$: Intensity-Based Dual Rate | Plan $C^{T}$: Intensity-Based Dual Rate | Plan $D^{NT}$: Mass-Based Existing Units | Plan $E^{T}$: Mass-Based Existing Units | Plan $F^{NT}$: Mass-Based All Units | Plan $G^{T}$: Mass-Based All Units | Plan $H^{NT}$: New Nuclear |
| 2018 | 0.06 | 0.06 | 0.06 | 0.06 | 0.07 | 0.07 | 0.60 |
| 2019 | 0.32 | 0.32 | 0.32 | 0.32 | 0.38 | 0.38 | 1.18 |
| 2020 | 0.40 | 0.40 | 0.40 | 0.40 | 0.61 | 0.61 | 2.11 |
| 2021 | 0.40 | 0.40 | 0.39 | 0.40 | 0.84 | 0.84 | 3.87 |
| 2022 | 4.20 | 4.21 | 5.09 | 5.19 | 6.27 | 5.61 | 11.15 |
| 2023 | 2.61 | 2.63 | 3.53 | 3.62 | 3.71 | 3.15 | 11.92 |
| 2024 | 3.78 | 3.79 | 4.74 | 4.87 | 4.14 | 3.30 | 15.41 |
| 2025 | 3.14 | 3.16 | 4.16 | 4.24 | 9.34 | 3.17 | 24.12 |
| 2026 | 2.96 | 3.01 | 4.07 | 4.13 | 5.05 | 3.31 | 22.62 |
| 2027 | 2.77 | 2.87 | 4.04 | 4.07 | 4.72 | 3.33 | 24.71 |
| 2028 | 2.57 | 2.55 | 3.94 | 3.85 | 4.82 | 3.46 | 25.68 |
| 2029 | 2.91 | 2.27 | 3.85 | 3.72 | 5.30 | 3.59 | 26.15 |
| 2030 | 2.39 | 2.09 | 3.77 | 3.68 | 5.35 | 3.31 | 29.44 |
| 2031 | 2.39 | 2.61 | 3.96 | 3.85 | 5.59 | 3.83 | 28.81 |
| 2032 | 2.39 | 2.31 | 4.01 | 3.94 | 5.49 | 3.55 | 26.86 |
| 2033 | 1.89 | 1.85 | 3.63 | 3.59 | 5.60 | 4.02 | 26.13 |
| 2034 | 2.19 | 2.16 | 4.33 | 4.06 | 6.63 | 4.48 | 25.36 |
| 2035 | 2.72 | 2.67 | 5.06 | 4.72 | 7.02 | 4.67 | 24.47 |
| 2036 | 2.12 | 2.12 | 4.52 | 4.31 | 6.64 | 4.45 | 22.89 |
| 2037 | 2.18 | 2.22 | 4.62 | 4.31 | 6.78 | 5.23 | 22.53 |
| 2038 | 2.34 | 2.39 | 4.99 | 4.34 | 7.89 | 5.92 | 22.03 |
| 2039 | 2.54 | 2.74 | 5.62 | 4.40 | 8.62 | 6.20 | 21.44 |
| 2040 | 2.49 | 2.57 | 5.68 | 5.06 | 8.51 | 6.11 | 20.30 |
| 2041 | 2.31 | 2.44 | 5.70 | 5.26 | 8.50 | 6.67 | 19.77 |
| 2042 | 2.25 | 2.40 | 6.00 | 5.55 | 9.20 | 7.04 | 19.02 |

## Figure 6.6.2.2 – Monthly Rate Increase of Alternative Plans vs. Plan A (%)

| | Increase Compared to Plan A: No $CO_2$ Limit (%) | | | | | | |
|---|---|---|---|---|---|---|---|
| | Plan $B^{NT}$: Intensity-Based Dual Rate | Plan $C^{T}$: Intensity-Based Dual Rate | Plan $D^{NT}$: Mass-Based Existing Units | Plan $E^{T}$: Mass-Based Existing Units | Plan $F^{NT}$: Mass-Based All Units | Plan $G^{T}$: Mass-Based All Units | Plan $H^{NT}$: New Nuclear |
| 2018 | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.5% |
| 2019 | 0.3% | 0.3% | 0.3% | 0.3% | 0.3% | 0.3% | 1.0% |
| 2020 | 0.3% | 0.3% | 0.3% | 0.3% | 0.5% | 0.5% | 1.8% |
| 2021 | 0.3% | 0.3% | 0.3% | 0.3% | 0.7% | 0.7% | 3.3% |
| 2022 | 3.5% | 3.5% | 4.2% | 4.3% | 5.2% | 4.7% | 9.3% |
| 2023 | 2.1% | 2.2% | 2.9% | 3.0% | 3.0% | 2.6% | 9.8% |
| 2024 | 3.1% | 3.1% | 3.8% | 3.9% | 3.3% | 2.7% | 12.5% |
| 2025 | 2.5% | 2.5% | 3.3% | 3.4% | 7.5% | 2.5% | 19.3% |
| 2026 | 2.3% | 2.4% | 3.2% | 3.3% | 4.0% | 2.6% | 17.9% |
| 2027 | 2.2% | 2.2% | 3.1% | 3.2% | 3.7% | 2.6% | 19.2% |
| 2028 | 2.0% | 2.0% | 3.0% | 3.0% | 3.7% | 2.7% | 19.7% |
| 2029 | 2.2% | 1.7% | 2.9% | 2.8% | 4.0% | 2.7% | 19.9% |
| 2030 | 1.8% | 1.6% | 2.8% | 2.7% | 4.0% | 2.5% | 22.0% |
| 2031 | 1.8% | 1.9% | 2.9% | 2.8% | 4.1% | 2.8% | 21.3% |
| 2032 | 1.7% | 1.7% | 2.9% | 2.9% | 4.0% | 2.6% | 19.5% |
| 2033 | 1.3% | 1.3% | 2.6% | 2.5% | 4.0% | 2.9% | 18.6% |
| 2034 | 1.5% | 1.5% | 3.0% | 2.9% | 4.7% | 3.1% | 17.8% |
| 2035 | 1.9% | 1.9% | 3.5% | 3.3% | 4.9% | 3.3% | 17.2% |
| 2036 | 1.5% | 1.5% | 3.1% | 3.0% | 4.6% | 3.1% | 15.8% |
| 2037 | 1.5% | 1.5% | 3.2% | 2.9% | 4.6% | 3.6% | 15.4% |
| 2038 | 1.6% | 1.6% | 3.4% | 2.9% | 5.3% | 4.0% | 14.9% |
| 2039 | 1.7% | 1.8% | 3.8% | 2.9% | 5.8% | 4.1% | 14.3% |
| 2040 | 1.6% | 1.7% | 3.7% | 3.3% | 5.6% | 4.0% | 13.4% |
| 2041 | 1.5% | 1.6% | 3.7% | 3.5% | 5.6% | 4.4% | 13.0% |
| 2042 | 1.5% | 1.6% | 3.9% | 3.6% | 6.0% | 4.6% | 12.4% |

**Figure 6.6.2.3 – Residential Monthly Bill Increase for Scenario 1 for Alternative Plans as Compared to Plan A (%)**

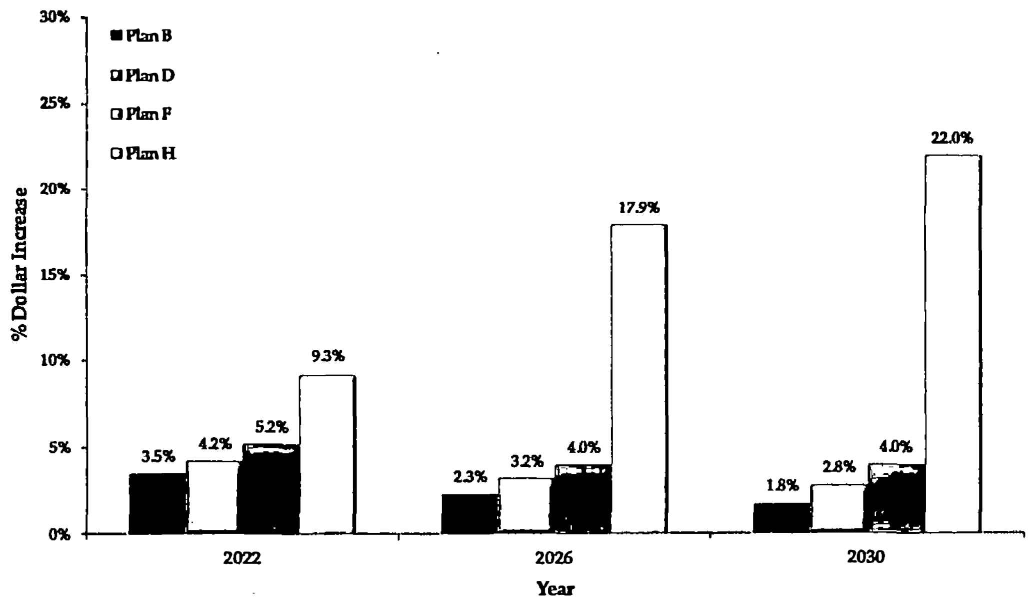


**Figure 6.6.2.4 – Residential Monthly Bill Increase for Scenario 1 for Alternative Plans as Compared to Plan A ($)**

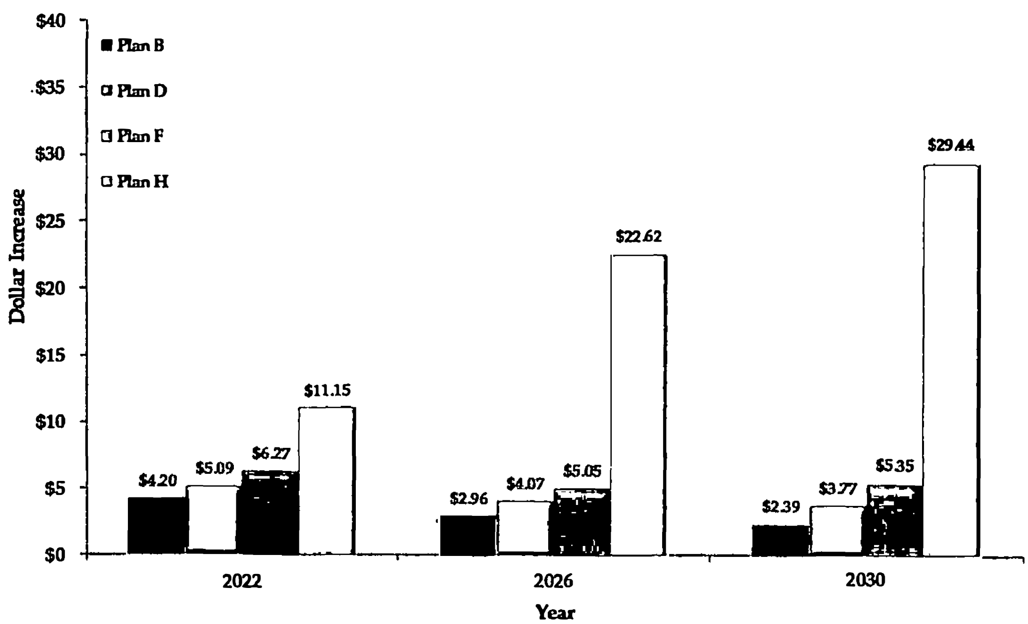

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**Figure 6.6.2.5 – Residential Monthly Bill Increase for Scenario 2 for Alternative Plans as Compared to Plan A (%)**

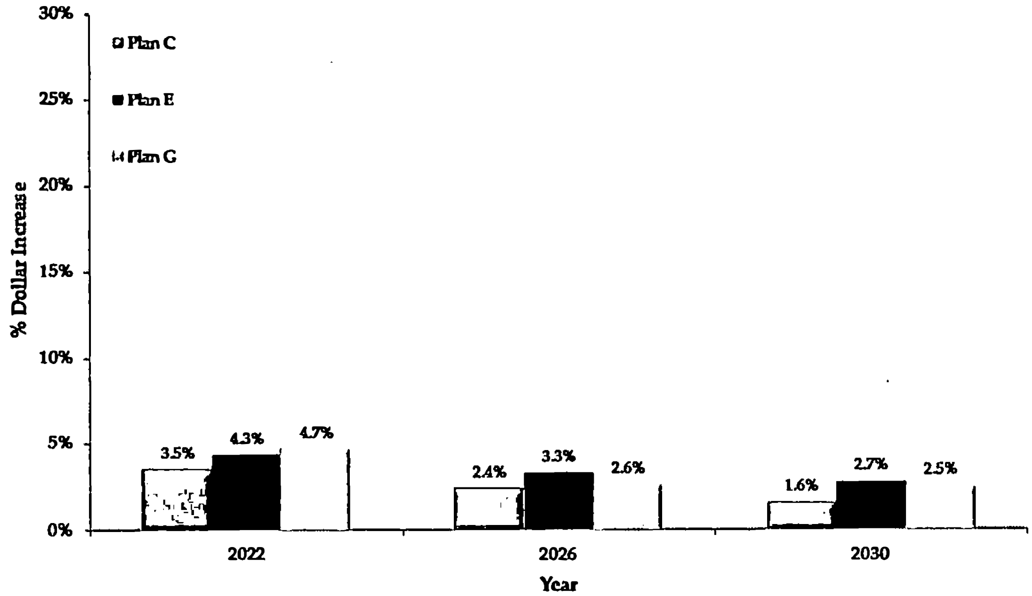


**Figure 6.6.2.6 – Residential Monthly Bill Increase for Scenario 2 for Alternative Plans as Compared to Plan A ($)**

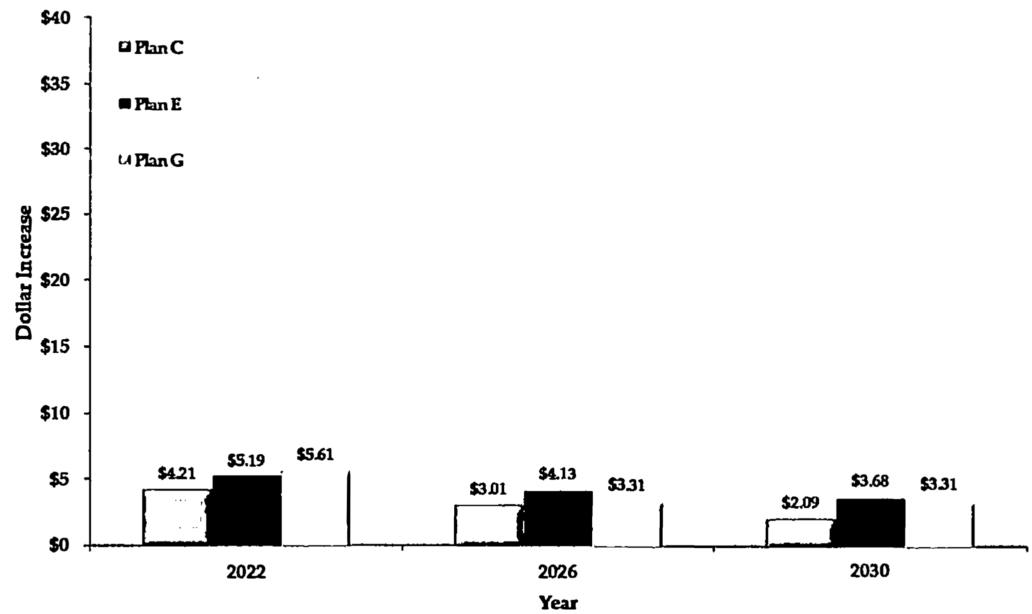

**Figure 6.6.2.7 – Residential Monthly Bill Increase for Alternative Plans as Compared to Plan A (%)**

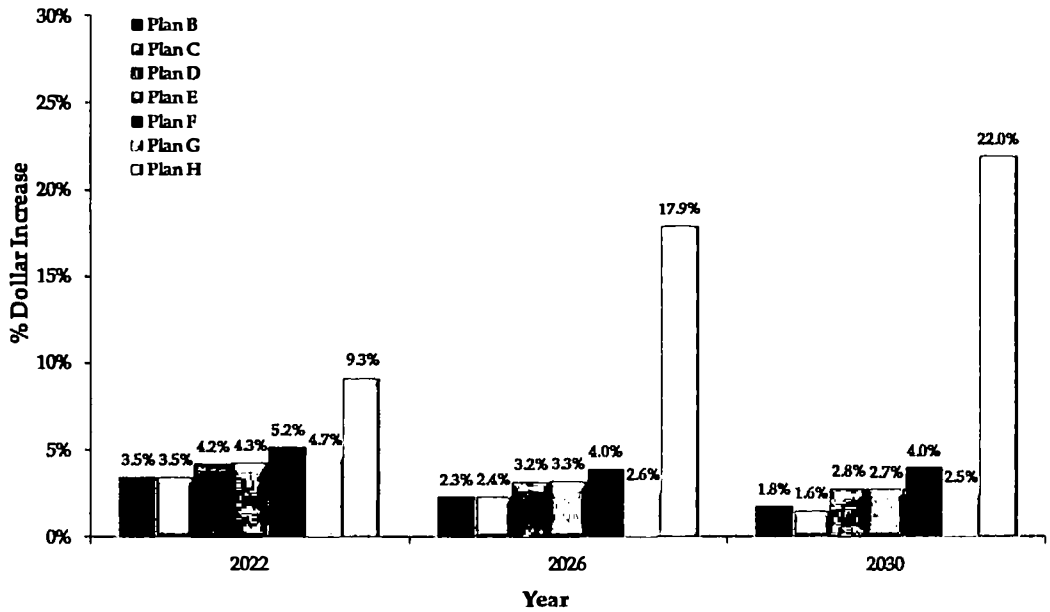


**Figure 6.6.2.8 – Residential Monthly Bill Increase for Alternative Plans as Compared to Plan A ($)**

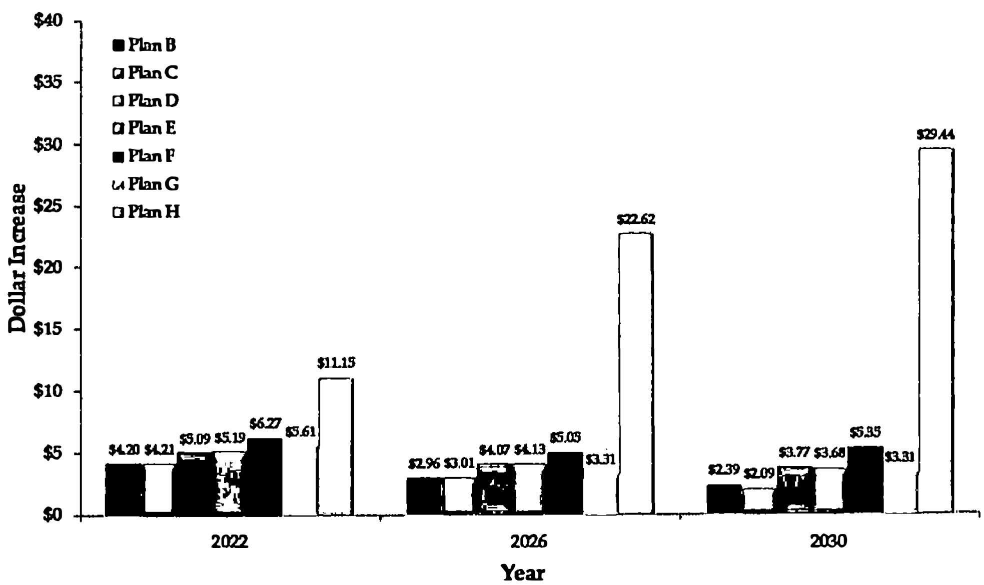

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**Figure 6.6.2.9 – Residential Monthly Bill Increase for CPP-Compliant Plans as Compared to Plan A (%)**

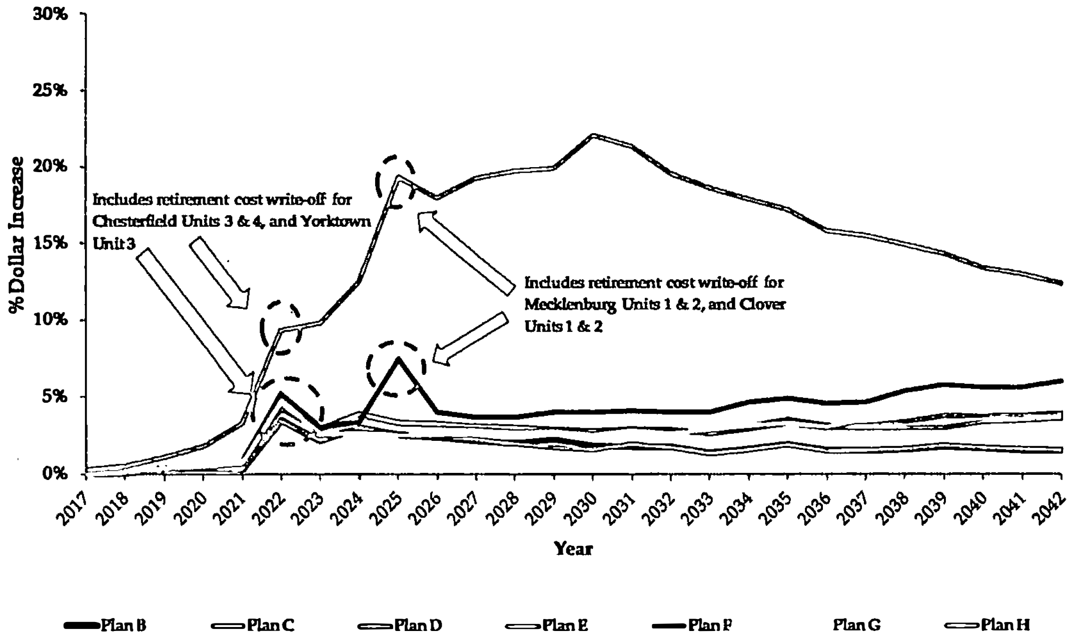
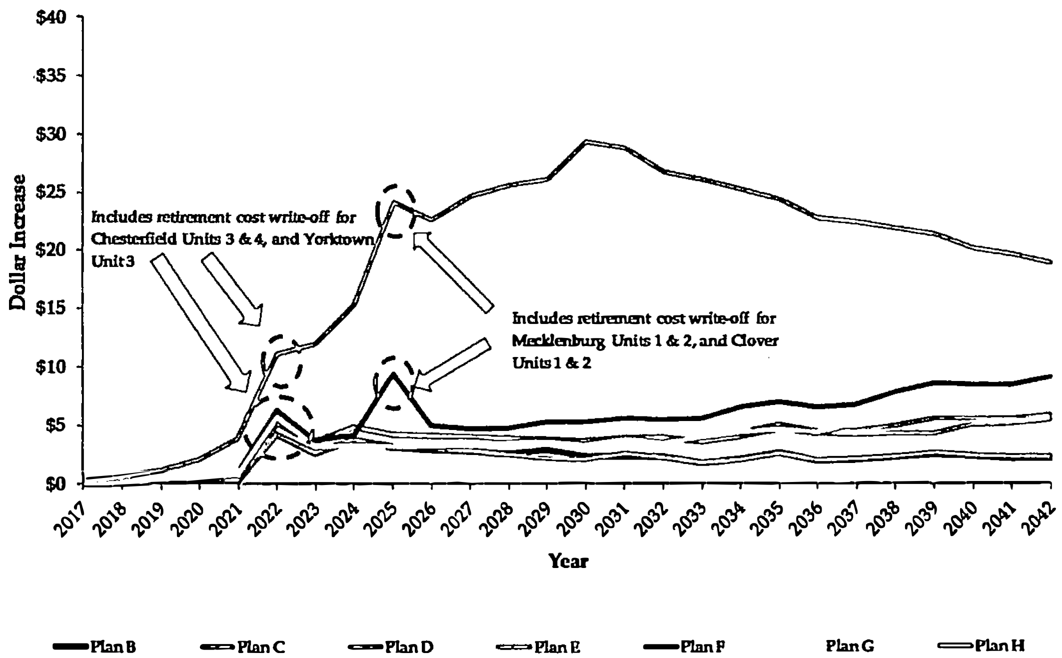



**Figure 6.6.2.10 – Residential Monthly Bill Increase for CPP-Compliant Plans as Compared to Plan A ($)**



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## 6.7 COMPREHENSIVE RISK ANALYSIS

### 6.7.1 OVERVIEW

Pursuant to the SCC's Final Order on the 2015 Plan (Case No. PUE-2015-00035) which directs the Company to "…continue to evaluate the risks associated with the plans that the Company prepares…" the Company is, in this 2017 Plan, including a comprehensive risk analysis methodology that was applied to the Alternative Plans presented in Section 6.4. Except for the inclusion of the additional key risk factors noted below, the Company utilized the same stochastic (probabilistic) methodology and supporting software developed by Pace Global (a Siemens business) and modifications to the AURORA multi-area production costing model (licensed from EPIS, Inc.) needed to reflect the final CPP regulations as in the 2016 Plan. Using this analytic and modeling framework (hereinafter referred to as the "Pace Global methodology"), the Alternative Plans, each treated as a fixed portfolio of existing and expansion resources plus demand-side measures, were evaluated and compared on the dimensions of average total production cost relative to two measures of cost-related risk, which are standard deviation cost and semi-standard deviation cost (further explained in Section 6.7.2).

The Pace Global methodology is an adaptation of Modern Portfolio Theory, which attempts to quantify the trade-off that usually exists between portfolio cost and portfolio risk that is not addressed in the traditional least-cost planning paradigm. Measuring the risk associated with proposed expansion plans quantifies, for example, whether adopting any one particular plan comes with greater cost and risk for customers when compared to the cost and risk for competing plans. In the same way, comparing plans with different capacity mixes, and consequently with different cost and risk profiles, potentially reveals the value of generation mix diversity. It is important to note that it is impractical to include all possible sources of risk in this assessment but only the most significant drivers to plan cost and variability.

Due to the significant proportion of new solar capacity in each of the Alternative Plans, variability in aggregate solar generation is now considered by the Company as an additional key portfolio risk factor. This risk principally reflects actual seasonal weather driven solar PV generation variance that has been historically observed from solar PV facilities currently interconnected to the Company's network.

At a high level, the Pace Global methodology is comprised of the following steps:

- Identify and create a stochastic model for each key source of portfolio risk which in this analysis are:
    - Natural gas prices;
    - Natural gas basis;
    - Coal prices;
    - Load (electricity demand);
    - Hourly solar generation;
    - $CO_2$ emission allowance prices/ERC prices; and
    - New generation capital cost.
- Generate a set of stochastic realizations for the key risk factors within the PJM region and over the Study Period using Monte-Carlo techniques. For purposes of this analysis, 200 stochastic realizations were produced for each of the key risk factors;

- Subject each of the Alternative Plans separately to this same set of stochastic risk factor outcomes by performing 200 AURORA multi-area model production cost simulations, which cover a significant part of the Eastern Interconnection, using the risk factor outcomes as inputs;
- The AURORA simulation results were then used to calculate the expected levelized all-in average cost and the associated risk measures for each of the Alternative Plans.

The following Alternative Plans were evaluated under the comprehensive risk analysis:

- Plan A: No CPP
- Plan $C^T$: Intensity-Based Dual Rate
- Plan $E^T$: Mass-Based Existing Units
- Plan $G^T$: Mass-Based All Units
- Plan $H^{NT}$: New Nuclear

Given that Plans $B^{NT}$, $D^{NT}$, and $F^{NT}$ are similar in design to their trading counterparts, the Company expects that the portfolio risk associated with these Plans will be similar.

**Clean Power Plan Risk Modeling Assumptions**

Each of the CPP-Compliant Plans were developed as the lowest cost means to comply with one of three corresponding CPP compliance options for the state of Virginia. In order to appropriately reflect the key features of the CPP in the risk simulations, the following general assumptions were implemented:

- With the exception of Virginia, the CPP compliance standards for each state within the simulation footprint, which included states within PJM and a significant portion of the U.S. Eastern Interconnection, were modeled according to the individual state compliance assumptions provided by ICF, as shown in Appendix 4A;

- The CPP compliance standard assumed for Virginia was consistent with the Alternative Plan being evaluated. In other words, for Mass-Based plans, the Virginia generation units in question were evaluated using appropriate $CO_2$ allowance prices. Likewise for Intensity-Based plans, the Virginia generation units in question were evaluated using the appropriate ERC prices.

- Plan A: No CPP was evaluated using a set of stochastic realizations that assumed no $CO_2$ regulations whatsoever. All other Plans evaluated in the comprehensive risk analysis were evaluated using stochastic realizations that assume a future CPP;

- Stochastic draws for carbon allowance prices were based on the annual expected prices in ICF's CPP commodity forecast (see Appendix 4A) and were applied to affected EGUs in any state, including Virginia under Plans $E^T$, $G^T$, and $H^{NT}$, that are assumed to adopt a Mass-Based compliance limit; and

- Risk scores included in the Portfolio Evaluation Scorecard for Scenario 1 (no $CO_2$ trading) Plans, detailed in Section 6.8, will correspond to the Scenario 2 ($CO_2$ trading) Plans evaluated in the process above.

Similar to the 2016 Plan, the cost and risk levels estimated for the Alternative Plans reflect not only the inherent characteristics of each Plan but also the effect of the particular Virginia CPP compliance option.

### 6.7.2 PORTFOLIO RISK ASSESSMENT

Upon completion of the AURORA simulations described above, post-processing of each Alternative Plan's annual average total (fixed plus variable) production costs proceeded in the following steps:

- For each of the 200 draws, the annual average total production costs are levelized over the 25-year Study Period using a nominal discount rate of 6.22%.
- The 200 levelized average total production costs values are then statistically summarized into:
    - **Expected value**: the arithmetic average value of the 200 draws.
    - **Standard deviation**: the square-root of the average of the squared differences between each draw's levelized value and the mean of all 200 levelized values. This is a standard measure of overall cost risk to the Company's customers.
    - **One way (upward) standard deviation (semi-standard deviation)**: the standard deviation of only those levelized average production costs which <u>exceed</u> the expected value (i.e., the mean of all 200 levelized values). This is a measure of adverse cost risk to the Company's customers.

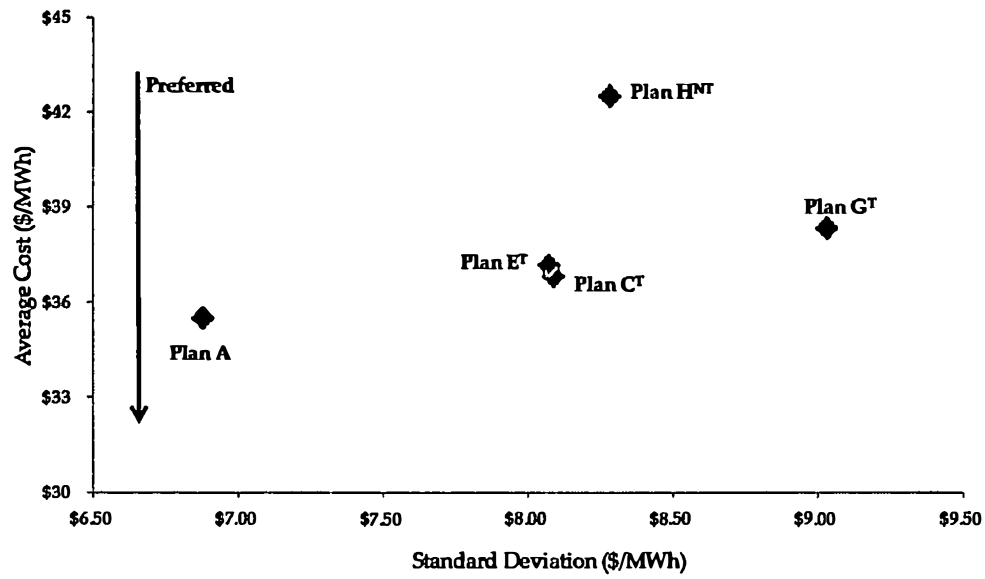
The resulting values are shown for the Alternative Plans in Figure 6.7.2.1 for comparative purposes. Plans with lower values for expected levelized average cost, standard deviation, and semi-standard deviation are more beneficial for customers.

**Figure 6.7.2.1 - Alternative Plan Portfolio Risk Assessment Results**

| 2017 $/MWh Plan | Expected Levelized Average Cost | Standard Deviation | Semi-Standard Deviation |
|---|---|---|---|
| Plan A: No CPP | $35.51 | $6.88 | $7.35 |
| Plan $C^{T}$: Intensity-Based Dual Rate | $36.81 | $8.09 | $9.88 |
| Plan $E^{T}$: Mass-Based Existing Units | $37.15 | $8.07 | $9.84 |
| Plan $G^{T}$: Mass-Based All Units | $38.31 | $9.03 | $11.29 |
| Plan $H^{NT}$: New Nuclear | $42.49 | $8.28 | $10.22 |

Plan A: No CPP, evaluated under the assumption of no regulation of carbon emissions in all states including Virginia, had the lowest levelized average cost and risk of all Alternative Plans. This result is expected given that Plan A was evaluated in a future that assumes no $CO_2$ regulation whatsoever, which includes lower fuel prices and lower fuel price volatility. Also, Plan A includes a significant level of solar PV generation which helps mitigate fuel and traditional emission price risk. Among all CPP-Compliant Plans under Scenario 2 ($CO_2$ trading), Plan $C^{T}$: Intensity-Based Dual Rate had the lowest expected cost and Plan $E^{T}$: Mass-Based Existing Units had the lowest risk based on the standard deviation. A visual display of average cost against risk as measured by standard deviation for the Alternative Plans is shown in Figure 6.7.2.2.

**Figure 6.7.2.2 – Alternative Plans Mean-Variance Plot**




### 6.7.3 INCLUSION OF THE DISCOUNT RATE AS A CRITERION IN RISK ANALYSIS

In the SCC's Final Order on the 2015 Plan (Case No. PUE-2015-00035), the Company was directed to "...include discount rate as a criterion in the Company's risk analysis..." As described in Section 6.4, each of the Alternative Plans was developed based on minimization of total NPV utility costs over the Study Period, subject to constraints, such as the reserve margin target, and CPP Intensity- or Mass-Based limits. The discount rate is a key parameter in the NPV calculation and plays an important role in computing the risk analysis results. To form a background for the subsequent discussion, the following points should be noted:

- The appropriate discount rate to evaluate alternative expansion plans is, in principle, from the standpoint of utility customers collectively, not the utility. While the customer discount rate is unobservable, it is a function of the opportunity costs facing utility consumers. This rate would be the same regardless of the expansion plan being evaluated. Absent knowledge of the customer discount rate, it is not unreasonable to use the utility discount rate as a proxy.
- In developing the Alternative Plans and in the comprehensive risk analysis, the discount rate used is the Company's five-year forecasted nominal after-tax weighted average cost of capital ("WACC"). This same discount rate is applied regardless of the expansion options under consideration. In this way, NPV costs are calculated on a consistent basis across all the Alternative Plans. Since risk simulation results are in nominal 2017 dollars, after-tax WACC is used to levelize the average production costs over the Study Period for each of 200 stochastic realizations.
- Capital revenue requirements projected for each generation expansion option include engineering, procurement, and construction ("EPC") costs, capitalized financing costs, and equity return incurred prior to commercial operation.

- The comprehensive risk analysis results include the effect of uncertainty in the levelized capital revenue requirements for each type of expansion option. The risk analysis assumed the greatest uncertainty was for new nuclear and offshore wind projects and the least uncertainty was for technologies for which there is a lower per project capital requirements and/or for which the Company has proven construction experience.

Inclusion of the discount rate as a risk criterion is advisable because expansion plans that include significantly large and risky future capital outlays imply that investors would require higher returns in compensation for the larger amount of capital at risk. It may also imply potentially significant changes in the Company's future capital structure because the appropriate discount rate would be higher than that for Plans comprised of less capital intensive or risky projects. Therefore, using a higher discount rate for such Plans would have the incorrect and implausible result of yielding lower expected NPV costs.

An alternative approach is to apply a risk-adjusted discount rate to the Plan that includes the high capital cost or high risk project. Determining the appropriate risk-adjustment to the discount rate is problematic and is not known by the Company. For the present purpose of including the discount rate as a criterion in the risk analysis, Figure 6.7.3.1 shows the results before and after a zero discount rate is applied to Plan $H^{NT}$: New Nuclear, which has the highest NPV cost of the Alternative Plans. Using a zero discount rate attributes the maximum possible degree of risk adjustment to the discount rate for this Plan and therefore provides an upper bound for such risk-adjusted discounting.

**Figure 6.7.3.1 – Plan $H^{NT}$: New Nuclear Risk Assessment Results**

| Plan | Levelized Average Cost | Standard Deviation | Semi-Standard Deviation |
|---|---|---|---|
| Plan $H^{NT}$: New Nuclear - not risk adjusted | $42.49 | $8.28 | $10.22 |
| Plan $H^{NT}$: New Nuclear - risk adjusted | $52.69 | $11.67 | $14.81 |

It is evident that on a risk-adjusted basis, Plan $H^{NT}$: New Nuclear still has the largest expected average production cost, but now also has the largest risk measured by both standard deviation and semi-standard deviation among all Alternative Plans.

### 6.7.4 IDENTIFICATION OF LEVELS OF NATURAL GAS GENERATION WITH EXCESSIVE COST RISKS

In the SCC's Final Order on the 2015 Plan (Case No. PUE-2015-00035), the Company was directed to "...specifically identify the levels of natural gas-fired generation where operating cost risks may become excessive or provide a detailed explanation as to why such a calculation cannot be made..." In this 2017 Plan, the Company is presenting the Alternative Plans, each of which, with the exception of Plan A: No CPP, was developed to comply on a standalone basis with one of three possible alternatives for Virginia under the CPP. The results of the comprehensive risk analysis reflect the expected cost and estimated risk associated with each Plan in the context of a particular mode of CPP compliance for Virginia. In developing each of the Alternative Plans, the criterion used was minimization (subject to constraints) of NPV costs without considering the associated level of risk.

Alternative Plan risk levels were assessed only after it was determined to be the lowest cost from among all feasible candidate plans. To have developed the Alternative Plans considering both cost and risk jointly as a criterion would have required the following:

- The expansion planning process would have to determine the "efficient frontier" from among all feasible candidate plans. The efficient frontier identifies a range of feasible plans each with the lowest level of risk for its given level of expected cost. Identifying the efficient frontier is not practical using traditional utility planning software and computing resources. If the efficient frontier could be determined, then any candidate plan with risk levels higher than the efficient frontier could reasonably be characterized as having excess risk in the sense that there exists a plan on the efficient frontier with the same expected cost but with lower risk.
- The Company would need to know the "mean-variance utility function" (i.e., the risk aversion coefficient) of its customers collectively in order to select the feasible plan that optimally trades off cost and risk from among competing plans. This function could be applied regardless of whether it is possible to determine the efficient frontier. However, this function is <u>not</u> known and planners are thus unable to determine levels of plan risk that are unacceptable or become excessive for customers.

In the absence of these risk evaluation tools, it is technically not possible to determine an absolute level of plan risk that becomes excessive, much less to determine that level of gas-fired generation within a plan that poses excessive cost risk for customers. Moreover, the absolute level of natural gas generation within a plan does not necessarily lead to greater risk but rather, all else being equal, it is the degree of overall supply diversity that drives production cost risk.

Since the notion of excessive risk is inherently a relative rather than absolute notion, Company planners can apply a ranked preference approach whereby a plan is preferred if its expected cost and measured risk are both less than the corresponding values of any competing plan. The ranked preference approach, when it can be applied, does not need to rely on a definition of excessive risk, but only on the principle that customers should prefer a plan that is simultaneously lowest in cost and in risk among competing plans. Thus, for example, the results of the comprehensive risk analysis show that Plan A: No CPP has the lowest expected cost and risk than any of the other Alternative Plans. However, Plan A is not a CPP-Compliant Plan and may not be preferred on grounds unrelated to risk. On the other hand, comparing Plan $C^T$: Intensity-Based Dual Rate with Plan $E^T$: Mass-Based Existing Units shows that Plan $E^T$ has somewhat lower risk than Plan $C^T$, but with a slightly higher expected cost. In this case, which of the two Plans should be preferred is not clear. The planner could apply, if known, a customer risk aversion coefficient (a mean-variance utility function) to ultimately determine which Plan is preferable. In the absence of this coefficient, however, it can be reasonably assumed that Plan $C^T$ would be preferable because it is lower cost with approximately the same level of risk. Still, it is important to note that the Company does not rely solely on the comprehensive risk analysis in its summary scoring of the Alternative Plans. Rather, each Plan's measured risk (standard deviation) is entered as one dimension of the Portfolio Evaluation Scorecard presented in Section 6.8.

### 6.7.5 OPERATING COST RISK ASSESSMENT

The Company analyzed ways to mitigate operating cost risk associated with natural gas-fired generation by use of long-term supply contracts that lock in a stable price, long-term investment in gas reserves, securing long-term firm transportation, and on-site liquefied natural gas storage.

#### Supply Contract/Investment in Gas Reserves

For the purpose of analyzing long-term supply contracts and long-term investments in gas reserves, the Company utilized the stochastic analysis to determine the reduction in volatility that can be achieved by stabilizing prices on various volumes of natural gas. The expected price of natural gas as determined by the stochastic analysis is utilized to stabilize market price for this analysis. To analyze operating cost risk of such price stabilizing arrangements the price of natural gas is "fixed" at the expected value prices for a portion of the total fueling needs. The evaluation measures the reduction in plan risk by comparing the standard deviation between a plan with various quantities of "fixed" price natural gas and the same plan without "fixed" price natural gas. This methodology is representative of measuring the impact a long-term supply contract and/or long-term investment in gas reserves on overall plan risk. In either case, the actions would simulate committing to the purchase of natural gas supply over a long term at prevailing market prices at the time of the transaction. The primary benefit of such a strategy is to stabilize fuel prices, not to ensure below-market prices. Figures 6.7.5.1 – 6.7.5.4 indicate the reduction in portfolio risk associated with various quantities of natural gas at fixed price contracts or a natural gas reserve investment.

**Figure 6.7.5.1 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – No Natural Gas at Fixed Price**

| No Natural Gas At Fixed Price | | | |
|---|---|---|---|
| 2017 $/MWh Plan | Expected Levelized Average Cost | Standard Deviation | Semi-Standard Deviation |
| Plan A: No CPP | $35.51 | $6.88 | $7.35 |
| Plan $C^{T}$: Intensity-Based Dual Rate | $36.81 | $8.09 | $9.88 |
| Plan $E^{T}$: Mass-Based Existing Units | $37.15 | $8.07 | $9.84 |
| Plan $G^{T}$: Mass-Based All Units | $38.31 | $9.03 | $11.29 |
| Plan $H^{NT}$: New Nuclear | $42.49 | $8.28 | $10.22 |

**Figure 6.7.5.2 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 10% of Natural Gas at Fixed Price**

| 10% of Natural Gas At Fixed Price | | | | |
|---|---|---|---|---|
| 2017 $/MWh Plan | Expected Levelized Average Cost | Standard Deviation | Semi-Standard Deviation | % Reduction in Standard Deviation |
| Plan A: No CPP | $35.56 | $6.23 | $6.64 | 9.4% |
| Plan $C^{T}$: Intensity-Based Dual Rate | $36.88 | $7.25 | $8.79 | 10.4% |
| Plan $E^{T}$: Mass-Based Existing Units | $37.21 | $7.26 | $8.78 | 10.1% |
| Plan $G^{T}$: Mass-Based All Units | $38.36 | $8.43 | $10.58 | 6.7% |
| Plan $H^{NT}$: New Nuclear | $42.53 | $7.72 | $9.63 | 6.9% |

## Figure 6.7.5.3 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 20% of Natural Gas at Fixed Price

| 2017 $/MWh Plan | 20% of Natural Gas At Fixed Price Expected Levelized Average Cost | Standard Deviation | Semi-Standard Deviation | % Reduction in Standard Deviation |
|---|---|---|---|---|
| Plan A: No CPP | $35.68 | $5.60 | $5.93 | 18.7% |
| Plan $C^T$: Intensity-Based Dual Rate | $37.04 | $6.42 | $7.68 | 20.7% |
| Plan $E^T$: Mass-Based Existing Units | $37.37 | $6.46 | $7.75 | 20.0% |
| Plan $G^T$: Mass-Based All Units | $38.47 | $7.84 | $9.85 | 13.2% |
| Plan $H^{NT}$: New Nuclear | $42.65 | $7.17 | $9.13 | 13.5% |

## Figure 6.7.5.4 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 30% of Natural Gas at Fixed Price

| 2017 $/MWh Plan | 30% of Natural Gas At Fixed Price Expected Levelized Average Cost | Standard Deviation | Semi-Standard Deviation | % Reduction in Standard Deviation |
|---|---|---|---|---|
| Plan A: No CPP | $35.89 | $4.98 | $5.28 | 27.6% |
| Plan $C^T$: Intensity-Based Dual Rate | $37.31 | $5.60 | $6.70 | 30.8% |
| Plan $E^T$: Mass-Based Existing Units | $37.62 | $5.67 | $6.80 | 29.8% |
| Plan $G^T$: Mass-Based All Units | $38.66 | $7.28 | $9.21 | 19.4% |
| Plan $H^{NT}$: New Nuclear | $42.82 | $6.65 | $8.56 | 19.7% |

Note: Base volume and fixed market prices established from expected case results of stochastic analysis. Percent reduction in standard deviation relative to Figure 6.7.5.1 – No Gas at Fixed Price analysis.

Included in the analysis of cost and risk mitigation effects of the long-term contracts or reserve investment is an estimate of the price impact the purchase of a large volume of natural gas would have on the market. The cost of such a transaction used in this analysis are representative of the impact on upward price movement that is likely to occur in the market for natural gas with the purchase of a significant quantity of gas on a long-term basis. The market impact of transacting significant volumes on a long-term contract is a function of the amount of time required to execute the contract volume and the price impact/potential movement of the price strip contract during the execution time. The cost of executing a contract of this type is estimated using the price of gas, the daily volatility of the five-year price strip, and the number of days needed to procure the volume. The larger the volume, the longer it takes to execute the transaction, which exposes the total transaction volume to market volatility for a longer period of time and thereby increases the potential for increased cost associated with the transaction. The estimated cost adders included in the analysis are summarized in Figure 6.7.5.5.

## Figure 6.7.5.5 – Cost Adders for a Fixed Price Natural Gas Long-Term Contract ($/mmbtu)

| | | Yearly Volume (Bcf) | | | |
|---|---|---|---|---|---|
| | | 25 | 50 | 75 | 100 |
| Gas Price | $3.00 | $0.09 | $0.14 | $0.20 | $0.25 |
| | $5.00 | $0.12 | $0.21 | $0.31 | $0.40 |
| | $7.00 | $0.16 | $0.29 | $0.42 | $0.55 |

The analyzed volumes will have an impact on forward market prices; as such, the Company considers it prudent to include an estimate of the impact of transactions involving large volumes of natural gas on the gas price as a cost adder in this analysis and recognizes the actual impact may be higher or lower than estimated. These costs are presented as representative based on assumptions determined from current market conditions. The salient value to these estimates is the inclusion of estimated market impact verses assuming the transactions can be conducted with no market price impact.

The primary benefit of such a strategy is to mitigate fuel price volatility, not to ensure below market prices. Stable natural gas pricing over the long term does have advantages in terms of rate stability but also carries the risk of higher fuel cost should the market move against the stabilized price. Figures 6.7.5.6 and 6.7.5.7 provide a hypothetical example of stabilizing natural gas price at prevailing market prices available in February of 2011 and February 2012. In this simplified example the assumption is a total fuel volume of 100 million cubic feet ("mmcf") per day is needed for the entire period. The analysis then evaluates the impact of stabilizing the natural gas price, (February 1, 2011 and 2012 forward curve), for 20% of the volume against allowing the total volume to be priced at daily market prices. The key parameter is the cumulative difference between programs that stabilize the price of 20% of the natural gas volume while purchasing 80% of the volume at daily market prices versus purchasing all the natural gas at daily market prices for the entire term. In these examples, the cumulative cost of the natural gas purchased by the 20% fixed cost program are higher by 5% to 13% depending on when the contract was established. These examples indicate that although the use of long-term contracts or reserve investments provides an effective method for mitigating fuel prices volatility, it does not ensure lower fuel cost to the customer.

**Figure 6.7.5.6 – Hypothetical Example of the Cost of Purchasing 100 mmcf/d of Natural Gas**

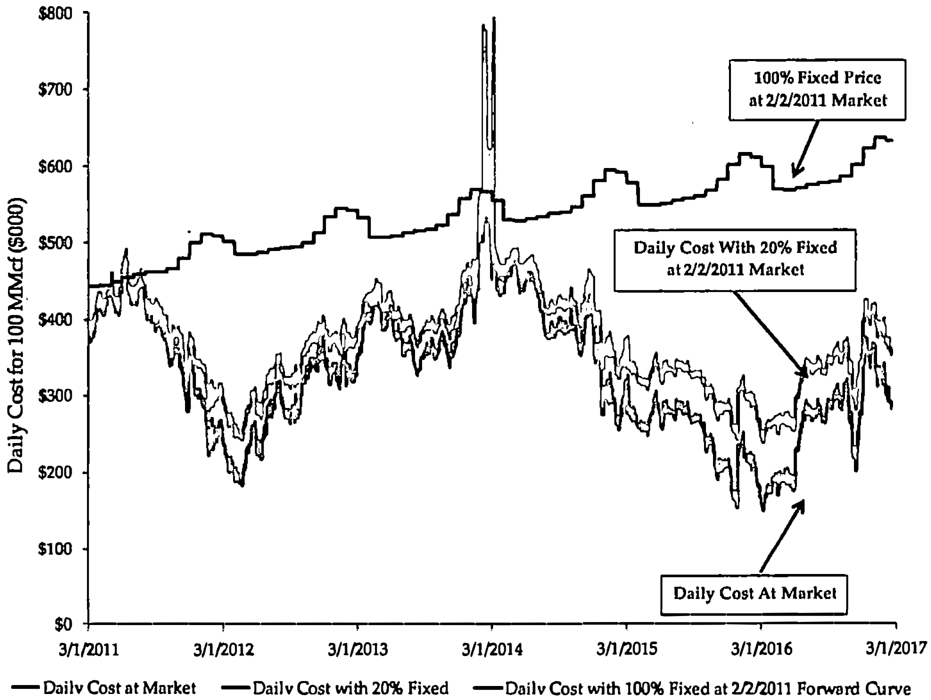
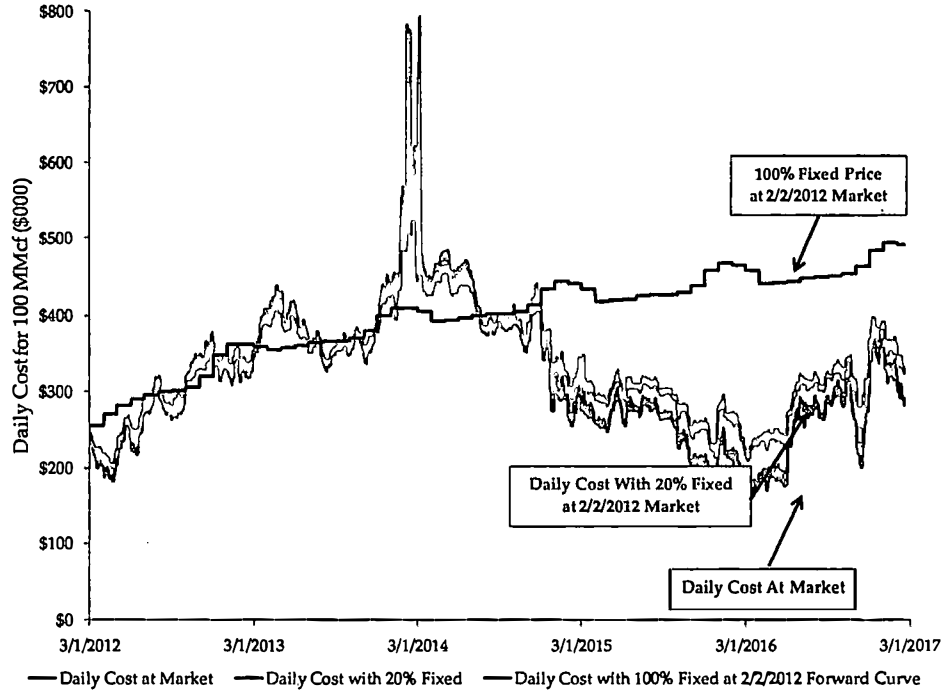


**Figure 6.7.5.7 – Hypothetical Example of the Cost of Purchasing 100 mmcf/d of Natural Gas**




## Firm Transportation

To evaluate the risk mitigation impact of securing long-term firm transportation, historic prices were analyzed at two natural gas supply basin trading hubs, Henry Hub and South Point, and at a natural gas trading hub representative of the Company's service territory, Transco Zone 5. The risk mitigation impact is a function of the difference in volatility between various natural gas trading hubs. Pipeline constraints can limit the ability of the pipeline network to move natural gas from supply basins to the market area. These constraints, coupled with weather-driven demand, have historically resulted in significant location specific price volatility for natural gas. Long-term transportation contracts to various supply basin trading hubs affords the opportunity to mitigate location specific volatility risk by having the option to purchase natural gas at trading hubs that have less volatile pricing characteristics. Figure 6.7.5.8 shows the location of key natural gas trading hubs. Figures 6.7.5.9 – 6.7.5.11 illustrate the historic price variations (2009 – 2016) for natural gas at three trading hubs. The shaded area of the graphs indicates one standard deviation of pricing history for each year, meaning that 68% of all daily prices for each year fall within the shaded area. As can be seen in these figures, the historic variations in price differ between the three trading hubs with Transco Zone 5 having a higher variation in natural gas prices than the two trading hubs located in supply basins. Based on historic pricing patterns this would indicate a long-term transportation contract to either Henry Hub or South Point would provide the opportunity to purchase natural gas at a trading hub which has historically experienced less short-term variations in price.

**Figure 6.7.5.8 – Map of Key Natural Gas Pipelines and Trading Hubs**

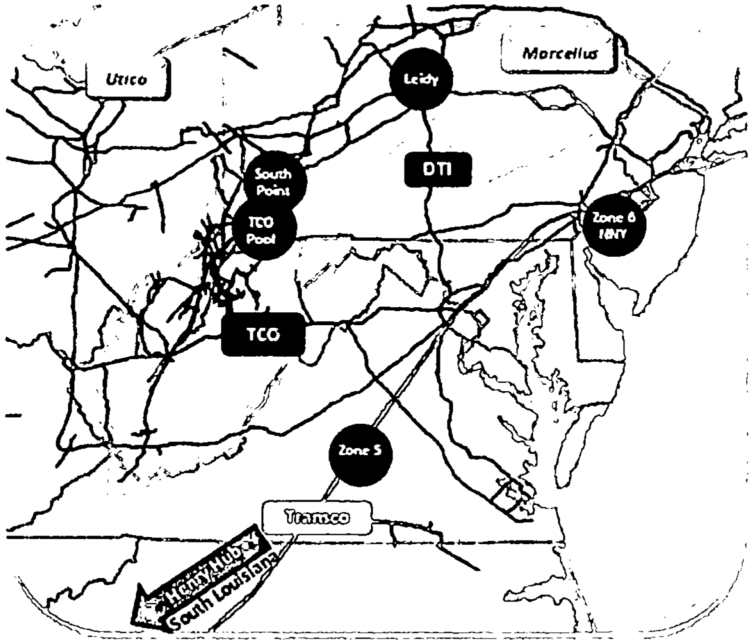
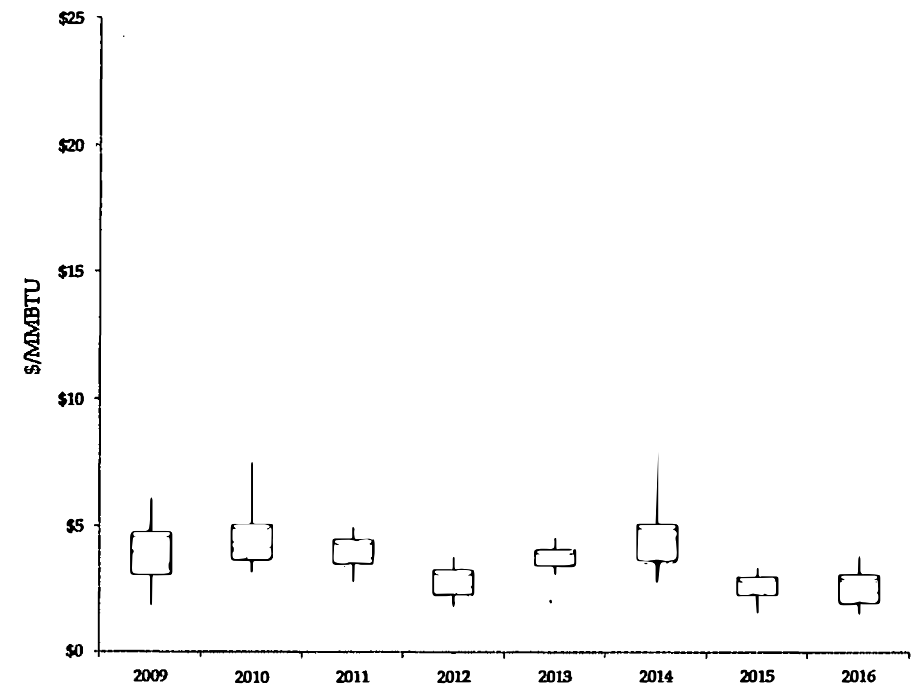



**Figure 6.7.5.9 – Natural Gas Daily Average Price Ranges – Henry Hub**




Note: A larger box indicates greater price volatility than a smaller box.

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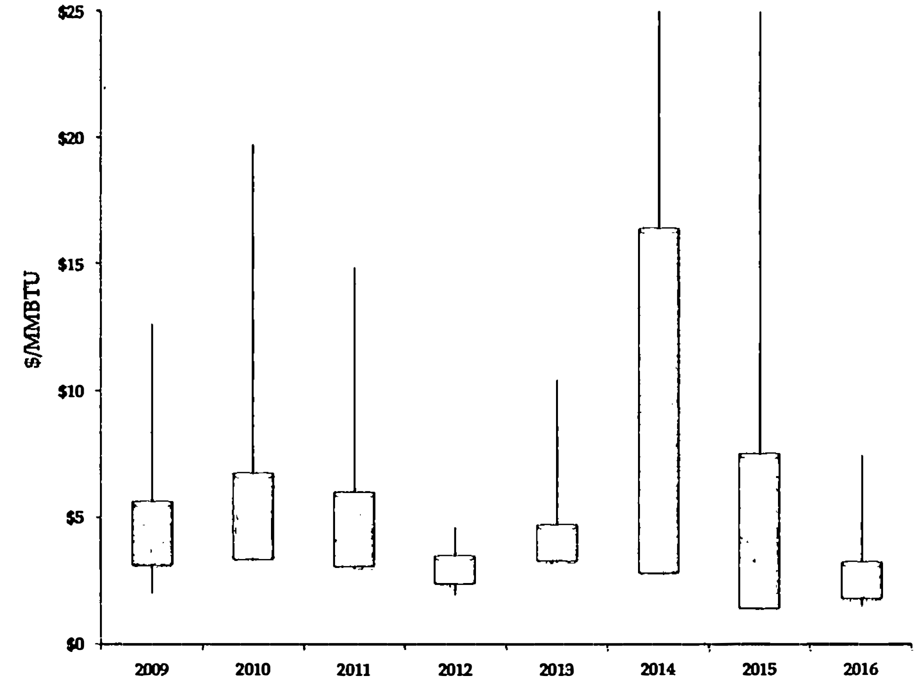
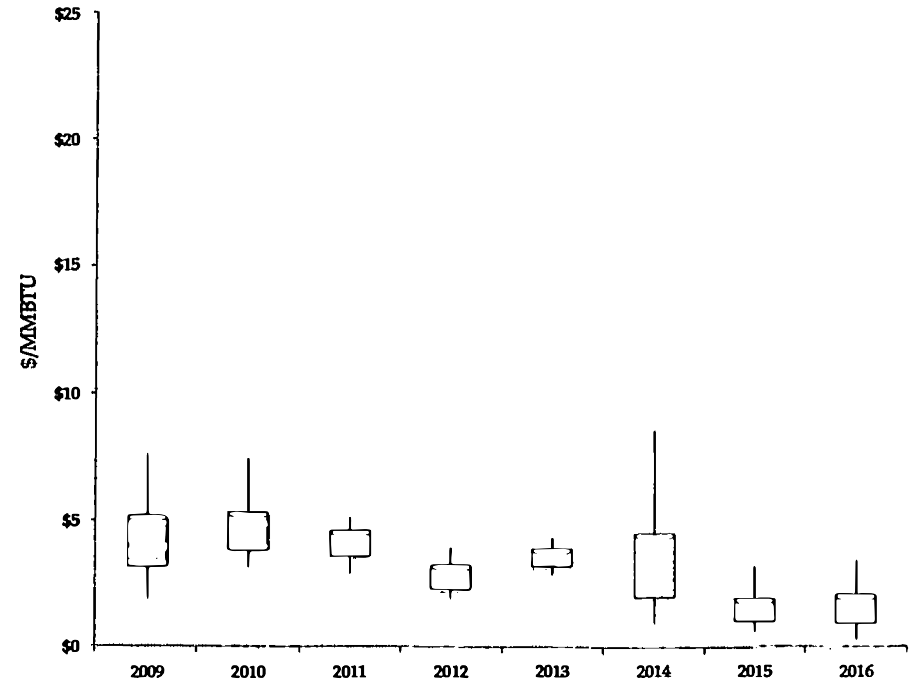
## Figure 6.7.5.10 – Natural Gas Daily Average Price Ranges – Transco Zone 5




Note: A larger box indicates greater price volatility than a smaller box.

## Figure 6.7.5.11 – Natural Gas Daily Average Price Ranges – South Point




Note: A larger box indicates greater price volatility than a smaller box.

### On-site Liquid Natural Gas Storage

On-site Liquid Natural Gas ("LNG") storage provides short periods of plant fueling and requires long refill times. It also serves as a backup fueling arrangement capable of mitigating risk associated with a system-wide pipeline disruption scenario, while providing an option that has operating characteristics similar to natural gas. However, this type of fueling arrangement provides limited operating cost risk mitigation. The natural gas required to fill LNG storage would be supplied using natural gas purchased at market prices with limited assurance price would be lower during the refill process than when used as a fueling source. LNG storage capacity would generally be large enough to fuel a plant for several days, while taking several months to refill the storage. This provides limited fuel price risk mitigation as the fueling cost for the plant remains exposed to gas market price variability with the exception of the few days the plant can operate on the LNG stored on site.

### Risk Mitigation of Gas Generation Displaced by North Anna 3

The Company analyzed the cost of mitigating risk associated with the share of natural gas-fired generation that is equivalent to the amount the Company expects would be displaced by the construction of North Anna 3.

As shown in Figure 6.5.2, compliance under Plan $H^{NT}$: New Nuclear is the highest cost alternative of the Alternative Plans. Plan $H^{NT}$ includes 5,760 MW of solar generation by 2042, and models the potential retirement of a significant percentage of the Company's Virginia coal generation fleet. In order to evaluate the risk mitigation associated with replacing North Anna 3 with natural gas-fired generation, stochastic simulations of a test case were performed where North Anna 3 was replaced with natural gas-fired generation. An analysis of the 200 test case simulations resulted in a higher overall risk than the North Anna 3 compliance scenario, as shown in Figure 6.7.5.12. The higher risk of the test case may be mitigated to a level nearly equal to the North Anna 3 plan by price hedging approximately 16% of the natural gas burned by the Company's generation portfolio.

**Figure 6.7.5.12 – Risk Assessment of Gas Generation Replacing North Anna 3**

| | Total Plan Standard Deviation ($/MWh) |
|---|---|
| Plan $H^{NT}$: New Nuclear | $8.28 |
| Test Case Gas Only | $9.38 |

Note: Higher standard deviation indicative of higher operating risk.

## 6.8 PORTFOLIO EVALUATION SCORECARD

As discussed in Section 6.1, the Company developed a Portfolio Evaluation Scorecard to provide a quantitative and qualitative measurement system to further examine the Alternative Plans compared to Plan A. This analysis combines the results of the PLEXOS NPV cost results with other assessment criteria.

A brief description of each assessment criteria follows:

### Total Cost

This assessment criterion evaluates the Alternative Plans according to the results of the PLEXOS NPV analysis given the applicable assumptions. Of the Alternative Plans, the lowest NPV cost is assessed the highest score, while the highest cost is assessed the lowest score. As mentioned above, Alternative Plans $B^{NT}$, $D^{NT}$, and $F^{NT}$ were not evaluated as part of comprehensive risk analysis and, thus, do not have a risk score. Because the portfolio designs are similar, the Company expects that the risk score of these Plans $B^{NT}$, $D^{NT}$, and $F^{NT}$ would be similar to the risk score of Plans $C^{T}$, $E^{T}$, and $G^{T}$, respectively. Therefore, for purposes of this assessment, Plan $B^{NT}$ was given a risk score equal to Plan $C^{T}$; Plan $D^{NT}$ was given a risk score equal to Plan $E^{T}$; and Plan $F^{NT}$ was given a risk score equal to Plan $G^{T}$.

### Portfolio Risk

This metric reflects the results of the comprehensive risk analysis using the standard deviation metric. This metric represents the standard deviation in the average energy costs ($/MWh) for each of the Alternative Plans and provides a measure of portfolio risk. The Alternative Plan with the lowest standard deviation is assessed the highest score, while the Plan with the highest standard deviation is given the lowest score.

### Capital Investment Concentration

Portfolios that include disproportionate capital expenditures on any single generating unit or facility could increase financial risk to the Company and its customers. In this category, the Alternative Plan that includes the lowest ratio of a single generating unit or facility's capital spend as compared to the Company's current rate base (approximately $22 billion) will be given the highest score, while the Alternative Plan that includes the highest ratio will be given the lowest score.

**Figure 6.8.1 – Portfolio Evaluation Scorecard**

| Portfolio | Total Cost Delta[1] | Portfolio Risk[2] | Capital Investment Concentration |
|---|---|---|---|
| Plan A: No CPP | $0.00 | $6.88 | 3.2% |
| Plan $B^{NT}$: Intensity-Based Dual Rate | $2.45 | $8.09 | 6.5% |
| Plan $C^{T}$: Intensity-Based Dual Rate | $2.30 | $8.09 | 6.5% |
| Plan $D^{NT}$: Mass-Based Existing Units | $3.89 | $8.07 | 6.5% |
| Plan $E^{T}$: Mass-Based Existing Units | $3.70 | $8.07 | 6.5% |
| Plan $F^{NT}$: Mass-Based All Units | $5.71 | $9.03 | 3.2% |
| Plan $G^{T}$: Mass-Based All Units | $4.44 | $9.03 | 3.2% |
| Plan $H^{NT}$: New Nuclear | $14.79 | $8.28 | 56.8% |

Note: Trading and Non-Trading Plans for each CPP Program are assumed to have the same Portfolio Risk due to AURORA modeling limitations.

1) Total Cost Delta is measured in billions of dollars versus Plan A: No CPP.

2) Portfolio Risk scores are in $/MWh.

**Figure 6.8.2 – Portfolio Evaluation Scorecard with Scores**

| Portfolio | Total Cost | Portfolio Risk | Capital Investment Concentration | Total Score | Rank |
|---|---|---|---|---|---|
| Plan A: No CPP | 8.00 | 8.00 | 8.00 | 8.00 | 1 |
| Plan $B^{NT}$: Intensity-Based Dual Rate | 6.00 | 5.00 | 5.00 | 5.60 | 3 |
| Plan $C^{T}$: Intensity-Based Dual Rate | 7.00 | 5.00 | 5.00 | 6.20 | 2 |
| Plan $D^{NT}$: Mass-Based Existing Units | 4.00 | 7.00 | 5.00 | 4.90 | 5 |
| Plan $E^{T}$: Mass-Based Existing Units | 5.00 | 7.00 | 5.00 | 5.50 | 4 |
| Plan $F^{NT}$: Mass-Based All Units | 2.00 | 1.00 | 8.00 | 2.65 | 7 |
| Plan $G^{T}$: Mass-Based All Units | 3.00 | 1.00 | 8.00 | 3.25 | 6 |
| Plan $H^{NT}$: New Nuclear | 1.00 | 3.00 | 1.00 | 1.50 | 8 |

Note: Total Cost, Portfolio Risk, and Capital Concentration scores vary from 1 (low) to 8 (high).

Each Alternative Plan was weighed based on 60% Total Cost, 25% Portfolio Risk, and 15% Capital Investment Concentration, and then ranked accordingly. As illustrated in Figure 6.8.2, each Alternative Plan was assigned a rank from 1 to 8 (1 being favorable, 8 being unfavorable). The Scorecard analysis concludes that Plan A: No CPP is more favorable compared to the other Alternative Plans. If the CPP goes forward as promulgated, Plan $C^{T}$: Intensity-Based Dual Rate is more favorable compared to the other CPP-Compliant Plans.

## 6.9 MISCELLANEOUS ANALYSIS

The following sections contain the results of several analyses that the Company has been directed by the SCC to perform or the Company has agreed to perform based on stakeholder requests.

**Optimal Timing of North Anna 3**

Pursuant to its Final Order on the 2015 Plan (PUE-2015-00035), the SCC directed the Company to perform an optimum timing analysis that assessed the cost of delaying the in-service date of North Anna 3. Using least-cost planning techniques and due to the high initial cost of North Anna 3 coupled with a relative low price forecast for natural gas, the optimal timing of the North Anna 3 facility, from a least-cost perspective, is beyond the term of the Study Period for all Alternative Plans. In an attempt to provide additional information associated with this SCC directive, the Company, in this 2017 Plan, ran an additional PLEXOS case similar to Plan $H^{NT}$: New Nuclear with the exception that the on-line date of North Anna 3 was moved to the last year of the Study Period (i.e. 2042). When the NPV result of this new Plan is compared to Plan A: No CPP, the cost delta is $3.4 billion. These results reflect that moving the online date of North Anna 3 out to a later date in the Study Period lowers the overall cost to customers. It should be noted that the results of this comparison are limited given that the assessment of North Anna 3 is only for one year of the Study Period. Given that the useful life of the North Anna 3 facility could range between 60 years to 80 years, its true value to customers will be based on the relative market conditions that exist during its useful life. This type of analysis that extends well beyond the Study Period is difficult and, more importantly, highly speculative. This is because of the difficulty in reasonably assessing market conditions (including technology, fuel prices, etc.) 30 to 50 years into the future.

**Retire/Co-Fire/Repower Analysis of the Company's Coal Fired Facilities**

This analysis was focused on the Company's coal-fired and heavy oil-fired facilities and assessed the cost to customers of the retirement, co-firing natural gas, and repowering of these facilities to exclusively burn natural gas. In the case of retirement, this analysis considered the cost of retirement and replacement of these facilities. The co-firing and repowering analysis considered all plant capital costs associated with natural gas fueling along with all pipeline and other fuel costs associated with delivering natural gas to the facility. The analysis was performed using the PLEXOS model and assumes $CO_2$ limitations and market forecasts consistent with Mass-Based Existing Units compliance program under a no $CO_2$ trading option. The retirement analysis assumed a retirement date of 2022 for all units except for Clover Power Station, which was retired in 2025. Clover's retirement date is set commensurate with the expiration of certain Clover specific fueling contracts. The co-fire and repower alternatives assume a commercial operations date of 2019.

Each of the Company's coal fired facilities was evaluated under a retirement scenario, a 25% co-fire scenario, a 100% co-fire scenario, and a repower scenario. The resulting NPV figures were then compared against a basecase where the unit continued to operate unaltered. The results of the analysis are included in Figure 6.9.1. A negative sign indicates an adverse impact (increase) on cost to the customer.

**Figure 6.9.1 – Retirement, Co-fire, and Repower Analysis Results**

| Units | Retire | 25% Co-fire | 100% Co-fire | Repower |
|---|---|---|---|---|
| Chesterfield 3 | + | - | - | - |
| Chesterfield 4 | + | - | - | - |
| Chesterfield 5 - 6 | - | - | - | - |
| Clover 1 - 2 | - | - | - | - |
| Mecklenburg 1 - 2 | - | - | - | - |
| Mt. Storm 1 - 3 | - | - | - | - |
| Possum Point 5 | - | - | - | - |
| Yorktown 3 | + | - | - | - |

Based on the results of this analysis, the retirement and replacement of Chesterfield Units 3 and 4 and Yorktown Unit 3 decrease overall costs (as shown by a positive sign above). All other retire/co-fire/repower options examined increase costs.

## 6.10 2017 PLAN

Based on the definition of an "optimal plan" (i.e., least-cost, basecase) set forth in the SCC's 2015 Plan Final Order, Plan A: No CPP could be considered optimal if CPP compliance is not necessary, and Plans $B^{NT}$: Intensity-Based Dual Rate or Plan $C^{T}$: Intensity-Based Dual Rate could be considered optimal if CPP compliance is necessary and Virginia chooses an Intensity-Based regulatory approach consistent with Plans $B^{NT}$ or $C^{T}$. However, as mentioned in the Executive Summary, the 2017 Plan offers no "Preferred Plan" or a recommended path forward other than the guidance offered in the Short-Term Action Plan discussed in Chapter 7.

Rather, this 2017 Plan offers the Alternative Plans, each of which may be a likely path forward once the uncertainty of GHG regulation is resolved. Plan A offers a path forward should the CPP be struck down in its entirety (and no replacement carbon legislation or alternative regulation is put in its place, an admittedly unlikely event). Plans $B^{NT}$ through $H^{NT}$ each identify CPP-Compliant plans consistent with the three programs that may be adopted by the Commonwealth of Virginia.

The Company plans to further study and assess all reasonable options over the coming year, should the future form of carbon regulation become clearer. Also, the coming year could also clarify if Virginia pursues and identifies any state specific $CO_2$ mitigation measures. At this time and as was the case in the 2016 Plan, the Company is unable to pick a "Preferred Plan" or a recommended path forward beyond the STAP. Rather in compliance with the 2016 Plan Final Order, the Company is presenting eight Alternative Plans. The Company believes the Alternative Plans represent plausible future paths for meeting the future electric needs of its customers while responding to uncertain and changing regulatory requirements and changing customer preferences. Collectively, this analysis and presentation of the Alternative Plans, along with the decision to pursue the STAP, comprises the 2017 Plan.

## 6.11 CONCLUSION

Rather than selecting any single path forward, the Company has created the Alternative Plans which, along with the Short-Term Action Plan, are collectively the 2017 Plan. These Alternative Plans are being presented to compare and contrast the advantages and risks of each Alternative Plan. The Company maintains that it is premature to pick any single long-term strategic path forward until the uncertainty surrounding the federal carbon regulation diminishes or is resolved. As discussed in the 2016 Plan, to the extent a Virginia state program regarding GHG mitigation is developed during the coming year, the Company maintains its preference for programs designed around $CO_2$ intensity metrics. The Company maintains that programs such as these provide the lowest cost option for the Company and its customers and also offer the Commonwealth the most compliance and operational flexibility relative to other likely programs. Conversely, Mass-Based programs like those shown in Plans $F^{NT}$ through $H^{NT}$ are typically the most expensive and constraining program designs for a state with an EGU make-up like Virginia, which forecasts economic growth and a capacity deficit position. These types of program designs could adversely impact the economic growth potential of Virginia relative to other states and could impose unnecessary economic hardships on the Virginia localities in and around the Company's coal generation facilities.

For the short term, the Company will follow the STAP presented in Chapter 7. At this time, it is especially important to both the Company and its customers to keep all viable options open and available as the Company gradually transitions to a low carbon future.

# CHAPTER 7 – SHORT-TERM ACTION PLAN

The STAP provides the Company's strategic plan for the next five years (2018 – 2022), as well as a discussion of the specific short-term actions the Company is taking to meet the initiatives discussed in this 2017 Plan. The Company continues to proactively position itself in the short-term to address the evolving developments surrounding future $CO_2$ emission mitigation rules or regulations, or societal and customer preferences for the benefit of all stakeholders over the long-term. Major components of the Company's strategy for the next five years are expected to:

- Continue development of planning processes that will reasonably assess the actions and costs associated with the integration of large volumes of intermittent renewable generation on the transmission/distribution network.
- Enhance and upgrade the Company's existing transmission and distribution grid;
- Enhance the Company's access and deliverability to natural gas supplies, including shale gas supplies from multiple supply basins;
- Construct additional generation while maintaining a balanced fuel mix;
- Continue to develop and implement a renewable strategy that supports the Virginia RPS goals, the North Carolina REPS requirements, and continue to lower the Company's emissions footprint;
- Implement cost-effective programs based on measures identified in the DSM Potential Study and continue to implement cost-effective DSM programs in Virginia and North Carolina;
- Continue to evaluate potential unit retirements in light of changing market conditions and regulatory requirements;
- Enhance reliability and customer service;
- Identify improvements to the Company's infrastructure that will reliably facilitate larger quantities of solar PV generation including continuing to assess the steps and costs associated with electric power grid modernization;
- Continue development of the VOWTAP facility through a stakeholder process; and
- Continue analysis and evaluations for the 20-year nuclear license extensions for Surry Units 1 and 2, and North Anna Units 1 and 2.

Figure 7.1 displays the differences between the 2016 STAP and the 2017 STAP.

**Figure 7.1 - Changes between the 2016 and 2017 Short-Term Action Plans**

| | Supply-side Resources | | | | | |
|---|---|---|---|---|---|---|
| Year | New Conventional | New Renewable | Retrofit | Repower | Retire | Demand-side Resources[1] |
| 2017 | | SLR NUG<br>SLR | | | YT 1-2[4] | Approved DSM<br>Proposed DSM |
| 2018 | | SLR NUG[2]<br>~~VOWTAP~~ | | | | |
| 2019 | Greensville | SLR | PP5 - SNCR | | | |
| 2020 | | ~~VA SLR~~<br>SLR | | | | |
| 2021 | | VOWTAP<br>SLR | | | | |
| 2022 | | SLR | | | YT 3[3], CH 3-4[3],<br>~~MB1-3~~ | |

Key: Retrofit: Additional environmental control reduction equipment; Retire: Remove a unit from service; Brunswick: Brunswick County Power Station; CH: Chesterfield Power Station; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; PP5: Possum Point Unit 5; SNCR: Selective Non-Catalytic Reduction; SLR NUG: Solar NUG; SPP: Solar Partnership Program; SLR: Generic Solar: VA SLR: Generic Solar built in Virginia; VOWTAP: Virginia Offshore Wind Technology Advancement Project; YT: Yorktown Unit.

Color Key: Blue: Updated resource since 2016 Plan; Red with Strike: 2016 Plan Resource Replacement.

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

2) Solar NUG capacity increased to 990 MW in VA and NC.

3) The potential retirements of Mecklenburg Units 1 & 2 are no longer included in Plan CT: Intensity-Based Dual Rate.

4) Yorktown Units 1 and 2 ceased operations on April 15, 2017 to comply with the MATS rule.

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

## 7.1 GENERATION RESOURCES

- Greensville County Power Station (1,585 MW), approved on March 29, 2016, is currently under construction.
- Continue the reasonable development efforts associated with obtaining the COL for North Anna 3, which is expected in 2017.
- Continue technical evaluations and aging management programs required to support a second license extension of the Company's existing Surry Units 1 and 2 and North Anna Units 1 and 2.
- Submit an application for the second renewed operating licenses for Surry Units 1 and 2 by the end of the first quarter of 2019.

Figure 7.1.1 lists the generation plants that are currently under construction and are expected to be operational by 2022. Figure 7.1.2 lists the generation plants that are currently under development and are expected to be operational by 2022 subject to SCC approval.

### Figure 7.1.1 - Generation under Construction

| Forecasted COD[1] | Unit Name | Location | Primary Fuel | Unit Type | Capacity (Net MW) | | |
|---|---|---|---|---|---|---|---|
| | | | | | Nameplate | Summer | Winter |
| 2017 | SPP | VA | Solar | Intermittent | 8 | 2 | 2 |
| 2019 | Greensville County Power Station | VA | Natural Gas | Intermediate/Baseload | 1,585 | 1,585 | 1,710 |

Note: 1) Commercial Operation Date.

### Figure 7.1.2 - Generation under Development[1]

| Forecasted COD | Unit | Location | Primary Fuel | Unit Type | Nameplate Capacity (MW) | Capacity (Net MW) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Summer | Winter |
| 2021 | VOWTAP | VA | Wind | Intermittent | 12 | 2 | 2 |

Note: 1) All Generation under Development projects and planned capital expenditures are preliminary in nature and subject to regulatory and/or Board of Directors approvals.

### Generation Uprates/Derates

Figure 7.1.3 lists the Company's planned changes to existing generating units.

### Figure 7.1.3 - Changes to Existing Generation

| Unit Name | Type | MW | Year Effective |
|---|---|---|---|
| Possum Point 5 | SNCR | - | 2019 |

## 7.2 RENEWABLE ENERGY RESOURCES

Approximately 657 MW of qualifying renewable generation is currently in operation.

### Virginia

- As part of the SPP, the Company has installed or has under development 7.7 MW (nameplate) of solar generation.
- 61 MW of biomass capacity at VCHEC by 2022.
- Virginia RPS Program: The Company plans to meet its targets by applying renewable generation from existing qualified facilities and purchasing cost-effective RECs.
- Virginia Annual Report: On November 2, 2016, the Company submitted its Annual Report to the SCC, as required, detailing its efforts towards the RPS plan.
- Continue development of VOWTAP.
- Continued development of solar PV resources consistent with the generic solar facilities specified in Figure 7.2.1.

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### North Carolina

- North Carolina REPS Compliance Report: The Company achieved its 2015 solar set-aside, poultry waste set-aside and general obligation requirement, which is detailed in its annual REPS Compliance Report submitted on August 25, 2016. The 2017 REPS Compliance Report for compliance year 2016 wil be submitted in August 2017.
- North Carolina REPS Compliance Plan: The Company submitted its annual REPS Compliance Plan, which is filed as North Carolina Plan Addendum 1 to this 2017 Plan.
- The Company has recently entered into or are negotiating PPAs with approximately 950 MW (nameplate) of North Carolina solar NUGs by 2022.

Figure 7.2.1 lists the Company's renewable resources included in all Alternative Plans for the next five years.

**Figure 7.2.1 - Renewable Resources by 2022**

| Resource | Nameplate MW |
|---|---|
| Existing Resources[1] | 610 |
| VCHEC Biomass | 61 |
| SPP | 8 |
| Solar NUGs[2] | 990 |
| VOWTAP | 12 |
| Solar 2019 | 240 |
| Solar 2020 | 240 |
| Solar 2021 | 240 |
| Solar 2022 | 240 |

Note: 1) Existing Resources include hydro, biomass (excluding VCHEC), and solar.
2) Solar NUGs include forecasted VA and NC solar NUGs through 2022.

## 7.3 TRANSMISSION

### Virginia

The following planned Virginia transmission projects detailed in Figure 7.3.1 are pending SCC approval or are tentatively planned for filing with the SCC:

- Line #65 Norris Bridge Rebuild;
- Line #534 Cunningham to Dooms Rebuild;
- Line #2176 Gainesville to Haymarket and Line #2169 Haymarket to Loudoun – New 230kV Lines and New 230kV Substation;
- Line #2175 Idylwood to Tysons – New 230kV Line and New 230kV Tysons Substation;
- Line #2189 Glebe to Potomac River – New 230kV Line;
- Line #18 Possum Point to Smoketown and Line #145 Smoketown to Possum Point Rebuild;
- Idylwood Substation Rebuild;

- Line #567 Willcox Wharf to Windmill Point Rebuild;
- Line #2153 Remington to Gordonsville – New 230kV Line; and
- Line #549 Dooms to Valley Rebuild.

Figure 7.3.1 lists the major transmission additions including line voltage, capacity, and expected operation target dates.

**Figure 7.3.1 - Planned Transmission Additions**

| Line Terminals | Line Voltage (kV) | Line Capacity (MVA) | Target Date | Location |
|---|---|---|---|---|
| Line #2027 Bremo to Midlothian Rebuild | 230 | 1,047 | May-17 | VA |
| Line #65 Norris Bridge Rebuild | 115 | 147 | Dec-17 | VA |
| Line #567 Willcox Wharf to Windmill Point Rebuild | 500 | 3,464 | Feb-18 | VA |
| Line #2176 Gainesville to Haymarket and Line #2169 Haymarket to Loudoun – New 230kV Lines and New 230kV Substation | 230 | 1,047 | May-18 | VA |
| Line #47 Kings Dominion to Fredericksburg Rebuild | 115 | 353 | May-18 | VA |
| Line #47 Four Rivers to Kings Dominion Rebuild | 115 | 353 | May-18 | VA |
| Line #159 Acca to Hermitage Reconductor | 115 | 353 | May-18 | VA |
| Line #4 Bremo to Cartersville Uprate | 115 | 151 | May-18 | VA |
| Line #2172 Brambleton to Yardley Ridge – New 230kV Line | 230 | 1,047 | May-18 | VA |
| Line #2183 Brambleton to Poland Road – New 230kV Line and New 230kV Substation | 230 | 1,047 | May-18 | VA |
| Line #2174 Vint Hill to Wheeler – New 230kV Line | 230 | 1,047 | Jun-18 | VA |
| Line #553 Cunningham to Elmont Rebuild | 500 | 4,330 | Jun-18 | VA |
| Line #137 Ridge Road to Kerr Dam Rebuild | 115 | 346 | Jun-18 | VA |
| Line #1009 Ridge Road to Chase City Rebuild | 115 | 346 | Jun-18 | VA |
| Line #1020 Pantego to Trowbridge – New 115kV Line | 115 | 346 | Jun-18 | NC |
| Line #1015 Scotland Neck to South Justice Branch – New 115kV Line | 115 | 346 | Jun-18 | NC |
| Line #2086 Remington Combustion Turbine to Warrenton Rebuild | 230 | 1,047 | Oct-18 | VA |
| Line #2161 Wheeler to Gainesville Uprate | 230 | 1,047 | Dec-18 | VA |
| Line #48 Sewells Point to Thole Street and Line #107 Oakwood to Sewells Point Partial Rebuild | 115 | 317 (#48)<br>353 (#107) | Dec-18 | VA |
| Line #585 Carson to Rogers Road Rebuild | 500 | 4,330 | Dec-18 | VA |
| Line #54 Carolina to Woodland Reconductor | 115 | 174 | Dec-18 | NC |
| Line #34 Skiffes Creek to Yorktown and Line #61 Whealton to Yorktown Partial Rebuild | 115 | 353 (#34) | Dec-18 | VA |
| Line #582 Surry to Skiffes Creek – New 500kV Line | 500 | 4,330 | Dec-18 | VA |
| Line #2138 Skiffes Creek to Whealton – New 230kV Line | 230 | 1,047 | Dec-18 | VA |
| Line #2104 Cranes Corner to Aquia Harbor Partial Reconductor | 230 | 1,047 | May-19 | VA |
| Line #2153 Remington to Gordonsville – New 230kV Line | 230 | 1,047 | Jun-19 | VA |
| Line #534 Cunningham to Dooms Rebuild | 500 | 4,330 | Jun-19 | VA |
| Line #382 Everetts to Voice of America Rebuild | 115 | 353 | Dec-19 | NC |
| Line #166 and Line #67 Greenwich to Burton Rebuild | 115 | 353 | Dec-19 | VA |
| Line #90 Carolina to Kerr Dam Rebuild | 115 | 346 | Dec-19 | VA/NC |
| Line #130 Clubhouse to Carolina Rebuild | 115 | 353 | Dec-19 | VA/NC |
| Line #18 Possum Point to Smoketown and Line #145 Smoketown to Possum Point Rebuild | 115 | 524 | Dec-19 | VA |
| Harry Byrd – New 230kV Line | 230 | 1,047 | Feb-20 | VA |
| Line #2175 Idylwood to Tysons – New 230kV Line and New 230kV Tysons Substation | 230 | 1,047 | May-20 | VA |
| Line #154 Twittys Creek to Pamplin Rebuild | 115 | 353 | Dec-20 | VA |
| Line #38 Boydton Plank Road to Kerr Dam Rebuild | 115 | 353 | Dec-20 | VA |
| Line #550 Mount Storm to Valley Rebuild | 500 | 4,330 | Jun-21 | VA |
| Line #549 Dooms to Valley Rebuild | 500 | 4,330 | Jun-21 | VA |
| Line #127 Buggs Island to Plywood Rebuild | 115 | 353 | Dec-21 | VA |
| Line #16 Great Bridge to Hickory and Line #74 Chesapeake Energy Center to Great Bridge Rebuild | 115 | 353 | Dec-21 | VA |
| Line #2189 Glebe to Potomac River – New 230kV Line | 230 | 900 | 2022 | VA |

## 7.4 DEMAND-SIDE MANAGEMENT

The Company continues to evaluate the measures identified in the DSM Potential Study and may include additional measures in DSM programs in future Plans. The measures included in the DSM Potential Study still need to be part of a program design effort that looks at the viability of the potential measures as a single or multi-measure DSM program. These fully-designed DSM programs would also need to be evaluated for cost effectiveness.

### Virginia

The Company will continue its analysis of future programs and may file for approval of new or revised programs that meet the Company requirements for new DSM resources in October 2017. The Company filed its "Phase VI" DSM Application in October 2016, seeking approval of two new energy efficiency DSM programs: Residential Home Energy Assessment Program and the Non-Residential Prescriptive Program (Case No. PUE-2016-00111). In addition, the Company has filed for continuation of two DSM Phase II programs, the Residential Heat Pump Upgrade Program through May 31, 2019 and the Non-Residential Distributed Generation Program through May 31, 2022. The SCC is expected to issue its Final Order in this case by June 2017.

### North Carolina

The Company will continue its analysis of future programs and will file for approval in North Carolina for those programs that have been approved in Virginia that continue to meet the Company requirements for new DSM resources. On July 29, 2016, the Company filed in Docket No. E-22, Sub 538 for NCUC approval of the Small Business Improvement Program that was approved in Virginia in Case No. PUE-2015-00089. On October 26, 2016, the NCUC approved this new DSM program, which has been available to qualifying North Carolina customers since January 2017. On October 31, 2016, in Docket No. E-22, Sub 539, the Company filed for NCUC approval of a North Carolina only Residential Retail LED Lighting Program. On December 20, 2016, the NCUC approved the new program. The program is being offered in the Company's North Carolina service territory for a two-year period beginning in 2017.

Figure 7.4.1 lists the projected demand and energy savings by 2022 from the approved and proposed DSM programs.

## Figure 7.4.1 - DSM Projected Savings By 2022

| Program | Projected MW Reduction | Projected GWh Savings | Status (VA / NC) |
|---|---|---|---|
| Air Conditioner Cycling Program | 78 | - | Approved / Approved |
| Residential Low Income Program | 2 | 13 | Completed / Completed |
| Residential Lighting Program | - | - | |
| Commercial Lighting Program | 1 | 12 | Closed / Closed |
| Commercial HVAC Upgrade | 1 | 4 | |
| Non-Residential Distributed Generation Program | 10 | - | Approved / Rejected |
| Non-Residential Energy Audit Program | 1 | 10 | Completed / Completed |
| Non-Residential Duct Testing and Sealing Program | 19 | 51 | |
| Residential Bundle Program | 10 | 46 | |
| Residential Home Energy Check-Up Program | 7 | 34 | |
| Residential Duct Sealing Program | - | 1 | |
| Residential Heat Pump Tune Up Program | - | - | |
| Residential Heat Pump Upgrade Program | 3 | 11 | Extension Under Consideration / Suspended |
| Non-Residential Window Film Program | 102 | 112 | Approved / Approved |
| Non-Residential Lighting Systems & Controls Program | 32 | 206 | |
| Non-Residential Heating and Cooling Efficiency Program | 62 | 165 | |
| Income and Age Qualifying Home Improvement Program | 3 | 13 | |
| Residential Appliance Recycling Program | 2 | 13 | Approved / No Plans |
| Small Business Improvement Program | 21 | 75 | Approved / Approved |
| Residential Home Energy Assessment | 12 | 89 | Proposed / Future |
| Non-Residential Prescriptive Program | 58 | 409 | |

### Grid Modernization

Continue the development of a detailed plan that includes the actions and associated costs necessary to transform the Company's existing distribution network to a more modern design capable of facilitating DERs while maintaining the highest levels of reliability.

### Advanced Metering Infrastructure

The Company has AMI, or smart meters, in homes and businesses in areas throughout Virginia. The AMI meter upgrades are part of an on-going demonstration effort that will help the Company further evaluate the effectiveness of AMI meters in achieving voltage optimization, voltage stability, remotely turning off and on electric service, power outage and restoration detection and reporting, remote daily meter readings, and offering dynamic rates.

# APPENDIX

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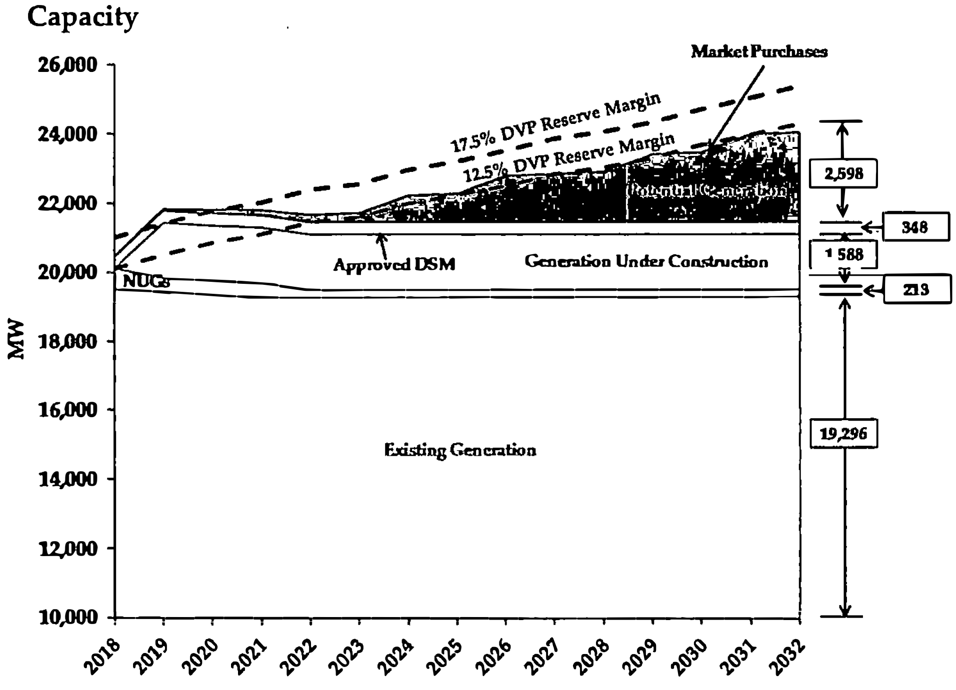
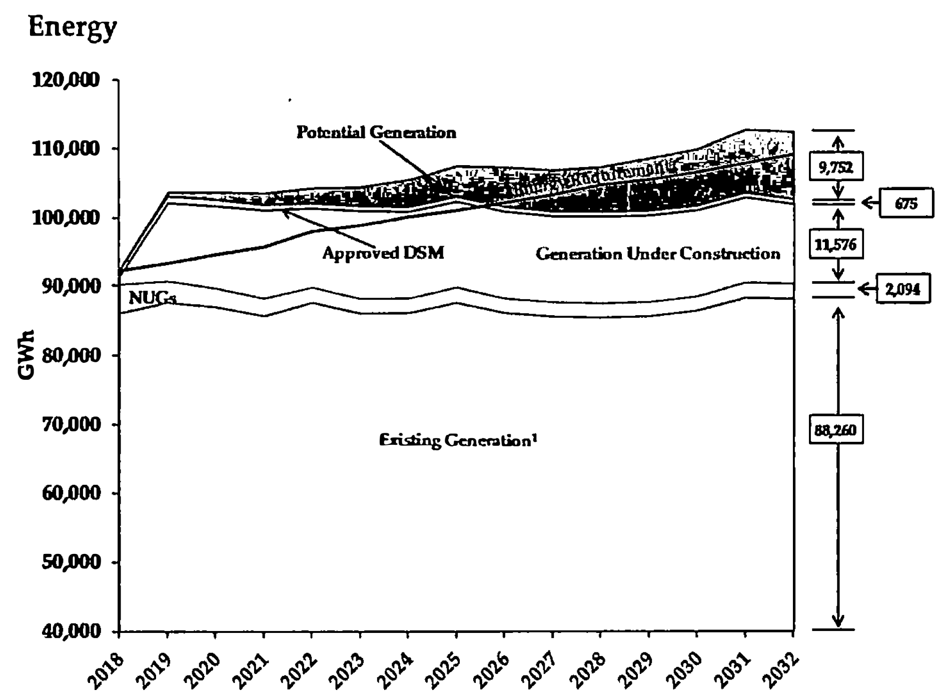
## Appendix 1A – Plan A: No CPP – Capacity & Energy




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

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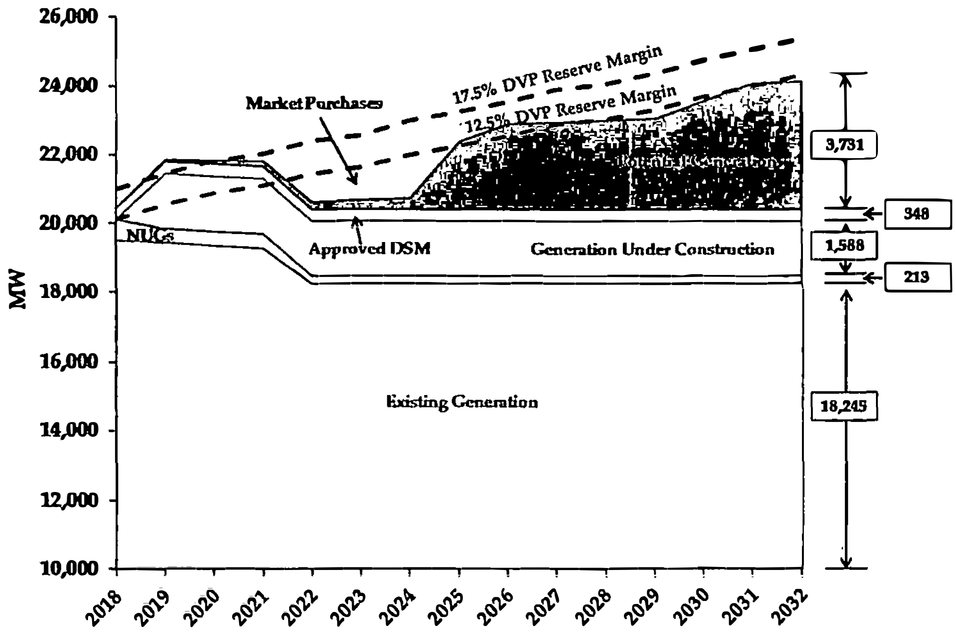
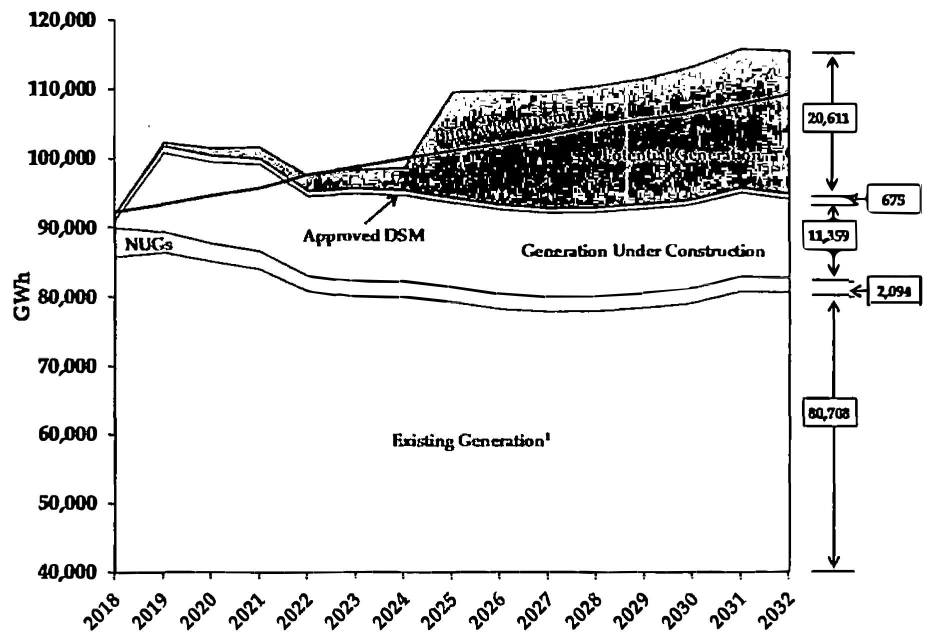
# Appendix 1A – Plan B^NT: Intensity-Based Dual Rate – Capacity & Energy

## Capacity



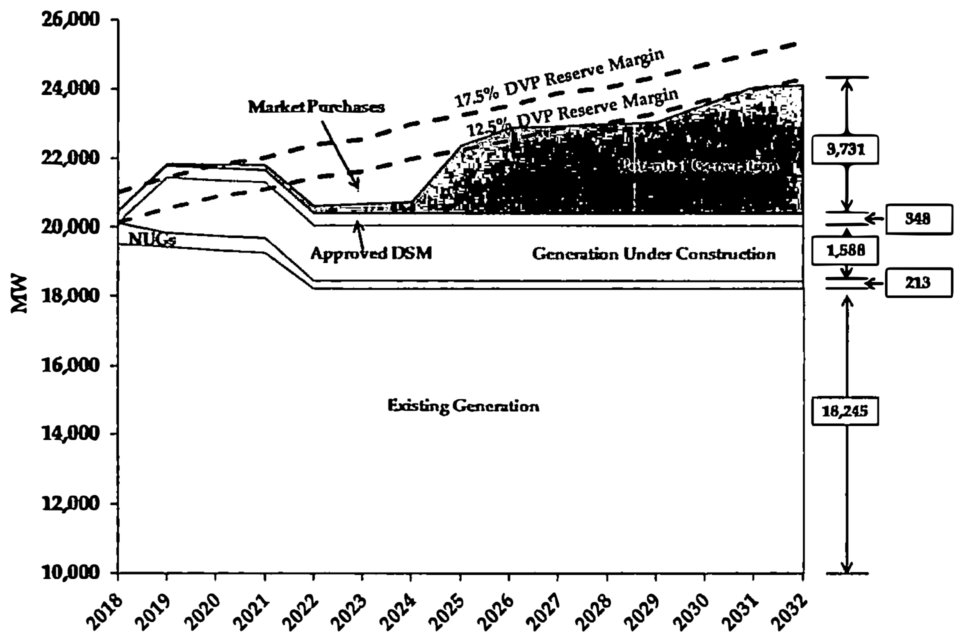

## Energy



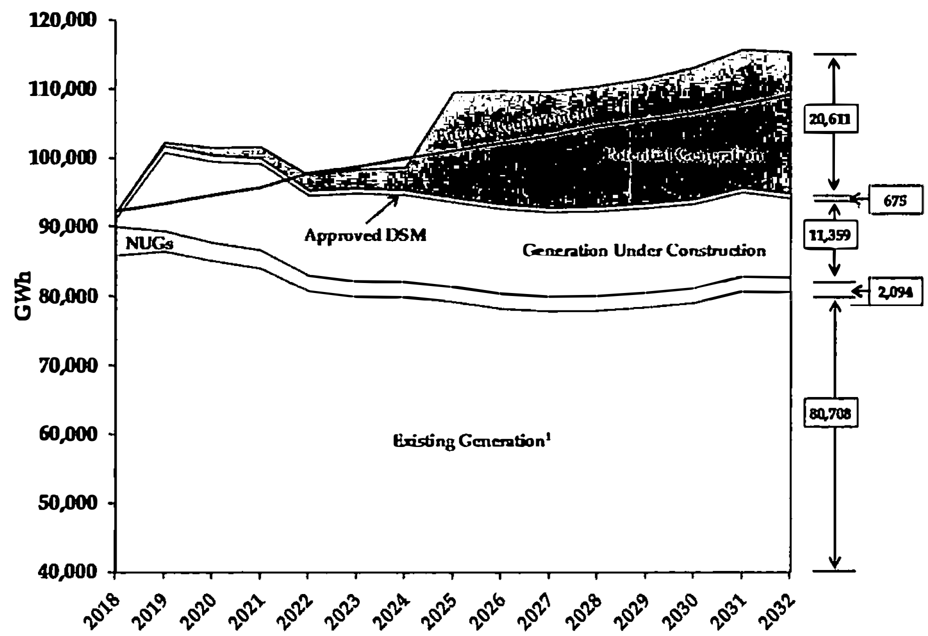

Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

## Appendix 1A – Plan C$^T$: Intensity-Based Dual Rate – Capacity & Energy

### Capacity



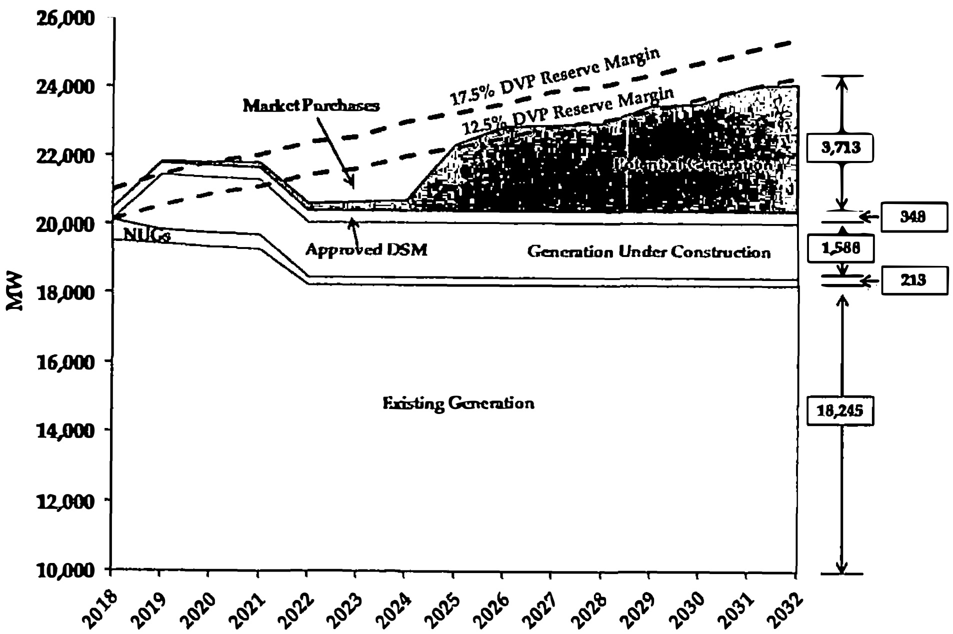

### Energy



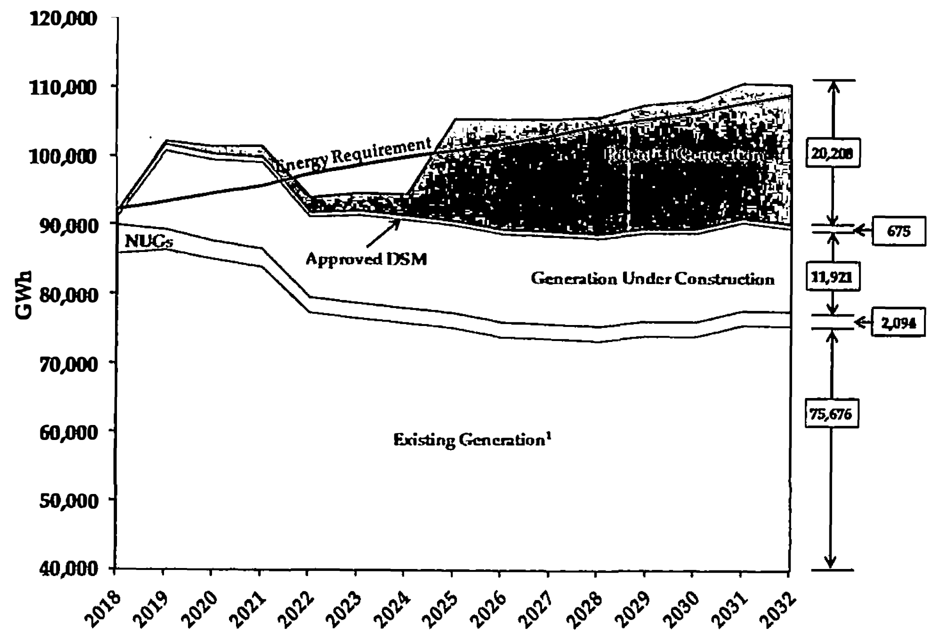

Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

## Appendix 1A – Plan D^NT: Mass-Based Existing Units – Capacity & Energy

### Capacity



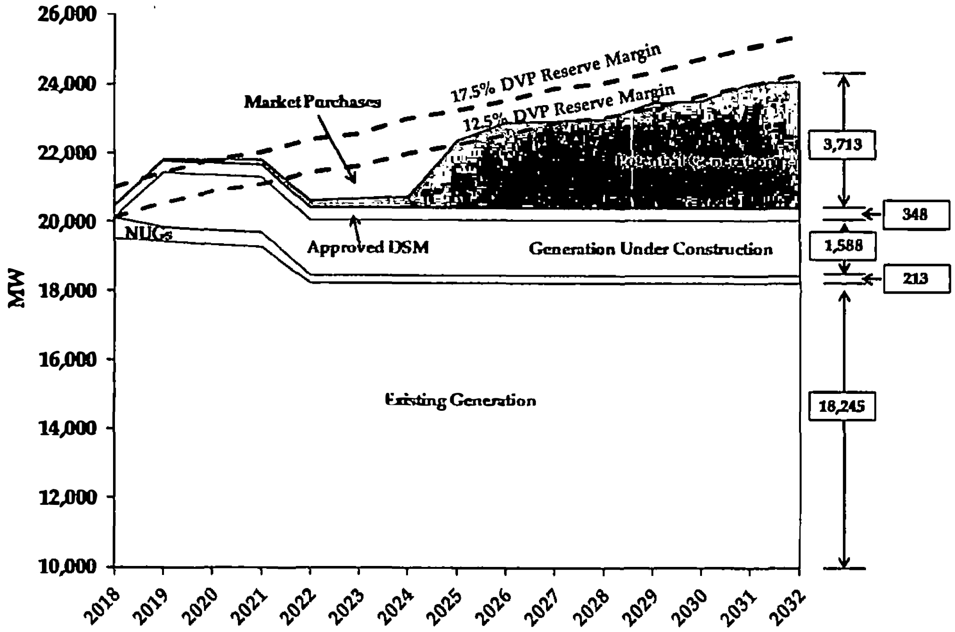

### Energy



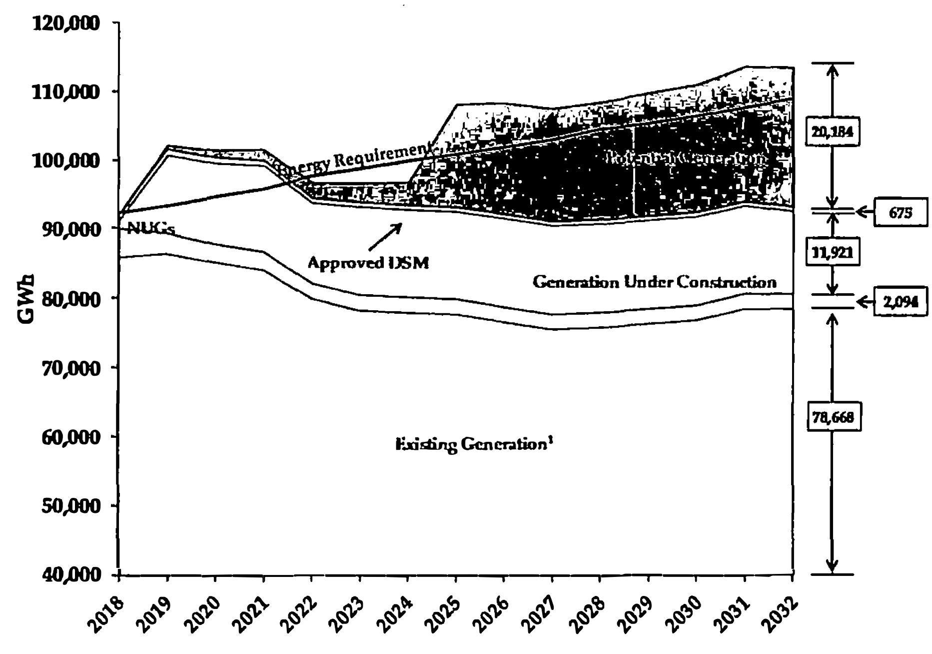

Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

# Appendix 1A – Plan E$^T$: Mass-Based Existing Units – Capacity & Energy

## Capacity



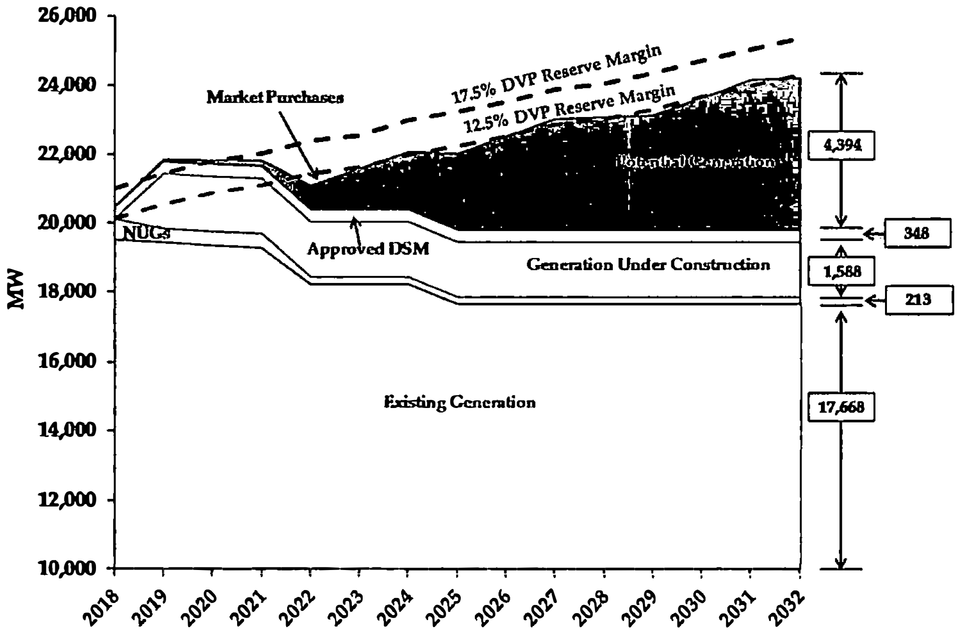

## Energy



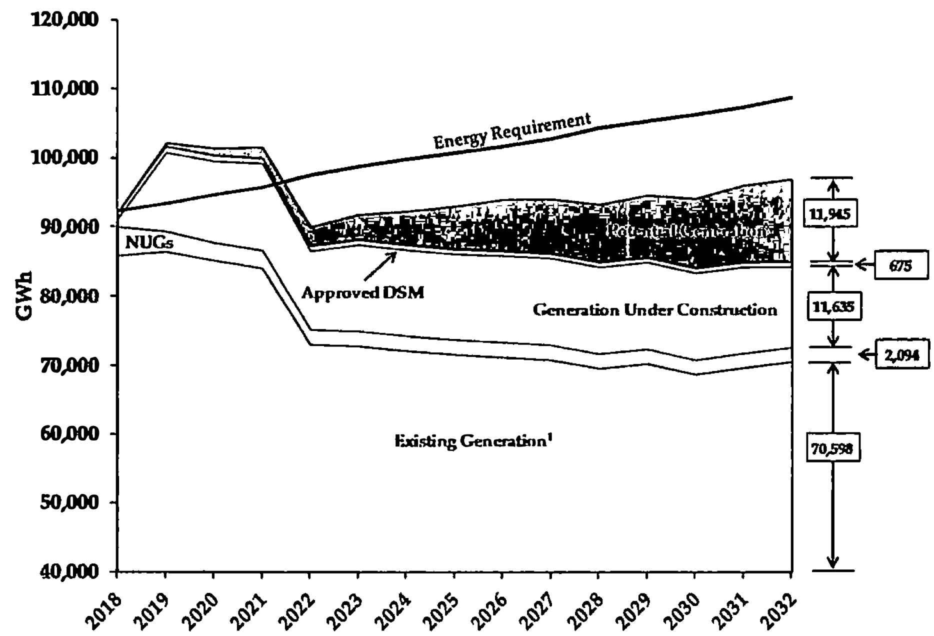

Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

## Appendix 1A – Plan F^NT: Mass-Based All Units – Capacity & Energy

### Capacity




### Energy




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

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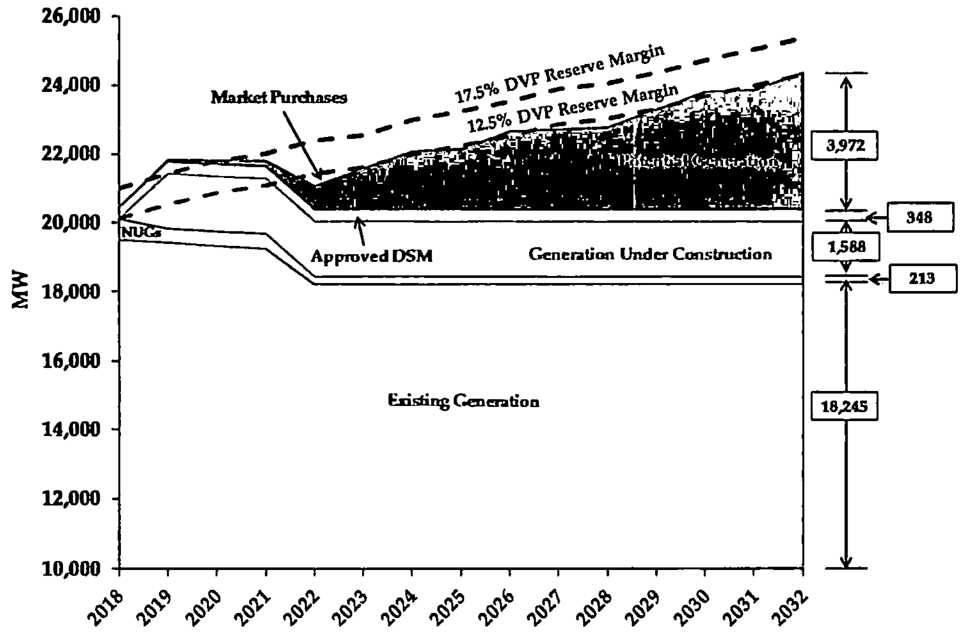
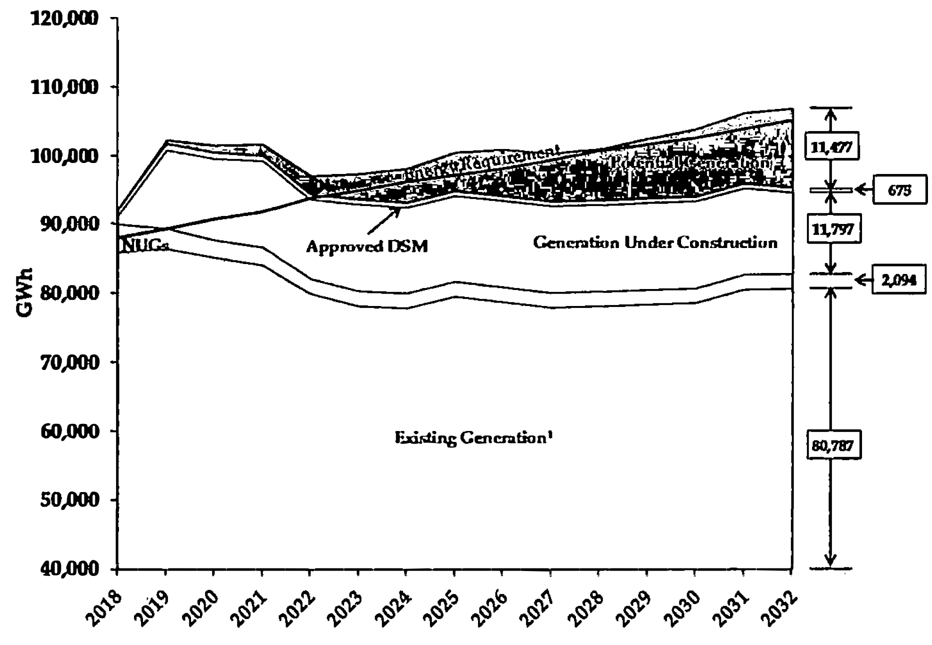
## Appendix 1A – Plan G$^T$: Mass-Based All Units – Capacity & Energy

### Capacity




### Energy




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

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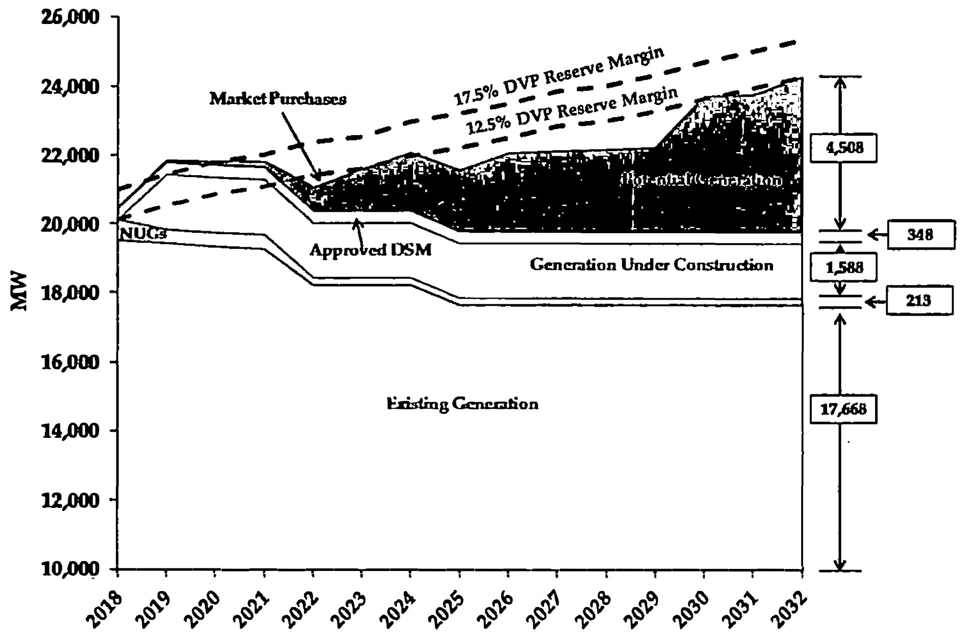
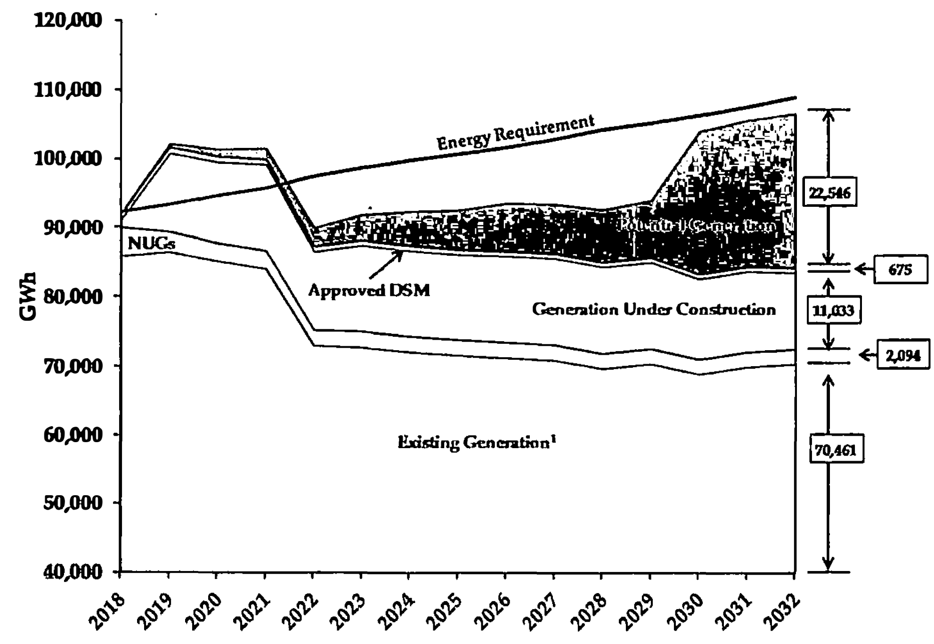
## Appendix 1A – Plan H[NT]: New Nuclear – Capacity & Energy

### Capacity




### Energy




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

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# Appendix 2A – Total Sales by Customer Class
## (DOM LSE) (GWh)

| Year | Residential | Commercial | Industrial | Public Authority | Street and Traffic Lighting | Sales for Resale | Total |
|---|---|---|---|---|---|---|---|
| 2007 | 30,469 | 28,416 | 10,094 | 10,660 | 283 | 1,990 | 81,912 |
| 2008 | 29,646 | 28,484 | 9,779 | 10,529 | 282 | 1,932 | 80,652 |
| 2009 | 29,904 | 28,455 | 8,644 | 10,448 | 276 | 1,921 | 79,646 |
| 2010 | 32,547 | 29,233 | 8,512 | 10,670 | 281 | 2,011 | 83,254 |
| 2011 | 30,779 | 28,957 | 7,960 | 10,555 | 273 | 1,984 | 80,509 |
| 2012 | 29,174 | 28,927 | 7,849 | 10,496 | 277 | 1,956 | 78,680 |
| 2013 | 30,184 | 29,372 | 8,097 | 10,261 | 276 | 1,981 | 80,171 |
| 2014 | 31,290 | 29,964 | 8,812 | 10,402 | 261 | 1,856 | 82,585 |
| 2015 | 30,923 | 30,282 | 8,765 | 10,159 | 275 | 1,609 | 82,013 |
| 2016 | 28,213 | 31,366 | 8,715 | 10,161 | 253 | 1,607 | 80,315 |
| 2017 | 30,742 | 31,884 | 8,494 | 10,207 | 297 | 1,789 | 83,413 |
| 2018 | 31,174 | 33,068 | 8,387 | 10,244 | 301 | 1,823 | 84,997 |
| 2019 | 31,567 | 33,791 | 8,270 | 10,270 | 306 | 1,836 | 86,039 |
| 2020 | 31,913 | 34,662 | 8,154 | 10,336 | 310 | 1,875 | 87,250 |
| 2021 | 32,273 | 35,407 | 8,048 | 10,430 | 313 | 1,904 | 88,376 |
| 2022 | 32,513 | 37,215 | 7,951 | 10,500 | 317 | 1,938 | 90,434 |
| 2023 | 32,852 | 37,937 | 7,546 | 10,991 | 321 | 1,966 | 91,612 |
| 2024 | 33,312 | 38,672 | 7,538 | 11,080 | 325 | 1,998 | 92,924 |
| 2025 | 33,564 | 39,187 | 7,480 | 11,131 | 329 | 2,020 | 93,710 |
| 2026 | 33,797 | 39,905 | 7,472 | 11,214 | 332 | 2,042 | 94,763 |
| 2027 | 34,078 | 40,665 | 7,469 | 11,329 | 336 | 2,061 | 95,937 |
| 2028 | 34,570 | 41,484 | 7,478 | 11,380 | 339 | 2,084 | 97,335 |
| 2029 | 34,839 | 42,075 | 7,464 | 11,477 | 342 | 2,096 | 98,294 |
| 2030 | 35,198 | 42,633 | 7,455 | 11,714 | 346 | 2,110 | 99,456 |
| 2031 | 35,240 | 43,486 | 7,520 | 11,671 | 349 | 2,124 | 100,390 |
| 2032 | 35,585 | 44,240 | 7,530 | 11,765 | 352 | 2,141 | 101,613 |

Note: Historic (2007 – 2016), Projected (2017 – 2032).

# Appendix 2B– Virginia Sales by Customer Class (DOM LSE) (GWh)

| Year | Residential | Commercial | Industrial | Public Authority | Street and Traffic Lighting | Sales for Resale | Total |
|---|---|---|---|---|---|---|---|
| 2007 | 28,890 | 27,606 | 8,359 | 10,519 | 274 | 1,901 | 77,551 |
| 2008 | 28,100 | 27,679 | 8,064 | 10,391 | 273 | 1,883 | 76,390 |
| 2009 | 28,325 | 27,646 | 7,147 | 10,312 | 268 | 1,870 | 75,567 |
| 2010 | 30,831 | 28,408 | 6,872 | 10,529 | 273 | 1,958 | 78,872 |
| 2011 | 29,153 | 28,163 | 6,342 | 10,423 | 265 | 1,934 | 76,281 |
| 2012 | 27,672 | 28,063 | 6,235 | 10,370 | 269 | 1,906 | 74,515 |
| 2013 | 28,618 | 28,487 | 6,393 | 10,134 | 267 | 1,930 | 75,829 |
| 2014 | 29,645 | 29,130 | 6,954 | 10,272 | 253 | 1,803 | 78,057 |
| 2015 | 29,293 | 29,432 | 7,006 | 10,029 | 266 | 1,556 | 77,583 |
| 2016 | 26,652 | 30,537 | 6,947 | 10,033 | 245 | 1,555 | 75,969 |
| 2017 | 29,138 | 31,036 | 6,761 | 10,081 | 289 | 1,732 | 79,037 |
| 2018 | 29,561 | 32,223 | 6,646 | 10,117 | 293 | 1,765 | 80,605 |
| 2019 | 29,947 | 32,943 | 6,521 | 10,142 | 297 | 1,777 | 81,628 |
| 2020 | 30,289 | 33,811 | 6,398 | 10,208 | 301 | 1,816 | 82,823 |
| 2021 | 30,645 | 34,554 | 6,284 | 10,301 | 305 | 1,845 | 83,933 |
| 2022 | 30,881 | 36,357 | 6,178 | 10,371 | 309 | 1,878 | 85,974 |
| 2023 | 31,214 | 37,078 | 5,745 | 10,857 | 312 | 1,905 | 87,111 |
| 2024 | 31,667 | 37,812 | 5,737 | 10,945 | 316 | 1,936 | 88,413 |
| 2025 | 31,915 | 38,326 | 5,674 | 10,996 | 320 | 1,958 | 89,189 |
| 2026 | 32,145 | 39,042 | 5,666 | 11,078 | 323 | 1,980 | 90,235 |
| 2027 | 32,421 | 39,800 | 5,662 | 11,192 | 327 | 1,999 | 91,401 |
| 2028 | 32,906 | 40,617 | 5,672 | 11,242 | 330 | 2,021 | 92,789 |
| 2029 | 33,171 | 41,208 | 5,657 | 11,339 | 334 | 2,031 | 93,740 |
| 2030 | 33,525 | 41,764 | 5,648 | 11,573 | 337 | 2,046 | 94,892 |
| 2031 | 33,565 | 42,615 | 5,718 | 11,531 | 340 | 2,059 | 95,828 |
| 2032 | 33,906 | 43,368 | 5,728 | 11,624 | 343 | 2,075 | 97,043 |

Note: Historic (2007 – 2016), Projected (2017 – 2032).

# 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 |
|---|---|---|---|---|---|---|---|
| 2007 | 1,579 | 810 | 1,735 | 140 | 8 | 88 | 4,361 |
| 2008 | 1,546 | 806 | 1,715 | 138 | 8 | 49 | 4,263 |
| 2009 | 1,579 | 809 | 1,497 | 136 | 8 | 51 | 4,079 |
| 2010 | 1,716 | 825 | 1,640 | 141 | 8 | 53 | 4,382 |
| 2011 | 1,626 | 795 | 1,618 | 132 | 8 | 50 | 4,229 |
| 2012 | 1,502 | 864 | 1,614 | 126 | 8 | 50 | 4,164 |
| 2013 | 1,567 | 885 | 1,704 | 127 | 8 | 51 | 4,342 |
| 2014 | 1,645 | 834 | 1,858 | 130 | 8 | 53 | 4,528 |
| 2015 | 1,630 | 850 | 1,759 | 130 | 8 | 53 | 4,431 |
| 2016 | 1,562 | 829 | 1,768 | 128 | 8 | 52 | 4,346 |
| 2017 | 1,604 | 848 | 1,733 | 126 | 8 | 56 | 4,376 |
| 2018 | 1,613 | 845 | 1,741 | 127 | 8 | 57 | 4,392 |
| 2019 | 1,620 | 849 | 1,749 | 127 | 8 | 58 | 4,411 |
| 2020 | 1,624 | 851 | 1,757 | 128 | 8 | 59 | 4,428 |
| 2021 | 1,628 | 854 | 1,765 | 129 | 9 | 60 | 4,444 |
| 2022 | 1,632 | 857 | 1,773 | 129 | 9 | 60 | 4,460 |
| 2023 | 1,638 | 859 | 1,801 | 134 | 9 | 61 | 4,501 |
| 2024 | 1,645 | 860 | 1,801 | 135 | 9 | 62 | 4,511 |
| 2025 | 1,649 | 861 | 1,806 | 135 | 9 | 62 | 4,521 |
| 2026 | 1,652 | 863 | 1,806 | 136 | 9 | 62 | 4,528 |
| 2027 | 1,657 | 865 | 1,806 | 137 | 9 | 63 | 4,536 |
| 2028 | 1,664 | 866 | 1,806 | 138 | 9 | 64 | 4,546 |
| 2029 | 1,668 | 868 | 1,807 | 138 | 9 | 64 | 4,554 |
| 2030 | 1,674 | 869 | 1,807 | 141 | 9 | 65 | 4,564 |
| 2031 | 1,674 | 871 | 1,803 | 140 | 9 | 65 | 4,562 |
| 2032 | 1,680 | 872 | 1,802 | 141 | 9 | 66 | 4,570 |

Note: Historic (2007 – 2016), Projected (2017 – 2032).

# Appendix 2D – Total Customer Count
## (DOM LSE)

| Year | Residential | Commercial | Industrial | Public Authority | Street and Traffic Lighting | Sales for Resale | Total |
|---|---|---|---|---|---|---|---|
| 2007 | 2,102,751 | 227,829 | 620 | 28,770 | 2,347 | 5 | 2,362,321 |
| 2008 | 2,124,089 | 230,715 | 598 | 29,008 | 2,513 | 5 | 2,386,927 |
| 2009 | 2,139,604 | 232,148 | 581 | 29,073 | 2,687 | 5 | 2,404,099 |
| 2010 | 2,157,581 | 232,988 | 561 | 29,041 | 2,798 | 4 | 2,422,973 |
| 2011 | 2,171,795 | 233,760 | 535 | 29,104 | 3,031 | 3 | 2,438,227 |
| 2012 | 2,187,670 | 234,947 | 514 | 29,114 | 3,246 | 3 | 2,455,495 |
| 2013 | 2,206,657 | 236,596 | 526 | 28,847 | 3,508 | 3 | 2,476,138 |
| 2014 | 2,229,639 | 237,757 | 631 | 28,818 | 3,653 | 3 | 2,500,500 |
| 2015 | 2,252,438 | 239,623 | 662 | 28,923 | 3,814 | 3 | 2,525,463 |
| 2016 | 2,275,551 | 240,804 | 654 | 29,069 | 3,941 | 3 | 2,550,022 |
| 2017 | 2,296,977 | 242,915 | 653 | 29,202 | 4,079 | 3 | 2,573,829 |
| 2018 | 2,325,492 | 245,392 | 652 | 29,311 | 4,223 | 3 | 2,605,073 |
| 2019 | 2,355,754 | 247,994 | 651 | 29,422 | 4,367 | 3 | 2,638,191 |
| 2020 | 2,384,100 | 250,479 | 650 | 29,522 | 4,511 | 3 | 2,669,266 |
| 2021 | 2,410,868 | 252,860 | 649 | 29,606 | 4,655 | 3 | 2,698,641 |
| 2022 | 2,438,035 | 255,261 | 648 | 29,679 | 4,799 | 3 | 2,728,426 |
| 2023 | 2,465,970 | 257,713 | 647 | 29,749 | 4,943 | 3 | 2,759,025 |
| 2024 | 2,493,658 | 260,153 | 646 | 29,813 | 5,087 | 3 | 2,789,360 |
| 2025 | 2,520,212 | 262,523 | 645 | 29,870 | 5,231 | 3 | 2,818,484 |
| 2026 | 2,545,382 | 264,805 | 644 | 29,920 | 5,375 | 3 | 2,846,129 |
| 2027 | 2,569,447 | 267,018 | 643 | 29,961 | 5,519 | 3 | 2,872,591 |
| 2028 | 2,592,790 | 269,184 | 642 | 29,997 | 5,663 | 3 | 2,898,279 |
| 2029 | 2,615,560 | 271,314 | 641 | 30,028 | 5,807 | 3 | 2,923,354 |
| 2030 | 2,637,911 | 273,418 | 640 | 30,056 | 5,951 | 3 | 2,947,979 |
| 2031 | 2,660,454 | 275,537 | 639 | 30,083 | 6,099 | 3 | 2,972,814 |
| 2032 | 2,683,189 | 277,673 | 638 | 30,110 | 6,250 | 3 | 2,997,863 |

Note: Historic (2007 – 2016), Projected (2017 – 2032).

# Appendix 2E – Virginia Customer Count
## (DOM LSE)

| Year | Residential | Commercial | Industrial | Public Authority | Street and Traffic Lighting | Sales for Resale | Total |
|---|---|---|---|---|---|---|---|
| 2007 | 2,002,884 | 212,369 | 554 | 26,896 | 1,971 | 3 | 2,244,676 |
| 2008 | 2,023,592 | 215,212 | 538 | 27,141 | 2,116 | 3 | 2,268,602 |
| 2009 | 2,038,843 | 216,663 | 522 | 27,206 | 2,290 | 3 | 2,285,526 |
| 2010 | 2,056,576 | 217,531 | 504 | 27,185 | 2,404 | 2 | 2,304,202 |
| 2011 | 2,070,786 | 218,341 | 482 | 27,252 | 2,639 | 2 | 2,319,502 |
| 2012 | 2,086,647 | 219,447 | 464 | 27,265 | 2,856 | 2 | 2,336,680 |
| 2013 | 2,105,500 | 221,039 | 477 | 26,996 | 3,118 | 2 | 2,357,131 |
| 2014 | 2,128,313 | 222,143 | 579 | 26,966 | 3,267 | 2 | 2,381,269 |
| 2015 | 2,150,818 | 223,946 | 611 | 27,070 | 3,430 | 2 | 2,405,877 |
| 2016 | 2,173,472 | 225,029 | 603 | 27,223 | 3,560 | 2 | 2,429,889 |
| 2017 | 2,194,670 | 227,259 | 593 | 27,350 | 3,687 | 2 | 2,453,561 |
| 2018 | 2,222,839 | 229,708 | 591 | 27,462 | 3,829 | 2 | 2,484,431 |
| 2019 | 2,252,745 | 232,272 | 590 | 27,576 | 3,972 | 2 | 2,517,158 |
| 2020 | 2,280,757 | 234,722 | 589 | 27,680 | 4,116 | 2 | 2,547,866 |
| 2021 | 2,307,210 | 237,068 | 589 | 27,766 | 4,259 | 2 | 2,576,893 |
| 2022 | 2,334,058 | 239,435 | 588 | 27,841 | 4,402 | 2 | 2,606,326 |
| 2023 | 2,361,664 | 241,852 | 587 | 27,913 | 4,545 | 2 | 2,636,562 |
| 2024 | 2,389,026 | 244,256 | 586 | 27,979 | 4,689 | 2 | 2,666,537 |
| 2025 | 2,415,268 | 246,592 | 585 | 28,038 | 4,832 | 2 | 2,695,316 |
| 2026 | 2,440,141 | 248,842 | 584 | 28,089 | 4,975 | 2 | 2,722,633 |
| 2027 | 2,463,923 | 251,022 | 583 | 28,132 | 5,118 | 2 | 2,748,780 |
| 2028 | 2,486,992 | 253,157 | 582 | 28,169 | 5,261 | 2 | 2,774,163 |
| 2029 | 2,509,494 | 255,257 | 581 | 28,201 | 5,405 | 2 | 2,798,939 |
| 2030 | 2,531,582 | 257,330 | 580 | 28,229 | 5,548 | 2 | 2,823,271 |
| 2031 | 2,553,860 | 259,419 | 579 | 28,257 | 5,695 | 2 | 2,847,811 |
| 2032 | 2,576,327 | 261,524 | 578 | 28,285 | 5,845 | 2 | 2,872,562 |

Note: Historic (2007 – 2016), Projected (2017 – 2032).

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# Appendix 2F – North Carolina Customer Count (DOM LSE)

| Year | Residential | Commercial | Industrial | Public Authority | Street and Traffic Lighting | Sales for Resale | Total |
|---|---|---|---|---|---|---|---|
| 2007 | 99,867 | 15,460 | 66 | 1,874 | 376 | 2 | 117,645 |
| 2008 | 100,497 | 15,502 | 60 | 1,867 | 397 | 2 | 118,325 |
| 2009 | 100,761 | 15,485 | 59 | 1,867 | 398 | 2 | 118,573 |
| 2010 | 101,005 | 15,457 | 56 | 1,857 | 395 | 2 | 118,772 |
| 2011 | 101,009 | 15,418 | 53 | 1,852 | 392 | 1 | 118,725 |
| 2012 | 101,024 | 15,501 | 50 | 1,849 | 390 | 1 | 118,815 |
| 2013 | 101,158 | 15,557 | 50 | 1,851 | 390 | 1 | 119,007 |
| 2014 | 101,326 | 15,614 | 52 | 1,853 | 386 | 1 | 119,231 |
| 2015 | 101,620 | 15,677 | 52 | 1,853 | 384 | 1 | 119,586 |
| 2016 | 102,079 | 15,775 | 51 | 1,846 | 381 | 1 | 120,133 |
| 2017 | 102,307 | 15,655 | 60 | 1,852 | 392 | 1 | 120,268 |
| 2018 | 102,653 | 15,684 | 61 | 1,849 | 394 | 1 | 120,642 |
| 2019 | 103,009 | 15,722 | 61 | 1,846 | 395 | 1 | 121,033 |
| 2020 | 103,343 | 15,757 | 61 | 1,843 | 395 | 1 | 121,400 |
| 2021 | 103,658 | 15,792 | 61 | 1,840 | 396 | 1 | 121,747 |
| 2022 | 103,977 | 15,826 | 61 | 1,838 | 397 | 1 | 122,100 |
| 2023 | 104,306 | 15,862 | 61 | 1,836 | 398 | 1 | 122,463 |
| 2024 | 104,632 | 15,897 | 60 | 1,834 | 398 | 1 | 122,822 |
| 2025 | 104,944 | 15,931 | 60 | 1,832 | 399 | 1 | 123,168 |
| 2026 | 105,240 | 15,964 | 60 | 1,831 | 400 | 1 | 123,496 |
| 2027 | 105,523 | 15,996 | 60 | 1,829 | 401 | 1 | 123,811 |
| 2028 | 105,798 | 16,027 | 60 | 1,828 | 402 | 1 | 124,116 |
| 2029 | 106,066 | 16,057 | 60 | 1,827 | 402 | 1 | 124,414 |
| 2030 | 106,329 | 16,088 | 60 | 1,827 | 403 | 1 | 124,708 |
| 2031 | 106,594 | 16,118 | 60 | 1,826 | 404 | 1 | 125,003 |
| 2032 | 106,862 | 16,149 | 60 | 1,825 | 405 | 1 | 125,301 |

Note: Historic (2007 – 2016), Projected (2017 – 2032).

# Appendix 2G – Zonal Summer and Winter Peak Demand (MW)

| Year | Summer Peak Demand (MW) | Winter Peak Demand (MW) |
|---|---|---|
| 2007 | 19,688 | 18,079 |
| 2008 | 19,051 | 17,028 |
| 2009 | 18,137 | 17,904 |
| 2010 | 19,140 | 17,689 |
| 2011 | 20,061 | 17,889 |
| 2012 | 19,249 | 16,881 |
| 2013 | 18,763 | 17,623 |
| 2014 | 18,692 | 19,784 |
| 2015 | 18,980 | 21,651 |
| 2016 | 19,538 | 18,948 |
| 2017 | 20,014 | 17,478 |
| 2018 | 20,442 | 17,702 |
| 2019 | 20,848 | 17,959 |
| 2020 | 21,208 | 18,232 |
| 2021 | 21,440 | 18,541 |
| 2022 | 21,795 | 18,932 |
| 2023 | 21,957 | 19,069 |
| 2024 | 22,364 | 19,243 |
| 2025 | 22,607 | 19,470 |
| 2026 | 22,888 | 19,642 |
| 2027 | 23,235 | 19,950 |
| 2028 | 23,402 | 20,245 |
| 2029 | 23,694 | 20,314 |
| 2030 | 24,065 | 20,466 |
| 2031 | 24,371 | 20,704 |
| 2032 | 24,681 | 20,945 |

Note: Historic (2007 – 2016), Projected (2017 – 2032).

# Appendix 2H – Summer & Winter Peaks for Plan C^T: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company — Schedule 5

POWER SUPPLY DATA

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| II. Load (MW) | | | | | | | | | | | | | | | | | | | |
| 1. Summer | | | | | | | | | | | | | | | | | | | |
| a. Adjusted Summer Peak(1) | 16,348 | 16,461 | 16,819 | 17,319 | 17,615 | 17,928 | 18,228 | 18,421 | 18,730 | 18,871 | 19,225 | 19,439 | 19,683 | 19,987 | 20,131 | 20,384 | 20,706 | 20,973 | 21,243 |
| b. Other Commitments(2) | -98 | 72 | 95 | 182 | 260 | 302 | 317 | 326 | 328 | 329 | 330 | 329 | 330 | 330 | 332 | 334 | 336 | 337 | 338 |
| c. Total System Summer Peak | 16,250 | 16,533 | 16,914 | 17,501 | 17,875 | 18,230 | 18,545 | 18,747 | 19,058 | 19,200 | 19,555 | 19,768 | 20,013 | 20,317 | 20,463 | 20,718 | 21,042 | 21,310 | 21,581 |
| d. Percent Increase in Total Summer Peak | -0.7% | 1.7% | 2.3% | 3.5% | 2.1% | 2.0% | 1.7% | 1.1% | 1.7% | 0.7% | 1.8% | 1.1% | 1.2% | 1.5% | 0.7% | 1.2% | 1.6% | 1.3% | 1.3% |
| 2. Winter | | | | | | | | | | | | | | | | | | | |
| a. Adjusted Winter Peak(1) | 16,938 | 18,616 | 16,078 | 14,923 | 15,084 | 15,280 | 15,510 | 15,777 | 16,116 | 16,235 | 16,385 | 16,583 | 16,733 | 17,003 | 17,255 | 17,315 | 17,446 | 17,650 | 17,857 |
| b. Other Commitments(2) | -98 | 72 | 95 | 121.0 | 152 | 177 | 182 | 181 | 179 | 178 | 178 | 175 | 172 | 168 | 169 | 169 | 169 | 170 | 170 |
| c. Total System Winter Peak | 16,840 | 18,688 | 16,173 | 15,044 | 15,236 | 15,457 | 15,692 | 15,958 | 16,295 | 16,413 | 16,563 | 16,758 | 16,905 | 17,171 | 17,424 | 17,484 | 17,615 | 17,820 | 18,027 |
| d. Percent Increase in Total Winter Peak | 11.5% | 11.0% | -13.5% | -7.0% | 1.3% | 1.5% | 1.5% | 1.7% | 2.1% | 0.7% | 0.9% | 1.2% | 0.9% | 1.6% | 1.5% | 0.3% | 0.8% | 1.2% | 1.2% |

(1) Adjusted load from Appendix 2I.

(2) Includes firm Additional Forecast, Conservation Efficiency, and Peak Adjustments from Appendix 2I.

# Appendix 2I – Projected Summer & Winter Peak Load & Energy Forecast for Plan C^T: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company — Schedule 1

I. PEAK LOAD AND ENERGY FORECAST

| | (ACTUAL)[1] | | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| 1. Utility Peak Load (MW) | | | | | | | | | | | | | | | | | | | |
| A. Summer | | | | | | | | | | | | | | | | | | | |
| 1a. Base Forecast | 16,249 | 16,530 | 16,914 | 17,501 | 17,875 | 18,230 | 18,545 | 18,747 | 19,058 | 19,200 | 19,555 | 19,768 | 20,013 | 20,317 | 20,463 | 20,718 | 21,042 | 21,310 | 21,581 |
| 1b. Additional Forecast | | | | | | | | | | | | | | | | | | | |
| NCEMC | 150 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 2. Conservation, Efficiency[5] | -52 | -72 | -95 | -182 | -260 | -302 | -317 | -326 | -328 | -329 | -330 | -329 | -330 | -330 | -332 | -334 | -336 | -337 | -338 |
| 3. Demand Response[2][5] | -74 | -82 | -103 | -85 | -86 | -86 | -87 | -87 | -88 | -88 | -88 | -88 | -88 | -88 | -88 | -88 | -88 | -88 | -88 |
| 4. Demand Response-Existing[2][3] | -3 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 |
| 5. Peak Adjustment | - | - | - | | | | | | | | | | | | | | | | |
| 6.. Adjusted Load | 16,348 | 16,461 | 16,819 | 17,319 | 17,615 | 17,928 | 18,228 | 18,421 | 18,730 | 18,871 | 19,225 | 19,439 | 19,683 | 19,987 | 20,131 | 20,384 | 20,706 | 20,973 | 21,243 |
| 7. % Increase in Adjusted Load (from previous year) | -0.7% | 0.7% | 2.2% | 3.0% | 1.7% | 1.8% | 1.7% | 1.1% | 1.7% | 0.8% | 1.9% | 1.1% | 1.3% | 1.5% | 0.7% | 1.3% | 1.6% | 1.3% | 1.3% |
| B. Winter | | | | | | | | | | | | | | | | | | | |
| 1a. Base Forecast | 16,840 | 18,688 | 16,173 | 15,044 | 15,236 | 15,457 | 15,692 | 15,958 | 16,295 | 16,413 | 16,563 | 16,758 | 16,905 | 17,171 | 17,424 | 17,484 | 17,615 | 17,820 | 18,027 |
| 1b. Additional Forecast | | | | | | | | | | | | | | | | | | | |
| NCEMC | 150 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 2. Conservation, Efficiency[5] | -52 | -72 | -95 | -121.0 | -152.0 | -177.0 | -182.0 | -181.0 | -179.0 | -178.0 | -178.0 | -175.0 | -172.0 | -168.0 | -169.0 | -169.0 | -169.0 | -170.0 | -170.0 |
| 3. Demand Response[2][4] | -14 | -5 | -4 | -7.0 | -7.0 | -8.0 | -9.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 |
| 4. Demand Response-Existing[2][3] | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 |
| 5. Adjusted Load | 16,938 | 18,616 | 16,078 | 14,923 | 15,084 | 15,280 | 15,510 | 15,777 | 16,116 | 16,235 | 16,385 | 16,583 | 16,733 | 17,003 | 17,255 | 17,315 | 17,446 | 17,650 | 17,857 |
| 6. % Increase in Adjusted Load | 11.4% | 9.9% | -13.6% | -7.2% | 1.1% | 1.3% | 1.5% | 1.7% | 2.1% | 0.7% | 0.9% | 1.2% | 0.9% | 1.6% | 1.5% | 0.3% | 0.8% | 1.2% | 1.2% |
| 2. Energy (GWh) | | | | | | | | | | | | | | | | | | | |
| A. Base Forecast | 84,401 | 84,755 | 84,698 | 86,940 | 88,442 | 89,680 | 91,046 | 92,170 | 94,178 | 95,262 | 96,599 | 97,448 | 98,495 | 99,640 | 101,119 | 102,047 | 102,990 | 104,268 | 105,562 |
| B. Additional Forecast | | | | | | | | | | | | | | | | | | | |
| Future BTM[6] | - | - | - | -416 | -416 | -416 | -416 | -416 | -416 | -416 | -416 | -416 | -416 | -416 | -416 | -416 | -416 | -416 | -416 |
| C. Conservation & Demand Response[5] | 365 | 460 | 581 | -810 | -1,096 | -1,165 | -1,224 | -1,231 | -1,217 | -1,214 | -1,209 | -1,202 | -1,198 | -1,190 | -1,197 | -1,204 | -1,212 | -1,215 | -1,221 |
| D. Demand Response-Existing[2][3] | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| E. Adjusted Energy | 84,767 | 85,214 | 85,279 | 85,714 | 86,930 | 88,099 | 89,406 | 90,523 | 92,545 | 93,632 | 94,974 | 95,830 | 96,881 | 98,034 | 99,506 | 100,427 | 101,362 | 102,637 | 103,925 |
| F. % Increase in Adjusted Energy | 1.1% | 0.5% | 0.1% | 0.5% | 1.4% | 1.3% | 1.5% | 1.2% | 2.2% | 1.2% | 1.4% | 0.9% | 1.1% | 1.2% | 1.5% | 0.9% | 0.9% | 1.3% | 1.3% |

(1) Actual metered data.

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

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

(4) Actual historical data based upon measured and verified EM&V results.

(5) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.

(6) Future BTM, which is not included in the Base forecast.

# Appendix 2J – Required Reserve Margin for Plan CT: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company

Schedule 6

POWER SUPPLY DATA (continued)

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| I. Reserve Margin(1) | | | | | | | | | | | | | | | | | | | |
| (Including Cold Reserve Capability) | | | | | | | | | | | | | | | | | | | |
| 1. Summer Reserve Margin | | | | | | | | | | | | | | | | | | | |
| a. MW(1) | 3,955 | 3,742 | 3,919 | 3,124 | 2,654 | 3,711 | 3,384 | 3,192 | 2,384 | 2,403 | 2,502 | 2,733 | 3,000 | 2,750 | 2,659 | 2,900 | 2,631 | 2,718 | 2,760 |
| b. Percent of Load | 24.2% | 22.7% | 23.2% | 18.0% | 15.1% | 20.7% | 18.6% | 17.3% | 12.7% | 12.7% | 13.0% | 14.1% | 15.2% | 13.8% | 13.2% | 14.2% | 12.7% | 13.0% | 13.0% |
| c. Actual Reserve Margin(3) | N/A | N/A | N/A | 17.0% | 13.6% | 19.0% | 16.8% | 15.6% | 7.2% | 6.8% | 5.1% | 12.4% | 13.6% | 12.1% | 11.6% | 11.6% | 11.1% | 11.4% | 10.9% |
| 2. Winter Reserve Margin | | | | | | | | | | | | | | | | | | | |
| a. MW(1) | N/A | N/A | N/A | 6,136 | 4,824 | 6,204 | 5,724 | 5,530 | 4,685 | 4,719 | 4,865 | 5,122 | 5,419 | 5,208 | 5,132 | 5,405 | 5,179 | 5,298 | 5,373 |
| b. Percent of Load | N/A | N/A | N/A | 41.1% | 32.0% | 40.6% | 36.9% | 35.0% | 29.1% | 29.1% | 29.7% | 30.9% | 32.4% | 30.6% | 29.7% | 31.2% | 29.7% | 30.0% | 30.1% |
| c. Actual Reserve Margin(3) | 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) | | | | | | | | | | | | | | | | | | | |
| (Excluding Cold Reserve Capability) | | | | | | | | | | | | | | | | | | | |
| 1. Summer Reserve Margin | | | | | | | | | | | | | | | | | | | |
| a. MW(1) | 3,955 | 3,742 | 3,919 | 3,124 | 2,654 | 3,711 | 3,384 | 3,192 | 2,384 | 2,403 | 2,502 | 2,733 | 3,000 | 2,750 | 2,659 | 2,900 | 2,631 | 2,718 | 2,760 |
| b. Percent of Load | 24.2% | 22.7% | 23.2% | 18.0% | 15.1% | 20.7% | 18.6% | 17.3% | 12.7% | 12.7% | 13.0% | 14.1% | 15.2% | 13.8% | 13.2% | 14.2% | 12.7% | 13.0% | 13.0% |
| c. Actual Reserve Margin(3) | N/A | N/A | N/A | 17.0% | 13.6% | 19.0% | 16.8% | 15.6% | 7.2% | 6.8% | 5.1% | 12.4% | 13.6% | 12.1% | 11.6% | 11.6% | 11.1% | 11.4% | 10.9% |
| 2. Winter Reserve Margin | | | | | | | | | | | | | | | | | | | |
| a. MW(1) | N/A | N/A | N/A | 6,136 | 4,824 | 6,204 | 5,724 | 5,530 | 4,685 | 4,719 | 4,865 | 5,122 | 5,419 | 5,208 | 5,132 | 5,405 | 5,179 | 5,298 | 5,375 |
| b. Percent of Load | N/A | N/A | N/A | 41.1% | 32.0% | 40.6% | 36.9% | 35.0% | 29.1% | 29.1% | 29.7% | 30.9% | 32.4% | 30.6% | 29.7% | 31.2% | 29.7% | 30.0% | 30.1% |
| c. Actual Reserve Margin(3) | 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(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 |

(1) To be calculated based on Total Net Capability for summer and winter.

(2) The Company and PJM forecast a summer peak throughout the Planning Period.

(3) Does not include spot purchases of capacity.

(4) The Company follows PJM reserve requirements which are based on LOLE.

# Appendix 2K – Economic Assumptions used In the Sales and Hourly Budget Forecast Model

## (Annual Growth Rate)

| Year | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | CAGR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Population: Total, (Ths.) | 8,509 | 8,574 | 8,640 | 8,706 | 8,772 | 8,836 | 8,900 | 8,964 | 9,027 | 9,089 | 9,150 | 9,210 | 9,269 | 9,327 | 9,384 | 9,439 | 0.7% |
| Disposable Personal Income; (Mil. 09$; SAAR) | 365,950 | 377,278 | 387,490 | 394,384 | 401,240 | 409,165 | 417,599 | 426,195 | 435,536 | 445,512 | 456,403 | 467,756 | 479,593 | 491,709 | 504,174 | 516,539 | 2.3% |
| Per Capita Disposable Personal Income; (C 09$; SAAR) | 43.0 | 44.0 | 44.9 | 45.3 | 45.8 | 46.3 | 46.9 | 47.6 | 48.3 | 49.0 | 49.9 | 50.8 | 51.8 | 52.7 | 53.7 | 54.7 | 1.6% |
| Residential Permits: Total, (#, SAAR) | 42,506 | 48,313 | 45,191 | 40,717 | 40,897 | 42,895 | 43,159 | 41,366 | 38,737 | 36,428 | 35,057 | 34,060 | 33,036 | 32,699 | 32,105 | 30,863 | -2.1% |
| Employment: Total Manufacturing, (Ths., SA) | 228 | 227 | 226 | 223 | 220 | 216 | 214 | 211 | 208 | 206 | 204 | 202 | 200 | 198 | 196 | 195 | -1.1% |
| Employment: Total Government, (Ths., SA) | 718.7 | 721.4 | 724.9 | 729.1 | 734.3 | 740.3 | 745.8 | 750.8 | 755.9 | 761.3 | 766.7 | 772.3 | 778.1 | 783.8 | 789.2 | 793.4 | 0.7% |
| Employment: Military personnel, (Ths., SA) | 135 | 133 | 131 | 129 | 128 | 127 | 127 | 126 | 126 | 125 | 125 | 124 | 124 | 124 | 123 | 123 | -0.6% |
| Employment: State and local government, (Ths., SA) | 539 | 542 | 545 | 549 | 554 | 560 | 565 | 570 | 575 | 580 | 586 | 591 | 596 | 602 | 607 | 611 | 0.8% |
| Employment: Commercial Sector (Ths., SA) | 2,844.4 | 2,895.8 | 2,946.0 | 2,970.3 | 2,983.4 | 3,003.2 | 3,029.1 | 3,053.0 | 3,077.3 | 3,102.5 | 3,127.5 | 3,152.7 | 3,179.0 | 3,206.0 | 3,234.0 | 3,263.5 | 0.9% |
| Gross State Product: Total Manufacturing; (Bil. Chained 2009 $; SAAR) | 39,054 | 39,979 | 40,547 | 40,828 | 41,230 | 41,727 | 42,317 | 42,896 | 43,490 | 44,138 | 44,831 | 45,550 | 46,269 | 46,973 | 47,674 | 48,352 | 1.4% |
| Gross State Product: Total; (Bil. Chained 2009 $; SAAR) | 459.0 | 473.2 | 483.8 | 491.2 | 500.1 | 510.5 | 521.3 | 531.6 | 542.1 | 553.2 | 564.6 | 575.9 | 587.3 | 598.7 | 610.1 | 621.5 | 2.0% |
| Gross State Product: Local Government; (Bil. Chained 2009 $; SAAR) | 35,094 | 35,409 | 35,616 | 35,798 | 36,188 | 36,640 | 37,058 | 37,452 | 37,852 | 38,256 | 38,638 | 38,979 | 39,307 | 39,623 | 39,929 | 40,247 | 0.92% |

Source: Economy.com October 2016 vintage

| Year | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | CAGR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Population: Total, (Ths.) | 8,460 | 8,530 | 8,601 | 8,672 | 8,742 | 8,812 | 8,881 | 8,950 | 9,017 | 9,084 | 9,149 | 9,213 | 9,276 | 9,337 | 9,398 | 9,457 | 0.7% |
| Disposable Personal Income; (Mil. 09$; SAAR) | 361,796 | 376,487 | 391,916 | 401,253 | 407,657 | 414,967 | 423,047 | 431,289 | 439,572 | 448,502 | 458,073 | 468,674 | 479,719 | 491,195 | 503,004 | 514,989 | 2.4% |
| Per Capita Disposable Personal Income; (C 09$; SAAR) | 42.8 | 44.1 | 45.6 | 46.3 | 46.6 | 47.1 | 47.6 | 48.2 | 48.8 | 49.4 | 50.1 | 50.9 | 51.7 | 52.6 | 53.5 | 54.5 | 1.6% |
| Residential Permits: Total, (#, SAAR) | 41,215 | 48,965 | 50,700 | 48,332 | 48,682 | 50,797 | 52,252 | 51,558 | 48,937 | 46,053 | 43,973 | 42,642 | 41,570 | 40,561 | 40,164 | 39,716 | -0.2% |
| Employment: Total Manufacturing, (Ths., SA) | 235 | 235 | 236 | 235 | 232 | 228 | 225 | 222 | 219 | 216 | 214 | 211 | 209 | 207 | 206 | 204 | -0.9% |
| Employment: Total Government, (Ths., SA) | 712.2 | 714.2 | 716.6 | 719.4 | 722.7 | 727.4 | 733.2 | 738.4 | 743.1 | 747.8 | 752.6 | 757.5 | 762.6 | 767.9 | 773.3 | 778.4 | 0.6% |
| Employment: Military personnel, (Ths., SA) | 136 | 133 | 131 | 129 | 127 | 126 | 125 | 125 | 124 | 124 | 124 | 123 | 123 | 122 | 122 | 121 | -0.7% |
| Employment: State and local government, (Ths., SA) | 542 | 544 | 547 | 550 | 553 | 558 | 563 | 568 | 573 | 578 | 583 | 587 | 592 | 598 | 603 | 608 | 0.8% |
| Employment: Commercial Sector (Ths., SA) | 2,728.3 | 2,798.2 | 2,866.8 | 2,914.0 | 2,933.4 | 2,948.4 | 2,969.9 | 2,994.0 | 3,015.7 | 3,038.3 | 3,061.7 | 3,084.8 | 3,108.8 | 3,134.6 | 3,161.4 | 3,188.7 | 1.0% |
| Gross State Product: Total Manufacturing; (Bil. Chained 2009 $; SAAR) | 40,619 | 41,758 | 42,620 | 43,283 | 43,699 | 44,198 | 44,781 | 45,372 | 45,928 | 46,499 | 47,123 | 47,808 | 48,535 | 49,275 | 50,007 | 50,733 | 1.5% |
| Gross State Product: Total; (Bil. Chained 2009 $; SAAR) | 451.4 | 467.2 | 480.9 | 491.2 | 499.3 | 508.7 | 519.1 | 529.3 | 539.0 | 548.8 | 559.0 | 569.8 | 581.0 | 592.5 | 604.1 | 615.8 | 2.1% |
| Gross State Product: Local Government; (Bil. Chained 2009 $; SAAR) | 36,330 | 36,794 | 37,117 | 37,294 | 37,488 | 37,838 | 38,234 | 38,614 | 38,968 | 39,325 | 39,687 | 40,038 | 40,364 | 40,676 | 40,973 | 41,265 | 0.85% |

Source: Economy.com December 2015 vintage

# 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[2] | MW Winter[2] |
|---|---|---|---|---|---|---|
| Altavista | Altavista, VA | Base | Renewable | Feb-1992 | 51 | 51 |
| Bath County 1-6 | Warm Springs, VA | Intermediate | Hydro-Pumped Storage | Dec-1985 | 1,808 | 1,808 |
| Bear Garden | Buckingham County, VA | Intermediate | Natural Gas-CC | May-2011 | 616 | 622 |
| Bellemeade | Richmond, VA | Intermediate | Natural Gas-CC | Mar-1991 | 267 | 267 |
| Bremo 3 | Bremo Bluff, VA | Peak | Natural Gas | Jun-1950 | 71 | 74 |
| Bremo 4 | Bremo Bluff, VA | Peak | Natural Gas | Aug-1958 | 156 | 161 |
| Brunswick | Brunswick County, VA | Intermediate | Natural Gas-CC | May-2016 | 1,376 | 1,509 |
| Chesapeake CT 1, 2, 4, 6 | Chesapeake, VA | Peak | Light Fuel Oil | Dec-1967 | 51 | 69 |
| Chesterfield 3 | Chester, VA | Base | Coal | Dec-1952 | 98 | 102 |
| Chesterfield 4 | Chester, VA | Base | Coal | Jun-1960 | 163 | 168 |
| Chesterfield 5 | Chester, VA | Base | Coal | Aug-1964 | 336 | 342 |
| Chesterfield 6 | Chester, VA | Base | Coal | Dec-1969 | 670 | 690 |
| 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 | 220 | 222 |
| Clover 2 | Clover, VA | Base | Coal | Mar-1996 | 219 | 219 |
| Cushaw Hydro | Big Island, VA | Intermediate | Hydro-Conventional | Jan-1930 | 2 | 3 |
| Darbytown 1 | Richmond, VA | Peak | Natural Gas-Turbine | May-1990 | 84 | 98 |
| Darbytown 2 | Richmond, VA | Peak | Natural Gas-Turbine | May-1990 | 84 | 97 |
| Darbytown 3 | Richmond, VA | Peak | Natural Gas-Turbine | Apr-1990 | 84 | 95 |
| Darbytown 4 | Richmond, VA | Peak | Natural Gas-Turbine | Apr-1990 | 84 | 97 |
| Elizabeth River 1 | Chesapeake, VA | Peak | Natural Gas-Turbine | Jun-1992 | 116 | 121 |
| Elizabeth River 2 | Chesapeake, VA | Peak | Natural Gas-Turbine | Jun-1992 | 116 | 120 |
| Elizabeth River 3 | Chesapeake, VA | Peak | Natural Gas-Turbine | Jun-1992 | 116 | 124 |
| Gaston Hydro | Roanoake Rapids, NC | Intermediate | Hydro-Conventional | Feb-1963 | 220 | 220 |
| Gordonsville 1 | Gordonsville, VA | Intermediate | Natural Gas-CC | Jun-1994 | 109 | 139 |
| Gordonsville 2 | Gordonsville, VA | Intermediate | Natural Gas-CC | Jun-1994 | 109 | 139 |
| Gravel Neck 1-2 | Surry, VA | Peak | Light Fuel Oil | Aug-1970 | 28 | 38 |
| Gravel Neck 3 | Surry, VA | Peak | Natural Gas-Turbine | Oct-1989 | 85 | 98 |
| Gravel Neck 4 | Surry, VA | Peak | Natural Gas-Turbine | Jul-1989 | 85 | 97 |
| Gravel Neck 5 | Surry, VA | Peak | Natural Gas-Turbine | Jul-1989 | 85 | 98 |
| Gravel Neck 6 | Surry, VA | Peak | Natural Gas-Turbine | Nov-1989 | 85 | 97 |
| Hopewell | Hopewell, VA | Base | Renewable | Jul-1989 | 51 | 51 |
| Ladysmith 1 | Woodford, VA | Peak | Natural Gas-Turbine | May-2001 | 151 | 183 |
| Ladysmith 2 | Woodford, VA | Peak | Natural Gas-Turbine | May-2001 | 151 | 183 |
| Ladysmith 3 | Woodford, VA | Peak | Natural Gas-Turbine | Jun-2008 | 161 | 183 |
| Ladysmith 4 | Woodford, VA | Peak | Natural Gas-Turbine | Jun-2008 | 160 | 183 |
| Ladysmith 5 | Woodford, VA | Peak | Natural Gas-Turbine | Apr-2009 | 160 | 183 |
| Lowmoor CT 1-4 | Covington, VA | Peak | Light Fuel Oil | Jul-1971 | 48 | 65 |
| Mecklenburg 1 | Clarksville, VA | Base | Coal | Nov-1992 | 69 | 69 |
| Mecklenburg 2 | Clarksville, VA | Base | Coal | Nov-1992 | 69 | 69 |

(1) Commercial Operation Date.

(2) All values shown are nameplate capacity (MW) and do not necessarily represent contribution at peak.

# Appendix 3A cont. – Existing Generation Units in Service

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

| Unit Name | Location | Unit Class | Primary Fuel Type | C.O.D.(1) | MW Summer(2) | MW Winter(2) |
|---|---|---|---|---|---|---|
| Mount Storm 1 | Mt. Storm, WV | Base | Coal | Sep-1965 | 554 | 569 |
| Mount Storm 2 | Mt. Storm, WV | Base | Coal | Jul-1966 | 555 | 570 |
| Mount Storm 3 | Mt. Storm, WV | Base | Coal | Dec-1973 | 520 | 573 |
| Mount Storm CT | Mt. Storm, WV | Peak | Light Fuel Oil | Oct-1967 | 11 | 15 |
| North Anna 1 | Mineral, VA | Base | Nuclear | Jun-1978 | 838 | 868 |
| North Anna 2 | Mineral, VA | Base | Nuclear | Dec-1980 | 834 | 863 |
| North Anna Hydro | Mineral, VA | Intermediate | Hydro-Conventional | Dec-1987 | 1 | 1 |
| Northern Neck CT 1-4 | Warsaw, VA | Peak | Light Fuel Oil | Jul-1971 | 47 | 70 |
| Pittsylvania | Hurt, VA | Base | Renewable | Jun-1994 | 83 | 83 |
| Possum Point 3 | Dumfries, VA | Peak | Natural Gas | Jun-1955 | 96 | 100 |
| Possum Point 4 | Dumfries, VA | Peak | Natural Gas | Apr-1962 | 220 | 225 |
| Possum Point 5 | Dumfries, VA | Peak | Heavy Fuel Oil | Jun-1975 | 786 | 805 |
| Possum Point 6 | Dumfries, VA | Intermediate | Natural Gas-CC | Jul-2003 | 573 | 615 |
| Possum Point CT 1-6 | Dumfries, VA | Peak | Light Fuel Oil | May-1968 | 72 | 106 |
| Remington 1 | Remington, VA | Peak | Natural Gas-Turbine | Jul-2000 | 153 | 187 |
| Remington 2 | Remington, VA | Peak | Natural Gas-Turbine | Jul-2000 | 151 | 187 |
| Remington 3 | Remington, VA | Peak | Natural Gas-Turbine | Jul-2000 | 152 | 187 |
| Remington 4 | Remington, VA | Peak | Natural Gas-Turbine | Jul-2000 | 152 | 188 |
| Roanoke Rapids Hydro | Roanoake Rapids, NC | Intermediate | Hydro-Conventional | Sep-1955 | 95 | 95 |
| Rosemary | Roanoke Rapids, NC | Peak | Natural Gas-CC | Dec-1990 | 165 | 165 |
| Scott Solar | Powhatan, VA | Intermittent | Renewable | Dec-2016 | 17 | 17 |
| Solar Partnership Program | Distributed | Intermittent | Renewable | Jan-2012 | 7 | 7 |
| Southampton | Franklin, VA | Base | Renewable | Mar-1992 | 51 | 51 |
| Surry 1 | Surry, VA | Base | Nuclear | Dec-1972 | 838 | 875 |
| Surry 2 | Surry, VA | Base | Nuclear | May-1973 | 838 | 875 |
| Virginia City Hybrid Energy Center | Virginia City, VA | Base | Coal | Jul-2012 | 610 | 624 |
| Warren | Warrenton, VA | Intermediate | Natural Gas-CC | Dec-2014 | 1,342 | 1,436 |
| Whitehouse Solar | Louisa, VA | Intermittent | Renewable | Dec-2016 | 20 | 20 |
| Woodland Solar | Isle of Wight, VA | Intermittent | Renewable | Dec-2016 | 19 | 19 |
| Yorktown 1 | Yorktown, VA | Base | Coal | Jul-1957 | 0 | 0 |
| Yorktown 2 | Yorktown, VA | Base | Coal | Jan-1959 | 0 | 0 |
| Yorktown 3 | Yorktown, VA | Peak | Heavy Fuel Oil | Dec-1974 | 790 | 792 |
| ***Subtotal - Base*** | | | | | 7,667 | 7,897 |
| ***Subtotal - Intermediate*** | | | | | 6,915 | 7,316 |
| ***Subtotal - Peak*** | | | | | 4,956 | 5,491 |
| ***Subtotal - Intermittent*** | | | | | 63 | 63 |
| ***Total*** | | | | | 19,602 | 20,768 |

(1) Commercial Operation Date.

(2) All values shown are nameplate capacity (MW) and do not necessarily represent contribution at peak.

part 6





# Appendix 3B – Other Generation Units

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

**UNIT PERFORMANCE DATA**

**Existing Supply-Side Resources (kW)**

| Unit Name | Location | Unit Class | Primary Fuel Type | kW Summer | Capacity Resource | Contract Start | Contract Expiration |
|---|---|---|---|---|---|---|---|
| **Non-Utility Generation (NUG) Units(1)** | | | | | | | |
| Spruance Genco, Facility 1 (Richmond 1) | Richmond, VA | Base | Coal | 115,500 | Yes | 8/1/1992 | 7/31/2017 |
| Spruance Genco, Facility 2 (Richmond 2) | Richmond, VA | Base | Coal | 85,000 | Yes | 8/1/1992 | 7/31/2017 |
| Doswell Complex | Ashland, VA | Intermedia | Natural Gas | 605,000 | Yes | 5/16/1992 | 5/5/2017 |
| Roanoke Valley II | Weldon, NC | Base | Coal | 44,000 | Yes | 6/1/1995 | 3/31/2019 |
| Roanoke Valley Project | Weldon, NC | Base | Coal | 165,000 | Yes | 5/29/1994 | 3/31/2019 |
| SEI Birchwood | King George, VA | Base | Coal | 217,800 | Yes | 11/15/1996 | 11/14/2021 |
| **Behind-The-Meter (BTM) Generation Units** | | | | | | | |
| BTM Alexandria/Arlington - Covanta | VA | NUG | MSW | 21,000 | No | 1/29/1988 | 1/28/2023 |
| BTM Brasfield Dam | VA | Must Take | Hydro | 2,500 | No | 10/12/1993 | Auto renew |
| BTM Suffolk Landfill | VA | Must Take | Methane | 3,000 | No | 11/4/1994 | Auto renew |
| BTM Columbia Mills | VA | Must Take | Hydro | 343 | No | 2/7/1985 | Auto renew |
| BTM Schoolfield Dam | VA | Must Take | Hydro | 2,500 | No | 12/1/1990 | 1/218/2017 |
| BTM Lakeview (Swift Creek) Dam | VA | Must Take | Hydro | 400 | No | 11/26/2008 | Auto renew |
| BTM MeadWestvaco (formerly Westvaco) | VA | NUG | Coal/Biomass | 140,000 | No | 11/3/1982 | 12/31/2028 |
| BTM Banister Dam | VA | Must Take | Hydro | 1,785 | No | 9/28/2008 | Auto renew |
| BTM Jockey's Ridge State Park | NC | Must Take | Wind | 10 | No | 5/21/2010 | Auto renew |
| BTM 302 First Flight Run | NC | Must Take | Solar | 3 | No | 5/5/2010 | Auto renew |
| BTM 3620 Virginia Dare Trail N | NC | Must Take | Solar | 4 | No | 9/14/2009 | Auto renew |
| BTM Weyerhaeuser/Domtar | NC | NUG | Coal/biomass | 28400(2) | No | 7/27/1991 | Auto renew |
| BTM Chapman Dam | VA | Must Take | Hydro | 300 | No | 10/17/1984 | Auto renew |
| BTM Smurfit-Stone Container | VA | NUG | Coal/biomass | 48400(3) | No | 3/21/1981 | Auto renew |
| BTM Rivanna | VA | Must Take | Hydro | 100 | No | 4/21/1998 | Auto renew |
| BTM Rapidan Mill | VA | Must Take | Hydro | 100 | No | 6/15/2009 | Auto renew |
| BTM Burnshire Dam | VA | Must Take | Hydro | 100 | No | 7/11/2018 | Auto renew |
| BTM Dairy Energy | VA | Must Take | Biomass | 400 | No | 8/2/2011 | 8/1/2016 |
| BTM W. E. Partners II | NC | Must Take | Biomass | 300 | No | 3/15/2012 | 3/14/2017 |
| BTM Plymouth Solar | NC | Must Take | Solar | 5,000 | No | 10/4/2012 | 10/3/2027 |
| BTM W. E. Partners 1 | NC | Must Take | Biomass | 100 | No | 4/26/2013 | 4/25/2017 |
| BTM Dogwood Solar | NC | Must Take | Solar | 20,000 | No | 12/9/2014 | 12/8/2029 |

(1) In operation as of March 1, 2017.

(2) Agreement to provide excess energy only.

(3) PPA is for excess energy only, typically 4,000 – 14,000 kW.

# Appendix 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Behind-The-Meter (BTM) Generation Units | | | | | | | |
| BTM HXOap Solar | NC | Must Take | Solar | 20,000 | No | 12/16/2014 | 12/15/2029 |
| BTM Bethel Price Solar | NC | Must Take | Solar | 5,000 | No | 12/9/2014 | 12/8/2029 |
| BTM Jakana Solar | NC | Must Take | Solar | 5,000 | No | 12/4/2014 | 12/3/2029 |
| BTM Lewiston Solar | NC | Must Take | Solar | 5,000 | No | 12/18/2014 | 12/17/2029 |
| BTM Williamston Solar | NC | Must Take | Solar | 5,000 | No | 12/4/2014 | 12/3/2029 |
| BTM Windsor Solar | NC | Must Take | Solar | 5,000 | No | 12/17/2014 | 12/16/2029 |
| BTM 510 REPP One Solar | NC | Must Take | Solar | 5,000 | No | 3/11/2015 | 3/10/2030 |
| BTM Everetts Wildcat Solar | NC | Must Take | Solar | 5,000 | No | 3/11/2015 | 3/10/2030 |
| SolNC5 Solar | NC | Must Take | Solar | 5,000 | No | 5/12/2015 | 5/11/2030 |
| Creswell Allgood Solar | NC | Must Take | Solar | 14,000 | No | 5/13/2015 | 5/12/2030 |
| Two Mile Desert Road - SolNC1 | NC | Must Take | Solar | 5,000 | No | 8/10/2015 | 8/9/2030 |
| SolNCPower6 Solar | NC | Must Take | Solar | 5,000 | No | 11/1/2015 | 10/31/2030 |
| Downs Farm Solar | NC | Must Take | Solar | 5,000 | No | 12/1/2015 | 11/30/2030 |
| GKS Solar- SolNC2 | NC | Must Take | Solar | 5,000 | No | 12/16/2015 | 12/15/2030 |
| Windsor Cooper Hill Solar | NC | Must Take | Solar | 5,000 | No | 12/18/2015 | 12/17/2030 |
| Green Farm Solar | NC | Must Take | Solar | 5,000 | No | 1/6/2016 | 1/5/2031 |
| FAE X - Shawboro | NC | Must Take | Solar | 20,000 | No | 1/26/2016 | 1/25/2031 |
| FAE XVII - Watson Seed | NC | Must Take | Solar | 20,000 | No | 1/28/2016 | 1/27/2031 |
| Bradley PVI- FAE IX | NC | Must Take | Solar | 5,000 | No | 2/4/2016 | 2/3/2031 |
| Conetoe Solar | NC | Must Take | Solar | 5,000 | No | 2/5/2016 | 2/4/2031 |
| SolNC3 Solar | NC | Must Take | Solar | 5,000 | No | 2/5/2016 | 2/4/2031 |
| Gates Solar | NC | Must Take | Solar | 5,000 | No | 2/8/2016 | 2/7/2031 |
| Long Farm 46 Solar | NC | Must Take | Solar | 5,000 | No | 2/12/2016 | 2/11/2031 |
| Battboro Farm Solar | NC | Must Take | Solar | 5,000 | No | 2/17/2016 | 2/16/2031 |
| Winton Solar | NC | Must Take | Solar | 5,000 | No | 2/8/2016 | 2/7/2031 |
| SolNC10 Solar | NC | Must Take | Solar | 5,000 | No | 1/13/2016 | 1/12/2031 |
| Tarboro Solar | NC | Must Take | Solar | 5,000 | No | 12/31/2015 | 12/30/2030 |
| Bethel Solar | NC | Must Take | Solar | 4,400 | No | 3/3/2016 | 3/2/2031 |
| Garysburg Solar | NC | Must Take | Solar | 5,000 | No | 3/18/2016 | 3/17/2031 |
| Woodland Solar | NC | Must Take | Solar | 5,000 | No | 4/7/2016 | 4/6/2031 |
| Gaston Solar | NC | Must Take | Solar | 5,000 | No | 4/18/2016 | 4/17/2031 |
| TWE Kelford Solar | NC | Must Take | Solar | 4,700 | No | 6/6/2016 | 6/5/2031 |
| FAE XVIII - Meadows | NC | Must Take | Solar | 20,000 | No | 6/9/2016 | 6/8/2031 |
| Seaboard Solar | NC | Must Take | Solar | 5,000 | No | 6/29/2016 | 6/28/2031 |
| Simons Farm Solar | NC | Must Take | Solar | 5,000 | No | 7/13/2016 | 7/12/2031 |
| Whitakers Farm Solar | NC | Must Take | Solar | 3,400 | No | 7/20/2016 | 7/19/2031 |
| MC1 Solar | NC | Must Take | Solar | 5,000 | No | 8/19/2016 | 8/18/2031 |
| Williamston West Farm Solar | NC | Must Take | Solar | 5,000 | No | 8/23/2016 | 8/22/2031 |
| River Road Solar | NC | Must Take | Solar | 5,000 | No | 8/23/2016 | 8/22/2031 |
| White Farm Solar | NC | Must Take | Solar | 5,000 | No | 8/26/2016 | 8/25/2031 |
| Hardison Farm Solar | NC | Must Take | Solar | 5,000 | No | 9/9/2016 | 9/8/2031 |
| Modlin Farm Solar | NC | Must Take | Solar | 5,000 | No | 9/14/2016 | 9/13/2031 |
| Battleboro Solar | NC | Must Take | Solar | 5,000 | No | 10/7/2016 | 10/6/2031 |
| Williamston Speight Solar | NC | Must Take | Solar | 15,000 | No | 11/23/2016 | 11/22/2031 |
| Barnhill Road Solar | NC | Must Take | Solar | 3,100 | No | 11/30/2016 | 11/29/2031 |
| Hemlock Solar | NC | Must Take | Solar | 5,000 | No | 12/5/2016 | 12/4/2031 |
| Leggett Solar | NC | Must Take | Solar | 5,000 | No | 12/14/2016 | 12/13/2031 |
| Schell Solar Farm | NC | Must Take | Solar | 5,000 | No | 12/22/2016 | 12/21/2031 |

# Appendix 3B cont. – Other Generation Units

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

Schedule 14b

**UNIT PERFORMANCE DATA**

**Existing Supply-Side Resources (kW)**

| Unit Name | Location | Unit Class | Primary Fuel Type | kW Summer | Capacity Resource | Contract Start | Contract Expiration |
|---|---|---|---|---|---|---|---|
| Customer Owned[3] | | | | | | | |
| | Ahoskie | Standby | Diesel | 2550 | No | N/A | N/A |
| | Tillery | Standby | Diesel | 585 | No | N/A | N/A |
| | Whitakers | Standby | Diesel | 10000 | No | N/A | N/A |
| | Columbia | Standby | Diesel | 400 | No | N/A | N/A |
| | Grandy | Standby | Diesel | 400 | No | N/A | N/A |
| | Kill Devil Hills | Standby | Diesel | 500 | No | N/A | N/A |
| | Moyock | Standby | Diesel | 350 | No | N/A | N/A |
| | Nags Head | Standby | Diesel | 400 | No | N/A | N/A |
| | Nags Head | Standby | Diesel | 450 | No | N/A | N/A |
| | Roanoke Rapids | Standby | Diesel | 400 | No | N/A | N/A |
| | Conway | Standby | Diesel | 500 | No | N/A | N/A |
| | Conway | Standby | Diesel | 500 | No | N/A | N/A |
| | Roanoke Rapids | Standby | Diesel | 500 | No | N/A | N/A |
| | Corolla | Standby | Diesel | 700 | No | N/A | N/A |
| | Kill Devil Hills | Standby | Diesel | 700 | No | N/A | N/A |
| | Rocky Mount | Standby | Diesel | 700 | No | N/A | N/A |
| | Roanoke Rapids | Standby | Coal | 25000 | No | N/A | N/A |
| | Manteo | Standby | Diesel | 300 | No | N/A | N/A |
| | Conway | Standby | Diesel | 800 | No | N/A | N/A |
| | Lewiston | Standby | Diesel | 4000 | No | N/A | N/A |
| | Roanoke Rapids | Standby | Diesel | 1200 | No | N/A | N/A |
| | Weldon | Standby | Diesel | 750 | No | N/A | N/A |
| | Tillery | Standby | Diesel | 450 | No | N/A | N/A |
| | Elizabeth City | Standby | Unknown | 2000 | No | N/A | N/A |
| | Greenville | Standby | Diesel | 1800 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 50 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 1270 | No | N/A | N/A |
| | Alexandria | Standby | Diesel | 300 | No | N/A | N/A |
| | Alexandria | Standby | Diesel | 475 | No | N/A | N/A |
| | Alexandria | Standby | Diesel | 2 - 60 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 14000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 10000 | No | N/A | N/A |
| | Norfolk | Standby | Diesel | 4000 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 4470 | No | N/A | N/A |
| | Arlington | Standby | Diesel | 5650 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 22950 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 50 | No | N/A | N/A |
| | Hampton Roads | Standby | Diesel | 3000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 900 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 20110 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 3500 | No | N/A | N/A |
| | Richmond | Standby | Natural Gas | 10 | No | N/A | N/A |
| | Richmond | Standby | LP | 120 | No | N/A | N/A |
| | VA Beach | Standby | Diesel | 2000 | No | N/A | N/A |

# Appendix 3B cont. – Other Generation Units

Company Name: Virginia Electric and Power Company

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Schedule 14b

| Unit Name | Location | Unit Class | Primary Fuel Type | kW Summer | Capacity Resource | Contract Start | Contract Expiration |
|---|---|---|---|---|---|---|---|
| Customer Owned[3] | | | | | | | |
| | Chesapeake | Standby | Diesel | 500 | No | N/A | N/A |
| | Chesapeake | Standby | Diesel | 2500 | No | N/A | N/A |
| | Fredericksburg | Standby | Diesel | 700 | No | N/A | N/A |
| | Hopewell | Standby | Diesel | 75 | No | N/A | N/A |
| | Newport News | Standby | Unknown | 1000 | No | N/A | N/A |
| | Newport News | Standby | Unknown | 4500 | No | N/A | N/A |
| | Norfolk | Standby | Diesel | 2000 | No | N/A | N/A |
| | Norfolk | Standby | Diesel | 9000 | No | N/A | N/A |
| | Portsmouth | Standby | Diesel | 2250 | No | N/A | N/A |
| | VA Beach | Standby | Diesel | 3500 | No | N/A | N/A |
| | VA Beach | Standby | Diesel | 2000 | No | N/A | N/A |
| | Chesterfield | Standby | Diesel | 2000 | No | N/A | N/A |
| | Central VA | Merchant | Coal | 92000 | No | N/A | N/A |
| | Central VA | Merchant | Coal | 115000 | No | N/A | N/A |
| | Williamsburg | Standby | Diesel | 2800 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 30000 | No | N/A | N/A |
| | Charlottesville | Standby | Diesel | 40000 | No | N/A | N/A |
| | Arlington | Standby | Diesel | 13042 | No | N/A | N/A |
| | Arlington | Standby | Diesel/ Natural Gas | 5000 | No | N/A | N/A |
| | Fauquier | Standby | Diesel | 1885 | No | N/A | N/A |
| | Hanover | Standby | Diesel | 12709.5 | No | N/A | N/A |
| | Hanover | Standby | Natural Gas | 13759.5 | No | N/A | N/A |
| | Hanover | Standby | LP | 81.25 | No | N/A | N/A |
| | Henrico | Standby | Natural Gas | 1341 | No | N/A | N/A |
| | Henrico | Standby | LP | 126 | No | N/A | N/A |
| | Henrico | Standby | Diesel | 828 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 200 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 8000 | No | N/A | N/A |
| | Newport News | Standby | Diesel | 1750 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 37000 | No | N/A | N/A |
| | Chesapeake | Standby | Unknown | 750 | No | N/A | N/A |
| | Northern VA | Merchant | Natural Gas | 50000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 138000 | No | N/A | N/A |
| | Richmond | Standby | Steam | 20000 | No | N/A | N/A |
| | Herndon | Standby | Diesel | 415 | No | N/A | N/A |
| | Herndon | Standby | Diesel | 50 | No | N/A | N/A |
| | VA | Merchant | Hydro | 2700 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 37000 | No | N/A | N/A |
| | Fairfax County | Standby | Diesel | 20205 | No | N/A | N/A |
| | Fairfax County | Standby | Natural Gas | 2139 | No | N/A | N/A |
| | Fairfax County | Standby | LP | 292 | No | N/A | N/A |
| | Springfield | Standby | Diesel | 6500 | No | N/A | N/A |
| | Warrenton | Standby | Diesel | 2 - 750 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 5350 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 16400 | No | N/A | N/A |
| | Norfolk | Standby | Diesel | 350 | No | N/A | N/A |

# Appendix 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

| Unit Name | Location | Unit Class | Primary Fuel Type | kW Summer | Capacity Resource | Contract Start | Contract Expiration |
|---|---|---|---|---|---|---|---|
| Customer Owned[3] | | | | | | | |
| | Charlottesville | Standby | Diesel | 400 | No | N/A | N/A |
| | Farmville | Standby | Diesel | 350 | No | N/A | N/A |
| | Mechanicsville | Standby | Diesel | 350 | No | N/A | N/A |
| | King George | Standby | Diesel | 350 | No | N/A | N/A |
| | Chatham | Standby | Diesel | 350 | No | N/A | N/A |
| | Hampton | Standby | Diesel | 350 | No | N/A | N/A |
| | Virginia Beach | Standby | Diesel | 350 | No | N/A | N/A |
| | Portsmouth | Standby | Diesel | 400 | No | N/A | N/A |
| | Powhatan | Standby | Diesel | 350 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 350 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 350 | No | N/A | N/A |
| | Chesapeake | Standby | Diesel | 400 | No | N/A | N/A |
| | Newport News | Standby | Diesel | 350 | No | N/A | N/A |
| | Dinwiddie | Standby | Diesel | 300 | No | N/A | N/A |
| | Goochland | Standby | Diesel | 350 | No | N/A | N/A |
| | Portsmouth | Standby | Diesel | 350 | No | N/A | N/A |
| | Fredericksburg | Standby | Diesel | 350 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 22690 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 5000 | No | N/A | N/A |
| | Hampton Roads | Standby | Diesel | 15100 | No | N/A | N/A |
| | Herndon | Standby | Diesel | 1250 | No | N/A | N/A |
| | Herndon | Standby | Diesel | 500 | No | N/A | N/A |
| | Henrico | Standby | Diesel | 1000 | No | N/A | N/A |
| | Alexandria | Standby | Diesel | 2 - 910 | No | N/A | N/A |
| | Alexandria | Standby | Diesel | 1000 | No | N/A | N/A |
| | Fairfax | Standby | Diesel | 4 - 750 | No | N/A | N/A |
| | Loudoun | Standby | Diesel | 2100 | No | N/A | N/A |
| | Loudoun | Standby | Diesel | 710 | No | N/A | N/A |
| | Mount Vernon | Standby | Diesel | 1500 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 50 | No | N/A | N/A |
| | Eastern VA | Standby | Black Liquor/Natural Gas | 112500 | No | N/A | N/A |
| | Central VA | Standby | Diesel | 1700 | No | N/A | N/A |
| | Hopewell | Standby | Diesel | 500 | No | N/A | N/A |
| | Falls Church | Standby | Diesel | 200 | No | N/A | N/A |
| | Falls Church. | Standby | Diesel | 250 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 500 | No | N/A | N/A |
| | Fredericksburg | Standby | Diesel | 4200 | No | N/A | N/A |
| | Norfolk | Standby | NG | 1050 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 6400 | No | N/A | N/A |
| | Henrico | Standby | Diesel | 500 | No | N/A | N/A |
| | Elkton | Standby | Natural Gas | 6000 | No | N/A | N/A |
| | Southside VA | Standby | Diesel | 30000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 5000 | No | N/A | N/A |
| | Northern VA | Standby | #2 FO | 5000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 50 | No | N/A | N/A |
| | Vienna | Standby | Diesel | 5000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 200 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 50 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 1270 | No | N/A | N/A |

# Appendix 3B cont. – Other Generation Units

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

**UNIT PERFORMANCE DATA**

**Existing Supply-Side Resources (kW)**

| Unit Name | Location | Unit Class | Primary Fuel Type | kW Summer | Capacity Resource | Contract Start | Contract Expiration |
|---|---|---|---|---|---|---|---|
| Customer Owned[3] | | | | | | | |
| | Alexandria | Standby | Diesel | 300 | No | N/A | N/A |
| | Alexandria | Standby | Diesel | 475 | No | N/A | N/A |
| | Alexandria | Standby | Diesel | 2 - 60 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 14000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 10000 | No | N/A | N/A |
| | Norfolk | Standby | Diesel | 4000 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 4470 | No | N/A | N/A |
| | Arlington | Standby | Diesel | 5650 | No | N/A | N/A |
| | Ashburn | Standby | Diesel | 22000 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 22950 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 50 | No | N/A | N/A |
| | Hampton Roads | Standby | Diesel | 3000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 900 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 20110 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 3500 | No | N/A | N/A |
| | Richmond | Standby | NG | 10 | No | N/A | N/A |
| | Richmond | Standby | LP | 120 | No | N/A | N/A |
| | Va Beach | Standby | Diesel | 2000 | No | N/A | N/A |
| | Chesapeake | Standby | Diesel | 500 | No | N/A | N/A |
| | Chesapeake | Standby | Diesel | 2500 | No | N/A | N/A |
| | Fredericksburg | Standby | Diesel | 700 | No | N/A | N/A |
| | Hopewell | Standby | Diesel | 75 | No | N/A | N/A |
| | Newport News | Standby | Unknown | 1000 | No | N/A | N/A |
| | Newport News | Standby | Unknown | 4500 | No | N/A | N/A |
| | Norfolk | Standby | Diesel | 2000 | No | N/A | N/A |
| | Norfolk | Standby | Diesel | 9000 | No | N/A | N/A |
| | Portsmouth | Standby | Diesel | 2250 | No | N/A | N/A |
| | Va Beach | Standby | Diesel | 3500 | No | N/A | N/A |
| | Va Beach | Standby | Diesel | 2000 | No | N/A | N/A |
| | Chesterfield | Standby | Diesel | 2000 | No | N/A | N/A |
| | Central VA | Merchant | Coal | 92000 | No | N/A | N/A |
| | Central VA | Merchant | Coal | 115000 | No | N/A | N/A |
| | Williamsburg | Standby | Diesel | 2800 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 30000 | No | N/A | N/A |
| | Charlottesville | Standby | Diesel | 40000 | No | N/A | N/A |
| | Arlington | Standby | Diesel | 13042 | No | N/A | N/A |
| | Arlington | Standby | Diesel/NG | 5000 | No | N/A | N/A |
| | Fauquier | Standby | Diesel | 1885 | No | N/A | N/A |
| | Hanover | Standby | Diesel | 12709.5 | No | N/A | N/A |
| | Hanover | Standby | NG | 13759.5 | No | N/A | N/A |
| | Hanover | Standby | LP | 81.25 | No | N/A | N/A |
| | Henrico | Standby | NG | 1341 | No | N/A | N/A |
| | Henrico | Standby | LP | 126 | No | N/A | N/A |
| | Henrico | Standby | Diesel | 828 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 200 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 8000 | No | N/A | N/A |
| | Newport News | Standby | Diesel | 1750 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 37000 | No | N/A | N/A |
| | Chesapeake | Standby | Unknown | 750 | No | N/A | N/A |
| | Northern VA | Merchant | NG | 50000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 138000 | No | N/A | N/A |
| | Richmond | Standby | Steam | 20000 | No | N/A | N/A |

170510021

# Appendix 3B cont. – Other Generation Units

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

Schedule 14b

**UNIT PERFORMANCE DATA**

**Existing Supply-Side Resources (kW)**

| Unit Name | Location | Unit Class | Primary Fuel Type | kW Summer | Capacity Resource | Contract Start | Contract Expiration |
|---|---|---|---|---|---|---|---|
| **Customer Owned**[3] | | | | | | | |
| | Herndon | Standby | Diesel | 415 | No | N/A | N/A |
| | Herndon | Standby | Diesel | 50 | No | N/A | N/A |
| | VA | Merchant | Hydro | 2700 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 37000 | No | N/A | N/A |
| | Fairfax County | Standby | Diesel | 20205 | No | N/A | N/A |
| | Fairfax County | Standby | NG | 2139 | No | N/A | N/A |
| | Fairfax County | Standby | LP | 292 | No | N/A | N/A |
| | Springfield | Standby | Diesel | 6500 | No | N/A | N/A |
| | Warrenton | Standby | Diesel | 2 - 750 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 5350 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 16400 | No | N/A | N/A |
| | Norfolk | Standby | Diesel | 350 | No | N/A | N/A |
| | Charlottesville | Standby | Diesel | 400 | No | N/A | N/A |
| | Farmville | Standby | Diesel | 350 | No | N/A | N/A |
| | Mechanicsville | Standby | Diesel | 350 | No | N/A | N/A |
| | King George | Standby | Diesel | 350 | No | N/A | N/A |
| | Chatham | Standby | Diesel | 350 | No | N/A | N/A |
| | Hampton | Standby | Diesel | 350 | No | N/A | N/A |
| | Virginia Beach | Standby | Diesel | 350 | No | N/A | N/A |
| | Portsmouth | Standby | Diesel | 400 | No | N/A | N/A |
| | Powhatan | Standby | Diesel | 350 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 350 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 350 | No | N/A | N/A |
| | Chesapeake | Standby | Diesel | 400 | No | N/A | N/A |
| | Newport News | Standby | Diesel | 350 | No | N/A | N/A |
| | Dinwiddie | Standby | Diesel | 300 | No | N/A | N/A |
| | Goochland | Standby | Diesel | 350 | No | N/A | N/A |
| | Portsmouth | Standby | Diesel | 350 | No | N/A | N/A |
| | Fredericksburg | Standby | Diesel | 350 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 22690 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 5000 | No | N/A | N/A |
| | Hampton Roads | Standby | Diesel | 15100 | No | N/A | N/A |
| | Herndon | Standby | Diesel | 1250 | No | N/A | N/A |
| | Herndon | Standby | Diesel | 500 | No | N/A | N/A |
| | Henrico | Standby | Diesel | 1000 | No | N/A | N/A |
| | Alexandria | Standby | Diesel | 2 - 910 | No | N/A | N/A |
| | Alexandria | Standby | Diesel | 1000 | No | N/A | N/A |
| | Fairfax | Standby | Diesel | 4 - 750 | No | N/A | N/A |
| | Loudoun | Standby | Diesel | 2100 | No | N/A | N/A |
| | Loudoun | Standby | Diesel | 710 | No | N/A | N/A |
| | Mount Vernon | Standby | Diesel | 1500 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 50 | No | N/A | N/A |
| | Eastern VA | Standby | Black liquor/Natural Gas | 112500 | No | N/A | N/A |
| | Central VA | Standby | Diesel | 1700 | No | N/A | N/A |
| | Hopewell | Standby | Diesel | 500 | No | N/A | N/A |
| | Falls Church | Standby | Diesel | 200 | No | N/A | N/A |
| | Falls Church | Standby | Diesel | 250 | No | N/A | N/A |

# Appendix 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

| Unit Name | Location | Unit Class | Primary Fuel Type | kW Summer | Capacity Resource | Contract Start | Contract Expiration |
|---|---|---|---|---|---|---|---|
| Customer Owned[5] | | | | | | | |
| | Northern VA | Standby | Diesel | 500 | No | N/A | N/A |
| | Fredericksburg | Standby | Diesel | 4200 | No | N/A | N/A |
| | Norfolk | Standby | NG | 1050 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 6400 | No | N/A | N/A |
| | Henrico | Standby | Diesel | 500 | No | N/A | N/A |
| | Elkton | Standby | Nat gas | 6000 | No | N/A | N/A |
| | Southside VA | Standby | Diesel | 30000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 5000 | No | N/A | N/A |
| | Northern VA | Standby | #2 FO | 5000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 50 | No | N/A | N/A |
| | Vienna | Standby | Diesel | 5000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 200 | No | N/A | N/A |
| | Norfolk | Standby | Diesel | 1000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 1000 | No | N/A | N/A |
| | Norfolk | Standby | Diesel | 1500 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 3000 | No | N/A | N/A |
| | Newport News | Standby | Diesel | 750 | No | N/A | N/A |
| | Chesterfield | Standby | Coal | 500 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 1500 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 1000 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 1000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 3000 | No | N/A | N/A |
| | Richmond Metro | Standby | NG | 25000 | No | N/A | N/A |
| | Suffolk | Standby | Diesel | 2000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 8000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 21000 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 500 | No | N/A | N/A |
| | Hampton Roads | Standby | Diesel | 4000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 10000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 5000 | No | N/A | N/A |
| | Hampton Roads | Standby | Diesel | 12000 | No | N/A | N/A |
| | West Point | Standby | Unknown | 50000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 100 | No | N/A | N/A |
| | Herndon | Standby | Diesel | 18100 | No | N/A | N/A |
| | VA | Merchant | RDF | 60000 | No | N/A | N/A |
| | Stafford | Standby | Diesel | 3000 | No | N/A | N/A |
| | Chesterfield | Standby | Diesel | 750 | No | N/A | N/A |
| | Henrico | Standby | Diesel | 750 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 5150 | No | N/A | N/A |
| | Culpepper | Standby | Diesel | 7000 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 8000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 2000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 6000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 500 | No | N/A | N/A |
| | Northern VA | Standby | NG | 50000 | No | N/A | N/A |
| | Hampton Roads | Standby | Unknown | 4000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 10000 | No | N/A | N/A |

17051 0021

# Appendix 3B cont. – Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

| Unit Name | Location | Unit Class | Primary Fuel Type | kW Summer | Capacity Resource | Contract Start | Contract Expiration |
|---|---|---|---|---|---|---|---|
| Customer Owned[3] | | | | | | | |
| | Northern VA | Standby | Diesel | 13000 | No | N/A | N/A |
| | Southside VA | Standby | Water | 227000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 300 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 1000 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 1500 | No | N/A | N/A |
| | Richmond | Standby | Diesel | 30 | No | N/A | N/A |
| | Newport News | Standby | Diesel | 1000 | No | N/A | N/A |
| | Hampton | Standby | Diesel | 12000 | No | N/A | N/A |
| | Newport News | Standby | Natural gas | 3000 | No | N/A | N/A |
| | Newport News | Standby | Diesel | 2000 | No | N/A | N/A |
| | Petersburg | Standby | Diesel | 1750 | No | N/A | N/A |
| | Various | Standby | Diesel | 3000 | No | N/A | N/A |
| | Various | Standby | Diesel | 30000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 5000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 2000 | No | N/A | N/A |
| | Ashburn | Standby | Diesel | 16000 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 6450 | No | N/A | N/A |
| | Virginia Beach | Standby | Diesel | 2000 | No | N/A | N/A |
| | Ashburn | Standby | Diesel | 12 - 2000 | No | N/A | N/A |
| | Innsbrook-Richmond | Standby | Diesel | 6050 | No | N/A | N/A |
| | Northern VA | Standby | Diesel | 150 | No | N/A | N/A |
| | Henrico | Standby | Diesel | 500 | No | N/A | N/A |
| | Virginia Beach | Standby | Diesel | 1500 | No | N/A | N/A |
| | Ahoskie | Standby | Diesel | 2550 | No | N/A | N/A |
| | Tillery | Standby | Diesel | 585 | No | N/A | N/A |
| | Whitakers | Standby | Diesel | 10000 | No | N/A | N/A |
| | Columbia | Standby | Diesel | 400 | No | N/A | N/A |
| | Grandy | Standby | Diesel | 400 | No | N/A | N/A |
| | Kill Devil Hills | Standby | Diesel | 500 | No | N/A | N/A |
| | Moyock | Standby | Diesel | 350 | No | N/A | N/A |
| | Nags Head | Standby | Diesel | 400 | No | N/A | N/A |
| | Nags Head | Standby | Diesel | 450 | No | N/A | N/A |
| | Roanoke Rapids | Standby | Diesel | 400 | No | N/A | N/A |
| | Conway | Standby | Diesel | 500 | No | N/A | N/A |
| | Conway | Standby | Diesel | 500 | No | N/A | N/A |
| | Roanoke Rapids | Standby | Diesel | 500 | No | N/A | N/A |
| | Corolla | Standby | Diesel | 700 | No | N/A | N/A |
| | Kill Devil Hills | Standby | Diesel | 700 | No | N/A | N/A |
| | Rocky Mount | Standby | Diesel | 700 | No | N/A | N/A |
| | Roanoke Rapids | Standby | Coal | 30000 | No | N/A | N/A |
| | Manteo | Standby | Diesel | 300 | No | N/A | N/A |
| | Conway | Standby | Diesel | 800 | No | N/A | N/A |
| | Lewiston | Standby | Diesel | 4000 | No | N/A | N/A |
| | Roanoke Rapids | Standby | Diesel | 1200 | No | N/A | N/A |
| | Weldon | Standby | Diesel | 750 | No | N/A | N/A |
| | Tillery | Standby | Diesel | 450 | No | N/A | N/A |
| | Elizabeth City | Standby | Unknown | 2000 | No | N/A | N/A |
| | Greenville | Standby | Diesel | 1800 | No | N/A | N/A |

# Appendix 3C – Equivalent Availability Factor for Plan C$^{T}$: Intensity-Based Dual Rate (%)

Company Name: Virginia Electric and Power Company — Schedule 8

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

| Unit Name | 2014 (ACTUAL) | 2015 | 2016 | 2017 | 2018 (PROJECTED) | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Altavista | 55 | 67 | 63 | 74 | 81 | 83 | 83 | 83 | 83 | 81 | 81 | 81 | 81 | 81 | 81 | 81 | 90 | 90 | 85 |
| Bath County 1-6 | 78 | 77 | 80 | 95 | 93 | 94 | 94 | 94 | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 98 |
| Bear Garden | 79 | 81 | 85 | 84 | 90 | 80 | 86 | 90 | 90 | 88 | 89 | 88 | 90 | 89 | 88 | 89 | 97 | 97 | 87 |
| Bellemeade | 70 | 83 | 80 | 68 | 81 | 91 | 91 | 89 | 89 | 89 | 87 | 87 | 89 | 89 | 87 | 89 | 87 | 87 | 88 |
| Bremo 3 | 65 | 78 | 86 | 88 | 94 | 84 | 86 | 89 | 89 | 86 | 93 | 86 | 93 | 86 | 86 | 93 | 86 | 86 | 90 |
| Bremo 4 | 53 | 80 | 83 | 86 | 92 | 83 | 83 | 78 | 88 | 85 | 92 | 85 | 92 | 85 | 92 | 85 | 92 | 85 | 88 |
| Brunswick | - | - | 83 | 75 | 90 | 84 | 88 | 90 | 91 | 93 | 85 | 93 | 79 | 93 | 93 | 85 | 93 | 93 | 84 |
| Chesapeake CT 1, 2, 4, 6 | 95 | 92 | 98 | 91 | 91 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 3 | 81 | 85 | 86 | 88 | 88 | 87 | 87 | 87 | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 4 | 92 | 65 | 75 | 86 | 86 | 85 | 85 | 85 | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 5 | 77 | 83 | 74 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 |
| Chesterfield 6 | 73 | 84 | 74 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 |
| Chesterfield 7 | 79 | 90 | 67 | 96 | 89 | 96 | 89 | 96 | 89 | 96 | 91 | 96 | 89 | 96 | 81 | 96 | 91 | 96 | 81 |
| Chesterfield 8 | 80 | 90 | 66 | 96 | 88 | 96 | 89 | 96 | 92 | 96 | 89 | 96 | 89 | 96 | 89 | 96 | 89 | 96 | 80 |
| Clover 1 | 93 | 76 | 88 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 92 |
| Clover 2 | 80 | 90 | 88 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 |
| Cushaw Hydro | 52 | 56 | 47 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| Darbytown 1 | 88 | 96 | 91 | 93 | 93 | 68 | 93 | 93 | 93 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 93 |
| Darbytown 2 | 93 | 80 | 97 | 95 | 95 | 84 | 94 | 94 | 94 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 93 |
| Darbytown 3 | 94 | 91 | 98 | 93 | 95 | 84 | 94 | 94 | 94 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 93 |
| Darbytown 4 | 95 | 92 | 92 | 95 | 95 | 84 | 94 | 94 | 94 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 93 |
| Demand Response - AC | | | | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Demand Response - DG | | | 98 | 59 | 56 | 59 | 56 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 |
| Doswell Complex | 86 | 85 | 85 | 92 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Elizabeth River 1 | 72 | 99 | 98 | 83 | 95 | 91 | 94 | 94 | 94 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 90 |
| Elizabeth River 2 | 64 | 97 | 98 | 83 | 95 | 91 | 94 | 94 | 94 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 90 |
| Elizabeth River 3 | 82 | 99 | 71 | 83 | 95 | 94 | 94 | 91 | 91 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Energy Efficiency | | | | 38 | 35 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 |
| Existing NC Solar NUGs | - | 20 | 20 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| Existing VA Solar NUGs | - | - | - | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 |
| Gaston Hydro | 91 | 88 | 90 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Generic 1x1 CC | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Generic 1x1 CC - Post 2025 | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Generic 2x1 CC | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Generic 2x1 CC - Post 2025 | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Generic 3x1 CC | - | - | - | - | - | - | - | - | - | - | - | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 |
| Generic 3x1 CC - Post 2025 | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Generic Aero CT | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Generic Brownfield CT | - | - | - | - | - | - | - | - | - | - | - | - | 87 | 87 | 87 | 87 | 87 | 87 | 87 |
| Generic Greenfield 4CT | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Generic Greenfield CT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 87 |
| Generic Greenfield CT - FT | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Generic Solar PV | - | - | - | - | - | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| Generic Solar PV B2 | - | - | | - | - | - | - | - | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| Generic Solar PV B3 | - | - | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 25 | 25 |
| Gordonsville 1 | 74 | 81 | 89 | 89 | 84 | 93 | 93 | 93 | 86 | 97 | 91 | 97 | 86 | 97 | 91 | 97 | 86 | 97 | 87 |
| Gordonsville 2 | 85 | 83 | 91 | 65 | 89 | 93 | 93 | 86 | 97 | 97 | 91 | 97 | 84 | 91 | 97 | 91 | 97 | 91 | 93 |
| Gravel Neck 1-2 | 88 | 96 | 96 | 91 | 91 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gravel Neck 3 | 94 | 89 | 96 | 95 | 95 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 |
| Gravel Neck 4 | 96 | 90 | 97 | 95 | 95 | 94 | 94 | 94 | 94 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 94 | 94 | 94 |
| Gravel Neck 5 | 95 | 92 | 97 | 95 | 95 | 92 | 94 | 94 | 94 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 94 |
| Gravel Neck 6 | 97 | 91 | 97 | 95 | 95 | 94 | 94 | 94 | 91 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 94 |

Note: EAF for intermittent resources shown as a capacity factor.

# Appendix 3C cont. – Equivalent Availability Factor for Plan C<sup>T</sup>: Intensity-Based Dual Rate (%)

Company Name: Virginia Electric and Power Company — Schedule 8

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Unit Name | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| Greensville | - | - | - | - | 8 | 80 | 86 | 91 | 82 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 84 |
| Hopewell | 70 | 64 | 74 | 81 | 81 | 83 | 81 | 83 | 83 | 81 | 81 | 81 | 81 | 81 | 81 | 81 | 81 | 81 | 85 |
| Ladysmith 1 | 96 | 93 | 90 | 91 | 91 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 95 | 95 | 90 |
| Ladysmith 2 | 95 | 92 | 90 | 91 | 91 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Ladysmith 3 | 90 | 94 | 91 | 84 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Ladysmith 4 | 94 | 94 | 91 | 88 | 84 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Ladysmith 5 | 92 | 94 | 90 | 88 | 90 | 83 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Lowmoor CT 1-4 | 85 | 98 | 98 | 91 | 91 | 91 | 90 | - | - | - | - | - | - | - | - | - | - | - | - |
| MeadWestVACO (BTM) | | | 95 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| Mecklenburg 1 | 95 | 84 | 95 | 94 | 94 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 |
| Mecklenburg 2 | 91 | 82 | 96 | 94 | 94 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 |
| Mount Storm 1 | 91 | 80 | 82 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 |
| Mount Storm 2 | 73 | 78 | 80 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 | 86 |
| Mount Storm 3 | 82 | 79 | 65 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 87 |
| Mount Storm CT | 92 | 57 | 100 | 91 | 90 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| North Anna 1 | 98 | 92 | 90 | 98 | 89 | 92 | 98 | 91 | 91 | 98 | 91 | 91 | 98 | 91 | 91 | 98 | 91 | 91 | 98 |
| North Anna 2 | 90 | 100 | 88 | 89 | 98 | 89 | 91 | 98 | 91 | 91 | 98 | 91 | 91 | 98 | 91 | 91 | 91 | 98 | 91 |
| North Anna Hydro | - | - | - | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| Northern Neck CT 1-4 | 99 | 100 | 98 | 91 | 91 | 90 | 89 | - | - | - | - | - | - | - | - | - | - | - | - |
| Pittsylvania | 92 | 88 | 60 | 91 | 90 | 91 | 91 | 91 | 91 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 | 93 |
| Possum Point 3 | 72 | 89 | 71 | 81 | 84 | 87 | 91 | 91 | 91 | 84 | 91 | 84 | 91 | 84 | 84 | 91 | 84 | 91 | 82 |
| Possum Point 4 | 59 | 83 | 69 | 81 | 84 | 83 | 91 | 78 | 91 | 83 | 91 | 87 | 91 | 83 | 91 | 87 | 91 | 83 | 89 |
| Possum Point 5 | 30 | 33 | 52 | 73 | 79 | 72 | 78 | 72 | 64 | 78 | 78 | 85 | 78 | 71 | 78 | 78 | 78 | 78 | 80 |
| Possum Point 6 | 84 | 80 | 80 | 84 | 88 | 81 | 88 | 81 | 88 | 88 | 88 | 88 | 76 | 88 | 88 | 88 | 88 | 88 | 87 |
| Possum Point CT 1-6 | 96 | 100 | 99 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Remington 1 | 87 | 91 | 91 | 91 | 91 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Remington 2 | 94 | 86 | 92 | 91 | 91 | 90 | 90 | 87 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 95 | 95 | 90 |
| Remington 3 | 94 | 89 | 90 | 81 | 91 | 90 | 90 | 90 | 87 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Remington 4 | 87 | 92 | 92 | 91 | 91 | 90 | 87 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Roanoke Rapids Hydro | 86 | 88 | 90 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| Roanoke Valley II | 96 | 92 | 92 | 89 | 89 | 97 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Roanoke Valley Project | 87 | 90 | 90 | 87 | 87 | 95 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rosemary | 76 | 68 | 81 | 91 | 91 | 85 | 81 | 81 | 85 | 89 | 96 | 89 | 96 | 89 | 96 | 89 | 96 | 89 | 94 |
| Scott Solar | | | 2 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| SEI Birchwood | 87 | 90 | 90 | 80 | 80 | 80 | 80 | 74 | - | - | - | - | - | - | - | - | - | - | - |
| Solar Partnership Program | - | - | | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| Southampton | 70 | 74 | 69 | 80 | 80 | 81 | 81 | 80 | 83 | 81 | 81 | 81 | 81 | 81 | 81 | 81 | 81 | 81 | 86 |
| Spruance Genco, Facility 1 (Richmond 1) | 86 | 83 | 83 | 91 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Spruance Genco, Facility 2 (Richmond 2) | 96 | 93 | 93 | 93 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Surry 1 | 100 | 75 | 94 | 98 | 91 | 90 | 98 | 91 | 91 | 98 | 91 | 91 | 98 | 91 | 91 | 98 | 91 | 91 | 98 |
| Surry 2 | 89 | 81 | 99 | 92 | 89 | 98 | 91 | 91 | 98 | 91 | 91 | 98 | 91 | 91 | 98 | 91 | 91 | 98 | 98 |
| Virginia City Hybrid Energy Center | 74 | 66 | 76 | 76 | 76 | 78 | 80 | 77 | 92 | 77 | 77 | 77 | 77 | 77 | 77 | 71 | 77 | 77 | 88 |
| VOWTAP | - | - | - | - | - | - | - | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| Warren | - | 61 | 81 | 87 | 82 | 87 | 87 | 81 | 87 | 85 | 93 | 93 | 77 | 89 | 85 | 93 | 93 | 93 | 85 |
| Whitehouse Solar | | | 2 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| Woodland Solar | | | 2 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| Yorktown 1 | 67 | 79 | 87 | 30 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Yorktown 2 | 72 | 84 | 91 | 31 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Yorktown 3 | 28 | 35 | 59 | 82 | 82 | 81 | 81 | 81 | - | - | - | - | - | - | - | - | - | - | - |

Note: EAF for intermittent resources shown as a capacity factor.

# Appendix 3D – Net Capacity Factor for Plan $C^T$: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company

Schedule 9

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

| Unit Name | (ACTUAL) 2014 | 2015 | 2016 | 2017 | (PROJECTED) 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Altavista | 50.2 | 60.1 | 63.1 | 74.5 | 81.4 | 83.1 | 83.1 | 83.1 | 83.1 | 64.6 | 70.5 | 74.6 | 76.8 | 78.2 | 78.6 | 79.0 | 88.5 | 90.0 | 85.2 |
| Bath County 1-6 | 15.8 | 13.8 | 12.3 | 23.0 | 21.5 | 20.7 | 19.7 | 19.6 | 19.7 | 19.5 | 19.1 | 20.3 | 20.1 | 19.9 | 20.0 | 19.9 | 20.2 | 20.0 | 20.0 |
| Bear Garden | 61.3 | 67.0 | 69.7 | 49.1 | 51.7 | 44.1 | 37.7 | 41.5 | 44.5 | 47.6 | 45.9 | 46.7 | 49.8 | 45.1 | 44.0 | 44.1 | 48.2 | 48.1 | 43.0 |
| Bellemeade | 10.8 | 53.2 | 39.9 | 14.1 | 21.8 | 26.3 | 19.2 | 18.7 | 17.7 | 16.4 | 15.8 | 17.7 | 19.2 | 15.0 | 15.2 | 15.5 | 15.6 | 15.6 | 15.9 |
| Bremo 3 | 30.5 | 6.5 | 10.3 | 6.0 | 6.1 | 4.1 | 3.9 | 3.5 | 3.9 | 4.2 | 5.3 | 4.6 | 4.3 | 4.1 | 3.6 | 3.8 | 4.8 | 4.8 | 4.9 |
| Bremo 4 | 12.8 | 12.7 | 24.6 | 18.7 | 17.3 | 11.9 | 10.6 | 11.5 | 12.1 | 11.8 | 13.3 | 12.0 | 12.4 | 9.9 | 11.1 | 10.8 | 11.8 | 12.0 | 12.1 |
| Brunswick | - | - | 51.0 | 60.6 | 75.8 | 69.7 | 62.5 | 65.0 | 65.2 | 65.8 | 60.5 | 62.8 | 56.7 | 62.1 | 61.7 | 57.2 | 62.1 | 61.9 | 57.6 |
| Chesapeake CT 1, 2, 4, 6 | 0.2 | 0.2 | 0.0 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 3 | 12.8 | 12.6 | 6.2 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 4 | 67.7 | 23.4 | 53.7 | 45.2 | 41.1 | 48.2 | 53.7 | 51.9 | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 5 | 63.8 | 69.8 | 59.4 | 51.5 | 52.8 | 60.9 | 65.8 | 64.2 | 68.0 | 62.2 | 66.6 | 66.2 | 69.4 | 65.1 | 68.5 | 68.0 | 71.3 | 71.7 | 73.7 |
| Chesterfield 6 | 59.1 | 69.8 | 63.0 | 50.2 | 50.2 | 57.1 | 64.4 | 61.2 | 65.4 | 59.2 | 63.3 | 64.1 | 68.1 | 64.2 | 66.8 | 66.1 | 70.1 | 69.8 | 72.8 |
| Chesterfield 7 | 78.4 | 94.7 | 70.6 | 76.7 | 78.8 | 84.1 | 72.2 | 77.6 | 71.5 | 79.0 | 70.8 | 72.7 | 66.9 | 69.8 | 60.2 | 70.9 | 67.2 | 71.3 | 60.3 |
| Chesterfield 8 | 82.3 | 96.4 | 69.7 | 88.4 | 81.0 | 83.0 | 72.0 | 76.8 | 74.5 | 78.0 | 70.5 | 75.3 | 70.1 | 72.3 | 68.3 | 72.5 | 69.1 | 74.2 | 62.7 |
| Clover 1 | 80.5 | 65.3 | 69.4 | 61.2 | 61.4 | 66.5 | 74.6 | 72.0 | 78.1 | 72.0 | 79.4 | 46.9 | 49.6 | 50.8 | 50.2 | 53.4 | 52.6 | 55.3 | 55.6 |
| Clover 2 | 67.3 | 77.5 | 72.0 | 60.4 | 60.2 | 66.7 | 73.4 | 71.5 | 76.4 | 71.9 | 77.7 | 48.3 | 50.2 | 49.9 | 49.8 | 52.4 | 52.0 | 54.8 | 58.7 |
| Cushaw Hydro | 79.7 | 50.8 | 43.3 | 44.6 | 44.6 | 44.6 | 44.7 | 44.6 | 44.6 | 44.6 | 44.7 | 44.6 | 44.6 | 44.6 | 44.7 | 44.6 | 44.6 | 44.6 | 44.7 |
| Darbytown 1 | 1.6 | 4.2 | 0.9 | 9.0 | 9.0 | 5.9 | 5.7 | 5.2 | 5.2 | 4.7 | 5.9 | 4.6 | 4.5 | 3.6 | 3.9 | 4.0 | 4.3 | 4.8 | 4.8 |
| Darbytown 2 | 1.6 | 3.1 | 0.9 | 9.0 | 9.0 | 7.8 | 5.9 | 5.6 | 5.5 | 5.0 | 6.2 | 4.8 | 4.8 | 3.8 | 4.2 | 4.4 | 4.4 | 4.9 | 5.1 |
| Darbytown 3 | 1.7 | 5.2 | 1.2 | 9.0 | 9.0 | 7.4 | 6.2 | 5.8 | 5.7 | 5.1 | 6.3 | 5.0 | 4.9 | 4.0 | 4.3 | 4.5 | 4.8 | 5.2 | 5.2 |
| Darbytown 4 | 1.6 | 5.9 | 1.4 | 9.0 | 9.0 | 6.3 | 5.7 | 5.3 | 5.3 | 4.8 | 6.1 | 4.6 | 4.3 | 3.7 | 3.8 | 3.7 | 4.4 | 4.9 | 4.9 |
| Doswell Complex | 61.8 | 71.2 | 74.3 | 91.5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Elizabeth River 1 | 1.6 | 7.2 | 3.7 | 7.5 | 10.7 | 10.0 | 7.8 | 7.3 | 6.9 | 6.4 | 7.5 | 6.6 | 6.2 | 4.8 | 5.5 | 5.1 | 5.6 | 6.5 | 7.1 |
| Elizabeth River 2 | 1.2 | 6.1 | 7.0 | 7.5 | 10.8 | 8.9 | 7.6 | 6.8 | 6.8 | 6.4 | 7.4 | 6.1 | 6.1 | 4.8 | 5.0 | 5.1 | 5.6 | 6.3 | 7.0 |
| Elizabeth River 3 | 0.8 | 0.9 | 5.0 | 7.5 | 10.6 | 9.8 | 7.7 | 7.2 | 6.6 | 6.3 | 7.4 | 6.8 | 6.4 | 4.8 | 5.5 | 5.1 | 5.9 | 7.0 | 6.9 |
| Existing NC Solar NUGs | - | - | - | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 |
| Existing VA Solar NUGs | - | - | - | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 | 25.8 |
| Gaston Hydro | 16.1 | 16.4 | 21.2 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 |
| Generic 3x1 CC | - | - | - | - | - | - | - | - | - | - | - | 77.3 | 78.2 | 77.5 | 78.1 | 78.6 | 79.1 | 78.1 | 77.6 |
| Generic Brownfield CT | - | - | - | - | - | - | - | - | - | - | - | - | 13.3 | 11.9 | 11.6 | 12.0 | 12.3 | 12.4 | 12.4 |
| Generic Greenfield CT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 12.9 |
| Generic Solar PV | - | - | - | - | - | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 | 25.4 |
| Gordonsville 1 | 21.7 | 57.8 | 47.1 | 25.2 | 26.3 | 31.0 | 17.3 | 16.3 | 15.5 | 19.2 | 19.8 | 20.5 | 19.2 | 19.0 | 18.1 | 18.3 | 16.0 | 19.7 | 19.3 |
| Gordonsville 2 | 44.3 | 61.7 | 48.9 | 20.5 | 28.3 | 31.8 | 17.1 | 15.2 | 18.5 | 19.2 | 19.8 | 20.6 | 20.9 | 17.9 | 18.3 | 18.1 | 19.2 | 19.5 | 19.7 |
| Gravel Neck 1-2 | 0.1 | - | 0.1 | 0.7 | 1.0 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gravel Neck 3 | 1.3 | 1.1 | 5.3 | 6.3 | 8.7 | 7.6 | 6.2 | 5.8 | 5.9 | 5.5 | 6.5 | 5.1 | 5.6 | 4.4 | 4.7 | 4.9 | 5.5 | 5.2 | 5.0 |
| Gravel Neck 4 | 2.2 | 4.5 | 5.4 | 6.8 | 9.0 | 8.7 | 6.7 | 6.1 | 6.3 | 5.8 | 6.9 | 6.3 | 6.7 | 4.9 | 5.0 | 5.7 | 6.2 | 6.1 | 5.9 |
| Gravel Neck 5 | 2.1 | 3.6 | 5.1 | 6.7 | 8.9 | 7.7 | 6.3 | 6.1 | 5.9 | 5.7 | 6.6 | 5.3 | 5.8 | 4.6 | 4.9 | 5.2 | 5.6 | 5.6 | 5.5 |
| Gravel Neck 6 | 1.5 | 3.0 | 2.7 | 6.7 | 8.9 | 7.9 | 6.3 | 6.1 | 5.9 | 5.7 | 6.6 | 5.2 | 5.9 | 4.6 | 4.8 | 5.1 | 5.5 | 5.3 | 5.4 |

# Appendix 3D cont. – Net Capacity Factor for Plan C$^T$: Intensity-Based Dual Rate

**Company Name:** Virginia Electric and Power Company **Schedule 9**

**UNIT PERFORMANCE DATA**

**Net Capacity Factor (%)**

| | (ACTUAL) | | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Unit Name** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** |
| Greensville | - | - | - | - | 0.7 | 75.8 | 78.1 | 83.2 | 76.8 | 84.0 | 82.6 | 80.9 | 81.3 | 80.5 | 80.8 | 80.9 | 80.6 | 80.6 | 75.6 |
| Hopewell | 58.2 | 58.8 | 68.3 | 79.8 | 78.2 | 74.9 | 77.2 | 81.9 | 83.0 | 18.7 | 20.3 | 24.8 | 27.2 | 29.8 | 31.1 | 37.8 | 41.1 | 46.4 | 52.8 |
| Ladysmith 1 | 14.2 | 4.1 | 7.0 | 17.0 | 17.0 | 17.0 | .15.4 | 15.9 | 14.3 | 13.9' | 14.3 | 14.6 | 15.1 | 12.0 | 12.6 | 13.3 | 13.4 | 13.6 | 13.2 |
| Ladysmith 2 | 12.8 | 3.3 | 15.3 | 17.0 | 17.0 | 17.0 | 15.4 | 15.7 | 14.5 | 13.7 | 14.3 | 14.5 | 14.7 | 12.2 | 12.6 | 13.3 | 13.3 | 13.3 | 13.0 |
| Ladysmith 3 | 7.8 | 10.1 | 11.4 | 17.0 | 17.0 | 17.0 | 16.3 | 16.6 | 15.3 | 14.5 | 15.2 | 15.4 | 15.6 | 13.4 | 13.4 | 13.8 | 14.3 | 14.2 | 13.9 |
| Ladysmith 4 | 9.7 | 9.4 | 9.6 | 17.0 | 17.0 | 17.0 | 16.3 | 16.5 | 15.3 | 14.5 | 15.1 | 15.4 | 15.7 | 13.4 | 13.5 | 13.8 | 14.1 | 14.4 | 13.7 |
| Ladysmith 5 | 10.7 | 5.3 | 12.8 | 17.0 | 17.0 | 17.0 | 16.3 | 16.5 | 15.3 | 14.7 | 15.1 | 15.5 | 16.0 | 13.2 | 13.6 | 13.8 | 14.2 | 14.4 | 13.9 |
| Lowmoor CT 1-4 | 0.5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mecklenburg 1 | 39.3 | 28.0 | 25.6 | 29.0 | 17.0 | 14.0 | 11.5 | 11.4 | 12.6 | 12.6 | 13.9 | 14.2 | 14.9 | 14.9 | 14.9 | 17.1 | 16.5 | 18.5 | 17.3 |
| Mecklenburg 2 | 36.0 | 27.6 | 23.8 | 28.6 | 17.0 | 13.9 | 11.3 | 11.2 | 12.0 | 12.4 | 13.8 | 13.5 | 14.7 | 14.5 | 14.3 | 16.8 | 16.4 | 18,1 | 17.1 |
| Mount Storm 1 | 76.2 | 70.3 | 68.4 | 65.2 | 65.5 | 71.2 | 75.3 | 75.1 | 63.8 | 57.6 | 61.7 | 62.7 | 64.8 | 60.3 | 63.2 | 62.0 | 65.3 | 65.4 | 66.5 |
| Mount Storm 2 | 59.9 | 65.9 | 67.0 | 65.0 | 65.8 | 71.1 | 75.4 | 74.8 | 63.2 | 57.1 | 60.9 | 61.6 | 64.1 | 59.2 | 62.2 | 61.5 | 65.3 | 65.1 | 65.7 |
| Mount Storm 3 | 70.7 | 70.9 | 53.3 | 63.2 | 62.1 | 67.5 | 72.4 | 71.1 | 58.2 | 49.6 | 54.8 | 57.4 | 57.5 | 54.8 | 56.8 | 56.6 | 60.2 | 58.9 | 60.4 |
| Mount Storm CT | 0.1 | 0.1 | 0.2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| North Anna 1 | 99.9 | 93.8 | 91.6 | 96.3 | 87.3 | 90.6 | 96.3 | 88.8 | 89.0 | 96.3 | 88.9 | 89.0 | 96.3 | 88.8 | 89.0 | 96.3 | 88.8 | 89.0 | 96.3 |
| North Anna 2 | 92.0 | 102.6 | 90.4 | 87.4 | 96.4 | 87.3 | 89.4 | 96.4 | 89.0 | 89.1 | 96.4 | 88.9 | 89.1 | 96.4 | 88.9 | 89.1 | 88.9 | 96.4 | 89.1 |
| North Anna Hydro | - | 41.4 | 41.4 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 | 24.6 |
| Northern Neck CT 1-4 | 0.3 | - | 0.1 | 0.0 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pittsylvania | 44.3 | 36.8 | 20.1 | 54.1 | 48.8 | 46.8 | 51.7 | 59.0 | 65.5 | 70.9 | 76.0 | 82.3 | 86.1 | 87.3 | 88.9 | 89.1 | 90.7 | 91.9 | 93.2 |
| Possum Point 3 | 1.0 | 1.3 | 2.2 | 7.0 | 6.9 | 5.1 | 5.0 | 5.1 | 5.7 | 5.6 | 7.0 | 6.6 | 6.8 | 5.0 | 5.1 | 5.6 | 6.1 | 6.4 | 6.9 |
| Possum Point 4 | 2.2 | 1.4 | 3.5 | 9.3 | 10.2 | 6.5 | 6.9 | 6.8 | 7.8 | 8.1 | 9.3 | 9.0 | 9.0 | 7.1 | 8.1 | 8.0 | 8.4 | 8.7 | 8.8 |
| Possum Point 5 | 2.8 | 3.5 | 1.3 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 |
| Possum Point 6 | 69.5 | 66.4 | 67.2 | 59.9 | 70.1 | 61.4 | 53.7 | 51.1 | 56.2 | 58.5 | 56.5 | 54.2 | 48.7 | 53.8 | 53.7 | 54.3 | 55.7 | 55.7 | 55.8 |
| Possum Point CT 1-6 | 0.6 | - | 0.0 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Remington 1 | 8.9 | 18.4 | 13.0 | 17.4 | 15.0 | 10.6 | 9.0 | 9.8 | 10.3 | 10.5 | 11.4 | 10.8 | 10.5 | 8.8 | 9.4 | 9.4 | 9.9 | 10.6 | 9.8 |
| Remington 2 | 8.4 | 16.6 | 14.0 | 17.1 | 14.8 | 10.3 | 8.9 | 9.7 | 10.4 | 10.4 | 11.3 | 10.6 | 10.5 | 8.7 | 9.9 | 9.4 | 10.1 | 10.5 | 9.7 |
| Remington 3 | 8.3 | 15.7 | 11.0 | 14.5 | 15.5 | 10.7 | 9.2 | 10.2 | . 10.3 | 10.7 | 11.8 | 11.5 | 10.5 | 9.0 | 9.8 | 9.6 | 10.5 | 10.8 | 10.1 |
| Remington 4 | 8.1 | 16.5 | 12.1 | 17.9 | 15.5 | 11.1 | 9.1 | 10.5 | 10.8 | 10.7 | 11.8 | 11.8 | 10.8 | 9.1 | 10.1 | 9.7 | 10.8 | 11.0 | 10.2 |
| Roanoke Rapids Hydro | 35.8 | 34.9 | 43.1 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 | 30.4 |
| Roanoke Valley II | 22.0 | 6.1 | 3.6 | 88.9 | 88.8 | 97.0 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Roanoke Valley Project | 40.8 | 12.8 | 2.0 | 87.2 | 87.2 | 94.9 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rosemary | 4.6 | 7.8 | 5.2 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| Scott Solar | | | 2.1 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 | 24.8 |
| SEI Birchwood | 40.8 | 27.2 | 21.6 | 50.4 | 46.9 | 37.4 | 36.7 | 36.1 | - | - | - | - | - | - | - | - | - | - | - |
| Solar Partnership Program | - | - | - | 13.9 | 13.9 | 13.9 | 13.8 | 13.9 | 13.9 | 13.9 | 13.8 | 13.9 | 13.9 | 13.9 | 13.8 | 13.9 | 13.9 | 13.9 | 13.8 |
| Southampton | 55.3 | 65.0 | 66.1 | 79.3 | 79.1 | 80.8 | 81.3 | 79.6 | 83.1 | 32.8 | 34.3 | 45.0 | 47.7 | 49.6 | 53.9 | 56.8 | 63.3 | 66.2 | 75.7 |
| Spruance Genco, Facility 1 (Richmond 1) | 12.8 | 10.5 | 8.3 | 64.7 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Spruance Genco, Facility 2 (Richmond 2) | 15.9 | 11.4 | 7.2 | 93.4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Surry 1 | 103.1 | 77.2 | 96.6 | 95.9 | 89.2 | 87.9 | 95.9 | 88.7 | 88.4 | 95.9 | 88.7 | 88.4 | 95.9 | 88.7 | 88.4 | 95.9 | 88.7 | 88.4 | 95.9 |
| Surry 2 | 92.1 | 83.4 | 101.9 | 90.3 | 87.3 | 95.9 | 89.0 | 88.4 | 95.9 | 88.7 | 88.4 | 95.9 | 88.7 | 88.4 | 95.9 | 88.7 | 88.4 | 95.9 | 93.7 |
| Virginia City Hybrid Energy Center | 66.6 | 55.5 | 65.4 | 58.3 | 57.5 | 61.3 | 67.9 | 65.5 | 81.7 | 67.7 | 69.6 | 69.7 | 70.3 | 69.6 | 69.5 | 63.7 | 70.2 | 70.9 | 84.6 |
| VOWTAP | - | - | - | - | - | - | - | 44.8 | 44.8 | 44.8 | 44.8 | 44.8 | 44.8 | 44.8 | 44.8 | 44.8 | 44.8 | 44.8 | 44.8 |
| Warren | - | 54.7 | 72.3 | 56.5 | 54.8 | 59.6 | 51.9 | 49.4 | 53.1 | 55.7 | 57.5 | 58.9 | 50.9 | 54.3 | 52.3 | 56.1 | 57.0 | 57.4 | 52.4 |
| Whitehouse Solar | | | 2.1 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| Woodland Solar | | | 2.1 | 25.5 | 25.5 | 25.5 | 25.4 | 25.5 | 25.5 | 25.5 | 25.4 | 25.5 | 25.5 | 25.5 | 25.4 | 25.5 | 25.5 | 25.5 | 25.4 |
| Yorktown 1 | 30.6 | 10.5 | 3.4 | 19.8 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Yorktown 2 | 33.5 | 8.0 | 19.7 | 20.6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Yorktown 3 | 2.3 | 4.4 | 2.1 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | - | - | - | - | - | - | - | - | - | - | - |

# Appendix 3E – Heat Rates for Plan C$^T$: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company — Schedule 10

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh)

| Unit Name | (ACTUAL) 2014 | 2015 | 2016 | (PROJECTED) 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Altavista | 15.66 | 14.26 | 15.07 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 | 12.31 |
| Bath County 1-6 | | | | | | | | | | | | | | | | | | | |
| Bear Garden | 7.14 | 7.12 | 6.79 | 7.16 | 7.16 | 7.14 | 7.16 | 7.17 | 7.17 | 7.16 | 7.17 | 7.17 | 7.17 | 7.16 | 7.17 | 7.16 | 7.18 | 7.17 | 7.18 |
| Bellemeade | 8.98 | 8.62 | 8.72 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 | 8.59 |
| Bremo 3 | 12.16 | 12.06 | 12.37 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 | 12.86 |
| Bremo 4 | 10.60 | 10.59 | 10.45 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 | 10.22 |
| Brunswick | - | - | 8.34 | 6.98 | 6.92 | 6.90 | 6.94 | 6.92 | 6.91 | 6.92 | 6.91 | 6.93 | 6.89 | 6.92 | 6.91 | 6.90 | 6.92 | 6.93 | 6.92 |
| Chesapeake CT 1, 2, 4, 6 | 15.32 | 16.98 | 16.98 | 0.00 | 0.00 | | | | | | | | | | | | | | |
| Chesterfield 3 | 12.01 | 12.45 | 13.05 | 11.69 | 11.69 | 11.69 | 11.69 | 11.69 | | | | | | | | | | | |
| Chesterfield 4 | 10.61 | 10.52 | 10.46 | 10.16 | 10.16 | 10.16 | 10.16 | 10.16 | | | | | | | | | | | |
| Chesterfield 5 | 10.18 | 10.16 | 10.27 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 |
| Chesterfield 6 | 10.02 | 9.98 | 10.07 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 | 9.94 |
| Chesterfield 7 | 7.53 | 7.40 | 7.45 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 | 7.33 |
| Chesterfield 8 | 7.16 | 7.23 | 7.30 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 | 7.25 |
| Clover 1 | 10.04 | 9.99 | 10.06 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 | 10.53 |
| Clover 2 | 9.99 | 10.00 | 10.06 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 | 10.44 |
| Cushaw Hydro | | | | | | | | | | | | | | | | | | | |
| Darbytown 1 | 12.24 | 12.54 | 12.60 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 | 12.04 |
| Darbytown 2 | 12.36 | 12.56 | 12.47 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 |
| Darbytown 3 | 12.30 | 12.51 | 12.38 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 |
| Darbytown 4 | 12.23 | 12.58 | 12.48 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 | 12.03 |
| Doswell Complex | 10.00 | 10.00 | 10.00 | 8.55 | | | | | | | | | | | | | | | |
| Elizabeth River 1 | 11.89 | 11.69 | 11.86 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 | 12.14 |
| Elizabeth River 2 | 11.91 | 11.72 | 12.12 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 |
| Elizabeth River 3 | 11.39 | 11.23 | 12.32 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 |
| Energy Efficiency | | | | | | | | | | | | | | | | | | | |
| Existing NC Solar NUGs | | | | | | | | | | | | | | | | | | | |
| Existing VA Solar NUGs | | | | | | | | | | | | | | | | | | | |
| Gaston Hydro | | | | | | | | | | | | | | | | | | | |
| Generic 1x1 CC | | | | | | | | | | | | | | | | | | | |
| Generic 1x1 CC - Post 2025 | | | | | | | | | | | | | | | | | | | |
| Generic 2x1 CC | | | | | | | | | | | | | | | | | | | |
| Generic 2x1 CC - Post 2025 | | | | | | | | | | | | | | | | | | | |
| Generic 3x1 CC | | | | | | | | | | | | 6.53 | 6.50 | 6.57 | 6.58 | 6.58 | 6.56 | 6.53 | 6.56 |
| Generic 3x1 CC - Post 2025 | | | | | | | | | | | | | | | | | | | |
| Generic Aero CT | | | | | | | | | | | | | | | | | | | |
| Generic Brownfield CT | | | | | | | | | | | | | 10.03 | 10.02 | 10.02 | 10.03 | 10.03 | 10.03 | 10.03 |
| Generic Greenfield 4CT | | | | | | | | | | | | | | | | | | | |
| Generic Greenfield CT | | | | | | | | | | | | | | | | | | | 10.02 |
| Generic Greenfield CT - FT | | | | | | | | | | | | | | | | | | | |
| Generic Solar PV | | | | | | | | | | | | | | | | | | | |
| Generic Solar PV B2 | | | | | | | | | | | | | | | | | | | |
| Generic Solar PV B3 | | | | | | | | | | | | | | | | | | | |
| Gordonsville 1 | 8.57 | 8.47 | 8.17 | 8.18 | 8.18 | 8.18 | 8.18 | 8.18 | 8.17 | 8.17 | 8.17 | 8.18 | 8.18 | 8.18 | 8.17 | 8.17 | 8.17 | 8.18 | 8.18 |
| Gordonsville 2 | 8.43 | 8.45 | 8.17 | 8.17 | 8.18 | 8.18 | 8.18 | 8.18 | 8.17 | 8.17 | 8.17 | 8.18 | 8.18 | 8.18 | 8.17 | 8.17 | 8.17 | 8.18 | 8.18 |
| Gravel Neck 1-2 | 17.12 | 20.17 | 19.08 | 17.40 | 17.40 | | | | | | | | | | | | | | |
| Gravel Neck 3 | 12.47 | 12.79 | 12.57 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 |
| Gravel Neck 4 | 12.50 | 12.82 | 12.57 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 |
| Gravel Neck 5 | 12.78 | 13.22 | 12.99 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 | 12.35 |
| Gravel Neck 6 | 12.31 | 12.55 | 12.72 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 | 12.34 |
| Greensville | - | - | | | 6.44 | 6.65 | 6.66 | 6.66 | 6.66 | 6.67 | 6.66 | 6.66 | 6.66 | 6.66 | 6.66 | 6.66 | 6.66 | 6.66 | 6.66 |
| Hopewell | 16.00 | 15.75 | 15.32 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 | 12.09 |

# Appendix 3E cont. – Heat Rates for Plan $C^T$: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company — Schedule 10

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh)

| Unit Name | (ACTUAL) 2014 | 2015 | 2016 | (PROJECTED) 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ladysmith 1 | 10.59 | 10.09 | 10.06 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 |
| Ladysmith 2 | 10.32 | 9.86 | 9.68 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 |
| Ladysmith 3 | 10.61 | 9.94 | 9.89 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 |
| Ladysmith 4 | 10.48 | 9.86 | 9.92 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 |
| Ladysmith 5 | 10.48 | 9.90 | 9.83 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 | 10.31 |
| Lowmoor CT 1-4 | 15.65 | 17.83 | 16.59 | 0.00 | 0.00 | 0.00 | 0.00 | | | | | | | | | | | | |
| MeadWestVACO (BTM) | | | | | | | | | | | | | | | | | | | |
| Mecklenburg 1 | 12.11 | 11.89 | 11.95 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 | 11.72 |
| Mecklenburg 2 | 12.20 | 12.20 | 12.36 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 | 11.77 |
| Mount Storm 1 | 9.84 | 9.99 | 10.13 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 | 9.86 |
| Mount Storm 2 | 9.94 | 9.93 | 10.07 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 | 9.91 |
| Mount Storm 3 | 10.40 | 10.42 | 10.39 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 | 10.19 |
| Mount Storm CT | 14.88 | 21.83 | 16.75 | 0.00 | 0.00 | | | | | | | | | | | | | | |
| North Anna 1 | - | - | - | 10.40 | 10.40 | 10.39 | 10.40 | 10.41 | 10.39 | 10.40 | 10.41 | 10.39 | 10.40 | 10.41 | 10.39 | 10.40 | 10.41 | 10.39 | 10.40 |
| North Anna 2 | - | - | - | 10.42 | 10.42 | 10.44 | 10.41 | 10.42 | 10.43 | 10.41 | 10.42 | 10.43 | 10.41 | 10.42 | 10.43 | 10.41 | 10.43 | 10.42 | 10.41 |
| North Anna Hydro | | | | | | | | | | | | | | | | | | | |
| Northern Neck CT 1-4 | 15.84 | 18.19 | 16.32 | 16.83 | 0.00 | 0.00 | 0.00 | | | | | | | | | | | | |
| Pittsylvania | 16.59 | 15.98 | 17.36 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 | 14.35 |
| Possum Point 3 | 12.26 | 12.21 | 12.95 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 | 11.34 |
| Possum Point 4 | 12.17 | 12.96 | 11.49 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 | 10.91 |
| Possum Point 5 | 10.25 | 10.26 | 11.19 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 | 9.93 |
| Possum Point 6 | 7.34 | 7.19 | 7.13 | 7.38 | 7.39 | 7.38 | 7.40 | 7.40 | 7.40 | 7.41 | 7.41 | 7.43 | 7.41 | 7.42 | 7.42 | 7.42 | 7.42 | 7.42 | 7.41 |
| Possum Point CT 1-6 | 15.11 | 17.04 | 17.96 | | | | | | | | | | | | | | | | |
| Remington 1 | 10.54 | 9.97 | 10.02 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 |
| Remington 2 | 10.81 | 10.17 | 10.05 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 |
| Remington 3 | 10.71 | 10.30 | 10.26 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 |
| Remington 4 | 10.66 | 10.12 | 10.09 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 | 10.48 |
| Roanoke Rapids Hydro | | | | | | | | | | | | | | | | | | | |
| Roanoke Valley II | 10.00 | 10.00 | 10.00 | 16.00 | 16.00 | 16.00 | | | | | | | | | | | | | |
| Roanoke Valley Project | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | | | | | | | | | | | | | |
| Rosemary | 9.45 | 9.55 | 9.50 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 | 8.76 |
| Scott Solar | | | | | | | | | | | | | | | | | | | |
| SEI Birchwood | 10.00 | 10.00 | 10.00 | 9.61 | 9.61 | 9.61 | 9.61 | 9.61 | | | | | | | | | | | |
| Solar Partnership Program | | | | | | | | | | | | | | | | | | | |
| Southampton | 15.90 | 15.16 | 15.31 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 | 11.70 |
| Spruance Genco, Facility 1 (Richmond 1) | 10.00 | 10.00 | 10.00 | 10.00 | | | | | | | | | | | | | | | |
| Spruance Genco, Facility 2 (Richmond 2) | 10.00 | 10.00 | 10.00 | 10.00 | | | | | | | | | | | | | | | |
| Surry 1 | - | - | - | 10.31 | 10.29 | 10.33 | 10.31 | 10.29 | 10.33 | 10.31 | 10.29 | 10.33 | 10.31 | 10.29 | 10.33 | 10.31 | 10.29 | 10.33 | 10.31 |
| Surry 2 | - | - | - | 10.30 | 10.33 | 10.31 | 10.29 | 10.33 | 10.31 | 10.29 | 10.33 | 10.31 | 10.29 | 10.33 | 10.31 | 10.29 | 10.33 | 10.31 | 10.31 |
| Virginia City Hybrid Energy Center | 9.74 | 9.96 | 9.87 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 | 9.39 |
| VOWTAP | | | | | | | | | | | | | | | | | | | |
| Warren | - | 6.77 | 6.91 | 6.95 | 6.96 | 6.97 | 6.98 | 6.97 | 6.98 | 6.95 | 6.97 | 6.97 | 6.98 | 6.96 | 6.95 | 6.96 | 6.97 | 6.96 | 6.96 |
| Whitehouse Solar | | | | | | | | | | | | | | | | | | | |
| Woodland Solar | | | | | | | | | | | | | | | | | | | |
| Yorktown 1 | 10.60 | 10.70 | 11.54 | 10.43 | | | | | | | | | | | | | | | |
| Yorktown 2 | 10.44 | 10.66 | 11.63 | 10.49 | | | | | | | | | | | | | | | |
| Yorktown 3 | 10.43 | 10.79 | 10.55 | 10.15 | 10.15 | 10.15 | 10.15 | 10.15 | | | | | | | | | | | |

# Appendix 3F – Existing Capacity for Plan C$^T$: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company — Schedule 7

CAPACITY DATA

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| I. Installed Capacity (MW)(1) | | | | | | | | | | | | | | | | | | | |
| a. Nuclear | 3,348 | 3,357 | 3,357 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 | 3,349 |
| b. Coal | 4,406 | 4,400 | 4,081 | 4,043 | 4,037 | 4,031 | 4,025 | 4,022 | 3,761 | 3,761 | 3,761 | 3,761 | 3,761 | 3,761 | 3,761 | 3,761 | 3,761 | 3,761 | 3,761 |
| c. Heavy Fuel Oil | 1,575 | 1,575 | 1,575 | 1,576 | 1,576 | 1,576 | 1,576 | 1,576 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 |
| d. Light Fuel Oil | 596 | 596 | 596 | 246 | 246 | 167 | 72 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Natural Gas-Boiler | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 | 543 |
| f. Natural Gas-Combined Cycle | 2,077 | 3,543 | 4,919 | 4,954 | 4,954 | 6,542 | 6,542 | 6,542 | 6,542 | 6,542 | 6,542 | 8,133 | 8,133 | 8,133 | 8,133 | 8,133 | 8,133 | 8,133 | 8,133 |
| g. Natural Gas-Turbine | 3,538 | 2,052 | 2,053 | 2,426 | 2,415 | 2,415 | 2,415 | 2,415 | 2,415 | 2,415 | 2,415 | 2,415 | 2,873 | 2,873 | 2,873 | 2,873 | 3,331 | 3,789 | 3,789 |
| h. Hydro-Conventional | 317 | 317 | 317 | 318 | 318 | 318 | 318 | 318 | 318 | 318 | 318 | 318 | 318 | 318 | 318 | 318 | 318 | 318 | 318 |
| i. Pumped Storage | 1,802 | 1,809 | 1,809 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 | 1,808 |
| j. Renewable | 237 | 236 | 236 | 290 | 296 | 357 | 418 | 475 | 530 | 585 | 639 | 694 | 749 | 803 | 858 | 912 | 967 | 1,022 | 1,076 |
| k. Total Company Installed | 18,439 | 18,428 | 19,486 | 19,553 | 19,542 | 21,106 | 21,065 | 21,048 | 20,051 | 20,106 | 20,161 | 21,806 | 22,319 | 22,374 | 22,428 | 22,483 | 22,995 | 23,508 | 23,563 |
| l. Other (NUG) | 1,749 | 1,775 | 1,252 | 749 | 585 | 392 | 404 | 420 | 218 | 223 | 222 | 221 | 220 | 219 | 218 | 217 | 215 | 214 | 213 |
| n. Total | 20,327 | 20,203 | 20,738 | 20,302 | 20,127 | 21,498 | 21,469 | 21,468 | 20,270 | 20,329 | 20,383 | 22,027 | 22,539 | 22,592 | 22,646 | 22,699 | 23,211 | 23,722 | 23,776 |
| II. Installed Capacity Mix (%)(2) | | | | | | | | | | | | | | | | | | | |
| a. Nuclear | 16.5% | 16.6% | 16.2% | 16.5% | 16.6% | 15.6% | 15.6% | 15.6% | 16.5% | 16.5% | 16.4% | 15.2% | 14.9% | 14.8% | 14.8% | 14.8% | 14.4% | 14.1% | 14.1% |
| b. Coal | 21.7% | 21.8% | 19.7% | 19.9% | 20.1% | 18.7% | 18.7% | 18.7% | 18.6% | 18.5% | 18.4% | 17.1% | 16.7% | 16.6% | 16.6% | 16.6% | 16.2% | 15.9% | 15.8% |
| c. Heavy Fuel Oil | 7.7% | 7.8% | 7.6% | 7.8% | 7.8% | 7.3% | 7.3% | 7.3% | 3.9% | 3.9% | 3.9% | 3.6% | 3.5% | 3.5% | 3.5% | 3.5% | 3.4% | 3.3% | 3.3% |
| d. Light Fuel Oil | 2.9% | 3.0% | 2.9% | 1.2% | 1.2% | 0.8% | 0.3% | - | - | - | - | - | - | - | - | - | - | - | - |
| e. Natural Gas-Boiler | 2.7% | 2.7% | 2.6% | 2.7% | 2.7% | 2.5% | 2.5% | 2.5% | 2.7% | 2.7% | 2.7% | 2.5% | 2.4% | 2.4% | 2.4% | 2.4% | 2.3% | 2.3% | 2.3% |
| f. Natural Gas-Combined Cycle | 10.2% | 17.5% | 23.7% | 24.4% | 24.6% | 30.4% | 30.5% | 30.5% | 32.3% | 32.2% | 32.1% | 36.9% | 36.1% | 36.0% | 35.9% | 35.8% | 35.0% | 34.3% | 34.2% |
| g. Natural Gas-Turbine | 17.4% | 10.2% | 9.9% | 11.9% | 12.0% | 11.2% | 11.2% | 11.2% | 11.9% | 11.9% | 11.8% | 11.0% | 12.7% | 12.7% | 12.7% | 12.7% | 14.4% | 16.0% | 15.9% |
| h. Hydro-Conventional | 1.6% | 1.6% | 1.5% | 1.6% | 1.6% | 1.5% | 1.5% | 1.5% | 1.6% | 1.6% | 1.6% | 1.4% | 1.4% | 1.4% | 1.4% | 1.4% | 1.4% | 1.3% | 1.3% |
| i. Pumped Storage | 8.9% | 9.0% | 8.7% | 8.9% | 9.0% | 8.4% | 8.4% | 8.4% | 8.9% | 8.9% | 8.9% | 8.2% | 8.0% | 8.0% | 8.0% | 8.0% | 7.8% | 7.6% | 7.6% |
| j. Renewable | 1.2% | 1.2% | 1.1% | 1.4% | 1.5% | 1.7% | 1.9% | 2.2% | 2.6% | 2.9% | 3.1% | 3.2% | 3.3% | 3.6% | 3.8% | 4.0% | 4.2% | 4.3% | 4.5% |
| k. Total Company Installed | 90.7% | 91.2% | 94.0% | 96.3% | 97.1% | 98.2% | 98.1% | 98.0% | 98.9% | 98.9% | 98.9% | 99.0% | 99.0% | 99.0% | 99.0% | 99.0% | 99.1% | 99.1% | 99.1% |
| l. Other (NUG) | 8.6% | 8.8% | 6.0% | 3.7% | 2.9% | 1.8% | 1.9% | 2.0% | 1.1% | 1.1% | 1.1% | 1.0% | 1.0% | 1.0% | 1.0% | 1.0% | 0.9% | 0.9% | 0.9% |
| n. Total | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |

(1) Net dependable installed capability during peak season.

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

# Appendix 3G – Energy Generation by Type for Plan C[T]: Intensity-Based Dual Rate (GWh)

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

**GENERATION**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| **I. System Output (GWh)** | | | | | | | | | | | | | | | | | | | |
| a. Nuclear | 28,378 | 26,173 | 27,978 | 28,203 | 27,457 | 27,575 | 28,331 | 27,615 | 27,617 | 28,207 | 27,699 | 27,618 | 28,207 | 27,618 | 27,696 | 28,207 | 27,052 | 28,181 | 28,821 |
| b. Coal | 25,293 | 22,618 | 21,974 | 20,828 | 20,001 | 21,875 | 23,738 | 23,066 | 18,569 | 17,204 | 17,985 | 16,838 | 17,328 | 16,934 | 17,242 | 17,004 | 17,611 | 17,779 | 18,677 |
| c. Heavy Fuel Oil | 355 | 542 | 236 | 420 | 420 | 420 | 421 | 420 | 212 | 212 | 212 | 212 | 212 | 212 | 212 | 212 | 212 | 212 | 212 |
| d. Light Fuel Oil | 408 | 319 | 222.8 | 3 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| e. Natural Gas-Boiler | 415 | 253 | 487.5 | 547 | 544 | 367 | 355 | 363 | 400 | 402 | 467 | 434 | 440 | 350 | 387 | 407 | 413 | 408 | 436 |
| f. Natural Gas-Combined Cycle | 11,221 | 18,482 | 25,563 | 25,524 | 29,431 | 38,849 | 35,607 | 36,526 | 36,942 | 38,757 | 37,930 | 49,407 | 47,487 | 48,382 | 48,070 | 48,215 | 49,192 | 49,451 | 46,669 |
| g. Natural Gas-Turbine | 1,124 | 1,606 | 1,692 | 3,232 | 3,310 | 2,874 | 2,544 | 2,580 | 2,487 | 2,415 | 2,624 | 2,543 | 3,052 | 2,561 | 2,682 | 2,804 | 3,359 | 3,825 | 3,929 |
| h. Hydro-Conventional | 1,035 | 1,039 | 1,333 | 524 | 524 | 524 | 526 | 524 | 524 | 524 | 526 | 524 | 524 | 524 | 526 | 524 | 524 | 524 | 526 |
| i. Hydro-Pumped Storage | 2,493 | 2,217 | 1,971 | 3,643 | 3,411 | 3,286 | 3,133 | 3,111 | 3,039 | 3,069 | 3,023 | 3,159 | 3,119 | 3,131 | 3,114 | 3,113 | 3,151 | 3,110 | 3,159 |
| j. Renewable[1] | 1,128 | 1,191 | 1,246 | 1,984 | 2,026 | 2,645 | 3,372 | 3,975 | 4,767 | 4,586 | 5,228 | 5,886 | 6,493 | 7,046 | 7,640 | 8,142 | 8,845 | 9,439 | 10,206 |
| **k. Total Generation** | 71,849 | 74,440 | 82,703 | 84,907 | 87,128 | 98,416 | 98,027 | 98,180 | 94,557 | 95,375 | 95,695 | 106,622 | 106,862 | 106,759 | 107,570 | 108,628 | 110,358 | 112,931 | 112,634 |
| l. Purchased Power | 16,193 | 14,657 | 7,486 | 16,951 | 13,765 | 8,832 | 8,772 | 9,306 | 10,443 | 11,429 | 11,128 | 8,646 | 8,149 | 9,648 | 9,433 | 9,341 | 8,846 | 8,637 | 8,190 |
| m. Total Payback Energy[2] | - | - | | 4 | 6 | 3 | 6 | 4 | 5 | 4 | 3 | 3 | 5 | 4 | 5 | 4 | 4 | 4 | 5 |
| n. Less Pumping Energy | -3,126 | -2,800 | -2,480 | -4,553 | -4,264 | -4,088 | -3,917 | -3,888 | -3,917 | -3,861 | -3,788 | -4,017 | -3,972 | -3,937 | -3,997 | -3,930 | -3,992 | -3,969 | -3,976 |
| o. Less Other Sales[3] | -904 | -1,716 | -4,296 | -11,686 | -9,737 | -15,162 | -13,577 | -13,229 | -11,352 | -11,289 | -10,399 | -18,053 | -17,022 | -16,696 | -16,083 | -16,333 | -16,670 | -17,226 | -15,867 |
| **p. Total System Firm Energy Req.** | 84,011 | 84,581 | 83,414 | 85,618 | 86,891 | 87,998 | 89,305 | 90,370 | 89,730 | 91,654 | 92,636 | 93,198 | 94,017 | 95,774 | 96,923 | 97,705 | 98,542 | 100,374 | 100,981 |
| **II. Energy Supplied by Competitive Service Providers** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |

(1) Include current estimates for renewable energy generation by VCHEC.

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

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

# Appendix 3H – Energy Generation by Type for Plan C[T]: Intensity-Based Dual Rate (%)

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

**Schedule 3**

**GENERATION**

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** |
| **III. System Output Mix (%)** | | | | | | | | | | | | | | | | | | | |
| a. Nuclear | 33.8% | 30.9% | 33.5% | 32.9% | 31.6% | 31.3% | 31.7% | 30.6% | 30.8% | 30.8% | 29.9% | 29.6% | 30.0% | 28.8% | 28.6% | 28.9% | 27.5% | 28.1% | 28.5% |
| b. Coal | 30.1% | 26.7% | 26.3% | 24.3% | 23.0% | 24.9% | 26.6% | 25.5% | 20.7% | 18.8% | 19.4% | 18.1% | 18.4% | 17.7% | 17.8% | 17.4% | 17.9% | 17.7% | 18.5% |
| c. Heavy Fuel Oil | 0.4% | 0.6% | 0.3% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% |
| d. Light Fuel Oil | 0.5% | 0.4% | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | - | - | - | - | - | - | - | - | - | - | - | - |
| e. Natural Gas-Boiler | 0.5% | 0.3% | 0.6% | 0.6% | 0.6% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% | 0.5% | 0.5% | 0.5% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% | 0.4% |
| f. Natural Gas-Combined Cycle | 13.4% | 21.9% | 30.6% | 29.8% | 33.9% | 44.1% | 39.9% | 40.4% | 41.2% | 42.3% | 40.9% | 53.0% | 50.5% | 50.5% | 49.6% | 49.3% | 49.9% | 49.3% | 46.2% |
| g. Natural Gas-Turbine | 1.3% | 1.9% | 2.0% | 3.8% | 3.8% | 3.3% | 2.8% | 2.9% | 2.8% | 2.6% | 2.8% | 2.7% | 3.2% | 2.7% | 2.8% | 2.9% | 3.4% | 3.8% | 3.9% |
| h. Hydro-Conventional | 1.2% | 1.2% | 1.6% | 0.6% | 0.6% | 0.6% | 0.6% | 0.6% | 0.6% | 0.6% | 0.6% | 0.6% | 0.6% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% |
| i. Hydro-Pumped Storage | 3.0% | 2.6% | 2.4% | 4.3% | 3.9% | 3.7% | 3.5% | 3.4% | 3.4% | 3.3% | -3.3% | 3.4% | 3.3% | 3.3% | 3.2% | 3.2% | 3.2% | 3.1% | 3.1% |
| j. Renewable Resources | 1.3% | 1.4% | 1.5% | 2.3% | 2.3% | 3.0% | 3.8% | 4.4% | 5.3% | 5.0% | 5.6% | 6.3% | 6.9% | 7.4% | 7.9% | 8.3% | 9.0% | 9.4% | 10.1% |
| **k. Total Generation** | 85.5% | 88.0% | 99.1% | 99.2% | 100.3% | 111.8% | 109.8% | 108.6% | 105.4% | 104.1% | 103.3% | 114.4% | 113.7% | 111.5% | 111.0% | 111.2% | 112.0% | 112.5% | 111.5% |
| l. Purchased Power | 19.3% | 17.3% | 9.0% | 19.8% | 15.8% | 10.0% | 9.8% | 10.3% | 11.6% | 12.5% | 12.0% | 9.3% | 8.7% | 10.1% | 9.7% | 9.6% | 9.0% | 8.6% | 8.1% |
| 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 | -3.7% | -3.3% | -3.0% | -5.3% | -4.9% | -4.6% | -4.4% | -4.3% | -4.4% | -4.2% | -4.1% | -4.3% | -4.2% | -4.1% | -4.1% | -4.0% | -4.1% | -4.0% | -3.9% |
| o. Less Other Sales[1] | -1.1% | -2.0% | -5.1% | -13.6% | -11.2% | -17.2% | -15.2% | -14.6% | -12.7% | -12.3% | -11.2% | -19.4% | -18.1% | -17.4% | -16.6% | -16.7% | -16.9% | -17.2% | -15.7% |
| **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** | 58.5% | 58.5% | 57.9% | 56.5% | 56.3% | 56.1% | 55.8% | 56.1% | 56.4% | 56.6% | 56.2% | 56.3% | 56.2% | 56.0% | 56.3% | 56.2% | 55.9% | 55.9% | 55.7% |

(1) Economy energy.

# Appendix 3I – Planned Changes to Existing Generation Units

**Company Name:** Virginia Electric and Power Company **Schedule 13a**
**UNIT PERFORMANCE DATA[1]**
**Unit Size (MW) Uprate and Derate**

| Unit Name | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| Altavista | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Bath County 1-6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Bear Garden | - | - | - | 26 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Bellemeade | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Bremo 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Bremo 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Brunswick | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Chesapeake CT 1, 2, 4, 6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 7 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Chesterfield 8 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Clover 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Clover 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Cushaw Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Darbytown 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Darbytown 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Darbytown 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Darbytown 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Doswell Complex | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Elizabeth River 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Elizabeth River 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Elizabeth River 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Energy Efficiency | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Existing NC Solar NUGs | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Existing VA Solar NUGs | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gaston Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gordonsville 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gordonsville 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gravel Neck 1-2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gravel Neck 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gravel Neck 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gravel Neck 5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gravel Neck 6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Greensville | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Hopewell | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

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

# Appendix 3I cont. – Planned Changes to Existing Generation Units

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

**UNIT PERFORMANCE DATA[1]**

**Unit Size (MW) Uprate and Derate**

| Unit Name | (ACTUAL) 2014 | 2015 | 2016 | (PROJECTED) 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ladysmith 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Ladysmith 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Ladysmith 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Ladysmith 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Ladysmith 5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Lowmoor CT 1-4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mecklenburg 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mecklenburg 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mount Storm 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mount Storm 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mount Storm 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mount Storm CT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| North Anna 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| North Anna 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| North Anna Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Northern Neck CT 1-4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pittsylvania | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Possum Point 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Possum Point 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Possum Point 5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Possum Point 6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Possum Point CT 1-6 | - | 14 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Remington 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Remington 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Remington 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Remington 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Roanoke Rapids Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Roanoke Valley II | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Roanoke Valley Project | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rosemary | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Scott Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SEI Birchwood | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar Partnership Program | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Southampton | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Spruance Genco, Facility 1 (Richmond 1) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Spruance Genco, Facility 2 (Richmond 2) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Surry 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Surry 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Virginia City Hybrid Energy Center | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| VOWTAP | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Warren | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Whitehouse Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Woodland Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Yorktown 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Yorktown 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Yorktown 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

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

# Appendix 3I cont. – Planned Changes to Existing Generation Units

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

**UNIT PERFORMANCE DATA**[1]

**Planned Changes to Existing Generation Units**

| Station / Unit Name | Uprate/Derate Description | Expected Removal Date | Expected Return Date | Base Rating | Revised Rating | MW |
|---|---|---|---|---|---|---|
| Possum Point 5 | SNCR | Mar-19 | Apr-19 | 786 | 786 | - |
| Bear Garden | GT Upgrade | Apr-17 | May-17 | 590 | 616 | 26 |

(1) Peak net dependable capability as of this filing.

# Appendix 3J – Potential Unit Retirements

Company Name: Virginia Electric and Power Company

Schedule 19

UNIT PERFORMANCE DATA

Planned Unit Retirements[1]

| Unit Name | Location | Unit Type | Primary Fuel Type | Projected Retirement Year | MW Summer | MW Winter |
|---|---|---|---|---|---|---|
| Yorktown 1[4] | Yorktown, VA | Steam-Cycle | Coal | 2017 | 159 | 162 |
| Yorktown 2[4] | Yorktown, VA | Steam-Cycle | Coal | 2017 | 164 | 165 |
| Chesapeake CT 1 | Chesapeake, VA | CombustionTurbine | Light Fuel Oil | 2019 | 15 | 20 |
| Chesapeake GT1 | | | | | 15 | |
| Chesapeake CT 2 | Chesapeake, VA | CombustionTurbine | Light Fuel Oil | 2019 | 36 | 49 |
| Chesapeake GT2 | | | | | 12 | |
| Chesapeake GT4 | | | | | 12 | |
| Chesapeake GT6 | | | | | 12 | |
| Gravel Neck 1 | Surry, VA | CombustionTurbine | Light Fuel Oil | 2019 | 28 | 38 |
| Gravel Neck GT1 | | | | | 12 | |
| Gravel Neck GT2 | | | | | 16 | |
| Lowmoor CT | Covington, VA | CombustionTurbine | Light Fuel Oil | 2020 | 48 | 69 |
| Lowmoor GT1 | | | | | 12 | |
| Lowmoor GT2 | | | | | 12 | |
| Lowmoor GT3 | | | | | 12 | |
| Lowmoor GT4 | | | | | 12 | |
| Mount Storm CT | Mt. Storm, WV | CombustionTurbine | Light Fuel Oil | 2018 | 11 | 15 |
| Mt. Storm GT1 | | | | | 11 | |
| Northern Neck CT | Warsaw, VA | CombustionTurbine | Light Fuel Oil | 2020 | 47 | 63 |
| Northern Neck GT1 | | | | | 12 | |
| Northern Neck GT2 | | | | | 11 | |
| Northern Neck GT3 | | | | | 12 | |
| Northern Neck GT4 | | | | | 12 | |
| Possum Point CT | Dumfries, VA | Steam-Cycle | Light Fuel Oil | 2021 | 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 | |
| Chesterfield 3[2] | Chester, VA | Steam-Cycle | Coal | 2022 | 98 | 102 |
| Chesterfield 4[2] | Chester, VA | Steam-Cycle | Coal | 2022 | 163 | 168 |
| Mecklenburg 1[3] | Clarksville, VA | Steam-Cycle | Coal | 2025 | 69 | 69 |
| Mecklenburg 2[3] | Clarksville, VA | Steam-Cycle | Coal | 2025 | 69 | 69 |
| Yorktown 3[2] | Yorktown, VA | Steam-Cycle | Heavy Fuel Oil | 2022 | 790 | 792 |
| Clover 1[3] | Clover, VA | Steam-Cycle | Coal | 2025 | 220 | 222 |
| Clover 2[3] | Clover, VA | Steam-Cycle | Coal | 2025 | 219 | 219 |

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

(2) The potential retirements of Chesterfield Units 3 and 4 and Yorktown 3 are modeled in all of the CPP-Compliant Plans.

(3) The potential retirements of Clover Units 1 and 2 and Mecklenburg Units 1 and 2 are modeled in Plans $F^{NT}$ and H.

(4) Yorktown Units 1 and 2 ceased operations on April 15, 2017 to comply with the MATS rule.

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# Appendix 3K – Generation under Construction

Company Name: Virginia Electric and Power Company

Schedule 15a

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

| Unit Name | Location | Unit Type | Primary Fuel Type | C.O.D.[1] | MW Summer[2] | MW Nameplate |
|---|---|---|---|---|---|---|
| Under Construction | | | | | | |
| SPP | Distributed | Intermittent | Solar | 2017 | 2 | 8 |
| Greensville County Power Station | VA | Intermediate/Baseload | Natural Gas | 2019 | 1,585 | 1,585 |

(1) Commercial Operation Date.

(2) Firm capacity.

# Appendix 3L – Wholesale Power Sales Contracts

Company Name: Virginia Electric and Power Company

Schedule 20

WHOLESALE POWER SALES CONTRACTS

| Entity | Contract Length | Contract Type | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | (Actual) | | | | (Projected) | | | | | | | | | | | | | | |
| Craig-Botetourt Electric Coop | 12-Month Termination Notice | Full Requirements(1) | 11 | 12 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Town of Windsor, North Carolina | 12-Month Termination Notice | Full Requirements(1) | 10 | 11 | 11 | 11 | 11 | 11 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Virginia Municipal Electric Association | 5/31/2031 with annual renewal | Full Requirements(1) | 328 | 309 | 350 | 355 | 359 | 365 | 374 | 378 | 381 | 385 | 389 | 393 | 397 | 397 | 397 | 397 | 397 | 397 | 397 |

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

# Appendix 3M – Description of Approved DSM Programs

**Air Conditioner Cycling Program**

| | |
|---|---|
| Branded Name: | Smart Cooling Rewards |
| State: | Virginia & North Carolina |
| Target Class: | Residential |
| VA Program Type: | Peak-Shaving |
| NC Program Type: | Peak-Shaving |
| VA Duration: | Ongoing |
| NC Duration: | Ongoing |

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

**Program Marketing:**
The Company uses business reply cards, online enrollment, and call center services.

**Non-Residential Distributed Generation Program**

| | |
|---|---|
| Branded Name: | Distributed Generation |
| State: | Virginia |
| Target Class: | Non-Residential |
| VA Program Type: | Demand-Side Management |
| VA Duration: | 2012 – 2042 |

**Program Description:**
As part of this Program, a third-party contractor will dispatch, monitor, maintain and operate customer-owned generation when called upon by the Company at anytime for up to a total of 120 hours per year. The Company will supervise and implement the Non-Residential Distributed Generation Program through the third-party implementation contractor. Participating customers will receive an incentive in exchange for their agreement to reduce electrical load on the Company's system when called upon to do so by the Company. The incentive is based upon the amount of load curtailment delivered during control events. At least 80% of the program participation incentive is required to be passed through to the customer, with 100% of fuel and operations and maintenance compensation passed along to the customer. When not being dispatched by the Company, the generators may be used at the participants' discretion or to supply power during an outage, consistent with applicable environmental restrictions.

**Program Marketing:**
Marketing is handled by the Company's implementation vendor.

## Appendix 3M cont. – Description of Approved DSM Programs

**Non-Residential Energy Audit Program**

| | |
|---|---|
| Target Class: | Non-Residential |
| VA Program Type: | Energy Efficiency |
| NC Program Type: | Energy Efficiency |
| VA Duration: | Completed |
| NC Duration: | Completed |

**Program Description:**
As part of this Program, an energy auditor performed an on-site energy audit of a non-residential customer's facility. The customer received a report showing the projected energy and cost savings that could be anticipated from implementation of options identified during the audit. Once a qualifying customer provided documentation that some of the recommended energy efficiency improvements had been made at the customer's expense, a portion of the audit value was refunded depending upon the measures installed.

**Program Marketing:**
The Company used a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media and outreach events. Because these programs were implemented using a contractor network, customers were enrolled in the program by contacting a participating contractor. The Company utilized the contractor network to market the programs to customers as well.

**Non-Residential Duct Testing and Sealing Program**

| | |
|---|---|
| Target Class: | Non-Residential |
| VA Program Type: | Energy Efficiency |
| NC Program Type: | Energy Efficiency |
| VA Duration: | Completed |
| NC Duration: | Completed |

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

**Program Marketing:**
The Company used a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media and outreach events. Because these programs were implemented using a contractor network, customers were enrolled in the program by contacting a participating contractor. The Company utilized the contractor network to market the programs to customers as well.

## Appendix 3M cont. – Description of Approved DSM Programs

**Residential Bundle Program**

| | |
|---|---|
| Target Class: | Residential |
| VA Program Type: | Energy Efficiency |
| NC Program Type: | Energy Efficiency |
| VA Duration: | Completed |
| NC Duration: | Completed |

The Residential Bundle Program included the four DSM programs described below.

**Program Marketing:**
The Company used a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media and outreach events. Because these programs were implemented using a contractor network, customers were enrolled in the program by contacting a participating contractor. The Company utilized the contractor network to market the programs to customers as well.

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

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

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

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

## Appendix 3M cont. – Description of Approved DSM Programs

**Non-Residential Heating and Cooling Efficiency Program**

| | |
|---|---|
| Target Class: | Non-Residential |
| VA Program Type: | Energy Efficiency |
| NC Program Type: | Energy Efficiency |
| VA Duration: | 2014 – 2042 |
| NC Duration: | 2015 – 2042 |

**Program Description:**
This Program provides qualifying non-residential customers with incentives to implement new and upgrade existing HVAC equipment to more efficient HVAC technologies that can produce verifiable savings.

**Program Marketing:**
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

**Non-Residential Lighting Systems & Controls Program**

| | |
|---|---|
| Target Class: | Non-Residential |
| VA Program Type: | Energy Efficiency |
| NC Program Type: | Energy Efficiency |
| VA Duration: | 2014 – 2042 |
| NC Duration: | 2015 – 2042 |

**Program Description:**
This Program provides qualifying non-residential customers with an incentive to implement more efficient lighting technologies that can produce verifiable savings. The Program promotes the installation of lighting technologies including but not limited to efficient fluorescent bulbs, LED-based bulbs, and lighting control systems.

**Program Marketing:**
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

## Appendix 3M cont. – Description of Approved DSM Programs

**Non-Residential Window Film Program**

| | |
|---|---|
| Target Class: | Non-Residential |
| VA Program Type: | Energy Efficiency |
| NC Program Type: | Energy Efficiency |
| VA Duration: | 2014 – 2042 |
| NC Duration: | 2015 – 2042 |

**Program Description:**
This Program provides qualifying non-residential customers with an incentive to install solar reduction window film to lower their cooling bills and improve occupant comfort. Customers can receive rebates for installing qualified solar reduction window film in non-residential facilities based on the Solar Heat Gain Coefficient of window film installed.

**Program Marketing:**
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

**Residential Appliance Recycling Program**

| | |
|---|---|
| Target Class: | Residential |
| VA Program Type: | Energy Efficiency |
| VA Duration: | 2015 – 2017 |

**Program Description:**
This program provides incentives to residential customers to recycle specific types of qualifying appliances. Appliance pick-up and proper recycling services are included.

**Program Marketing:**
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media and outreach events.

## Appendix 3M cont. – Description of Approved DSM Programs

**Income and Age Qualifying Home Improvement Program**

| | |
|---|---|
| **Target Class:** | Residential |
| **VA Program Type:** | Energy Efficiency |
| **NC Program Type:** | Energy Efficiency |
| **VA Duration:** | 2015 – 2042 |
| **NC Duration:** | 2016 – 2042 |

**Program Description:**
This Program provides income and age-qualifying residential customers with energy assessments and direct install measures at no cost to the customer.

**Program Marketing:**
The Company markets this Program primarily through weatherization assistance providers and social services agencies.

**Small Business Improvement Program**

| | |
|---|---|
| Target Class: | Non-Residential |
| VA Program Type: | Energy Efficiency |
| NC Program Type: | Energy Efficiency |
| VA Duration: | 2016 – 2042 |
| NC Duration: | 2017 – 2042 |

**Program Description:**
This Program provides eligible small businesses an energy use assessment and tune-up or re-commissioning of electric heating and cooling systems, along with financial incentives for the installation of specific energy efficiency measures. Participating small businesses are required to meet certain connected load requirements.

**Program Marketing:**
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

# Appendix 3N – Approved Programs Non-Coincidental Peak Savings for Plan C<sup>T</sup>: Intensity-Based Dual Rate (kW) (System-Level)

| Programs | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Air Conditioner Cycling Program | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 79,962 | 82,386 | 83,276 | 81,357 | 80,482 | 80,007 | 77,995 | 77,995 |
| Residential Low Income Program | 5,081 | 5,081 | 5,081 | 5,081 | 5,081 | 5,081 | 5,081 | 5,034 | 4,373 | 2,780 | 1,785 | 986 | 237 | 0 | 0 | 0 |
| Residential Lighting Program | 39,902 | 38,275 | 28,750 | 19,384 | 9,565 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial Lighting Program | 10,144 | 10,144 | 10,144 | 9,187 | 6,842 | 2,418 | 87 | 68 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial HVAC Upgrade | 670 | 670 | 670 | 670 | 670 | 670 | 670 | 670 | 588 | 444 | 173 | 0 | 0 | 0 | 0 | 0 |
| Non-Residential Energy Audit Program | 4,505 | 4,505 | 4,503 | 4,128 | 2,707 | 1,577 | 1,471 | 1,471 | 1,471 | 1,471 | 0 | 0 | 0 | 0 | 0 | 0 |
| Non-Residential Duct Testing and Sealing Program | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 | 22,520 |
| Non-Residential Distributed Generation Program | 7,394 | 8,448 | 8,448 | 9,503 | 9,503 | 9,535 | 9,566 | 9,598 | 9,630 | 9,661 | 9,682 | 9,703 | 9,724 | 9,746 | 9,746 | 9,777 |
| Residential Bundle Program | 22,064 | 22,614 | 21,485 | 19,292 | 15,015 | 15,013 | 14,949 | 13,924 | 9,702 | 6,415 | 3,802 | 3,636 | 3,248 | 2,806 | 1,824 | 1,670 |
| Residential Home Energy Check-Up Program | 11,206 | 11,206 | 11,206 | 11,206 | 11,206 | 11,205 | 11,140 | 10,115 | 5,894 | 2,606 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential Duct Sealing Program | 391 | 391 | 391 | 391 | 391 | 391 | 391 | 391 | 391 | 391 | 391 | 391 | 391 | 391 | 389 | 377 |
| Residential Heat Pump Tune Up Program | 7,999 | 7,887 | 6,470 | 4,277 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential Heat Pump Upgrade Program | 2,468 | 3,131 | 3,418 | 3,418 | 3,418 | 3,418 | 3,418 | 3,418 | 3,418 | 3,418 | 3,411 | 3,245 | 2,857 | 2,415 | 1,434 | 1,293 |
| Non-Residential Window Film Program | 69,143 | 113,759 | 135,208 | 138,345 | 141,545 | 143,780 | 145,319 | 146,853 | 148,346 | 149,786 | 151,184 | 152,552 | 153,899 | 155,229 | 155,846 | 156,742 |
| Non-Residential Lighting Systems & Controls Program | 30,185 | 42,582 | 43,547 | 44,532 | 45,536 | 46,014 | 46,821 | 53,530 | 56,355 | 47,610 | 47,982 | 48,345 | 48,703 | 49,057 | 49,220 | 49,459 |
| Non-Residential Heating and Cooling Efficiency Program | 38,593 | 59,639 | 69,566 | 70,973 | 72,406 | 73,456 | 74,231 | 75,003 | 75,755 | 76,480 | 77,183 | 77,872 | 78,550 | 79,220 | 82,259 | 79,981 |
| Income and Age Qualifying Home Improvement Program | 1,338 | 1,780 | 2,405 | 3,084 | 3,764 | 4,338 | 4,384 | 4,431 | 4,476 | 4,519 | 4,561 | 4,600 | 4,639 | 4,726 | 4,715 | 4,757 |
| Residential Appliance Recycling Program | 1,888 | 1,973 | 1,973 | 1,973 | 1,973 | 1,973 | 1,704 | 432 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small Business Improvement Program | 5,026 | 8,483 | 12,885 | 18,124 | 20,661 | 20,967 | 21,199 | 21,429 | 21,653 | 21,870 | 22,080 | 22,286 | 22,488 | 23,122 | 22,784 | 22,915 |
| Total | 336,448 | 418,468 | 445,179 | 444,790 | 435,781 | 425,337 | 425,997 | 432,957 | 434,831 | 425,943 | 424,228 | 423,858 | 424,491 | 426,432 | 426,909 | 425,815 |

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

# Appendix 3O – Approved Programs Coincidental Peak Savings for Plan C$^T$: Intensity-Based Dual Rate (kW) (System-Level)

| Programs | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Air Conditioner Cycling Program | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 | 77,995 |
| Residential Low Income Program | 2,219 | 2,219 | 2,219 | 2,219 | 2,219 | 2,219 | 2,219 | 2,065 | 1,606 | 1,094 | 738 | 339 | 62 | 0 | 0 | 0 |
| Residential Lighting Program | 26,009 | 22,297 | 16,473 | 10,284 | 3,117 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial Lighting Program | 10,144 | 10,144 | 10,144 | 9,183 | 5,345 | 1,340 | 87 | 36 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial HVAC Upgrade | 670 | 670 | 670 | 670 | 670 | 670 | 670 | 670 | 584 | 341 | 88 | 0 | 0 | 0 | 0 | 0 |
| Non-Residential Energy Audit Program | 4,147 | 4,147 | 4,146 | 3,835 | 2,451 | 1,465 | 1,354 | 1,354 | 1,354 | 1,354 | 0 | 0 | 0 | 0 | 0 | 0 |
| Non-Residential Duct Testing and Sealing Program | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 | 19,012 |
| Non-Residential Distributed Generation Program | 7,394 | 8,009 | 8,448 | 9,063 | 9,503 | 9,521 | 9,553 | 9,585 | 9,616 | 9,648 | 9,673 | 9,695 | 9,716 | 9,737 | 9,746 | 9,764 |
| Residential Bundle Program | 14,824 | 15,297 | 14,255 | 12,535 | 10,204 | 10,201 | 10,080 | 8,489 | 6,280 | 4,400 | 3,631 | 3,391 | 2,961 | 2,430 | 1,692 | 1,328 |
| Residential Home Energy Check-Up Program | 6,567 | 6,567 | 6,567 | 6,567 | 6,567 | 6,564 | 6,443 | 4,853 | 2,643 | 764 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential Duct Sealing Program | 294 | 294 | 294 | 294 | 294 | 294 | 294 | 294 | 294 | 294 | 294 | 294 | 294 | 294 | 290 | 270 |
| Residential Heat Pump Tune Up Program | 6,023 | 5,431 | 4,052 | 2,331 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential Heat Pump Upgrade Program | 1,940 | 3,005 | 3,342 | 3,342 | 3,342 | 3,342 | 3,342 | 3,342 | 3,342 | 3,342 | 3,336 | 3,097 | 2,666 | 2,136 | 1,403 | 1,057 |
| Non-Residential Window Film Program | 48,251 | 81,037 | 96,316 | 98,550 | 100,830 | 102,422 | 103,519 | 104,611 | 105,675 | 106,701 | 107,696 | 108,671 | 109,631 | 110,578 | 111,017 | 111,656 |
| Non-Residential Lighting Systems & Controls Program | 18,195 | 26,505 | 30,582 | 31,277 | 31,986 | 32,451 | 32,740 | 33,027 | 33,307 | 33,577 | 33,839 | 34,095 | 34,348 | 34,597 | 34,712 | 34,880 |
| Non-Residential Heating and Cooling Efficiency Program | 31,619 | 50,245 | 58,729 | 59,917 | 61,126 | 62,013 | 62,667 | 63,319 | 63,954 | 64,566 | 65,160 | 65,741 | 66,314 | 66,879 | 67,141 | 67,522 |
| Income and Age Qualifying Home Improvement Program | 779 | 1,177 | 1,575 | 1,973 | 2,372 | 2,553 | 2,581 | 2,608 | 2,634 | 2,659 | 2,682 | 2,705 | 2,728 | 2,749 | 2,773 | 2,799 |
| Residential Appliance Recycling Program | 1,593 | 1,752 | 1,752 | 1,752 | 1,752 | 1,752 | 1,513 | 384 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small Business Improvement Program | 4,556 | 8,382 | 12,990 | 18,382 | 21,006 | 21,315 | 21,550 | 21,784 | 22,012 | 22,232 | 22,445 | 22,654 | 22,860 | 23,063 | 23,157 | 23,294 |
| Total | 267,405 | 328,888 | 355,307 | 356,648 | 349,587 | 344,929 | 345,539 | 344,959 | 344,028 | 343,578 | 342,959 | 344,299 | 345,625 | 347,039 | 347,245 | 348,249 |

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

# Appendix 3P – Approved Programs Energy Savings for Plan C$^T$: Intensity-Based Dual Rate (MWh) (System-Level)

| Programs | 2017 | 2015 | 2019 | 2020 | 2021 | 2022 | 2023 | 2021 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Air Conditioner Cycling Program | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential Low Income Program | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 12,434 | 9,514 | 6,093 | 3,752 | 1,678 | 327 | 0 | 0 | 0 |
| Residential Lighting Program | 276,436 | 239,806 | 177,495 | 112,278 | 36,445 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial Lighting Program | 82,666 | 82,666 | 82,666 | 75,519 | 45,139 | 11,799 | 707 | 321 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial HVAC Upgrade | 3,640 | 3,640 | 3,640 | 3,644 | 3,640 | 3,640 | 3,640 | 3,644 | 3,213 | 1,938 | 537 | 0 | 0 | 0 | 0 | 0 |
| Non-Residential Energy Audit Program | 28,723 | 28,723 | 28,716 | 26,691 | 17,458 | 10,211 | 9,379 | 9,379 | 9,379 | 9,379 | 0 | 0 | 0 | 0 | 0 | 0 |
| Non-Residential Duct Testing and Sealing Program | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 | 50,688 |
| Non-Residential Distributed Generation Program | 0 | 0 | 0 | 0 | 0 | 3 | 4 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| Residential Bundle Program | 63,681 | 64,779 | 61,388 | 55,289 | 46,357 | 46,346 | 45,786 | 38,359 | 26,529 | 16,628 | 11,901 | 11,231 | 9,844 | 8,156 | 5,597 | 4,575 |
| Residential Home Energy Check-Up Program | 34,439 | 34,439 | 34,439 | 34,439 | 34,439 | 34,428 | 33,868 | 26,442 | 14,611 | 4,710 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential Duct Sealing Program | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,051 | 1,037 | 975 |
| Residential Heat Pump Tune Up Program | 21,511 | 19,743 | 15,031 | 8,932 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential Heat Pump Upgrade Program | 6,680 | 9,546 | 10,866 | 10,866 | 10,866 | 10,866 | 10,866 | 10,866 | 10,866 | 10,866 | 10,849 | 10,180 | 8,793 | 7,105 | 4,560 | 3,600 |
| Non-Residential Window Film Program | 52,613 | 88,318 | 104,885 | 107,318 | 109,800 | 111,531 | 112,726 | 113,916 | 115,073 | 116,190 | 117,274 | 118,336 | 119,381 | 120,412 | 120,889 | 121,586 |
| Non-Residential Lighting Systems & Controls Program | 113,622 | 166,114 | 194,205 | 198,620 | 203,123 | 206,192 | 208,025 | 209,853 | 211,634 | 213,352 | 215,019 | 216,650 | 218,255 | 219,840 | 220,636 | 221,636 |
| Non-Residential Heating and Cooling Efficiency Program | 81,824 | 131,454 | 156,422 | 159,586 | 162,808 | 165,248 | 166,992 | 168,731 | 170,426 | 172,061 | 173,647 | 175,199 | 176,726 | 178,234 | 179,001 | 179,940 |
| Income and Age Qualifying Home Improvement Program | 3,930 | 6,018 | 8,107 | 10,196 | 12,284 | 13,380 | 13,523 | 13,665 | 13,802 | 13,933 | 14,058 | 14,179 | 14,298 | 14,414 | 14,534 | 14,667 |
| Residential Appliance Recycling Program | 11,302 | 12,556 | 12,556 | 12,556 | 12,556 | 12,556 | 10,959 | 2,748 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small Business Improvement Program | 15,659 | 28,980 | 45,033 | 63,832 | 73,452 | 74,546 | 75,368 | 76,188 | 76,986 | 77,755 | 78,502 | 79,233 | 79,953 | 80,663 | 81,008 | 81,469 |
| Total | 797,984 | 916,942 | 939,000 | 889,416 | 786,949 | 719,340 | 710,995 | 699,934 | 687,244 | 678,019 | 665,377 | 667,196 | 669,472 | 672,408 | 672,353 | 674,562 |

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

# Appendix 3Q – Approved Programs Penetrations for Plan $C^T$: Intensity-Based Dual Rate (System-Level)

| Programs | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Air Conditioner Cycling Program | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 | 107,173 |
| Residential Low Income Program | 12,743 | 12,743 | 12,743 | 12,743 | 12,743 | 12,743 | 12,743 | 11,312 | 7,192 | 4,656 | 2,653 | 653 | 0 | 0 | 0 | 0 |
| Residential Lighting Program | 7,798,234 | 5,890,547 | 4,259,629 | 2,243,150 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial Lighting Program | 2,456 | 2,456 | 2,456 | 2,057 | 749 | 21 | 21 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial HVAC Upgrade | 127 | 127 | 127 | 127 | 127 | 127 | 127 | 127 | 99 | 40 | 0 | 0 | 0 | 0 | 0 | 0 |
| Non-Residential Energy Audit Program | 2,355 | 2,355 | 2,354 | 2,052 | 920 | 769 | 769 | 769 | 769 | 769 | 0 | 0 | 0 | 0 | 0 | 0 |
| Non-Residential Duct Testing and Sealing Program | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 | 4,552 |
| Non-Residential Distributed Generation Program | 7 | 8 | 8 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Residential Bundle Program | 168,014 | 159,013 | 133,745 | 106,324 | 81,824 | 81,793 | 80,224 | 60,522 | 45,666 | 31,666 | 31,580 | 28,285 | 24,592 | 19,777 | 15,669 | 10,418 |
| Residential Home Energy Check-Up Program | 50,158 | 50,158 | 50,158 | 50,158 | 50,158 | 50,127 | 48,558 | 28,856 | 14,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential Duct Sealing Program | 4,300 | 4,300 | 4,300 | 4,300 | 4,300 | 4,300 | 4,300 | 4,300 | 4,300 | 4,300 | 4,300 | 4,300 | 4,300 | 4,292 | 4,184 | 3,783 |
| Residential Heat Pump Tune Up Program | 92,825 | 77,189 | 51,921 | 24,500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential Heat Pump Upgrade Program | 20,731 | 27,366 | 27,366 | 27,366 | 27,366 | 27,366 | 27,366 | 27,366 | 27,366 | 27,366 | 27,280 | 23,985 | 20,292 | 15,485 | 11,485 | 6,635 |
| Non-Residential Window Film Program | 2,837,857 | 4,388,538 | 4,490,547 | 4,594,596 | 4,700,726 | 4,750,989 | 4,801,911 | 4,852,046 | 4,900,427 | 4,947,086 | 4,992,575 | 5,037,264 | 5,081,291 | 5,124,856 | 5,128,504 | 5,176,442 |
| Non-Residential Lighting Systems & Controls Program | 4,662 | 6,588 | 6,738 | 6,891 | 7,047 | 7,110 | 7,173 | 7,235 | 7,295 | 7,353 | 7,410 | 7,465 | 7,520 | 7,574 | 7,579 | 7,639 |
| Non-Residential Heating and Cooling Efficiency Program | 1,807 | 2,667 | 2,721 | 2,776 | 2,832 | 2,862 | 2,892 | 2,922 | 2,951 | 2,978 | 3,005 | 3,032 | 3,058 | 3,084 | 3,086 | 3,114 |
| Income and Age Qualifying Home Improvement Program | 9,723 | 13,823 | 17,923 | 22,023 | 26,123 | 26,401 | 26,684 | 26,960 | 27,223 | 27,473 | 27,714 | 27,949 | 28,180 | 28,407 | 28,649 | 28,927 |
| Residential Appliance Recycling Program | 13,706 | 13,706 | 13,706 | 13,706 | 13,706 | 13,706 | 10,500 | 3,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small Business Improvement Program | 1,196 | 2,028 | 3,018 | 4,165 | 4,248 | 4,295 | 4,342 | 4,389 | 4,434 | 4,477 | 4,520 | 4,561 | 4,602 | 4,643 | 4,646 | 4,691 |
| Total | 10,964,612 | 10,606,324 | 9,057,440 | 7,122,344 | 4,962,779 | 5,012,549 | 5,059,119 | 5,081,016 | 5,107,790 | 5,138,233 | 5,181,191 | 5,220,944 | 5,260,977 | 5,300,074 | 5,299,868 | 5,342,964 |

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

# Appendix 3R – Description of Proposed DSM Programs

**Non-Residential Prescriptive Program**

| | |
|---|---|
| Target Class: | Non-Residential |
| VA Program Type: | Energy Efficiency |
| NC Program Type: | Energy Efficiency |
| VA Duration: | 2017 – 2042 |
| NC Duration: | 2018 – 2042 |

**Program Description:**
This Program will provide an incentive to eligible non-residential customers not otherwise eligible or who choose not to participate in the Company's Small Business Improvement Program. The Program would offer incentives for the installation of energy efficiency measures such as Refrigerator Evaporator Fans (Reach-in and Walk-in Coolers and Freezers), Commercial ENERGY STAR Appliances, Commercial Refrigeration, Commercial ENERGY STAR Ice Maker, Advanced Power Strip, Cooler/Freezer Strip Curtain, HVAC Tune-Up, Vending Machine Controls, Kitchen Fan Variable Speed Drives and Commercial Duct Testing and Sealing.

**Residential Home Energy Assessment Program**

| | |
|---|---|
| Target Class: | Residential |
| VA Program Type: | Energy Efficiency |
| NC Program Type: | Energy Efficiency |
| VA Duration: | 2017 - 2042 |
| NC Duration: | 2018 - 2042 |

**Program Description:** This Program will provide eligible residential customers an incentive to install a variety of energy saving measures following completion of a home energy assessment. The energy saving measures would include the replacement of existing light bulbs with LED bulbs, heat pump tune-up, door weatherization, heat pump and central AC filter replacement, installation of efficient faucet aerators and showerheads, and water heater and pipe insulation.

# Appendix 3S – Proposed Programs Non-Coincidental Peak Savings for Plan C$^T$: Intensity-Based Dual Rate (kW) (System-Level)

| Programs | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-Residential Prescriptive Program | 6,138 | 18,939 | 31,566 | 45,074 | 58,943 | 64,033 | 64,739 | 65,441 | 66,123 | 66,781 | 67,420 | 68,046 | 68,662 | 69,271 | 69,507 | 69,969 |
| Residential Home Energy Assessment | 3,257 | 10,032 | 17,078 | 24,405 | 32,026 | 34,413 | 34,880 | 35,345 | 35,792 | 36,217 | 36,625 | 37,021 | 37,408 | 37,788 | 38,182 | 38,620 |
| Total | 9,395 | 28,971 | 48,643 | 69,479 | 90,969 | 98,445 | 99,619 | 100,785 | 101,915 | 102,998 | 104,045 | 105,067 | 106,070 | 107,059 | 107,689 | 108,589 |

## Appendix 3T – Proposed Programs Coincidental Peak Savings for Plan C$^{T}$: Intensity-Based Dual Rate (kW) (System-Level)

| Programs | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-Residential Prescriptive Program | 0 | 14,784 | 27,456 | 40,128 | 52,799 | 58,452 | 59,097 | 59,739 | 60,364 | 60,967 | 61,552 | 62,125 | 62,689 | 63,246 | 63,504 | 63,879 |
| Residential Home Energy Assessment | 0 | 2,700 | 5,297 | 7,998 | 10,807 | 12,092 | 12,256 | 12,419 | 12,576 | 12,726 | 12,869 | 13,008 | 13,144 | 13,278 | 13,416 | 13,570 |
| Total | 0 | 17,484 | 32,753 | 48,126 | 63,607 | 70,544 | 71,353 | 72,158 | 72,940 | 73,693 | 74,421 | 75,133 | 75,833 | 76,523 | 76,920 | 77,449 |

# Appendix 3U – Proposed Programs Energy Savings for Plan C$^T$: Intensity-Based Dual Rate (MWh) (System-Level)

| Programs | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-Residential Prescriptive Program | 10,249 | 99,769 | 188,453 | 277,136 | 365,820 | 408,891 | 413,399 | 417,897 | 422,278 | 426,504 | 430,603 | 434,615 | 438,563 | 442,461 | 444,416 | 446,877 |
| Residential Home Energy Assessment | 1,784 | 18,865 | 37,883 | 57,662 | 78,232 | 88,664 | 89,868 | 91,067 | 92,223 | 93,322 | 94,376 | 95,398 | 96,397 | 97,378 | 98,389 | 99,511 |
| Total | 12,033 | 118,635 | 226,336 | 334,798 | 444,052 | 497,555 | 503,268 | 508,964 | 514,501 | 519,826 | 524,979 | 530,014 | 534,960 | 539,840 | 542,805 | 546,388 |

# Appendix 3V – Proposed Programs Penetrations for Plan C<sup>T</sup>: Intensity-Based Dual Rate (System-Level)

| Programs | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-Residential Prescriptive Program | 266 | 722 | 1,178 | 1,634 | 2,090 | 2,113 | 2,136 | 2,159 | 2,181 | 2,203 | 2,224 | 2,244 | 2,264 | 2,284 | 2,286 | 2,308 |
| Residential Home Energy Assessment | 11,568 | 35,629 | 60,653 | 86,678 | 113,744 | 115,287 | 116,855 | 118,388 | 119,846 | 121,233 | 122,572 | 123,877 | 125,155 | 126,414 | 127,761 | 129,301 |
| Total | 11,834 | 36,351 | 61,831 | 88,312 | 115,834 | 117,400 | 118,991 | 120,547 | 122,027 | 123,436 | 124,795 | 126,121 | 127,419 | 128,699 | 130,047 | 131,609 |

Part 7



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## Appendix 3W– Generation Interconnection Projects under Construction

| Project Name | PJM Queue | Line Voltage (kV) | Interconnection Cost (Million $) | Target Date | Location |
|---|---|---|---|---|---|
| Greensville Power Station Transmission Interconnection | Z1-086 | 500 | 93 | Nov-17 | VA |

## Appendix 3X – List of Transmission Lines under Construction

| Line Terminals | Line Voltage (kV) | Line Capacity (MVA) | Target Date | Location |
|---|---|---|---|---|
| Line #2027 Bremo to Midlothian Rebuild | 230 | 1,047 | May-17 | VA |
| Line #47 Kings Dominion to Fredericksburg Rebuild | 115 | 353 | May-18 | VA |
| Line #47 Four Rivers to Kings Dominion Rebuild | 115 | 353 | May-18 | VA |
| Line #2172 Brambleton to Yardley Ridge – New 230kV Line | 230 | 1,047 | May-18 | VA |
| Line #2183 Brambleton to Poland Road – New 230kV Line and New 230kV Substation | 230 | 1,047 | May-18 | VA |
| Line #2174 Vint Hill to Wheeler – New 230kV Line | 230 | 1,047 | Jun-18 | VA |
| Line #553 Cunningham to Elmont Rebuild | 500 | 4,330 | Jun-18 | VA |
| Line #137 Ridge Road to Kerr Dam Rebuild | 115 | 346 | Jun-18 | VA |
| Line #1009 Ridge Road to Chase City Rebuild | 115 | 346 | Jun-18 | VA |
| Line #2086 Remington Combustion Turbine to Warrenton Rebuild | 230 | 1,047 | Oct-18 | VA |
| Line #2161 Wheeler to Gainesville Uprate | 230 | 1,047 | Dec-18 | VA |
| Line #90 Carolina to Kerr Dam Rebuild | 115 | 346 | Dec-19 | VA/NC |

## Appendix 3Y – Letter of Intent for Nuclear License Extension for Surry Power Station Units 1 and 2

VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

November 5, 2015

10 CFR Part 54

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Serial No.: 15-293
NL&OS/DEA: R0
Docket Nos.: 50-280/281
License Nos.: DPR-32/37

**VIRGINIA ELECTRIC AND POWER COMPANY**
**SURRY POWER STATION UNITS 1 AND 2**
**INTENT TO PURSUE SECOND LICENSE RENEWAL**

This letter provides notification of Virginia Electric and Power Company's (Dominion) intention to submit an application for the second renewed Operating Licenses for Surry Power Station, Units 1 and 2.

The first renewed Operating Licenses for Surry Power Station, Units 1 and 2 were issued on March 20, 2003 and will expire at midnight on May 25, 2032 and January 29, 2033, respectively. Dominion intends to submit an application for the second renewed Operating Licenses for Surry Power Station, Units 1 and 2 in accordance with 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," by the end of the first quarter of 2019.

This notification is being provided consistent with RIS 2009-06, "Importance of Giving NRC Advance Notice of Intent to Pursue License Renewal," dated June 15, 2009. As discussed in RIS 2009-006, Dominion will keep the NRC informed of any changes to the anticipated schedule for filing the second license renewal application for Surry Power Station to facilitate NRC efforts to plan for processing of license renewal applications.

If you have any questions regarding this information, please contact Mr. Tom Huber at (804) 273-2229.

Sincerely,

Mark Sartain
Vice President - Nuclear Engineering

Commitments made in this letter: None

## Appendix 3Y cont. – Letter of Intent for Nuclear License Extension for Surry Power Station Units 1 and 2

Serial No. 15-293
Docket Nos. 50-280/281
Page 2 of 2

cc: U.S. Nuclear Regulatory Commission, Region II
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NRC Senior Resident Inspector
Surry Power Station

# Appendix 4A – ICF Commodity Price Forecasts for Virginia Electric and Power Company

Fall 2016 Forecast

**NOTICE PROVISIONS FOR AUTHORIZED THIRD PARTY USERS.**

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## ICF CPP Commodity Price Forecast (Nominal $)

| | Fuel Price | | | | | Power and REC Prices | | | | Emission Prices | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Henry Hub Natural Gas ($/MMBtu) | DOM Zone Delivered Natural Gas ($/MMBtu) | CAPP CSX: 12,500 1%S FOB ($/MMBtu) | No. 2 Oil ($/MMBtu) | 1% No.6 Oil ($/MMBtu) | PJM-DOM On-Peak ($/MWh) | PJM-DOM Off-Peak ($/MWh) | PJM Tier 1 REC Prices ($/MWh) | RTO Capacity Prices ($/kW-yr) | CSAPR $SO_2$ ($/Ton) | CSAPR Ozone $NO_x$ ($/Ton) | CSAPR Annual $NO_x$ ($/Ton) | $CO_2$ ($/Ton) |
| 2017 | 3.11 | 3.14 | 2.13 | 11.35 | 6.6 | 42.31 | 29.38 | 10.75 | 52.64 | 2.07 | 570.87 | 7.23 | - |
| 2018 | 3.03 | 3.11 | 2.08 | 11.97 | 7.04 | 40.57 | 29.29 | 11.25 | 58.12 | 2.12 | 612.94 | 7.42 | - |
| 2019 | 3.5 | 3.62 | 2.01 | 13.22 | 8.23 | 39.79 | 31.36 | 10.35 | 46.35 | 2.17 | 656.68 | 7.61 | - |
| 2020 | 4.13 | 4.18 | 2.06 | 14.26 | 9.06 | 40.7 | 32.74 | 10.56 | 49.02 | 2.22 | 701.27 | 7.77 | - |
| 2021 | 4.32 | 4.24 | 2.13 | 15.02 | 9.58 | 41.73 | 33.7 | 11.26 | 59.58 | 2.26 | 747.52 | 7.92 | - |
| 2022 | 4.52 | 4.29 | 2.2 | 15.69 | 10.04 | 43 | 34.7 | 12.01 | 61.59 | 2.31 | 796.9 | 8.08 | 3.19 |
| 2023 | 4.73 | 4.28 | 2.27 | 16.27 | 10.43 | 43.37 | 35.17 | 12.81 | 63.69 | 2.35 | 849.99 | 8.24 | 3.45 |
| 2024 | 4.95 | 4.46 | 2.34 | 16.81 | 10.8 | 46.01 | 37.19 | 13.66 | 65.83 | 2.4 | 906.44 | 8.4 | 3.72 |
| 2025 | 5.17 | 4.62 | 2.41 | 17.42 | 11.21 | 48.07 | 39.04 | 14.56 | 68.01 | 2.45 | 966.39 | 8.56 | 3.99 |
| 2026 | 5.34 | 4.83 | 2.48 | 18.12 | 11.69 | 49.77 | 40.49 | 15.53 | 70.61 | 2.5 | 1,030.84 | 8.74 | 4.27 |
| 2027 | 5.53 | 4.94 | 2.54 | 18.78 | 12.14 | 49.88 | 40.95 | 16.57 | 73.56 | 2.55 | 1,100.02 | 8.91 | 4.57 |
| 2028 | 5.72 | 5.13 | 2.6 | 19.43 | 12.58 | 51.6 | 42.31 | 17.69 | 76.63 | 2.6 | 1,174.29 | 9.1 | 4.88 |
| 2029 | 5.92 | 5.37 | 2.67 | 20.18 | 13.09 | 53.43 | 43.96 | 18.89 | 79.78 | 2.65 | 1,253.46 | 9.28 | 5.2 |
| 2030 | 6.12 | 5.62 | 2.74 | 20.81 | 13.52 | 55.74 | 45.76 | 20.15 | 83.01 | 2.71 | 1,337.58 | 9.47 | 5.52 |
| 2031 | 6.31 | 5.86 | 2.81 | 21.68 | 14.11 | 57.48 | 47.51 | 21.5 | 86.31 | 2.76 | 1,094.23 | 9.66 | 5.92 |
| 2032 | 6.5 | 6.13 | 2.87 | 22.57 | 14.73 | 59.67 | 49.46 | 22.94 | 89.71 | 2.82 | 840.58 | 9.85 | 6.32 |

Note: The 2017 - 2019 prices are a blend of futures/forwards and forecast prices for all commodities except emissions and capacity prices. 2020 and beyond are forecast prices. Capacity prices reflect PJM RPM auction clearing prices through delivery year 2019/2020, forecast thereafter. Emission prices are forecasted for all years. Refer to Sections 4.4.1 and 4.4.2 for additional details.

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## ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; Natural Gas

| Year | DOM Zone Natural Gas Price (Nominal $/MMBtu) | |
|---|---|---|
| | CPP Commodity Case | No $CO_2$ Cost Case |
| 2017 | 3.14 | 3.14 |
| 2018 | 3.11 | 3.09 |
| 2019 | 3.62 | 3.54 |
| 2020 | 4.18 | 4.06 |
| 2021 | 4.24 | 4.13 |
| 2022 | 4.29 | 4.19 |
| 2023 | 4.28 | 4.19 |
| 2024 | 4.46 | 4.37 |
| 2025 | 4.62 | 4.54 |
| 2026 | 4.83 | 4.77 |
| 2027 | 4.94 | 4.90 |
| 2028 | 5.13 | 5.11 |
| 2029 | 5.37 | 5.37 |
| 2030 | 5.62 | 5.65 |
| 2031 | 5.86 | 5.90 |
| 2032 | 6.13 | 6.17 |

Note: The 2017 - 2019 prices are a blend of futures/forwards and forecast prices. 2020 and beyond are forecast prices.

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## ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; Natural Gas

| Year | Henry Hub Natural Gas Price (Nominal $/MMBtu) CPP Commodity Case | Henry Hub Natural Gas Price (Nominal $/MMBtu) No $CO_2$ Cost Case |
|---|---|---|
| 2017 | 3.11 | 3.11 |
| 2018 | 3.03 | 3.02 |
| 2019 | 3.50 | 3.42 |
| 2020 | 4.13 | 4.01 |
| 2021 | 4.32 | 4.21 |
| 2022 | 4.52 | 4.42 |
| 2023 | 4.73 | 4.64 |
| 2024 | 4.95 | 4.86 |
| 2025 | 5.17 | 5.09 |
| 2026 | 5.34 | 5.29 |
| 2027 | 5.53 | 5.49 |
| 2028 | 5.72 | 5.71 |
| 2029 | 5.92 | 5.93 |
| 2030 | 6.12 | 6.15 |
| 2031 | 6.31 | 6.34 |
| 2032 | 6.50 | 6.54 |

Note: The 2017 - 2019 prices are a blend of futures/forwards and forecast prices. 2020 and beyond are forecast prices.

## ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; Coal: FOB

| Year | CAPP 12,500 1% S Coal (Nominal $/MMBtu) | |
|---|---|---|
| | CPP Commodity Case | No $CO_2$ Cost Case |
| 2017 | 2.13 | 2.13 |
| 2018 | 2.08 | 2.08 |
| 2019 | 2.01 | 2.01 |
| 2020 | 2.06 | 2.06 |
| 2021 | 2.13 | 2.13 |
| 2022 | 2.20 | 2.20 |
| 2023 | 2.27 | 2.28 |
| 2024 | 2.34 | 2.35 |
| 2025 | 2.41 | 2.43 |
| 2026 | 2.48 | 2.49 |
| 2027 | 2.54 | 2.56 |
| 2028 | 2.60 | 2.62 |
| 2029 | 2.67 | 2.69 |
| 2030 | 2.74 | 2.76 |
| 2031 | 2.81 | 2.83 |
| 2032 | 2.87 | 2.90 |

Note: The 2017 - 2019 prices are a blend of futures/forwards and forecast prices. 2020 and beyond are forecast prices.

# ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; Oil

| Year | No. 2 Oil (Nominal $/MMBtu) CPP Commodity Case | No $CO_2$ Cost Case |
|---|---|---|
| 2017 | 11.35 | 11.35 |
| 2018 | 11.97 | 11.97 |
| 2019 | 13.22 | 13.22 |
| 2020 | 14.26 | 14.26 |
| 2021 | 15.02 | 15.02 |
| 2022 | 15.69 | 15.69 |
| 2023 | 16.27 | 16.27 |
| 2024 | 16.81 | 16.81 |
| 2025 | 17.42 | 17.42 |
| 2026 | 18.12 | 18.12 |
| 2027 | 18.78 | 18.78 |
| 2028 | 19.43 | 19.43 |
| 2029 | 20.18 | 20.18 |
| 2030 | 20.81 | 20.81 |
| 2031 | 21.68 | 21.68 |
| 2032 | 22.57 | 22.57 |

Note: The 2017 - 2019 prices are a blend of futures/forwards and forecast prices. 2020 and beyond are forecast prices.

# ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; Oil

| Year | 1% No. 6 Oil (Nominal $/MMBtu) | |
|---|---|---|
| | CPP Commodity Case | No $CO_2$ Cost Case |
| 2017 | 6.60 | 6.60 |
| 2018 | 7.04 | 7.04 |
| 2019 | 8.23 | 8.23 |
| 2020 | 9.06 | 9.06 |
| 2021 | 9.58 | 9.58 |
| 2022 | 10.04 | 10.04 |
| 2023 | 10.43 | 10.43 |
| 2024 | 10.80 | 10.80 |
| 2025 | 11.21 | 11.21 |
| 2026 | 11.69 | 11.69 |
| 2027 | 12.14 | 12.14 |
| 2028 | 12.58 | 12.58 |
| 2029 | 13.09 | 13.09 |
| 2030 | 13.52 | 13.52 |
| 2031 | 14.11 | 14.11 |
| 2032 | 14.73 | 14.73 |

Note: The 2017 - 2019 prices are a blend of futures/forwards and forecast prices. 2020 and beyond are forecast prices.

# ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; On-Peak Power Price

| Year | DOM Zone Power On-Peak (Nominal $/MWh) CPP Commodity Case | No $CO_2$ Cost Case |
|---|---|---|
| 2017 | 42.31 | 42.31 |
| 2018 | 40.57 | 40.31 |
| 2019 | 39.79 | 38.00 |
| 2020 | 40.70 | 38.16 |
| 2021 | 41.73 | 39.20 |
| 2022 | 43.00 | 40.61 |
| 2023 | 43.37 | 41.03 |
| 2024 | 46.01 | 43.61 |
| 2025 | 48.07 | 45.39 |
| 2026 | 49.77 | 47.00 |
| 2027 | 49.88 | 47.00 |
| 2028 | 51.60 | 48.68 |
| 2029 | 53.43 | 50.50 |
| 2030 | 55.74 | 52.82 |
| 2031 | 57.48 | 54.65 |
| 2032 | 59.67 | 56.90 |

Note: The 2017 - 2019 prices are a blend of futures/forwards and forecast prices. 2020 and beyond are forecast prices.

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# ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; Off-Peak Power Price

| Year | DOM Zone Power Off-Peak (Nominal $/MWh) | |
|---|---|---|
| | CPP Commodity Case | No $CO_2$ Cost Case |
| 2017 | 29.38 | 29.38 |
| 2018 | 29.29 | 29.05 |
| 2019 | 31.36 | 29.96 |
| 2020 | 32.74 | 30.97 |
| 2021 | 33.70 | 31.84 |
| 2022 | 34.70 | 32.88 |
| 2023 | 35.17 | 33.29 |
| 2024 | 37.19 | 35.21 |
| 2025 | 39.04 | 36.73 |
| 2026 | 40.49 | 38.14 |
| 2027 | 40.95 | 38.54 |
| 2028 | 42.31 | 39.93 |
| 2029 | 43.96 | 41.62 |
| 2030 | 45.76 | 43.50 |
| 2031 | 47.51 | 45.33 |
| 2032 | 49.46 | 47.35 |

Note: The 2017 - 2019 prices are a blend of futures/forwards and forecast prices. 2020 and beyond are forecast prices.

# ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; PJM Tier 1 Renewable Energy Certificates

| Year | PJM Tier 1 REC Prices (Nominal $/MWh) | |
|---|---|---|
| | CPP Commodity Case | No $CO_2$ Cost Case |
| 2017 | 10.75 | 10.75 |
| 2018 | 11.25 | 11.40 |
| 2019 | 10.35 | 10.99 |
| 2020 | 10.56 | 11.41 |
| 2021 | 11.26 | 12.16 |
| 2022 | 12.01 | 12.97 |
| 2023 | 12.81 | 13.83 |
| 2024 | 13.66 | 14.75 |
| 2025 | 14.56 | 15.72 |
| 2026 | 15.53 | 16.77 |
| 2027 | 16.57 | 17.90 |
| 2028 | 17.69 | 19.11 |
| 2029 | 18.89 | 20.39 |
| 2030 | 20.15 | 21.76 |
| 2031 | 21.50 | 23.22 |
| 2032 | 22.94 | 24.77 |

Note: The 2017 - 2019 prices are a blend of futures/forwards and forecast prices. 2020 and beyond are forecast prices.

# ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; PJM RTO Capacity

| Year | RTO Capacity Prices (Nominal $/KW-yr) | |
|---|---|---|
| | CPP Commodity Case | No $CO_2$ Cost Case |
| 2017 | 52.64 | 52.64 |
| 2018 | 58.12 | 58.12 |
| 2019 | 46.35 | 46.35 |
| 2020 | 49.02 | 49.02 |
| 2021 | 59.58 | 60.70 |
| 2022 | 61.59 | 64.69 |
| 2023 | 63.69 | 68.85 |
| 2024 | 65.83 | 73.13 |
| 2025 | 68.01 | 77.53 |
| 2026 | 70.61 | 80.61 |
| 2027 | 73.56 | 82.72 |
| 2028 | 76.63 | 84.91 |
| 2029 | 79.78 | 87.14 |
| 2030 | 83.01 | 89.41 |
| 2031 | 86.31 | 91.71 |
| 2032 | 89.71 | 94.07 |

Note: PJM RPM auction clearing prices through delivery year 2019/20, forecast thereafter.

# ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; $SO_2$ Emission Allowances

| Year | CSAPR $SO_2$ Prices (Nominal $/Ton) | |
|---|---|---|
| | CPP Commodity Case | No $CO_2$ Cost Case |
| 2017 | 2.07 | 2.07 |
| 2018 | 2.12 | 2.12 |
| 2019 | 2.17 | 2.17 |
| 2020 | 2.22 | 2.22 |
| 2021 | 2.26 | 2.26 |
| 2022 | 2.31 | 2.31 |
| 2023 | 2.35 | 2.35 |
| 2024 | 2.40 | 2.40 |
| 2025 | 2.45 | 2.45 |
| 2026 | 2.50 | 2.50 |
| 2027 | 2.55 | 2.55 |
| 2028 | 2.60 | 2.60 |
| 2029 | 2.65 | 2.65 |
| 2030 | 2.71 | 2.71 |
| 2031 | 2.76 | 2.76 |
| 2032 | 2.82 | 2.82 |

## ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; $NO_x$ Emission Allowances

| Year | CSAPR Ozone NOx Prices (Nominal $/Ton) | |
|---|---|---|
| | CPP Commodity Case | No $CO_2$ Cost Case |
| 2017 | 570.87 | 601.04 |
| 2018 | 612.94 | 645.33 |
| 2019 | 656.68 | 691.38 |
| 2020 | 701.27 | 738.33 |
| 2021 | 747.52 | 787.03 |
| 2022 | 796.90 | 839.01 |
| 2023 | 849.99 | 894.91 |
| 2024 | 906.44 | 954.34 |
| 2025 | 966.39 | 1,017.46 |
| 2026 | 1,030.84 | 1,085.31 |
| 2027 | 1,100.02 | 1,158.16 |
| 2028 | 1,174.29 | 1,236.35 |
| 2029 | 1,253.46 | 1,319.70 |
| 2030 | 1,337.58 | 1,408.26 |
| 2031 | 1,094.23 | 1,502.37 |
| 2032 | 840.58 | 1,602.71 |

## ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; $NO_x$ Emission Allowances

| Year | CSAPR Annual NOx Prices (Nominal $/Ton) | |
|---|---|---|
| | CPP Commodity Case | No $CO_2$ Cost Case |
| 2017 | 7.23 | 7.23 |
| 2018 | 7.42 | 7.42 |
| 2019 | 7.61 | 7.61 |
| 2020 | 7.77 | 7.77 |
| 2021 | 7.92 | 7.92 |
| 2022 | 8.08 | 8.08 |
| 2023 | 8.24 | 8.24 |
| 2024 | 8.40 | 8.40 |
| 2025 | 8.56 | 8.56 |
| 2026 | 8.74 | 8.74 |
| 2027 | 8.91 | 8.91 |
| 2028 | 9.10 | 9.10 |
| 2029 | 9.28 | 9.28 |
| 2030 | 9.47 | 9.47 |
| 2031 | 9.66 | 9.66 |
| 2032 | 9.85 | 9.85 |

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## ICF CPP Commodity Case, No $CO_2$ Cost Case and Scenario Price Forecast; $CO_2$ & ERC

| Year | $CO_2$ (Nominal $/Ton) & ERC ($/MWh) | | | |
|---|---|---|---|---|
| | CPP Commodity Case | | No $CO_2$ Cost Case | |
| | $CO_2$ | ERC | $CO_2$ | ERC |
| 2017 | - | - | - | - |
| 2018 | - | - | - | - |
| 2019 | - | - | - | - |
| 2020 | - | - | - | - |
| 2021 | - | - | - | - |
| 2022 | 3.19 | 4.39 | - | - |
| 2023 | 3.45 | 4.55 | - | - |
| 2024 | 3.72 | 4.71 | - | - |
| 2025 | 3.99 | 4.87 | - | - |
| 2026 | 4.27 | 5.04 | - | - |
| 2027 | 4.57 | 5.22 | - | - |
| 2028 | 4.88 | 5.41 | - | - |
| 2029 | 5.20 | 5.60 | - | - |
| 2030 | 5.52 | 5.79 | - | - |
| 2031 | 5.92 | 6.17 | - | - |
| 2032 | 6.32 | 6.56 | - | - |

Note: Analysis of Plans assuming Intensity-Based CPP programs use ERC prices. $CO_2$ allowance prices are used for analysis of Mass-Based programs. Refer to Sections 4.4.1 and 4.4.2 for additional details.

# Projected State CPP Program

| | Projected State CPP Program | |
|---|---|---|
| | Mass Based | Intensity Based |
| 1 | AL | FL |
| 2 | AR | GA |
| 3 | AZ | IA |
| 4 | CA | ID |
| 5 | CO | IL |
| 6 | CT | MN |
| 7 | DE | ND |
| 8 | IN | NM |
| 9 | KS | NV |
| 10 | KY | OK |
| 11 | LA | SC |
| 12 | MA | TN |
| 13 | MD | TX |
| 14 | ME | VA |
| 15 | MI | |
| 16 | MO | |
| 17 | MS | |
| 18 | MT | |
| 19 | NC | |
| 20 | NE | |
| 21 | NH | |
| 22 | NJ | |
| 23 | NY | |
| 24 | OH | |
| 25 | OR | |
| 26 | PA | |
| 27 | RI | |
| 28 | SD | |
| 29 | UT | |
| 30 | WA | |
| 31 | WI | |
| 32 | WV | |
| 33 | WY | |

# Appendix 4B – Delivered Fuel Data for Plan $C^T$: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company

Schedule 18

**FUEL DATA**

| | (ACTUAL) | | | | (PROJECTED) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| **I. Delivered Fuel Price ($/mmBtu)[1]** | | | | | | | | | | | | | | | | | | | |
| a. Nuclear | 0.68 | 0.67 | 0.70 | 0.64 | 0.64 | 0.64 | 0.63 | 0.61 | 0.61 | 0.60 | 0.61 | 0.61 | 0.63 | 0.64 | 0.65 | 0.66 | 0.66 | 0.67 | 0.68 |
| b. Coal | 3.04 | 2.87 | 2.61 | 1.86 | 1.99 | 2.04 | 2.14 | 2.21 | 2.28 | 2.36 | 2.43 | 2.51 | 2.57 | 2.63 | 2.70 | 2.77 | 2.84 | 2.91 | 2.99 |
| c. Heavy Fuel Oil | 16.33 | 7.78 | 7.28 | 6.60 | 7.04 | 8.23 | 9.06 | 9.58 | 10.04 | 10.43 | 10.80 | 11.21 | 11.69 | 12.14 | 12.58 | 13.09 | 13.52 | 14.11 | 14.73 |
| d. Light Fuel Oil[2] | 21.60 | 14.54 | 10.63 | 11.35 | 11.97 | 13.22 | 14.26 | 15.02 | 15.69 | 16.27 | 16.81 | 17.42 | 18.12 | 18.78 | 19.43 | 20.18 | 20.81 | 21.68 | 22.57 |
| e. Natural Gas | 5.96 | 4.11 | 2.37 | 3.14 | 3.11 | 3.62 | 4.18 | 4.24 | 4.29 | 4.28 | 4.46 | 4.62 | 4.83 | 4.94 | 5.13 | 5.37 | 5.62 | 5.86 | 6.13 |
| f. Renewable[3] | 3.07 | 3.16 | 3.17 | 2.74 | 2.79 | 2.87 | 2.89 | 2.92 | 2.95 | 2.77 | 2.82 | 2.91 | 2.99 | 3.08 | 3.17 | 3.27 | 3.37 | 3.47 | 3.59 |
| **II. Primary Fuel Expenses (cents/kWh)[4]** | | | | | | | | | | | | | | | | | | | |
| a. Nuclear | 0.70 | 0.69 | 0.72 | 0.68 | 0.68 | 0.68 | 0.66 | 0.64 | 0.63 | 0.63 | 0.64 | 0.64 | 0.66 | 0.67 | 0.67 | 0.68 | 0.69 | 0.70 | 0.71 |
| b. Coal | 3.26 | 3.13 | 3.09 | 2.67 | 2.64 | 2.58 | 2.66 | 2.75 | 2.84 | 2.94 | 3.04 | 3.14 | 3.22 | 3.31 | 3.39 | 3.48 | 3.57 | 3.65 | 3.74 |
| c. Heavy Fuel Oil | 15.16 | 12.25 | 8.56 | 7.67 | 8.07 | 9.05 | 10.37 | 10.69 | 11.43 | 11.45 | 12.55 | 12.91 | 13.67 | 13.57 | 14.20 | 14.70 | 15.79 | 16.11 | 16.97 |
| d. Light Fuel Oil[2] | 15.46 | 11.62 | 6.80 | 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 |
| e. Natural Gas | 4.33 | 3.03 | 2.18 | 2.52 | 2.11 | 2.39 | 2.69 | 2.76 | 2.71 | 2.80 | 2.87 | 3.05 | 3.16 | 3.35 | 3.39 | 3.56 | 3.60 | 3.81 | 3.85 |
| f. Renewable[3] | 4.26 | 4.93 | 4.64 | 3.25 | 3.31 | 3.36 | 3.36 | 3.43 | 3.37 | 3.52 | 3.60 | 3.69 | 3.77 | 3.88 | 3.98 | 4.09 | 4.19 | 4.30 | 4.39 |
| g. NUG[5] | 4.30 | 3.21 | 2.98 | 2.89 | 1.04 | 0.95 | 0.94 | 0.81 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| i. Economy Energy Purchases[6] | 6.38 | 4.56 | 15.62 | 2.23 | 2.19 | 2.30 | 2.51 | 2.59 | 2.79 | 2.79 | 2.97 | 2.98 | 3.09 | 3.16 | 3.28 | 3.31 | 3.46 | 3.56 | 3.75 |
| j. Capacity Purchases ($/kW-Year) | 31.77 | 49.57 | 33.24 | 52.64 | 58.12 | 46.35 | 49.02 | 59.58 | 61.59 | 63.69 | 65.83 | 68.01 | 70.61 | 73.56 | 76.63 | 79.78 | 83.01 | 86.31 | 89.71 |

(1) Delivered fuel price for CAPP CSX (12,500, 1% FOB), No. 2 Oil, No. 6 Oil, DOM Zone Delivered Natural Gas are used to represent Coal, Heavy Fuel, Light Fuel Oil and Natural Gas respectively.

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

(3) Reflects biomass units only.

(4) Primary Fuel Expenses for Nuclear, Coal, Heavy Fuel Oil, Natural Gas and Renewable are based on North Anna 1, Chesterfield 6, Yorktown 3, Possum Point 6, Pittsylvania, respectively.

(5) Average of NUGs Fuel Expenses.

(6) Average cost of Market Energy Purchases.

## Appendix 5A - Tabular Results of Busbar

| | Capacity Factor (%) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $/kW-Year | 0% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
| 3X1 CC | $ 147 | $ 190 | $ 234 | $ 277 | $ 320 | $ 364 | $ 407 | $ 450 | $ 494 | $ 537 | $ 580 |
| 2X1 CC | $ 162 | $ 208 | $ 253 | $ 298 | $ 343 | $ 388 | $ 434 | $ 479 | $ 524 | $ 569 | $ 615 |
| 1X1 CC | $ 216 | $ 266 | $ 316 | $ 367 | $ 417 | $ 468 | $ 518 | $ 568 | $ 619 | $ 669 | $ 720 |
| CT | $ 60 | $ 140 | $ 221 | $ 301 | $ 381 | $ 461 | $ 541 | $ 622 | $ 702 | $ 782 | $ 862 |
| Aero CT | $ 130 | $ 195 | $ 261 | $ 327 | $ 393 | $ 459 | $ 524 | $ 590 | $ 656 | $ 722 | $ 788 |
| Solar & Aero CT | $ 213 | $ 267 | $ 320 | $ 374 | $ 427 | $ 480 | $ 534 | $ 587 | $ 641 | $ 694 | $ 747 |
| Nuclear | $ 1,113 | $ 1,123 | $ 1,133 | $ 1,143 | $ 1,153 | $ 1,163 | $ 1,173 | $ 1,182 | $ 1,192 | $ 1,202 | $ 1,212 |
| Biomass | $ 905 | $ 950 | $ 996 | $ 1,042 | $ 1,088 | $ 1,133 | $ 1,179 | $ 1,225 | $ 1,270 | $ 1,316 | $ 1,362 |
| Fuel Cell | $ 971 | $ 1,014 | $ 1,058 | $ 1,101 | $ 1,144 | $ 1,187 | $ 1,231 | $ 1,274 | $ 1,317 | $ 1,361 | $ 1,404 |
| SCPC w/ CCS | $ 648 | $ 790 | $ 931 | $ 1,073 | $ 1,215 | $ 1,357 | $ 1,499 | $ 1,640 | $ 1,782 | $ 1,924 | $ 2,066 |
| IGCC w/ CCS | $ 1,360 | $ 1,490 | $ 1,621 | $ 1,751 | $ 1,881 | $ 2,012 | $ 2,142 | $ 2,273 | $ 2,403 | $ 2,533 | $ 2,664 |
| Solar | | | | $ 113 | | | | | | | |
| Onshore Wind | | | | | $ 317 | | | | | | |
| Offshore Wind | | | | | $ 1,235 | | | | | | |
| VOWTAP | | | | | $ 3,103 | | | | | | |

(1) VOWTAP and Offshore Wind both have a capacity factor of 42%.

(2) Onshore Wind has a capacity factor of 37%.

(3) Solar PV has a capacity factor of 25%.

## Appendix 5B - Busbar Assumptions

| Nominal $ | Heat Rate MMBtu/MWh | Variable Cost [1][2][4] $/MWh | Fixed Cost $/kW-Year | Book Life Years | 2017 Real $ [3] $/kW |
|---|---|---|---|---|---|
| 3X1 CC | 6.55 | 49.47 | 146.88 | 36 | 850 |
| 2X1 CC | 6.59 | 51.64 | 162.30 | 36 | 1,023 |
| 1X1 CC | 6.63 | 57.54 | 215.63 | 36 | 1,378 |
| CT | 10.07 | 91.55 | 60.23 | 36 | 474 |
| Aero CT | 9.32 | 75.13 | 129.50 | 36 | 1,074 |
| Solar & Aero CT | 9.32 | 60.97 | 213.30 | 35 (Solar ) / 36 (CT) | 2,767 |
| Nuclear | 10.50 | 11.38 | 1112.74 | 60 | 8,919 |
| Biomass | 13.00 | 52.17 | 904.70 | 40 | 6,426 |
| Fuel Cell | 8.75 | 49.42 | 970.94 | 20 | 6,429 |
| SCPC w/ CCS | 11.06 | 161.82 | 647.98 | 55 | 5,180 |
| IGCC w/ CCS | 10.88 | 148.84 | 1359.82 | 40 | 10,862 |
| Solar | 0.00 | (29.11) | 177.04 | 35 | 1,693 |
| Onshore Wind | 0.00 | (44.87) | 460.63 | 25 | 3,129 |
| Offshore Wind | 0.00 | (44.51) | 1397.29 | 20 | 8,637 |
| VOWTAP | 0.00 | (44.51) | 3264.81 | 20 | 23,420 |

(1) Variable cost for Biomass, Solar, Onshore Wind, Offshore Wind, and VOWTAP includes value for RECs.

(2) Variable cost for Onshore Wind, Offshore Wind, and VOWTAP includes value for PTCs.

(3) Values in this column represent overnight installed costs.

(4) Variable cost for Solar includes values for ITCs.

# Appendix 5C – Planned Generation under Development

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

**UNIT PERFORMANCE DATA**

**Planned Supply-Side Resources (MW)**

| Unit Name | Location | Unit Type | Primary Fuel Type | C.O.D.[2] | MW Summer | MW Nameplate |
|---|---|---|---|---|---|---|
| Under Development[1] | | | | | | |
| VOWTAP | VA | Intermittent | Wind | 2021 | 2 | 12[3] |
| North Anna 3 | Mineral, VA | Baseload | Nuclear | 2030 | 1,452. | 1,452 |

(1) Includes the additional resources under development in the Alternative Plans.

(2) Estimated Commercial Operation Date.

(3) Accounts for line losses.

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

**Total Resource Cost Test**

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

**Ratepayer Impact Measure Test**

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

# Appendix 5E – DSM Programs Energy Savings for Plan C$^T$: Intensity-Based Dual Rate (MWh) (System-Level)

Company Name: Virginia Electric & Power Company

Schedule 12

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

ACTUAL - MWh (2014–2016); (PROJECTED - MWh) (2017–2032)

| Program Type (1) | Program Name | Date (2) | Life/ Duration (3) | Size kW (4) | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak Shaving | Air Conditioner Cycling Program | 2010 | 2032 | 77,995 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sub-total | | | | 77,995 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency - Demand Response | Non-Residential Distributed Generation Program | 2010 | 2032 | 9,764 | | | | 0 | 0 | 0 | 0 | 0 | 3 |
| | Standby Generation (Pricing Tariffs) (5) | 1987 | 2032 | 2,459 | 276 | 342 | 274 | 274 | 274 | 274 | 274 | 274 | 274 |
| Sub-total | | | | 12,223 | 276 | 343 | 274 | 275 | 275 | 275 | 274 | 274 | 278 |
| Energy Efficiency | Residential Low Income Program | 2010 | 2028 | 0 | 5,876 | 6,536 | 6,682 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 |
| | Residential Lighting Program | 2010 | 2021 | 0 | 228,832 | 228,892 | 228,892 | 276,436 | 239,806 | 177,495 | 112,278 | 36,443 | 0 |
| | Commercial Lighting Program | 2010 | 2022 | 0 | 72,940 | 73,417 | 73,417 | 82,666 | 82,666 | 82,666 | 73,519 | 43,139 | 11,799 |
| | Commercial HVAC Upgrade | 2010 | 2027 | 0 | 5,936 | 5,936 | 5,936 | 3,640 | 3,640 | 3,640 | 3,644 | 3,640 | 3,640 |
| | Non-Residential Energy Audit Program | 2010 | 2032 | 0 | 15,796 | 33,233 | 36,734 | 28,723 | 28,723 | 28,716 | 26,601 | 17,458 | 10,211 |
| | Non-Residential Duct Testing and Sealing Program | 2012 | 2032 | 19,072 | 11,663 | 36,674 | 68,648 | 50,688 | 50,683 | 50,688 | 50,688 | 50,683 | 50,688 |
| | Residential Bundle Program | 2010 (6) | 2032 | 1,329 | 23,510 | 43,292 | 66,609 | 63,681 | 64,779 | 61,388 | 55,289 | 46,357 | 46,346 |
| | Residential Home Energy Check-Up Program | 2012 | 2032 | 0 | 6,915 | 19,706 | 35,496 | 34,439 | 34,439 | 34,439 | 34,439 | 34,439 | 34,428 |
| | Residential Duct Sealing Program | 2012 | 2032 | 270 | 79 | 439 | 758 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 |
| | Residential Heat Pump Tune Up Program | 2012 | 2032 | 0 | 7,278 | 13,140 | 17,530 | 21,511 | 19,743 | 13,031 | 8,932 | 0 | 0 |
| | Residential Heat Pump Upgrade Program | 2012 | 2032 | 1,057 | 9,237 | 11,966 | 13,024 | 6,680 | 9,546 | 10,866 | 10,866 | 10,866 | 10,866 |
| | Non-Residential Window Film Program | 2014 | 2032 | 111,656 | 77 | 2,765 | 3,618 | 52,613 | 88,318 | 104,585 | 107,318 | 109,800 | 111,531 |
| | Non-Residential Lighting Systems & Controls Program | 2014 | 2032 | 34,880 | 427 | 21,142 | 69,410 | 113,622 | 166,114 | 194,205 | 198,620 | 203,123 | 206,192 |
| | Non-Residential Heating and Cooling Efficiency Program | 2014 | 2032 | 67,522 | 135 | 4,965 | 13,851 | 81,824 | 131,434 | 156,422 | 159,586 | 162,808 | 165,243 |
| | Income and Age Qualifying Home Improvement Program | 2015 | 2032 | 2,799 | 0 | 112 | 1,991 | 3,930 | 6,018 | 8,107 | 10,196 | 12,284 | 13,380 |
| | Residential Appliance Recycling Program | 2015 | 2032 | 0 | 0 | 639 | 3,459 | 11,302 | 12,556 | 12,556 | 12,556 | 12,556 | 12,556 |
| | Small Business Improvement Program | 2016 | 2032 | 23,294 | 0 | 0 | 87 | 15,659 | 28,980 | 45,033 | 63,632 | 73,452 | 74,346 |
| | Non-Residential Prescriptive Program | 2017 | 2032 | 63,879 | 0 | 0 | 0 | 10,249 | 99,769 | 188,453 | 277,136 | 365,820 | 408,891 |
| | Residential Home Energy Assessment | | 2032 | 13,570 | 0 | 0 | 0 | 1,784 | 18,865 | 37,880 | 57,662 | 78,232 | 88,664 |
| Sub-total | | | | 337,938 | 365,251 | 459,634 | 531,383 0 | 818,077 | 1,035,576 | 1,163,336 | 1,224,213 | 1,231,601 | 1,216,891 |
| Total Demand Side Management | | | | 428,156 | 365,527 | 459,976 | 531,657 0 | 818,351 | 1,035,851 | 1,163,610 | 1,224,459 | 1,231,876 | 1,217,169 |

| Program Name | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|
| Air Conditioner Cycling Program | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sub-total (Peak Shaving) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Non-Residential Distributed Generation Program | 4 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| Standby Generation (Pricing Tariffs) (5) | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 |
| Sub-total (Energy Efficiency - Demand Response) | 279 | 281 | 275 | 275 | 274 | 275 | 274 | 278 | 275 | 278 |
| Residential Low Income Program | 13,199 | 12,434 | 9,514 | 6,093 | 3,752 | 1,678 | 327 | 0 | 0 | 0 |
| Residential Lighting Program | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial Lighting Program | 707 | 321 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commercial HVAC Upgrade | 3,640 | 3,644 | 3,213 | 1,938 | 537 | 0 | 0 | 0 | 0 | 0 |
| Non-Residential Energy Audit Program | 9,379 | 9,379 | 9,379 | 9,379 | 0 | 0 | 0 | 0 | 0 | 0 |
| Non-Residential Duct Testing and Sealing Program | 50,688 | 50,688 | 50,683 | 50,683 | 50,688 | 50,683 | 50,683 | 50,688 | 50,688 | 50,688 |
| Residential Bundle Program | 45,786 | 38,399 | 26,529 | 16,628 | 11,901 | 11,231 | 9,844 | 8,156 | 5,597 | 4,575 |
| Residential Home Energy Check-Up Program | 33,868 | 26,442 | 14,611 | 4,710 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential Duct Sealing Program | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,052 | 1,051 | 1,037 | 975 |
| Residential Heat Pump Tune Up Program | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential Heat Pump Upgrade Program | 10,866 | 10,866 | 10,866 | 10,866 | 10,849 | 10,130 | 8,790 | 7,105 | 4,560 | 3,600 |
| Non-Residential Window Film Program | 112,726 | 113,916 | 115,073 | 116,190 | 117,274 | 118,336 | 119,381 | 120,412 | 120,859 | 121,586 |
| Non-Residential Lighting Systems & Controls Program | 208,023 | 209,853 | 211,634 | 213,362 | 215,019 | 216,650 | 218,255 | 219,840 | 220,636 | 221,636 |
| Non-Residential Heating and Cooling Efficiency Program | 166,972 | 168,731 | 170,426 | 172,061 | 173,647 | 175,199 | 176,726 | 178,234 | 179,001 | 179,940 |
| Income and Age Qualifying Home Improvement Program | 13,523 | 13,665 | 13,802 | 13,933 | 14,058 | 14,179 | 14,298 | 14,414 | 14,534 | 14,667 |
| Residential Appliance Recycling Program | 10,959 | 2,743 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small Business Improvement Program | 75,368 | 76,183 | 76,986 | 77,755 | 78,502 | 79,233 | 79,953 | 80,663 | 81,003 | 81,469 |
| Non-Residential Prescriptive Program | 413,399 | 417,897 | 422,278 | 426,504 | 430,600 | 434,615 | 438,563 | 442,461 | 444,416 | 446,877 |
| Residential Home Energy Assessment | 89,868 | 91,067 | 92,223 | 93,322 | 94,376 | 95,398 | 96,397 | 97,378 | 98,389 | 99,511 |
| Sub-total (Energy Efficiency) | 1,214,259 | 1,208,971 | 1,201,743 | 1,197,843 | 1,190,536 | 1,197,209 | 1,204,432 | 1,212,210 | 1,213,137 | 1,220,943 |
| Total Demand Side Management | 1,214,537 | 1,209,172 | 1,202,019 | 1,198,119 | 1,190,631 | 1,197,484 | 1,204,706 | 1,212,523 | 1,213,432 | 1,221,224 |

(1) The Program types have been categorized by the Virginia definitions of peak shaving, energy efficiency, and demand response.

(2) Implementation date.

(3) State expected life of facility or duration of purchase contract. The Company used Program Life (Years).

(4) The MWs reflected as of 2032.

(5) Reductions available during on-peak hours.

(6) Residential Bundle is comprised of the Residential Home Energy Check-Up Program, Residential Duct Testing & Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program.

****Confidential Information Redacted****

## Appendix 5F – Cost Estimates for Nuclear License Extensions

| | Capital Cost |
|---|---|
| North Anna Units 1 & 2 | [redacted] |
| Surry Units 1 & 2 | [redacted] |

# Appendix 6A – Renewable Resources for Plan C$^T$: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company

Schedule 11

RENEWABLE RESOURCE GENERATION (GWh)

| Resource Type[1] | Unit Name | C.O.D.[2] | Build/Purchase/ Convert[3] | Life/ Duration[4] | Size MW[5] | 2014 (ACTUAL) | 2015 | 2016 | 2017 (PROJECTED) | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hydro | | | | | | | | | | | | | | | | | | | | | | | | |
| | Cushaw Hydro | Jan-30 | Build | 60 | 2 | 12 | 9 | 8 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| | Gaston Hydro | Feb-63 | Build | 60 | 220 | 309 | 316 | 408 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 |
| | North Anna Hydro | Dec-87 | Build | 60 | 1 | 3 | 4 | 4 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| | Roanoke Rapids Hydro | Sep-55 | Build | 60 | 95 | 296 | 288 | 355 | 253 | 253 | 253 | 254 | 253 | 253 | 253 | 254 | 253 | 253 | 253 | 254 | 253 | 253 | 253 | 254 |
| Sub-total | | | | | 318 | 620 | 617 | 773 | 524 | 524 | 524 | 526 | 524 | 524 | 524 | 526 | 524 | 524 | 524 | 526 | 524 | 524 | 524 | 526 |
| Solar | | | | | | | | | | | | | | | | | | | | | | | | |
| | Solar Partnership Program | 2013-2017 | Build | 20 | 7 | 0.3 | 2 | 7 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 8 | 8 |
| | Existing NC Solar NUGs | 2014-2022 | Purchase | 20 | 950 | - | 161 | 441 | 1,101 | 1,457 | 1,616 | 1,736 | 1,889 | 2,047 | 2,097 | 2,092 | 2,076 | 2,066 | 2,055 | 2,051 | 2,035 | 2,025 | 2,014 | 2,010 |
| | Existing VA Solar NUGs | 2016-2017 | Purchase | 20 | 40 | - | - | - | 90 | 90 | 89 | 89 | 88 | 88 | 87 | 87 | 87 | 86 | 86 | 85 | 85 | 84 | 84 | 84 |
| | Whitehouse Solar | Dec-2016 | Build | 35 | 20 | - | - | 1 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 |
| | Scott Solar | Dec-2016 | Build | 35 | 17 | - | - | 1 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 |
| | Woodland Solar | Dec-2016 | Build | 35 | 19 | - | - | 1 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 |
| | Generic Solar PV | 2019-2032 | Build | 35 | 3,280 | - | - | - | - | - | 535 | 1,072 | 1,604 | 2,138 | 2,673 | 3,217 | 3,742 | 4,277 | 4,811 | 5,361 | 5,881 | 6,415 | 6,950 | 7,506 |
| Sub-total | | | | | 4,333 | 0 | 163.7 | 450 | 1,325 | 1,680 | 2,374 | 3,031 | 3,715 | 4,406 | 4,990 | 5,530 | 6,038 | 6,561 | 7,085 | 7,631 | 8,133 | 8,657 | 9,181 | 9,733 |
| Biomass | Unit Name | | | | | | | | | | | | | | | | | | | | | | | |
| | Pittsylvania | Jun-94 | Purchase | 60 | 83 | 324 | 267 | 146 | 393 | 355 | 340 | 377 | 429 | 488 | 520 | 554 | 599 | 626 | 635 | 648 | 648 | 659 | 668 | 679 |
| | Virginia City Hybrid Energy Center | Apr-12 | Build | 60 | 61 | 58 | 100 | 236 | 207 | 236 | 285 | 354 | 358 | 447 | 370 | 382 | 381 | 384 | 380 | 381 | 348 | 384 | 388 | 463 |
| | Altavista | Feb-92 | Convert | 30 | 51 | 227 | 269 | 283 | 333 | 364 | 371 | 372 | 371 | 371 | 290 | 316 | 333 | 343 | 349 | 352 | 353 | 396 | 402 | 382 |
| | Southampton | Mar-92 | Convert | 30 | 51 | 253 | 290 | 30 | 354 | 354 | 361 | 364 | 356 | 371 | 146 | 154 | 207 | 223 | 224 | 245 | 259 | 283 | 296 | 339 |
| | Hopewell | Jul-92 | Convert | 30 | 51 | 266 | 263 | 306 | 356 | 349 | 335 | 346 | 366 | 371 | 84 | 91 | 111 | 122 | 133 | 140 | 172 | 192 | 216 | 240 |
| Sub-total | | | | | 297 | 1,128 | 1,189 | 1,000 | 1,643 | 1,657 | 1,692 | 1,813 | 1,880 | 2,049 | 1,410 | 1,496 | 1,630 | 1,698 | 1,722 | 1,765 | 1,781 | 1,913 | 1,969 | 2,103 |
| Wind | | | | | | | | | | | | | | | | | | | | | | | | |
| | VOWTAP | Jan-21 | Build | 20 | 12 | - | - | - | - | - | - | - | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 |
| Sub-total | | | | | 12 | - | - | - | - | - | - | - | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 |
| Total Renewables | | | | | 4,960 | 1,748 | 1,969 | 2,225 | 3,493 | 3,861 | 4,590 | 5,370 | 6,163 | 7,023 | 6,968 | 7,596 | 8,236 | 8,828 | 9,375 | 9,966 | 10,481 | 11,138 | 11,718 | 12,406 |

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

(2) Commercial Operation Date.

(3) Company built, purchased or converted.

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

(5) Net Summer Capacity for Biomass and Hydro, Nameplate for Solar and Wind.

(6) Dual fired coal & biomass reaching 61 MW in 2021

# Appendix 6B – Potential Supply-Side Resources for Plan C$^T$: Intensity-Based Dual Rate

**Company Name:** ____________________ **Schedule 15b**

**UNIT PERFORMANCE DATA**

**Potential Supply-Side Resources (MW)**

| Unit Name | Unit Type | Primary Fuel Type | C.O.D.[1] | MW Summer [2] | MW Nameplate |
|---|---|---|---|---|---|
| Solar 2019 | Intermittent | Solar | 2019 | 55 | 240 |
| Solar 2020 | Intermittent | Solar | 2020 | 55 | 240 |
| Solar 2021 | Intermittent | Solar | 2021 | 55 | 240 |
| VOWTAP | Intermittent | Wind | 2021 | 2 | 12 |
| Solar 2022 | Intermittent | Solar | 2022 | 55 | 240 |
| Solar 2023 | Intermittent | Solar | 2023 | 55 | 240 |
| Solar 2024 | Intermittent | Solar | 2024 | 55 | 240 |
| Generic 3x1 Combined Cycle | Intermediate/Baseload | Natural Gas | 2025 | 1,591 | 1,591 |
| Solar 2025 | Intermittent | Solar | 2025 | 55 | 240 |
| Generic CT | Peak | Natural Gas | 2026 | 458 | 458 |
| Solar 2026 | Intermittent | Solar | 2026 | 55 | 240 |
| Solar 2027 | Intermittent | Solar | 2027 | 55 | 240 |
| Solar 2028 | Intermittent | Solar | 2028 | 55 | 240 |
| Generic CT | Peak | Natural Gas | 2029 | 458 | 458 |
| Solar 2029 | Intermittent | Solar | 2029 | 36 | 160 |
| Solar 2030 | Intermittent | Solar | 2030 | 55 | 240 |
| Solar 2031 | Intermittent | Solar | 2031 | 55 | 240 |
| Generic CT | Peak | Natural Gas | 2032 | 458 | 458 |
| Solar 2032 | Intermittent | Solar | 2032 | 55 | 240 |

(1) Estimated Commercial Operation Date.

(2) Summer MWs represent the firm capacity of each unit.

## ****Confidential Information Redacted****

# Appendix 6C – Summer Capacity Position for Plan CT: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company — Schedule 16

UTILITY CAPACITY POSITION (MW)

| | (ACTUAL) | | | (PROJECTED) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| **Existing Capacity** | | | | | | | | | | | | | | | | | | | |
| Conventional | 17,885 | 18,928 | 18,933 | 18,945 | 18,928 | 18,843 | 18,741 | 18,666 | 17,615 | 17,615 | 17,615 | 17,615 | 17,615 | 17,615 | 17,615 | 17,625 | 17,615 | 17,615 | 17,625 |
| Renewable | 554 | 553 | 553 | 608 | 614 | 620 | 626 | 630 | 630 | 630 | 629 | 629 | 629 | 629 | 629 | 629 | 629 | 629 | 629 |
| Total Existing Capacity | 18,439 | 19,481 | 19,486 | 19,553 | 19,542 | 19,463 | 19,368 | 19,296 | 18,245 | 18,245 | 18,245 | 18,245 | 18,245 | 18,245 | 18,245 | 18,245 | 18,245 | 18,245 | 18,245 |
| **Generation Under Constructino** | | | | | | | | | | | | | | | | | | | |
| Conventional | - | - | - | - | - | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 |
| Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Total Planned Construction Capacity | - | - | - | - | - | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 |
| **Generation Under Development** | | | | | | | | | | | | | | | | | | | |
| Conventional | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable | - | - | - | - | - | - | - | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Total Planned Development Capacity | - | - | - | - | - | - | - | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Potential (Expected) New Capacity** | | | | | | | | | | | | | | | | | | | |
| Conventional | - | - | - | - | - | - | - | - | | - | - | 1,591 | 2,049 | 2,049 | 2,049 | 2,049 | 2,507 | 2,965 | 2,965 |
| Renewable | - | - | - | - | - | 55 | 109 | 164 | 219 | 273 | 328 | 382 | 437 | 492 | 546 | 601 | 656 | 710 | 765 |
| Total Potential New Capacity | - | - | - | - | - | 55 | 109 | 164 | 219 | 273 | 328 | 1,973 | 2,486 | 2,541 | 2,595 | 2,650 | 3,163 | 3,675 | 3,730 |
| Other (NUG) | 1,749 | 1,775 | 1,252 | 749 | 585 | 392 | 404 | 420 | 218 | 223 | 222 | 221 | 220 | 219 | 218 | 217 | 215 | 214 | 213 |
| Unforced Availability | - | - | - | | | | | | | | | | | | | | | | |
| **Net Generation Capacity** | 20,188 | 20,203 | 20,738 | 20,302 | 20,127 | 21,498 | 21,469 | 21,469 | 20,271 | 20,331 | 20,384 | 22,029 | 22,540 | 22,594 | 22,647 | 22,701 | 23,212 | 23,724 | 23,777 |
| **Existing DSM Reductions** | | | | | | | | | | | | | | | | | | | |
| Demand Response | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Conservation/Efficiency | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Total Existing DSM Reductions[1] | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| **Approved DSM Reductions** | | | | | | | | | | | | | | | | | | | |
| Demand Response[4] | 74 | 82 | 103 | 85 | 86 | 86 | 87 | 87 | 88 | 88 | 88 | 88 | 88 | 88 | 89 | 88 | 88 | 88 | 88 |
| Conservation/Efficiency[2,4] | 52 | 72 | 95 | 182 | 243 | 269 | 270 | 262 | 257 | 258 | 257 | 256 | 256 | 255 | 257 | 258 | 259 | 260 | 260 |
| Total Approved DSM Reductions | 126 | 154 | 198 | 267 | 329 | 355 | 357 | 350 | 345 | 346 | 345 | 344 | 344 | 343 | 344 | 346 | 347 | 347 | 348 |
| **Proposed DSM Reductions** | | | | | | | | | | | | | | | | | | | |
| Demand Response[4] | - | - | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Conservation/Efficiency[2] | - | - | | - | 17 | 33 | 48 | 64 | 71 | 71 | 72 | 73 | 74 | 74 | 75 | 76 | 77 | 77 | 77 |
| Total Proposed DSM Reductions | - | - | | - | 17 | 33 | 48 | 64 | 71 | 71 | 72 | 73 | 74 | 74 | 75 | 76 | 77 | 77 | 77 |
| **Total Demand-Side Reductions[1]** | 129 | 156 | 201 | 269 | 348 | 390 | 407 | 416 | 418 | 419 | 419 | 419 | 420 | 419 | 421 | 424 | 426 | 426 | 428 |
| **Net Generation & Demand-side** | 20,317 | 20,358 | 20,939 | 20,571 | 20,475 | 21,888 | 21,876 | 21,885 | 20,689 | 20,749 | 20,803 | 22,448 | 22,960 | 23,013 | 23,065 | 23,124 | 23,635 | 24,150 | 24,205 |
| Capacity Sale[3] | [redacted] | | | | | | | | - | - | - | - | - | - | - | - | - | - | - |
| Capacity Purchase[3] | | | | | | | | | 700 | 800 | 1,200 | - | - | - | - | 200 | - | - | 100 |
| Capacity Adjustment[3] | | | | | | | | | - | - | - | - | - | - | - | - | - | - | - |
| **Capacity Requirement or PJM Capacity Obligation** | | | | | | | | | 21,436 | 21,596 | 21,995 | 22,233 | 22,510 | 22,852 | 23,017 | 23,303 | 23,668 | 23,969 | 24,274 |
| **Net Utility Capacity Position** | | | | | | | | | (747) | (847) | (1,192) | 213 | 449 | 160 | 52 | (179) | (29) | 181 | (69) |

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

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

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

(4) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.

# Appendix 6D – Construction Forecast for Plan C$^T$: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company | Schedule 17

CONSTRUCTION COST FORECAST (Thousand Dollars)

(PROJECTED)

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| I. New Traditional Generating Facilities | | | | | | | | | | | | | | | | |
| a. Construction Expenditures (non-AFUDC) | - | - | 19,318 | 48,039 | 130,208 | 479,883 | 1,026,639 | 563,140 | 390,912 | 245,323 | 360,575 | 424,031 | 454,570 | 642,454 | 686,087 | 598,091 |
| b. AFUDC | - | - | 27 | 123 | 375 | 15,221 | 45,280 | 131,312 | 71,736 | 30,272 | 3,082 | 4,191 | 4,636 | 6,146 | 8,024 | 8,901 |
| c. Annual Total | - | - | 19,346 | 48,161 | 130,583 | 495,105 | 1,071,919 | 694,452 | 462,648 | 275,595 | 363,657 | 428,223 | 459,206 | 648,600 | 694,112 | 606,992 |
| d. Cumulative Total | - | - | 19,346 | 67,507 | 198,090 | 693,194 | 1,765,113 | 2,459,565 | 2,922,213 | 3,197,808 | 3,561,465 | 3,989,687 | 4,448,893 | 5,097,493 | 5,791,605 | 6,398,597 |
| II. New Renewable Generating Facilities | | | | | | | | | | | | | | | | |
| a. Construction Expenditures (non-AFUDC) | 45,947 | 420,916 | 443,181 | 546,917 | 627,858 | 466,009 | 475,108 | 484,386 | 493,844 | 503,487 | 495,706 | 367,269 | 545,622 | 556,710 | 567,581 | 578,664 |
| b. AFUDC | 65 | 725 | 759 | 946 | 775 | 790 | 806 | 822 | 838 | 854 | 846 | 617 | 923 | 976 | 995 | 1,015 |
| c. Annual Total | 46,012 | 421,641 | 443,940 | 547,864 | 628,633 | 466,799 | 475,914 | 485,207 | 494,682 | 504,341 | 496,552 | 367,886 | 546,545 | 557,686 | 568,576 | 579,678 |
| d. Cumulative Total | 46,012 | 467,653 | 911,593 | 1,459,457 | 2,088,090 | 2,554,889 | 3,030,803 | 3,516,010 | 4,010,692 | 4,515,034 | 5,011,586 | 5,379,471 | 5,926,016 | 6,483,702 | 7,052,278 | 7,631,957 |
| III. Other Facilities | | | | | | | | | | | | | | | | |
| a. Transmission | 786,386 | 894,799 | 780,705 | 789,370 | 841,531 | 877,109 | 836,003 | 851,548 | 854,887 | 847,479 | 851,305 | 851,345 | 851,376 | 851,342 | 851,354 | 851,357 |
| b. Distribution | 707,280 | 835,450 | 878,460 | 869,892 | 883,278 | 894,728 | 882,632 | 886,879 | 888,080 | 885,864 | 886,941 | 711,941 | 711,941 | 711,941 | 711,941 | 711,941 |
| c. Energy Conservation & DR | 2,045 | 2,095 | 2,144 | 2,189 | 2,234 | 2,278 | 2,324 | 2,370 | 2,418 | 2,466 | 2,515 | 2,566 | 2,617 | 2,669 | 2,723 | 2,777 |
| d. Other | | | | | | | | | | | | | | | | |
| e. AFUDC | 455 | 8,501 | 10,560 | 8,533 | 10,112 | 10,292 | 9,646 | 10,017 | 9,985 | 9,882 | 9,961 | 9,943 | 9,929 | 9,944 | 9,939 | 9,937 |
| f. Annual Total | 1,496,166 | 1,740,845 | 1,671,869 | 1,669,983 | 1,737,154 | 1,784,407 | 1,730,605 | 1,750,814 | 1,755,369 | 1,745,691 | 1,750,722 | 1,575,795 | 1,575,863 | 1,575,896 | 1,575,957 | 1,576,013 |
| g. Cumulative Total | 1,496,166 | 3,237,011 | 4,908,880 | 6,578,863 | 8,316,017 | 10,100,425 | 11,831,030 | 13,581,844 | 15,337,212 | 17,082,904 | 18,833,626 | 20,409,420 | 21,985,283 | 23,561,180 | 25,137,136 | 26,713,149 |
| IV. Total Construction Expenditures | | | | | | | | | | | | | | | | |
| a. Annual | 1,542,178 | 2,162,486 | 2,135,155 | 2,266,009 | 2,496,370 | 2,746,311 | 3,278,438 | 2,930,474 | 2,712,698 | 2,525,628 | 2,610,931 | 2,371,903 | 2,581,614 | 2,782,182 | 2,838,644 | 2,762,683 |
| b. Cumulative | 1,542,178 | 3,704,664 | 5,839,818 | 8,105,827 | 10,602,197 | 13,348,508 | 16,626,946 | 19,557,419 | 22,270,117 | 24,795,745 | 27,406,676 | 29,778,579 | 32,360,193 | 35,142,375 | 37,981,020 | 40,743,703 |
| 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 |

## ****Confidential Information Redacted****

# Appendix 6E – Capacity Position for Plan $C^T$: Intensity-Based Dual Rate

Company Name: Virginia Electric and Power Company

Schedule 4

POWER SUPPLY DATA

| | (ACTUAL) | | | | | | | (PROJECTED) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| I. Capability (MW) | | | | | | | | | | | | | | | | | | | |
| 1. Summer | | | | | | | | | | | | | | | | | | | |
| a. Installed Net Dependable Capacity(1) | 18,439 | 19,481 | 19,486 | 19,553 | 19,542 | 21,106 | 21,065 | 21,049 | 20,053 | 20,108 | 20,162 | 21,808 | 22,320 | 22,375 | 22,430 | 22,484 | 22,997 | 23,510 | 23,564 |
| b. Positive Interchange Commitments(2) | 1,747 | 1,757 | 1,252 | 749 | 585 | 392 | 404 | 420 | 218 | 223 | 222 | 221 | 220 | 219 | 218 | 217 | 215 | 214 | 213 |
| c. Capability in Cold Reserve/ Reserve Shutdown Status(1) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| d. Demand Response - Existing | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| e. Demand Response - Approved(5) | 74 | 82 | 103 | 85 | 86 | 86 | 87 | 87 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 |
| f. Demand Response - Future(5) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| g. Capacity Sale(3) | [redacted] | | | | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| h. Capacity Purchase(3) | | | | | | | | - | 700 | 800 | 1,200 | - | - | - | - | 200 | - | - | 100 |
| i. Capacity Adjustment(3) | | | | | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| j. Total Net Summer Capability(4) | | | | | | | | 21,555 | 21,057 | 21,216 | 21,670 | 22,114 | 22,626 | 22,679 | 22,733 | 22,987 | 23,298 | 23,810 | 23,963 |
| 2. Winter | | | | | | | | | | | | | | | | | | | |
| a. Installed Net Dependable Capacity(1) | - | - | - | 20,767 | 20,752 | 22,409 | 22,329 | 22,277 | 21,270 | 21,325 | 21,379 | 23,117 | 23,655 | 23,710 | 23,764 | 23,819 | 24,357 | 24,895 | 24,950 |
| b. Positive Interchange Commitments(2) | - | - | - | 757 | 592 | 396 | 408 | 424 | 218 | 223 | 222 | 221 | 220 | 219 | 218 | 217 | 215 | 214 | 213 |
| c. Capability in Cold Reserve/ Reserve Shutdown Status(1) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| d. Demand Response(5) | 14 | 5 | 4 | 7 | 7 | 8 | 9 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| e. Demand Response-Existing(6) | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| f. Total Net Winter Capability(4) | - | - | - | 21,530 | 21,351 | 22,814 | 22,746 | 22,712 | 21,498 | 21,558 | 21,611 | 23,348 | 23,885 | 23,938 | 23,992 | 24,045 | 24,582 | 25,119 | 25,173 |

(1) Net Seasonal Capability.

(2) Includes firm commitments from existing Non-Utility Generation and estimated solar NUGs.

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

(4) Does not include Cold Reserve Capacity and Behind-the-Meter Generation MWs.

(5) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.

(6) Included in the winter capacity forecast.