Virginia Energy Plan Item 8: Impacts of Proposed Regulations under Section 111(d) of the Clean Air Act

Submitted to

The Virginia Department of Mines, Minerals and Energy

by

The Virginia Center for Coal and Energy Research, Virginia Tech

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VIRGINIA CENTER FOR COAL AND ENERGY RESEARCH

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The Virginia Center for Coal and Energy Research was created by an Act of the Virginia General Assembly on March 30, 1977, as an interdisciplinary study, research, information and resource facility for the Commonwealth of Virginia. In July of that year, a directive approved by the Virginia Tech Board of Visitors placed the VCCER under the University Provost because of its intercollegiate character, and because the Center's mandate encompasses the three missions of the University: instruction, research and extension. Derived from its legislative mandate and years of experience, the mission of the VCCER involves four primary functions:

- Research in interdisciplinary energy and coal-related issues of interest to the Commonwealth
- Coordination of coal and energy research at Virginia Tech
- Dissemination of coal and energy research information and data to users in the Commonwealth
- Examination of socio-economic implications related to energy and coal development and associated environmental impacts
- Assist Commonwealth of Virginia in implementing the Commonwealth's energy plan.

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Table of Contents

List of Tables

List of Figures

List of Abbreviations

Abbreviation	Description
$B	Billion Dollars
$M	Million Dollars
ACEEE	American Council for an Energy Efficient Economy
ASU	Air Separation Unit
Btu	British Thermal Unit
CAAA	Clean Air Act Amendments of 1990
CCRP	Clean Coal Research Program
CCS	Carbon Capture and Sequestration/Storage
CCUS	Carbon Capture, Utilization and Storage
CEMS	Continuous Emission Monitoring System
CF	Capacity Factor
CO_2	Carbon Dioxide
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CSLF	Carbon Sequestration Leadership Forum
DMME	Virginia Department of Mines, Minerals and Energy
DOE	US Department of Energy
DOE/EIA	US Department of Energy, Energy Information Administration
DSM	Demand Side Management
E&E	Energy and Environment
EE	Energy Efficiency
EGR	Enhanced Gas Recovery
EGU	Electric Generating Unit
EIA	Energy Information Administration (of US Department of Energy)
EOR	Enhanced Oil Recovery
EPA	US Environmental Protection Agency

ERC	Energy Research Center
F	Degrees Fahrenheit (as in “300 F”)
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurization
GW	Gigawatt
H_2	Hydrogen
H_2O	Water
HECA	Hydrogen Energy California Project
HS&E	Health, Safety And Environmental
IATFCCS	Interagency Task Force on Carbon Capture and Storage
IGCC	Integrated Gasification Combined Cycle
IOU	Investor-Owned Utility
IP	Intermediate Pressure (as In "IP Steam")
IPM	Integrated Planning Model
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISO	Independent System Operator
K	Thousand
kWh	Kilowatt Hour
LBNL	Lawrence Berkeley National Laboratory
lbs	Pounds
LLC	Limited Liability Company (or Corporation)
LP	Low Pressure (as in "LP Steam")
LPM	Linear Programming Model
LSIP	Large-Scale Integrated Projects
MATS	Mercury and Air Toxics Standards
MGSC	Midwest Geological Sequestration Consortium
MIT	Massachusetts Institute of Technology
MMBtu	Million Btus
MOU	Memorandum of Understanding

MRCSP	Midwest Regional Carbon Sequestration Partnership
MVA	Monitoring, Verification, and Accounting
MW	Megawatt
MWe	Megawatt Equivalent
MWh	Megawatt Hours
N/A	Not Applicable
NARUC	National Association of Regulatory Utility Commissioners
NCC	National Coal Council
NETL	National Energy Technology Laboratory, US Department of Energy
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NO_x	Mono-Nitrogen Oxides NO And NO_2 (Nitric Oxide and Nitrogen Dioxide)
NRC	Nuclear Regulatory Commission
NSR	New Source Review
O&M	Operations and Maintenance
OCS	Outer Continental Shelf
PC	Pulverized Coal
PCOR	Plains CO_2 Reduction Partnership
PJM	PJM Interconnection, a regional transmission organization
PM2.5	Particulate Matter of Less Than 2.5 Micrometers (In EPA Fine Particle Standard)
QER	Quadrennial Energy Review Task Force
R&D	Research and Development
RD&D	Research, Development, and Demonstration
REC	Renewable Energy Credit
RGGI	Regional Greenhouse Gas Initiative
RIA	Regulatory Impact Analysis
RPS	Renewable Portfolio Standard
S&L	Sargent and Lundy
SB	Senate Bill
SCC	Social Cost of Carbon

SCR	Selective Catalytic Reduction
SCS	SCS Energy LLC
SECARB	Southeastern Carbon Sequestration Partnership
SIP	State Implementation Plan
SO_2	Sodium Dioxide
SO_3^{2-}	Sulfite Ion
SSEB	Southern States Energy Board
SWP	Southwest Partnership on Carbon Sequestration
TECA	Texas Clean Energy Project
TRL	Technology Readiness Level
TSD	Technical Supporting Document
US	United States
VCCER	Virginia Center for Coal and Energy Research
VCEA	Virginia Coal and Energy Alliance
VCHEC	Virginia City Hybrid Energy Center (Dominion)
VEP	Virginia Energy Plan
VSCC	Virginia State Corporation Commission
VSD	Variable Speed Drives
WSU	Washington State University

I. Foreword

First enacted in 2007 (SB 262), **The Virginia Energy Plan (VEP or Plan)** is a vehicle for establishing energy policy for the Commonwealth. During the 2014 session, the VEP was amended to include a new Item 8 (§ 67-201. Development of the Virginia Energy Plan. Subsection B), described below:

> *8. With regard to any regulations proposed or promulgated by the U.S. Environmental Protection Agency to reduce carbon dioxide emissions from fossil fuel-fired electric generating units under § 111(d) of the Clean Air Act, 42 U.S.C. § 7411(d), an analysis of (i) the costs to and benefits for energy producers and electric utility customers; (ii) the effect on energy markets and reliability; and (iii) the commercial availability of technology required to comply with such regulations…*

Under Section § 67-202.Schedule, Subsection C., the new submission deadline for the VEP is defined as October 1, 2014, and every fourth October 1 thereafter. In addition, for the first time, interim updates on the Plan are requested by October 1 of the third year of each administration, to reassess goals, progress and lessons learned. According to Subsection D., the Plan should discuss "energy policy positions relevant to any potential regulations proposed or promulgated by the State Air Pollution Control Board to reduce carbon dioxide emissions from fossil-fired electric generating units under § 111(d) of the Clean Air Act." The Plan is also directed to ensure that Virginia promotes overall fuel diversity, assesses impacts to consumers—including disproportional impacts of energy price increases—and to identify options and measures that further the interests of the Commonwealth and its citizens.

The Division of Energy of the Department of Mines, Minerals and Energy (DMME) is given by the legislation the overall responsibility to prepare this comprehensive Plan, in consultation with the State Corporation Commission, the Department of Environmental Quality and the Virginia Center for Coal and Energy Research (VCCER), Virginia Tech. This report addresses the new requirement of the revised VEP legislation, under Item 8 referenced above, and was developed by the VCCER.

In order to employ the best possible expertise, and to complete the report in the short time that was available, the VCCER involved outside experts that enhanced the capability of the report team and provided additional experience and knowledge in drafting this report. As a result, the report includes significant contributions from the VCCER staff, Clean Air Markets LLC, J. E. Cichanowicz Inc., and Chmura Economics and Analytics.

The VCCER appreciates the opportunity to contribute to the discussion of carbon management in the Commonwealth of Virginia and to continue providing input to the Virginia Energy Plan.

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Virginia Tech

II. Acknowledgements

The Virginia Center for Coal and Energy Research (VCCER) would like to acknowledge the following individuals, departments, agencies, and their staff, for contributing ideas and suggestions for the preparation of this report:

- Secretary of Commerce and Trade
- Secretary of Natural Resources
- Department of Mines, Minerals, and Energy
- Department of Environmental Quality
- State Corporation Commission

Numerous discussions were also held with a number of other experts, energy companies, infrastructure companies and federal agencies, in order to ensure that the most updated information was included in this report. These discussions were invaluable in developing and completing this study.

Finally, the VCCER would like to acknowledge the Virginia General Assembly for the financial support to undertake the study and prepare this report.

III. Executive Summary

First enacted in 2007 (SB 262), **The Virginia Energy Plan (VEP or Plan)** is a vehicle for establishing energy policy for the Commonwealth. During the 2014 session, the VEP was amended to include a new Item 8 (§ 67-201. Development of the Virginia Energy Plan. Subsection B), an analysis of any regulations proposed or promulgated by the US Environmental Protection Agency (EPA), to include: the costs to and benefits for energy producers and electric utility customers; the effect on energy markets and reliability; and the commercial availability of technology required to comply with those regulations. This report examines the basic principles of the EPA's Clean Power Plan (CPP) and its implementation. It looks at various scenarios for generating adequate electricity for the Commonwealth, while reducing carbon dioxide emissions to the EPA proposed targets, and examines the costs and benefits for Virginia. The major points discussed within the report are summarized below.

The EPA Proposed Clean Air Act Section 111(d) Rules. President Obama has presented his vision for a US Climate Action Plan as "a series of executive actions" to be implemented through regulations issued by the Environmental Protection Agency (EPA). The White House stated, "the signs of climate change are all around us…these changes…are largely consequences of anthropogenic emissions of greenhouse gases" and, that immediate action will "substantially" decrease the cost of achieving compliance (White House, 2014).

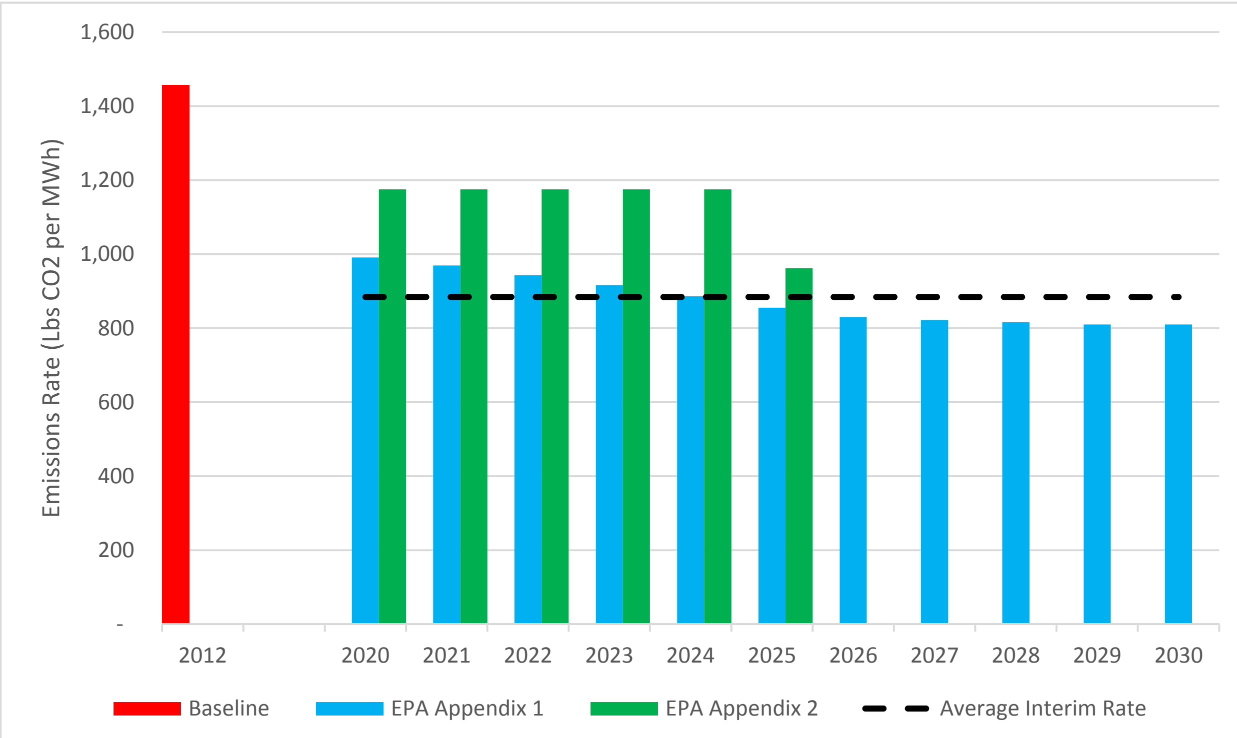
To implement the plan, EPA developed carbon emissions standards for ***new*** power plants by issuing proposed regulations to align with section 111(b) of the Clean Air Act on January 8, 2014, (EPA, 2014a). The EPA also released a proposal for additional carbon emissions regulations based on section 111(d) of the Clean Air Act for ***existing*** power plants on June 2, 2014, and published the proposal in the Federal Register on June 18, 2014. (EPA, 2014b) The EPA is expecting that final rules will be published in June 2015. State-specific compliance plans are due to the EPA for review and approval in June 2016, 2017, or possibly 2018, depending on the compliance and planning approach taken by the state. The first year for mandated compliance with the interim CO_2 emissions reduction goal in the proposed regulation is 2020.

EPA's Clean Power Plan (CPP) is based on four specific assumptions. EPA has proposed CO_2 targets (expressed in pounds of carbon dioxide per megawatt hour (lbs/MWh)) beginning in 2020, with final rates for each state in 2030. EPA established a baseline year of 2012 to calculate the targets for each state and created four major building block assumptions to arrive at these rates. These assumptions are:

- **Improve the unit heat rates at coal-fired plants by 6 percent**
- **Run all existing and new Natural Gas Combined Cycle (NGCC) units at a 70 percent capacity factor and preserve 6 percent of current nuclear capacity**
- **Implement mandatory state renewable energy programs reaching up to 13 percent by 2030**
- **Implement mandatory state energy efficiency programs reaching 10.7 percent market penetration by 2030.**

Virginia's targets under the proposed rule mandate large reductions. EPA's proposed rule shows Virginia emitting CO_2 at a rate of 1,438 lbs/MWh in 2012 and an initial interim target goal of 991 lbs/MWh in 2020, followed by a rate of 810 lbs/MWh by 2030. EPA's proposal also includes an alternative with a higher ultimate target of 962 lbs/MWh, but with compliance required by 2025. EPA's calculation of Virginia's targets does not count improvements in efficiency gained since 2005 nor the full effect of the 28.7 million MWh of non-emitting nuclear power generation in Virginia. (See Figure ES-1.)

Figure ES-1: Virginia Emission Targets



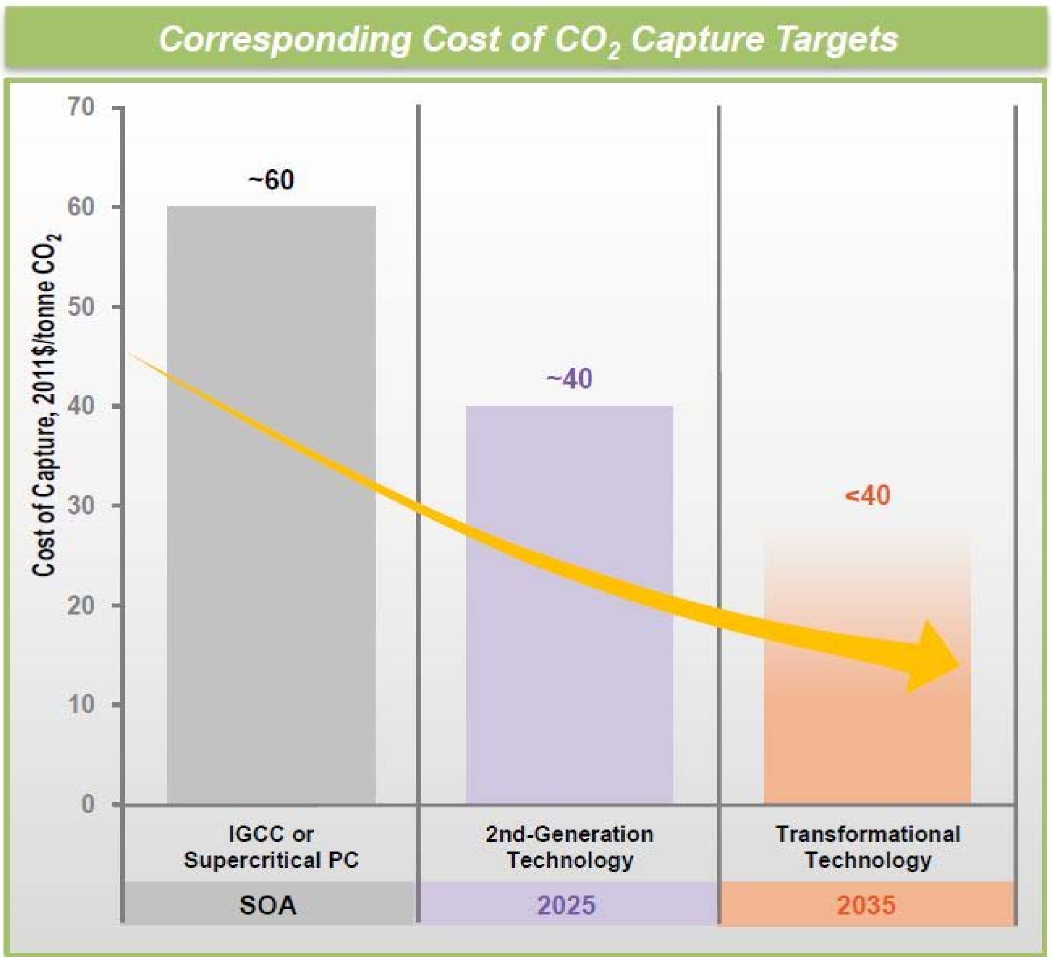
Changes in the power industry have been ongoing for decades. The US utility industry and its dependency on coal have undergone a series of abrupt changes during the past four decades. Virginia utilities responded quickly to meet environmental standards and fulfill their obligation to provide customers with reliable and affordable electricity. In most instances, the public utility commissions (PUC) in each state (in Virginia, the State Corporation Commission) reviewed the utilities' plans and reached agreement approving recovery of prudently incurred capital investments and increased operating costs associated with compliance. Cost recovery through rates is generally at the discretion of the PUC and utilities are very reluctant to risk non-recovery, as they develop plans for future generating capacity and environmental compliance. The current effort to curb carbon dioxide is something of a discontinuity when compared with previous environmental policy and represents a hurdle in terms of the challenge which it poses. Unlike other emissions such as sulfur, mercury and nitrogen oxides, carbon dioxide is not a toxic substance that occurs as a relatively minor by-product of fossil fuel combustion—it is a major and inescapable result of the chemistry of oxidation.

Commercially available technology for improving unit efficiency is widely used in Virginia. Coal-fired power plant operators have strong economic incentives to improve generating unit efficiency which directly affects CO_2 emissions. There are numerous efficiency-improving actions that can be applied, and in many cases these actions are routinely applied, to Virginia units to derive higher thermal efficiency for a coal-fired power plant. Specifically, advanced process control software, and in some cases upgraded sensors, can be used to assure that plant components operate in concert to extract the most thermal efficiency. Other improvements to the operation of the steam turbine and generator are key, as is minimizing parasitic load and improving cooling system performance.

The opportunity to apply these efficiency improvements across the existing fleet will vary significantly. In some cases, the opportunity will be negligible because the unit either is already operating in a highly efficient mode with some or all of the improvements in place, or because the implementation of potential improvements is not cost-effective and/or technically feasible. As such, the degree of efficiency improvement possible at a given unit is site-specific. The extremely low capacity factor at which coal-fired units may be forced to operate imposes a penalty to efficiency that negates most of the benefits. This study assumed that, through heat efficiency measures, at most a 3 percent improvement in heat rate is possible.

Carbon Capture, Utilization and Storage/Sequestration (CCUS) may be the best option, but will not be available until the mid-2020s. Historically, utilities have found the technology to implement environmental compliance to be ready when it was needed. In the case of controlling carbon dioxide emissions, however, although the means of capturing and storing this gas has been demonstrated, the technology is far from ready for commercial application. EPA has implied that CCUS technology is commercially “proven and available.” Other experts, including the US Department of Energy, suggest that a much longer time will be needed for development (see Figure ES-2). The cost will be much higher for controlling carbon than for other emissions. To make it affordable, the cost must be offset by beneficial uses for the CO_2, such as enhanced oil and gas recovery.

Figure ES-2: CCS Research Timeline (Source: NETL/DOE)

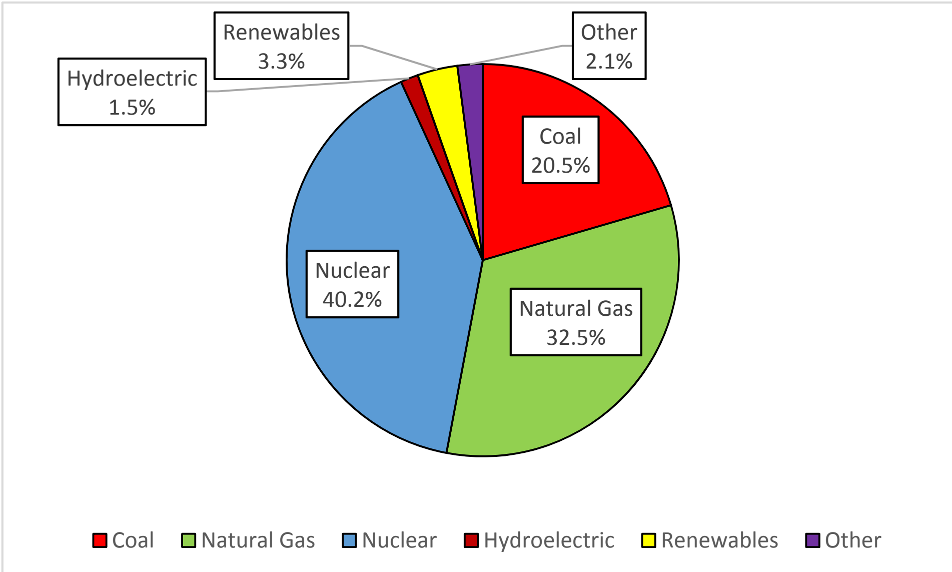


To ensure full implementation of CCUS, large field demonstration projects are necessary, requiring significant federal funding and state participation, including addressing significant legal issues. Based on the ongoing research conducted by the VCCER, Virginia is well-positioned to host and benefit from such demonstrations.

A new industry could result from CO_2 utilization in Virginia. Utilization of captured CO_2, including the development of necessary infrastructure for collection, compression and distribution of capture gas, has the potential to spawn a new industry to support emerging gas development in the state. Virginia also has the capacity for onshore and offshore storage/sequestration of CO_2. The participation of Governor McAuliffe in the Outer Continental Shelf Governor's Coalition provides a basis for further work in Virginia's offshore region and the development of associated CCUS infrastructure.

Virginia's electric generation mix has changed over time. In 2002, coal provided approximately 52 percent of the electric power needs for Virginia but had fallen to 21 percent by 2012, primarily because of the lower market price and lower overall pollutant emissions from natural gas (see Figure ES-3). Nuclear generation provided approximately 40 percent of the electric power. As the economics and regulatory requirements for coal-fired power have changed, retirements, fuel switches and new natural gas capacity have been announced. Plans for an additional nuclear unit at North Anna will further change Virginia's portfolio from 2012, the baseline for EPA's proposed regulations. Many of the changes have required improved efficiency and expansion of the natural gas pipeline network.

Figure ES-3: Virginia 2012 Generation Mix (EIA, 2014)



The study approach used a simple method to calculate changes to the portfolio. This report used data from EPA's technical supporting documents and appendices and constructed detailed spreadsheet models of the projected available generating sources in Virginia in 2020 and 2030. These analyses also considered optimum levels of renewables, preserved nuclear and energy efficiency megawatt hours. The analyses dispatched the most practical units (coal, oil, gas, biomass, etc.) for each scenario. This analysis methodology then utilized the 2020 and 2030 optimal operation of generating units to bring Virginia into compliance with the proposed regulations. While these spreadsheets do not show power flows and consider area "voltage protection," they indicate what actions will be required to comply with the new regulations. Four of the six defined scenarios did indicate that Virginia could achieve compliance but it would come at the cost of changing the energy portfolio to one of major reliance upon natural gas and nuclear, rather than coal and nuclear as major power generation sources. When practicable, EPA-recommended "heat rate" improvements were considered at coal units being dispatched. In many cases, the low capacity factors at coal units prevented the inclusion of this EPA "building block."

Compliance scenarios were defined using changes to the generation mix. A detailed model for establishing the projected generation mix in Virginia would include evaluating, at each generating unit in Virginia, fixed and variable operating cost, fuel cost, CO_2 emissions, and location in the grid (which could affect whether the unit is a candidate for retirement or continued operation is essential to grid stability). Additionally, natural gas-fired units would be assigned a priority based on likelihood of accessing adequate fuel supply. A detailed projection of future fuel prices for coal, natural gas, and biomass would be developed. The reliability of each generating unit would also be considered; specifically biasing the generation toward newer, more efficient, and more reliable units. These attributes of a generating unit provide the basis for selection of a portfolio of units to provide the required generation and meet the CO_2 target rate for the least cost.

This report, on the other hand, assumed a simpler and more basic approach. The overall production costs were used to assign a generation portfolio that approximates the outcome of the more robust analysis described earlier. The makeup of the portfolio in terms of the selection of coal-fired and natural gas-fired units was based on relative production cost and CO_2 emissions. Fuel availability and grid stability, however, were not factored into this analysis. The authors believe that the approach used in the analysis, although approximate, does provide realistic methodology and the results, in aggregate, will compare favorably with a more robust approach that may be necessary at a later stage, if and when the EPA rules are finalized.

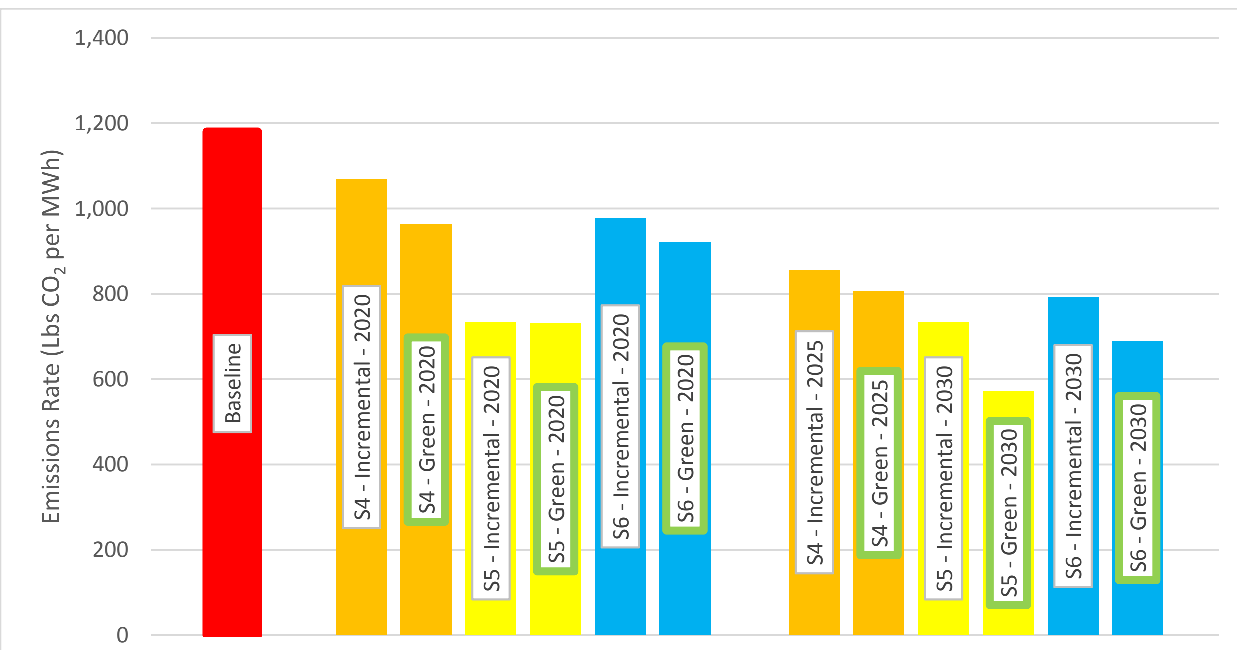
Scenarios represent possible alternative compliance approaches. Six unique operating or compliance scenarios were developed with the input of the Virginia Department of Environmental Quality, the Virginia Department of Mines, Minerals and Energy, the State Corporation Commission, and the report team to determine whether Virginia could comply with the proposed EPA CO_2 regulations while operating under the particular constraints of the scenario. These scenarios are by no means exhaustive and instead are illustrative of possible compliance strategies. The scenarios examined are described in summary below:

1. **Used 2012 base operating data, announced retirements and new generating capacity plus 2012 renewable MWh**
2. **Same as Scenario 1 but also added “6 percent preserved nuclear capacity”**
3. **Same as Scenario 2, but also dispatched all existing/new NGCC at up to 70 percent capacity factor**
4. **Used EPA’s alternative targets described in the proposed rule and the same assumptions as found in Scenario 3**
5. **Assumed all coal-fired capacity in the state is retired and NGCC’s, oil/steam, biomass, renewables, preserved nuclear and energy efficiency programs were the only generation choices**
6. **Removed dispatch constraints and optimized all available generation assets, plus renewables, plus preserved nuclear MWh, plus energy efficiency MWh, to meet EPA’s preferred emissions standards**

Analyses considered total electrical demand in Virginia, while focusing on EPA’s CPP compliance requirements. Because of the approach EPA used to determine target CO_2 emissions rates, it was necessary to define specific measures of electric energy generation and how they pertain to the proposed rule. First of these is “total generation” which includes all electric energy dispatched to customers in Virginia, regardless of the generating unit’s physical location or status under the proposed rule. Secondly, “in-state generation” is the portion of the total generation that is sourced from generating units physically located within Virginia. “Compliance generation” is comprised of the energy sourced from generating units subject to the proposed rule and thus contributes to the CO_2 emissions rate. For each of the scenarios representing compliance with the proposed EPA rule (S4, S5 and S6), “Incremental Dispatch” and “Green Dispatch” cases were presented to compare the effects of implementing the EPA building blocks for decreasing CO_2 emissions. Specifically, “Incremental” refers to the traditional method of dispatching energy based on minimizing cost to the rate payers whereas “Green” emphasizes lowering the CO2 emissions rate by employing an increased presence of renewable energy sources and efficiency improvements.

Virginia can comply with the CPP, but with changes in the electrical generation mix. After developing these scenarios, the study identified four (Scenarios 3 through 6) that could bring Virginia into compliance with the new EPA CO_2 regulations. These CO_2 reductions can be met with an energy policy shift in power generation to natural gas as the predominant base-load fuel. This will also necessitate a reliance on the US natural gas pipeline system to deliver the necessary natural gas into Virginia. The 2012 Virginia CO_2 emissions rate, or baseline, is 1,180 lbs CO_2/MWh (Figure ES-4). The contributions of coal, natural gas, and renewable energy sources are depicted on Figure ES-5, Figure ES-6, and Figure ES-7 for each compliance scenario, target year, and dispatch strategy. In each compliance scenario, the contribution of natural gas increased while coal decreased relative to the 2012 baseline. For the Green Dispatch cases, the role of natural gas was reduced by expansion of renewable energy and energy efficiency measures, but at a higher cost to utilities and consumers.

Figure ES-4: Virginia Projected CO_2 Emissions Rate for Selected Scenarios



System resilience and reliability could be impacted by altering the generation mix. Utilities in Virginia are members of an interstate transmission operator known as PJM which provides independent operation of the wholesale bulk power market for our region. This system enhances reliability and reduces cost by ranking the bids for power sales and buying from the bottom up until there is enough electricity on the grid to meet demand. This ranking has historically put coal generation in the "baseload" (lowest cost and most plentiful) category, but as this report shows, dispatch scenarios that enable compliance with the CPP will displace coal because of its high emissions of carbon dioxide. What is considered as the normal economic dispatch order will no longer be the case, because coal will play a diminishing role and more expensive, but lower carbon emitting sources, will take its place. A balanced and diverse portfolio of energy sources helps reduce risk and ensure affordable and reliable electric service, therefore efforts should be made to avoid undue dependency on any one fuel and to promote means of maintaining continued use of all available sources.

Figure ES-5: Coal Generation by Scenario

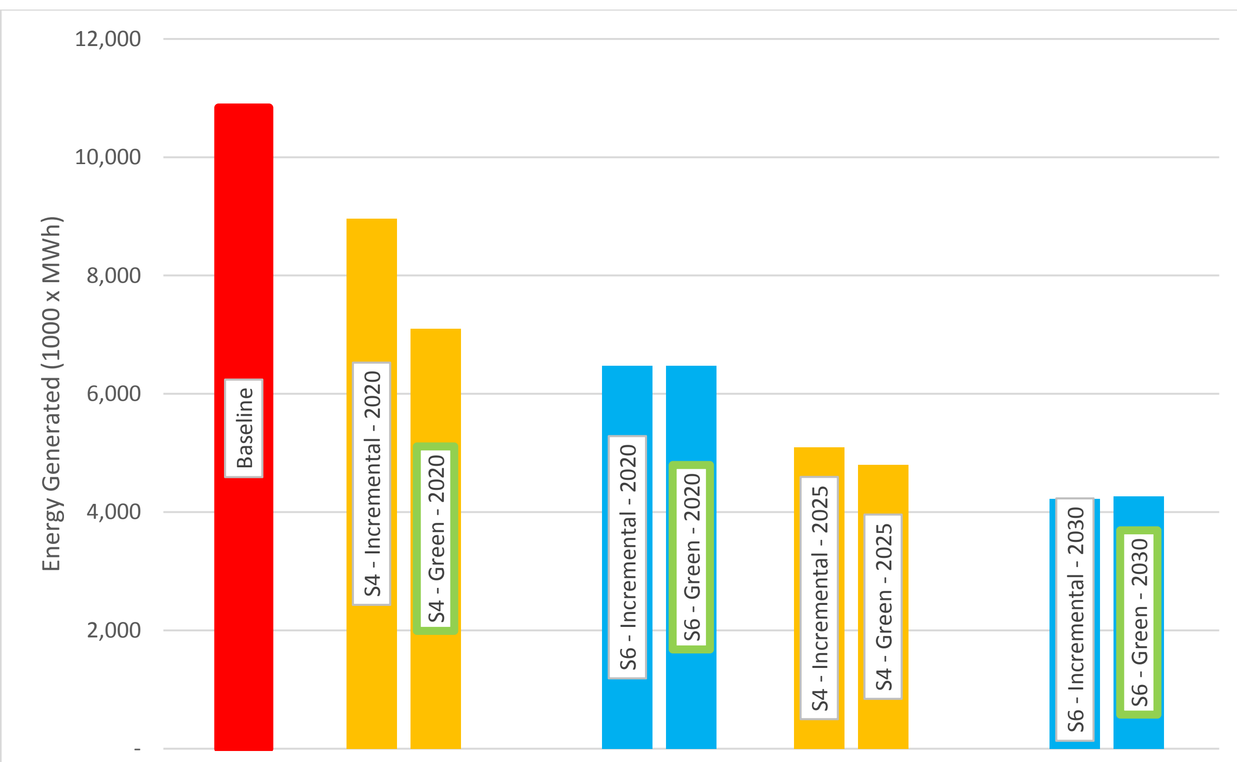


Figure ES-6: Natural Gas Generation by Scenario

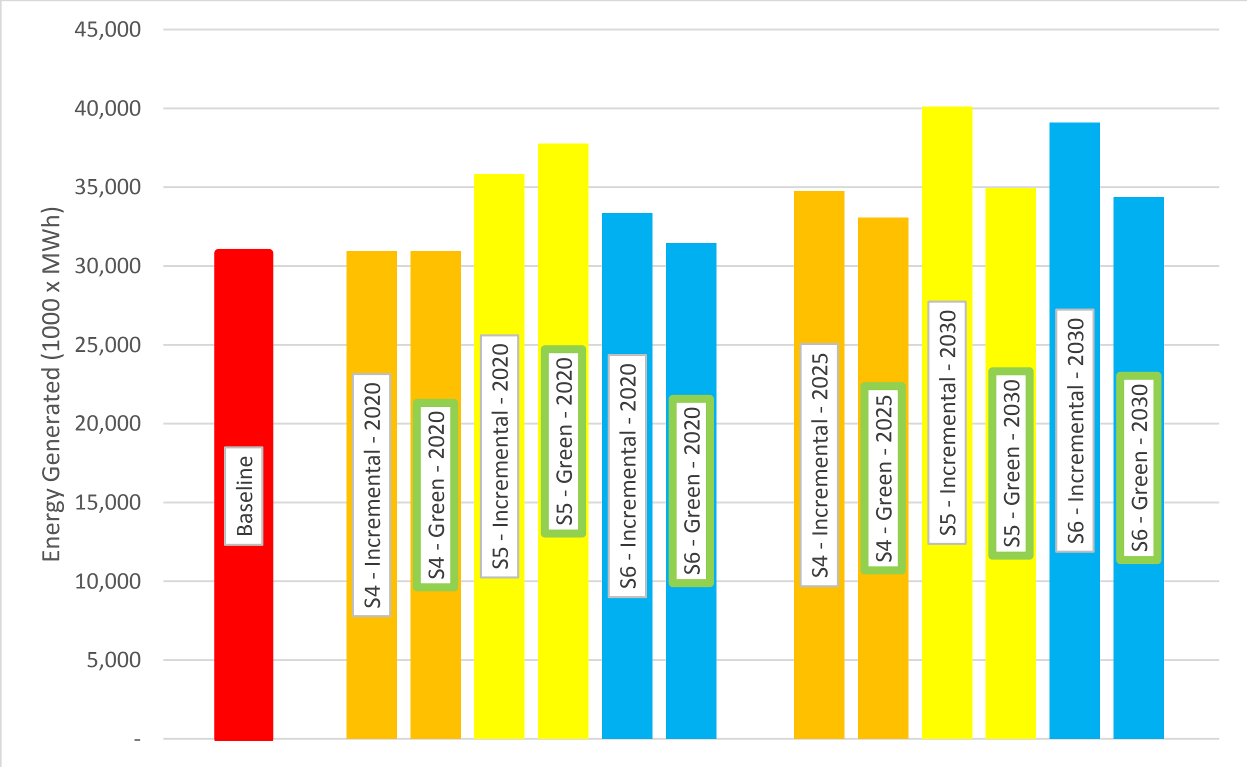
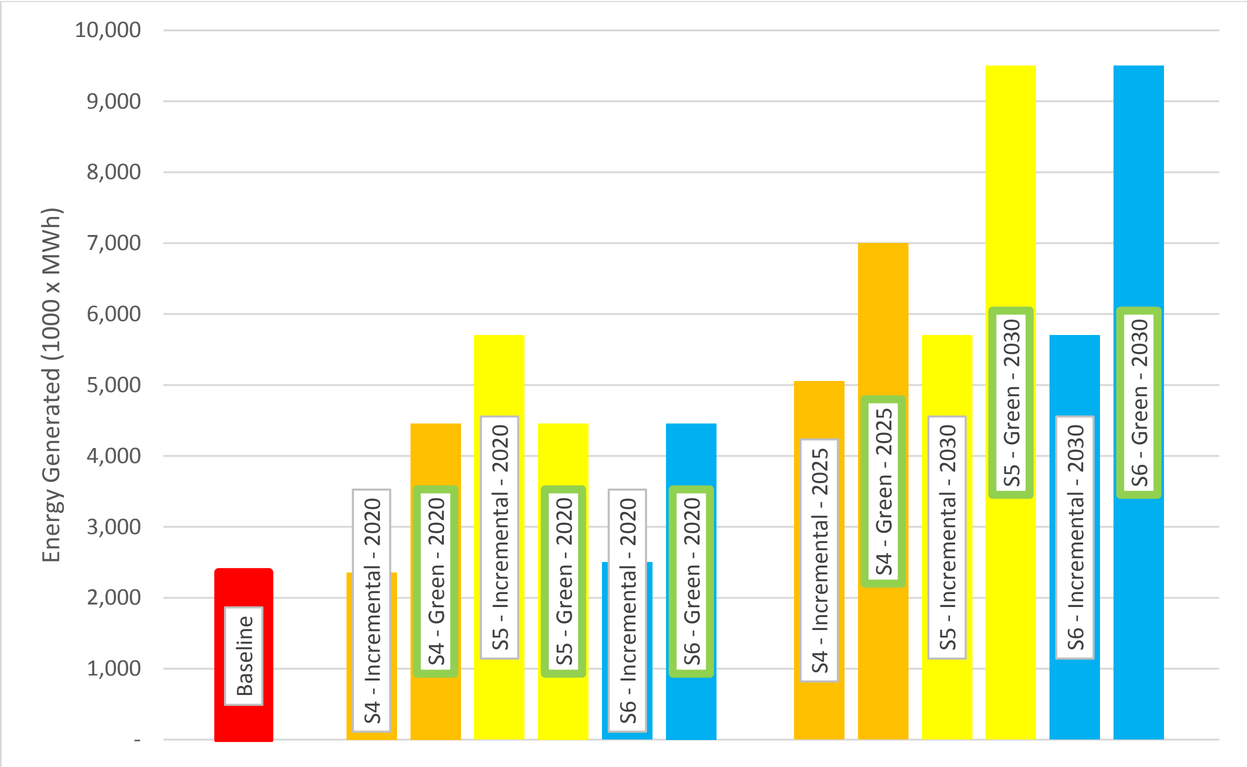


Figure ES-7: Renewable Energy Generation by Scenario



Virginia has flexibility in implementing the CPP. EPA proposed that the states have complete flexibility in developing their compliance plans. EPA indicates in the CPP proposal that that states may use, to whatever extent necessary, the suggested EPA "building block assumptions" for flexibility. Alternatively, states may choose to change from a CO_2 emissions rate based compliance approach and establish a mass-based (total CO_2 tonnage) cap that can be used in a regional trading program (like the RGGI program currently used by nine northeastern states). Previous experience shows that it can take several years to approve and establish such a program.

Virginia's CO_2 state compliance plan must be submitted to EPA by June 2016. To implement a regional trading program, Virginia would need to identify state trading partners, pass enabling legislation in Virginia (as would be required in the other states), sign multi-state MOU's, establish trading rules and compliance testing within the state trading group, and obtain EPA approval (and possibly Congressional approval of the interstate compact). Because of these timing obstacles, the use of a regional trading program for initial compliance with the EPA CPP regulations may not be possible. However, the report recommends that Virginia convene a "mass-based compliance team" to explore the use of this option as soon as practical.

Implications of EPA's Clean Power Plan for the Commonwealth. As previously mentioned, the scenarios that would allow the state to be in compliance include major increases in the use of natural gas generation and a corresponding need for reliable delivery from the natural gas pipeline network in the Commonwealth. The reliance on new renewable energy generation, energy efficiency and demand side management under the compliance scenarios also creates potential impacts on energy markets and reliability within Virginia.

One area in question is the intention that compliance measures beyond the power stations themselves are to be included in the state implementation plans. The inclusion of measures that are “outside the fence” of the power stations may be beyond the scope of Clean Air Act regulations, and thus prove difficult to implement and enforce.

Electric utilities need flexibility and low-risk technologies to facilitate compliance and assurance of cost recovery. Although EPA claims that the proposed regulations allow flexibility, it remains to be seen whether the state implementation plans approved by EPA will satisfy this need. Carbon capture and storage (CCS) technology does not appear likely to be well enough established in time to play a major role in compliance, at least not in the early stages, for the existing fleet.

Impacts of changing the generating mix include increased reliance on natural gas. The proposed rules drastically reduce carbon emissions at existing plants, so are not merely incremental steps in cleaning up the atmosphere; they will significantly alter fuel choices and associated investments by utilities for the 21st Century, which is exactly EPA’s intention.

Utilities and regulators are likely to criticize the excessive dependence on natural gas, but under the proposed rule, alternative choices will be limited. In fact, natural gas will play an increasing role as long as it is plentiful and affordable. Coal will continue to be part of a diversified fuel portfolio for power generation, but at diminishing levels. As the EPA rules go forward coal use will continue to trend downward faster than if it were only competing with natural gas. Examination of the “Green Dispatch” generation cases shows that the expansion of renewable energy at a rate compatible with EPA’s goals is possible and will result in a higher cost to utilities and consumers.

The role of nuclear generation in Virginia remains fundamental. Although full consideration of nuclear generation is not included in EPA’s CPP, consideration of nuclear power is significant in Virginia. In 2012, the four operating nuclear generating units provided about 27.4 million MWh. Considering that generation along with announced retirements and new natural gas generation would allow for Virginia to meet the emissions goals of the proposed regulations without requiring major changes to the existing generation mix.

A new generating unit being considered by Dominion at the North Anna plant (North Anna #3) would provide an additional 10.3 million MWh of CO_2 emission-free power once at full operation, allowing nuclear to provide over 40 percent of total generation. As such, the inclusion of nuclear generation in Virginia's portfolio will significantly alter the energy mix, decreasing the contribution of natural gas.

Economic impacts analysis shows costs statewide and in particular regions. To meet the CO_2 emission target, electricity producers in Virginia are expected to incur significant compliance costs. Compliance can be achieved through fuel switching, retirement of coal-fired plants, heat rate improvement, and demand conservation programs. Estimates of those costs for various scenarios are shown in Table ES-1.

Table ES-1 Estimated Costs to Producers in Virginia

	Scenario 3		Scenario 4		Scenario 5		Scenario 6	
	2020	**2030**	**2020**	**2025**	**2020**	**2030**	**2020**	**2030**
Total Compliance Cost ($Million)	$368	$499.9	$249.8	$598.1	$883.0	$795.8	$334.8	$738.8
Total CO_2 Emissions Reduction (million tons)	3.79	6.74	1.54	5.55	8.05	8.05	3.25	6.91
Compliance cost per ton of CO_2 reduction	**$97**	**$74**	**$162**	**$108**	**$110**	**$99**	**$103**	**$107**

Business and residential electricity customers in Virginia will also see their electricity payment increase. According to the EPA, the Clean Power Plan would increase electricity price by 2.4 percent in 2020 and 3.0 percent in both 2025 and 2030. The total costs for Virginia electricity customers range from $229.0 million in Scenario 4 (2020) to $484.5 million in Scenario 4 (2025). The cost is sensitive to future natural gas price. Table ES-2 highlights predicted costs to residential and business customers under different scenarios. Costs for consumers if the utilities are allowed to pass on 100 percent of increased cost to consumers are also shown.

Table ES-2: Costs to Residential and Business Consumers under Various Scenarios

	Scenario 3		Scenario 4		Scenario 5		Scenario 6	
	2020	2030	2020	2025	2020	2030	2020	2030
Cost to residential consumers ($Million)	$132.4	$221.1	$115.5	$242.2	$118.8	$205.4	$121.4	$205.4
Cost to business consumers ($Million)	$130.2	$205.7	$113.5	$242.2	$119.9	$195.0	$121.9	$195.0
Total cost to all consumers without utility pass-through ($Million)	$262.6	$426.8	$229.0	$484.5	$238.7	$400.4	$243.3	$400.4
Total CO_2 Emissions Reduction (million tons)	3.79	6.74	1.54	5.55	8.05	8.05	3.25	6.91
Consumer cost per ton of CO_2 reduction without utility pass-through	**$69**	**$63**	**$149**	**$87**	**$30**	**$50**	**$75**	**$58**
Residents								
Electricity Cost ($Million)	$132.4	$221.1	$115.5	$222.0	$112.5	$198.1	$116.3	$198.1
Conservation Cost ($Million)	$0.0	$0.0	$0.0	$20.3	$6.3	$7.3	$5.1	$7.3
Compliance Cost (100 percent pass-through) ($Million)	$185.5	$259.0	$125.9	$299.0	$439.4	$408.2	$167.1	$378.9
Residents Cost Total ($Million)	$317.9	$480.1	$241.4	$541.3	$558.2	$613.6	$288.5	$584.3
Business								
Electricity Cost ($Million)	$130.2	$205.7	$113.5	$212.3	$110.7	$184.3	$114.4	$184.3
Conservation Cost ($Million)	$0.0	$0.0	$0.0	$30.0	$9.2	$10.8	$7.5	$10.8
Compliance Cost (100 percent pass-through) ($Million)	$182.4	$240.9	$123.8	$299.0	$443.5	$387.6	$167.7	$359.8
Business Costs Total ($Million)	$312.7	$446.6	$237.4	$541.3	$563.4	$582.6	$289.6	$554.9
Total Costs to Customers (100 percent pass-through) ($Million)	**$630.6**	**$926.7**	**$478.8**	**$1,082.5**	**$1,121.7**	**$1,196.3**	**$578.1**	**$1,139.2**
Total CO_2 Emissions Reduction (million tons)	3.79	6.74	1.54	5.55	8.05	8.05	3.25	6.91
Costs to Customers (100 percent pass-through) per ton of CO_2 reduced	**$166**	**$137**	**$311**	**$195**	**$139**	**$149**	**$178**	**$165**

In the supporting documents for the proposed rule, EPA calculates the social benefits that can be obtained by reductions to emissions of CO_2 besides those directly related to health or the environment. Table ES-3 shows those benefits for various scenarios, based on the proportion of national emissions reductions expected to be realized in Virginia.

Table ES-3: Social Benefits Based on EPA Analysis for Selected Scenarios

	Scenario 3		Scenario 4		Scenario 5		Scenario 6	
	2020	**2030**	**2020**	**2025**	**2020**	**2030**	**2020**	**2030**
Estimated social benefits based on EPA analysis ($Million)	NA	NA	$310	$458	$606	$721	$400	$660
Estimated benefit per ton of CO_2 reduction	**NA**	**NA**	**$201**	**$83**	**$75**	**$90**	**$123**	**$96**

To meet the EPA's CO_2 emission target, many coal-fired plants would be retired, and workers at those plants could lose their jobs. Also, those lost jobs may not be offset by employment at natural gas plants or renewable generation plants where electricity output increases. Overall employment in the power industry would decline in all compliance scenarios (see Figure ES-8 and Table ES-4). Coal industry employment will be impacted under all scenarios, focused in Southwest Virginia.

Figure ES-8: Estimated Direct Job Losses in Power Industry

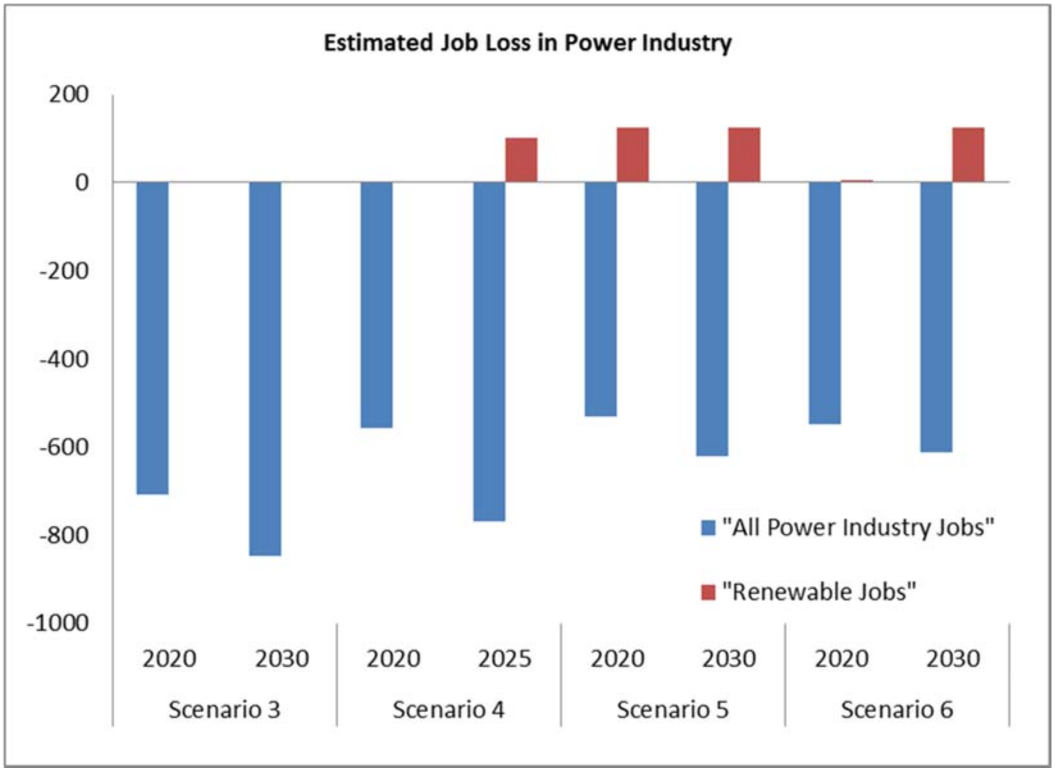


Table ES-4: Employment in the Coal, Oil and Gas, and Energy Efficiency Industries

Employment Impact on Other Industries								
	Scenario 3		**Scenario 4**		**Scenario 5**		**Scenario 6**	
	2020	**2030**	**2020**	**2025**	**2020**	**2030**	**2020**	**2030**
Coal Industry	-1,736	-2,748	-626	-1,782	-3,305	-3,305	-1,367	-2,024
Natural Gas Industry	3	5	1	0	3	2	2	2
Energy Efficiency	0	0	120	466	144	168	116	168
Average	**-1,733**	**-2,743**	**-505**	**-1,316**	**-3,158**	**-3,135**	**-1,249**	**-1,855**
Note: Comparison are made with respect to Scenario 2								
Source: Chmura, 2014								

Other impacts that are beyond the scope of this study include quantifying the Virginia-specific health benefits and fiscal impacts to the state and local governments of the Clean Power Plan.

Estimation methods of environmental and health impacts of the proposed rule are limited in scope. While the costs of the EPA Clean Power Plan are significant for electricity producers, business and residential consumers, it also has wide ranging environmental benefits. This report relies on the methodology used by the EPA in its “Regulatory Impact Analysis” to estimate these. The so-called “social cost of carbon” (which accounts for only some of the costs and impacts of CO_2 emissions) shows a reduction in costs in Virginia of approximately $160 million annually by 2030. EPA concedes in its proposed rule that most measurable health impacts and benefits are attributable to the reduction of other atmospheric emissions aside from CO_2 as a “co-benefit” of the proposed regulations. However, using EPA’s methodology, the estimate of specific health benefits for Virginia varies between $600 million and $1.4 billion in 2030.

Implementation of the proposed rules requires consideration of many policy options. The proposed timing for implementation of EPA’s CPP regulations requires immediate consideration of policy options. There are several broad areas that Virginia and other states must consider over the next several months. A detailed list of potential policy options are included in the full report. Among the most significant are:

1. **Enabling Legislation** to promote and implement the CPP requirements at the state level.
2. **Standards of Performance** should be developed for all EGUs in Virginia, including fossil fuel generation, nuclear generation, and renewable generation, to ensure that the mandates of the CPP can be achieved while meeting electricity demands.
3. **Institutional Structures** necessary to enable changes in generation mix, including legal framework and regulatory responsibilities, should be determined. Identify areas requiring legislation to establish funding and assignment of liability for issues such as storage/sequestration of CO_2, development of fuel distribution (i.e., gas pipelines), and other necessary infrastructure.
4. **Broad Involvement.** Engage all electrical generation utilities, including investor-owned, member cooperative, and public, in discussions, as well as pipeline companies, coal mining companies, natural gas companies, regulatory agencies and the State Corporation Commission, to determine what structural changes are necessary and what challenges must be overcome to ensure fuel availability and uninterrupted generation.
5. **Financial Incentives** for adoption of low- and zero-carbon generating facilities demonstrating and deploying new technologies that could benefit ratepayers, the economy and the environment should be provided.

6. **Investigation of Multi-State Cooperation.** Discussions should be begun with neighboring states to determine possibilities and options for partnerships to implement trading programs and other necessary areas of cooperation. Detailed consideration of the need for multiple-state compacts and multi-state enforcement mechanisms are critical.
7. **Evaluation of Impacts on the Grid.** Evaluate the CPP impacts on the reliability of the electrical distribution network in the state and in neighboring states, including appropriate involvement of regional grid organizations, such as the PJM.
8. **Carbon Management Resource Planning** measures, such as the most appropriate renewable energy portfolios and support for electrical efficiency and demand-side management programs should be instituted.
9. **Utilize All Generating Resources.** Ensure that state implementation plans incorporate all electrical generating units, including all nuclear generating units, small “non-affected” units, and planned new generation, to ensure that the electrical demands of the Commonwealth can be met reliably at the lowest possible dispatch costs to residential and business customers.
10. **Develop New Technology.** Encourage the development of new technologies for electrical efficiency, CCS/CCUS, and modernized grid, through support of research and demonstration projects.
11. **Determine the Needs of Cooperatives and Public Utilities.** Assist small rural electric cooperatives and public utilities in developing integrated resource plans to ensure that all utilities in the state are able to file plans at the same time to meet statewide goals and mandates.
12. **Address Negative Impacts.** Develop mechanisms to deal with negative economic impacts, including addressing regional unemployment in the coal mining sector and indirect and induced impacts on small businesses and industries across the state.
13. **Achievable CO_2 Reduction from Coal-Fired Units.** Policy should recognize that 4-6 percent CO_2 reduction is not likely to be attainable long-term for the existing coal-fired fleet, particularly when units are forced to operate at extremely low capacity factor.
14. **Relief from New Source Review.** The most effective improvements to power plant heat rate will require investment that, depending on EPA interpretation of actions, could impose additional environmental requirements which further increase CO_2 emissions. These units are already complying with federal and local emissions mandates. Imposing new-source limits restricts investment options.
15. **Recognize that Natural Gas Supply Limits NGCC Operation.** Much of the CO_2 reductions achieved come from substituting more costly natural gas-fired generation for coal. The extent to which existing and new proposed NGCC facilities can provide power will depend on a reliable natural gas supply. Expanding pipeline access and eliminating bottlenecks is key.

Many issues must be addressed by a follow-on comprehensive study. The analysis of the scenarios in this study demonstrates that Virginia’s compliance with the EPA proposed rules is theoretically possible, using both incremental power dispatch and “Green Dispatch” cases. While this exercise has drawn upon existing data and information and uses likely projections, more detailed consideration of the means of compliance and the costs and benefits is necessary in order to determine the true feasibility of compliance and its impacts.

To comply with the filing requirements of the Clean Power Plan in 2016, it is anticipated that EPA will require the use of a more complex production costing model, such as their Integrated Planning Model (IPM), to prove that the compliance plan chosen by Virginia will place the state into CO_2 compliance during the interim period (2020 through 2029) and into final compliance in 2030.

To meet the future CO_2 compliance requirements of EPA, it is recommended that a much more detailed analysis be conducted after this 2014 Virginia Energy Plan is released. This additional analysis should include the following:

- **IPM type modeling of the Virginia electrical grid system calculating total production costs.**
- **Cost implications of the financing of natural gas pipeline expansions, potential new nuclear, construction of new renewable projects and other new generation sources.**
- **A detailed study of the real potential market penetration of a state authorized energy efficiency standard and a state authorized demand side management program.**
- **Real potential MWh that could be realized from renewable generation in Virginia, including incentives, credits and trading with neighboring states.**
- **Feasibility of Virginia providing some form of financial backing/guarantees for construction of CCUS/CCSU projects on new and existing coal units in the state.**

With this expanded analysis, more in-depth data could be generated to provide input to policy makers to make final informed decisions as to the future energy policy for the Commonwealth of Virginia.

This report has attempted to identify compliance strategies, as directed by the General Assembly of Virginia in Item 8 (§ 67-201. Development of the Virginia Energy Plan. Subsection B). Effort was focused on satisfying the requirements of this legislation 1) by reporting on Virginia's energy policy positions relevant to the EPA's June 2014 proposal for additional carbon emissions regulations based on section 111(d) of the Clean Air Act for existing power plants; 2) by reviewing and reporting on Virginia's historical fuel portfolio and projected changes to this portfolio under various scenarios to meet the requirements of the proposed EPA regulations; and 3) by assessing the impacts of estimated energy price increases on consumers within the Commonwealth. In doing so, this report has identified options and measures that will further the interests of the Commonwealth and its citizens as it plans for Virginia's energy future and for compliance with the proposed federal regulations.

Fuel and technology diversity have historically been key strengths of the electricity generation sector serving Virginia, the region, and the US as a whole and have helped to ensure stable prices, a reliable electrical system, technology innovation, effective resource planning and integration, environmental protection, job creation, and strong economic growth. Diversity of fuels and technology in the electricity portfolio is fundamental to a properly functioning electricity system. It is crucial that the Commonwealth of Virginia recognize the importance and value of fuel and technological diversity and work with the electric power generation sector and its suppliers to preserve portfolio diversity, while at the same time addressing the challenges of CO_2 emission reductions.

IV. Virginia Energy Plan Item 8: Impacts of Proposed Regulations under Section 111(d) of the Clean Air Act

Section 1. Introduction

On June 25, 2013, in an address at Georgetown University, President Obama presented his vision for a US Climate Action Plan. The White House describes this plan as "a series of executive actions" to be implemented through regulations issued by the Environmental Protection Agency (EPA). In July 2014, the White House issued a report declaring that, "the signs of climate change are all around us…these changes…are largely consequences of anthropogenic emissions of greenhouse gases." (White House, 2014). Based on a report by the Council of Economic Advisors, the White House report also declared that immediate action will "substantially" decrease the cost of achieving compliance.

The first action under the President's plan was the development of carbon emissions standards for ***new*** power plants. To meet this objective of the President's plan, the EPA revised an existing version of proposed regulations to align with section 111(b) of the Clean Air Act. The revised, proposed rule was published in the Federal Register on January 8, 2014, (EPA, 2014a) and sets the following base limitations for CO_2 emissions from new power plants:

Coal and IGCC units:	1,100 lbs CO_2/MWh
Natural Gas-fired Combustion Turbines (stationary sources):	
- Heat input > 850MMBtu/h	1,000 lbs CO_2/MWh
- Heat Input < 850MMBtu/h	1,100 lbs CO_2/MWh

Currently, coal-fired power plants emit CO_2 at a rate of approximately 2,000 lbs of CO_2 per MWh. The level of 1,100 lbs required by the EPA proposal cannot be met by heat rate improvements, or coal switching alone. Citing the planned use of carbon capture and sequestration/storage (CCS) technology to lower emissions at four specific coal-fired power facilities, the EPA concluded that CCS technology is "technically feasible and available" and can be mandated for future coal-fired facilities. However, a number of experts dispute the “commercial availability” of CCS technology, highlighting a need for adequate large-scale demonstration. In contrast, the current state-of-the-art natural gas combined cycle units already routinely emit at a rate well below the EPA limit of 1,000 lbs per MWh and, therefore, would not require any additional CO_2 control technology.

Based on section 111(d) of the Clean Air Act, the EPA proposed additional carbon emissions regulations for ***existing*** power plants on June 2, 2014, and published the proposal in the Federal Register on June 18, 2014 (EPA, 2014b). The EPA is seeking comments on the regulatory proposal through October 16, 2014, with the expectation that final rules will be published in June 2015. State-specific compliance plans are due to the EPA for review and approval in June 2016, 2017, or possibly 2018, depending on the compliance and planning approach taken by the state. The first year for mandated compliance with the interim CO_2 emissions reduction goal in the proposed regulation is 2020.

This report, as instructed by the legislature, focuses on the proposed regulations for existing plants and their potential impacts on the energy landscape in the Commonwealth of Virginia.

Section 2. The EPA's Proposed Regulation of CO_2 Emissions from Existing Power Generating Facilities and Implications for the Commonwealth of Virginia

The EPA's public release of the proposed Clean Power Plant (CPP) rule on June 2, 2014, generated much publicity around requirements for an overall 30 percent reduction of CO_2 emissions from 2005 levels. However, the 2005 baseline has nothing to do with the goal calculations and establishing future CO_2 emission rate targets. In the proposed regulations, 2012 is the actual baseline year chosen by EPA to calculate the interim and final CO_2 goals for each state.

Many energy policy experts have indicated a similarity between the carbon control regulations and previous regulatory efforts to control acid rain. Unlike the simplistic one-step calculation used to allocate SO_2 allowances under Title IV of the Clean Air Act Amendments of 1990, however, this proposed EPA CO_2 regulation uses a seven step process, shown in a 54 column spreadsheet. The spreadsheet is further supplemented by the output of an Integrated Planning Model (IPM) simulation, plus implementation of a renewable energy program and an energy efficiency or demand-side management program in each state (EPA, 2014c). The EPA used the seven steps to develop the interim CO_2 goals (expressed in pounds of CO_2 per MWh) for the period 2020 through 2029 and the final CO_2 rate for 2030 and beyond.

Building Block Assumptions

For its calculations, the EPA uses a set of assumptions that they refer to as the "building blocks" of the program. These assumptions can be summarized as follows:

- **Plant heat rates at all coal-fired units can be improved by approximately 6 percent. This heat rate improvement will thus result in greater plant/unit efficiency and lower the CO_2 emission rate.** The technical issues associated with this assumption are addressed in Section 3 of this report. In reality, for many units this 6 percent improvement is not achievable. A recent report, requested by the Secretary of Energy and compiled by the National Coal Council (NCC, 2014), was unable to document such consistent heat rate improvements.
- **All natural gas combined cycle (NGCC) units can and will run at 70 percent capacity factors (CF) in the future.** This assumption further implies that natural gas prices will remain relatively low as compared to coal and that there will be no future constraints in the natural gas pipeline delivery system. In addition to the NGCC 70 percent CF assumption, this building block also assumes that currently planned nuclear capacity additions will be completed and added to the generation mix. Also, that 6 percent of the existing nuclear capacity, which EPA considers as "at risk" for retirement, is "preserved."
- **All states will implement some form of a mandatory renewables program.** EPA's optimal goal is for states to implement such a program, reaching a 16 percent level of renewable generation by 2030. Approximately 29 of the 50 states already have some form of a Renewable Portfolio Standard program (either mandatory or voluntary); therefore, legislation enabling such programs would be required.
- **Each of the states will implement energy conservation programs (also known as energy efficiency or demand-side management programs) by 2030.** These programs are assumed to grow at a rate of approximately 1.5 percent per year and to reach a level of 10.7 percent market penetration by 2030. Again, enabling legislation, or approval by the state public utility commission, is typically required to implement such programs.

Calculation of the EPA Target CO_2 Rates for Virginia

The first step in calculating the target CO_2 rate by state is a determination of the 2012 baseline fossil data (generation and emissions) for all coal and natural gas units. The 2012 data for Virginia for Step 1 is shown in Table 2-1.

Table 2-1: EPA Step 1 – Baseline Fossil Data

	Step 1 (2012 Data for Fossil Sources)									
State	Coal Rate (lb/MWh)	NGCC Rate (lb/MWh)	O/G rate (lb/MWh)	Other Emissions (lbs)	Hist Coal Gen (MWh)	Hist NGCC Gen. (MWh)	Historic OG steam Gen. (MWh)	Other Gen. (MWh)	NGCC Capacity (MW)	Under Construction NGCC Capacity (MW)
Virginia	2,268	903	1,652	2,581,898,592	13,641,552	23,070,350	343,908	1,140,288	4,346	1,928

In Step 2 (shown in Table 2-2 below), the average 2012 coal heat rate (from CO_2 per MWh rate from the “Coal Rate” column) is used to calculate an average 6 percent heat rate improvement for all coal units in the state. As shown below, the Virginia 2012 rate of 2,268 lbs per MWh was improved to 2,132.

Table 2-2: EPA Step 2 – Calculate Heat Rate Improvement

	Step 1 (2012 Data for Fossil Sources)										Step 2 (HRI)
State	Coal Rate (lb/MWh)	NGCC Rate (lb/MWh)	O/G rate (lb/MWh)	Other Emissions (lbs)	Hist Coal Gen (MWh)	Hist NGCC Gen. (MWh)	Historic OG steam Gen. (MWh)	Other Gen. (MWh)	NGCC Capacity (MW)	Under Construction NGCC Capacity (MW)	Adj. Coal Rate (lbs/MWh)
Virginia	2,268	903	1,652	2,581,898,592	13,641,552	23,070,350	343,908	1,140,288	4,346	1,928	2,132

For Steps 3A and 3B (shown in Table 2-3), the IPM is used to re-dispatch the entire statewide Virginia power system by increasing all NGCC units up to a 70 percent capacity factor. This results in reduced coal generation, falling from 13.6 million MWh to 7.6 million MWh. Additionally, NGCC generation increases by 6.19 million MWh under the re-dispatch and the revised NGCC CF is now at 70 percent.

Table 2-3: EPA Step 3 – Increase NGCC Units to 70 percent Capacity Factor

Step 3a & 3b (Redispatch)						
Redispatched Coal Gen. (MWh)	Redispatch O/G steam Gen. (MWh)	Redispatched NGCC Gen. (MWh)	Other Emissions (lbs)	Other Gen. (MWh)	2012 NGCC Capacity Factor*	Post Redispatch Assumed NGCC Capacity Factor for Existing Fleet
7,600,565	191,613	29,263,632	10,995,356,047	10,454,842	60%	70%

In Step 4A (shown in Table 2-4), the IPM is used again to calculate the total MWh of "preserved and new nuclear capacity" to be used in setting the future CO_2 rates. Because of concerns about the long-term viability of the existing nuclear generation fleet, the preserved nuclear capacity is defined as 6 percent of 2012 nuclear generation in the proposed rule.

Table 2-4: EPA Step 4a – Calculate Preserved and New Nuclear Capacity

Step 3a & 3b (Redispatch)							Step 4a Nuclear
Redispatched Coal Gen. (MWh)	Redispatch O/G steam Gen. (MWh)	Redispatched NGCC Gen. (MWh)	Other Emissions (lbs)	Other Gen. (MWh)	2012 NGCC Capacity Factor*	Post Redispatch Assumed NGCC Capacity Factor for Existing Fleet	Nuclear Generation Under Construction and "At Risk" (MWh)
7,600,565	191,613	29,263,632	10,995,356,047	10,454,842	60%	70%	1,645,275

In step 4B (Table 2-5), a value for projected renewable energy generation in MWh is incorporated into the calculation.

Table 2-5: EPA Step 4b – Incorporate Renewable Generation

Step 4b Renewable (MWh)									
2020 Existing and Incremental RE	2021 Existing and Incremental RE	2022 Existing and Incremental RE	2023 Existing and Incremental RE	2024 Existing and Incremental RE	2025 Existing and Incremental RE	2026 Existing and Incremental RE	2027 Existing and Incremental RE	2028 Existing and Incremental RE	2029 Existing and Incremental RE
4,458,736	5,228,273	6,130,626	7,188,717	8,429,425	9,884,268	11,192,008	11,192,008	11,192,008	11,192,008

In Step 5 (Table 2-6), estimates are determined for the projected percentages of current electrical generation that Virginia can ***avoid*** through the use of "energy efficiency" and/or what are referred to as "demand-side management" programs.

Table 2-6: EPA Step 5 – Estimate Percent Reduction from Demand-Side Management Programs

Step 5 (Demand Side EE - % of avoided MWh sales)											
2020 EE Potential	2021 EE Potential	2022 EE Potential	2023 EE Potential	2024 EE Potential	2025 EE Potential	2026 EE Potential	2027 EE Potential	2028 EE Potential	2029 EE Potential (%)	State Generation as % of sales	2012 Total MWh (sales x 1.0751)
1.23%	1.96%	2.82%	3.81%	4.91%	5.98%	6.95%	7.83%	8.62%	9.33%	58.01%	115,890,388

Steps number 6 and 7 (Table 2-7) generate the "interim" CO_2 emissions rate targets for 2020 through 2029 and the final CO_2 rate target for Virginia in 2030. These are expressed in pounds of CO_2 per MWh.

Table 2-7: EPA Steps 6 & 7 – Rate Targets

Step 6&7 (State Goal Phase I & II (lbs/MWh))											
2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Interim Goal (2020 - 2029 average)	Final Goal (2030 and thereafter)
991	969	943	916	886	855	830	822	816	810	884	810

Regulatory Flexibility

The EPA has provided some flexibility for the states in complying with this proposed rule. In the proposal, the EPA allows the states to convert the CO_2 rate-based goals (lbs CO_2 per MWh) into "mass-based" goals (tons CO_2). In such programs, states can take advantage of lower cost reduction opportunities found in neighboring states, which can create excess tradable allowances through "over-compliance" in the lower-cost states. Converting to mass or tons facilitates the calculation of allowances which are key to such emissions trading programs. The procedure for converting to a mass-based goal, however, is quite complex and can be found in a technical support document for the proposed EPA regulations (EPA, 2014d). Based on the complexity of the calculations, the EPA almost mandates the use of large scale computer based modeling using IPM or other comprehensive commercially available software to accomplish this conversion calculation.

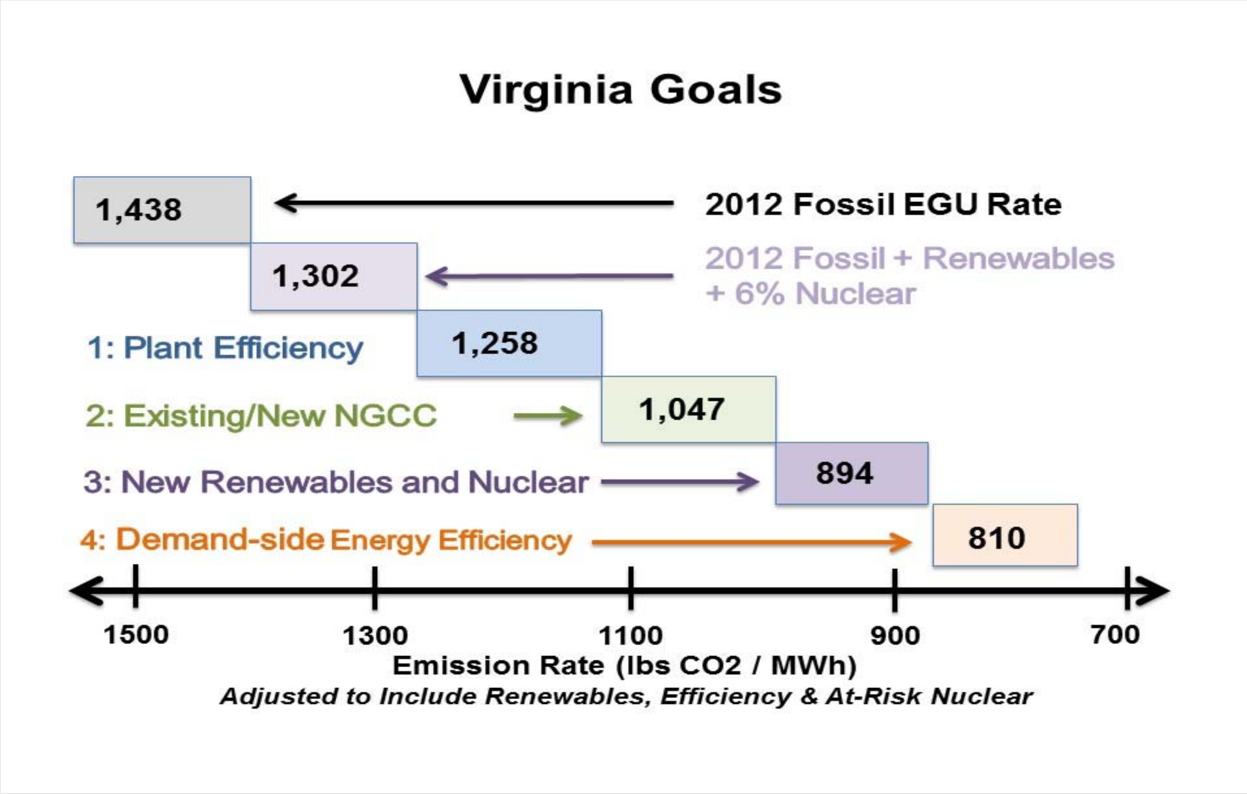
Discussion

The rates established for Virginia for 2020 and beyond do not appear to be attainable without addressing some major policy changes. As seen in Step 1 (Page 43), the coal CO_2 emissions rate is 2,268 lbs of CO_2 per MWh in Virginia while the NGCC average CO_2 rate is 903 lbs/MWh. With a target interim rate of 991 lbs/MWh in 2020 and 810 lbs/MWh in 2030, compliance with the EPA proposal will require a substantial change in Virginia's energy generation mix (see Figure 2-1). Natural gas will, of necessity, play a much greater role as the primary base-load generation fuel. The role of coal will decline in the generation mix. Nuclear, renewables and energy efficiency programs, which generate no CO_2, will help ease the transition to maintaining energy output while lowering emissions.

The EPA assumptions and process warrant discussion of a number of additional issues:

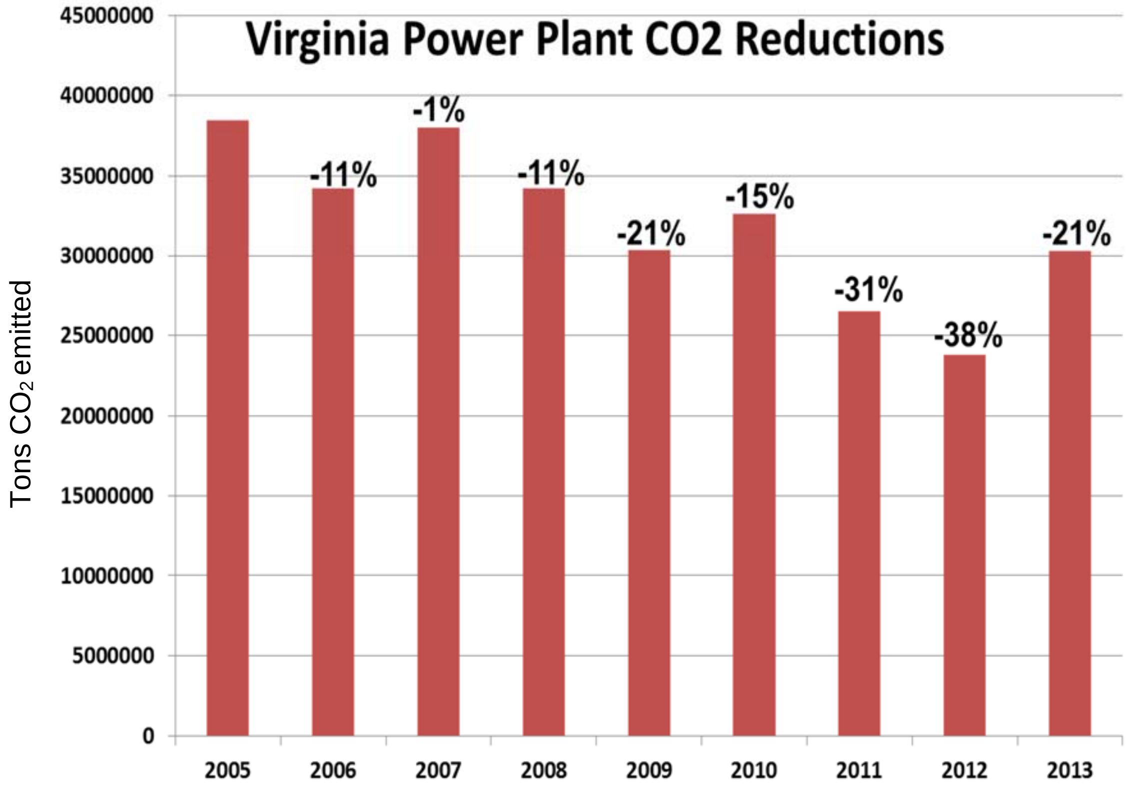
- CO_2 emissions from the coal-fired fleet have been decreasing in recent years due to both utilization and efficiency improvements. Between 2005 and 2012, many of the existing fossil fuel plants made a number of efficiency improvements which in addition to causing them to operate at lower capacity factors, reduced their emissions (Figure 2-2). The use of 2012 as a baseline year prevents credit for those improvements towards meeting the new goals. Because the improvements are already in place, achieving an additional 6 percent improvement in heat rate is nearly impossible for many generating units.

Figure 2-1: EPA Emission Reduction Goals for Virginia in 2030



- Based on both economic and technical feasibility, CO_2 emissions reductions using CCS technologies will most likely be limited to new facilities. While some units have been used for demonstration, adoption of CCS may be incompatible or cost prohibitive for commercial deployment in existing plants.
- The feasibility of switching to a generating fleet dominated by NGCC is vulnerable to a number of unknowns, including gas price volatility, gas availability due to expanding gas exports, and the assumption of available gas infrastructure. Significantly increased NGCC generation relies on suppositions about the availability of infrastructure (pipelines and other transportation) to provide fuel as needed. Unlike coal generation, where utilities can and do create fuel stockpiles to provide for 30 days of base load and to accommodate

Figure 2-2: Virginia Power Plant CO_2 Reductions, 2005-2013



fluctuations in demand, increased NGCC generation will require a complete reliance on the natural gas pipeline system to provide fuel in a consistent and timely manner. Alternatively, utilities may find the need to build gas storage facilities at generating stations, or to help create large geologic storage facilities to benefit the Commonwealth.

- A number of steps mandated by the EPA (for example: renewable portfolio standards, market efficiency improvements, emissions trading, among others) require approval of the state legislature which can be a lengthy process.
- Commercially viable increases in generation efficiency and CCS technologies may not exist in time to implement the mandated emissions reductions, limiting the policy and technical options for meeting compliance targets.

Section 3. Commercially Available Technology

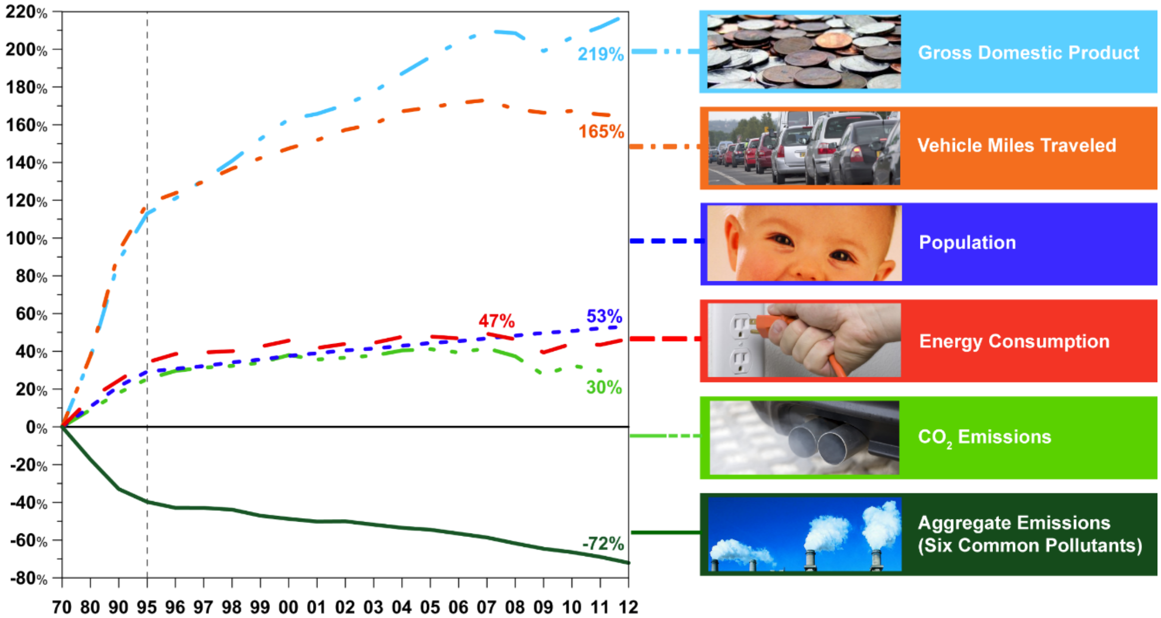
The power industry has developed and deployed environmental control technologies for a wide variety of emissions since the mid-1970s. As a result, emissions of major pollutants are significantly below historical levels even as power generation has grown to satisfy increased industrial, commercial, and residential demands. Through most of this period, mandates for lower emissions were issued in approximate progression with the evolution of technology. In some cases the environmental mandates were technology-forcing—that is, requiring refinement or commercialization of control technologies not yet proven. In these cases, the emissions reductions were achieved with the aid of flexibility in methods and timing of achieving compliance.

The CO_2 reduction mandates must be considered in light of this experience. Lowering CO_2 emissions by improving plant generating efficiency is a valid and proven pathway. However, the actual CO_2 that can be reduced through thermal efficiency improvements at this point in time is uncertain. Because many improvements have already been applied by utilities as best-practices to lower fuel consumption and minimize operating costs, opportunities for additional improvement using control technologies may be technically infeasible (NCC, 2014).

The other possibility for technological improvements is to reduce CO_2 emissions using Carbon Capture and Storage/Sequestration (CCS) or Carbon Capture, Utilization and Storage (CCUS), where part, or all of the $CO_{2,}$ is used for industrial applications such as Enhanced Oil Recovery (EOR) or Enhanced Gas Recovery (EGR). Unfortunately, the technology to accomplish this on a large scale is neither proven nor available and the timeline for commercial deployment is anticipated to extend well into the 2020s.

Past experience with the Acid Rain, Cross-State Air Pollution Rule (CSAPR), and Mercury and Air Toxics Standards (MATS) mandates of the 1990 Clean Air Act Amendments (CAAA) shows that with adequate time and resources, major emissions reductions are possible. Figure 3-1 below provides an example.

Figure 3-1: Past Experience with Acid Rain, CSAPR, and MATS Mandates



Source: EPA Office of Air and Radiation, (EPA, 2014e)

Control of CO_2, however, is significantly more challenging than anything contemplated by the CAAA. Most notably, the mass of material to be removed and stored or sequestered is much larger. For example, a typical generating plant will create at least 15 times more mass of CO_2 to be removed from the flue gas than the SO_2 removed during combustion of a high sulfur coal. Furthermore, whereas the flue gas desulphurization (FGD) byproduct is a stable solid and can be stacked, captured CO_2 is a gas that requires containment, presents transport challenges, and at present can only be injected underground for storage or used for enhanced recovery of oil and gas.

Improving the Efficiency of Power Generation

There are numerous means to improve the thermal efficiency of existing power plants—and to reduce the CO_2 emitted per MWh—although the payoff and applicability is specific to each individual generating unit.

The typical metrics used to measure the efficiency of power generation include:

- **Thermal efficiency:** the ratio of useful output energy divided by input energy, stated in terms of a percentage. The average efficiency of the US coal fleet in 2012 was 33 percent; but individual units vary significantly.
- **Heat rate:** the inverse of thermal efficiency—input energy divided by useful output energy. Heat rate is typically reported in British thermal units of input energy divided by kilowatt-hours of output energy (Btu/kWh). The average heat rate of coal-fired units operating in Virginia in 2012 was 10,295 Btu/kWh.

An increase in thermal efficiency of one percentage point—for example, from 33 percent to 34 percent—will reduce plant heat rate by approximately 300 Btu/kWh.

Efficiency and Unit Operation

The efficiency of a generating unit depends on how it is operated, how components wear and are maintained over time, and the specific features at the site. The thermal efficiency of generating power from fossil fuel plants degrades with time. Component wear is inevitable—critical tolerances between key components, such as the blades of a steam turbine, increase, while the mechanical grinding elements within coal pulverizers that affect the distribution of pulverized coal within the boiler, or deposits on heat transfer surfaces, restrict the removal of heat.

Equally important is how a plant is operated over a 24-hour period. Units originally designed for base load operation—that is, relatively constant load over a 24-hour period - now routinely “cycle” or shift between very low and high load. Boiler and environmental control system design is optimized for constant fuel properties—but these properties change with time. Maintenance periods have been extended so that 3 years or more can elapse between major service intervals.

Site-Specific Results

Most notably, the applicability and benefit of any given efficiency-improving measure at a power plant is site specific. The initial design and condition of a plant, age, the source and characteristics of coal, environmental requirements, and maintenance practices determine the applicability and payoff. The improvements and payback described in this section are only examples, and for many actions the benefits are not additive.

Regulatory factors complicate decisions to pursue efficiency-improving projects. Under certain conditions the increased utilization of a generating plant as a consequence of efficiency improvement measures could prompt state and federal regulators to designate the work as a “major modification,” requiring New Source Review.

Categories of Thermal Efficiency-Improving Options

The potential options available to improve thermal efficiency can be considered in seven categories defined by the aspect of the plant affected. These categories are (1) fuel type and fuel processing, (2) boiler and steam conditions, (3) process controls which instruct the various components how to operate during both steady-state and load-change conditions, (4) options for low temperature heat recovery, (5) auxiliary power consumption and thermal losses, (6) steam path for energy extraction, defined by the design of the steam turbine and the related components, and (7) the cooling system, to maximize heat rejection and thus maximize plant net thermal efficiency.

Approximate estimates of the cost to deploy these options, and their payoffs, are presented for a sampling of options in Table 3-1 and Table 3-2, and additional descriptions of these actions follow.

Table 3-1: Summary of Cost, Heat Rate Payoff, and Capacity Payoff for Steam Boiler Improvement Options

Action	Capital Cost, $M (annual fixed O&M)	Heat Rate Improvement (Btu/kWh)	Plant Generating Efficiency Improvement (percent)	Comment
Fuel Type, Fuel Processing				
Coal Switch: Subbituminous to bituminous	Wide range based on unit design	-	Up to 1.6 (for switch from subbituminous to bituminous)	Not broadly applicable in VA as bituminous coal typically used
Coal Drying	Not reported in literature	300	0.5	Based on reduction from 10 to 5percent H_2O
Coal Processing	Not addressed for pilot plant or commercial equipment	TBD	TBD	Work limited to pilot-scale tests (NCC, 2014)
Boiler Combustion and Heat Absorption				
Advanced Process Controls	0.75 (50K)	30-100	0.1-0.33	Source: (S&L, 2009)
Improve Existing Surface Use	1-5	50	0.17	Confidential data: plant owners
Intelligent Surface Cleaning	0.5 (50K)	30-90	0.10-0.30	Source: (S&L, 2009)
Air Heater				75K O&M
- leakage control	0.6-0.7 (75K)	10-40	0.03-0.13	Control of air intrusion
- acid dew point control	2.5-10 (500K-925K)	50-120	0.16-0.40	Requires injecting alkali sorbent

Fuel Type and Fuel Processing

The composition of the fuel burned affects the thermal efficiency of power generation in numerous ways. Emissions of CO_2 are in direct proportion to the carbon and moisture content of the fuel, the former providing the carbon for CO_2 and the latter a factor in establishing boiler and generation thermal efficiency. Three means to alter coal characteristics exist: switch coals, dry the coal, or process the coal.

Coal Switching

Coal-fired units in Virginia exclusively utilize bituminous coals; however, the moisture content and fuel characteristics of coals from bituminous mines can vary. It is important to emphasize that fuel choice is dictated by numerous variables (e.g. price, availability, boiler design and environmental controls) so changing coal rank may not be practical.

Of particular note is Dominion's Virginia City Hybrid Energy Center (VCHEC), a 585 MW nameplate capacity station located in Wise County, which not only utilizes bituminous coal but also biomass fuels and low heat content coals, including "gob" or waste coal which would otherwise be permanently disposed of in refuse piles. The environmental benefits of utilizing such biomass and coal refuse are numerous, but contribute to an overall lower thermal efficiency.

Coal Quality Improvement

Lowering the moisture or ash content of coal increases thermal efficiency and lowers the amount of CO_2 emitted per unit of useful power generated. Investigations by Couch (2000) indicate that more than 4,000 coal-fired boilers (>50 MW capacity) worldwide could improve thermal efficiencies and reduce CO_2 emissions by improving feedstock qualities. According to a recent congressional study, increasing the average efficiency of coal-fired power stations from 32.5

percent to 36.0 percent could reduce total U.S. greenhouse emissions by 2.5 percent (Campbell, 2013).

Coal Drying

One method of improving power station efficiency is to remove unwanted moisture from coal prior to combustion. For example, the Great River Energy (550 MW) power station in North Dakota increased thermal efficiency by 2.6-2.8 percent by removing 6 percent of the fuel moisture from a lignite coal feedstock (Bullinger et al., 2002). While the moisture contents of coals supplied to Virginia power stations are already relatively low (e.g., less than 8-10 percent), the utilization of on-site waste heat for pre-combustion drying could still provide modest improvements in boiler efficiencies. While a detailed investigation of the projected costs and benefits of this approach for Virginia's power stations has not been conducted, estimates suggest that a 1 percentage point reduction in fuel moisture will provide approximately 0.15 percentage point increase in thermal efficiency (Zhang, 2013).

Coal Cleaning

Another method of improving power station efficiency is to remove solid impurities (mineral matter) from the coal prior to combustion using low-coal physical separation processes (Harrison et al., 1995). Higher quality coals are more reactive and require less excess air for effective combustion, thereby improving efficiency via a reduction in heat lost with the flue gas. Higher quality coals also improve efficiency by avoiding fouling/slagging problems in the boiler, which tend to raise the flue gas temperature and increase heat losses (Skorupska, 1993). The extent to which the proper application of coal "cleaning" improves thermal efficiency is highly case specific and difficult to predict from theoretical considerations. One classic study (Smith, 1988), which monitored boiler efficiency during a switch from 15 percent to 9 percent ash coal, showed a 1.5 percentage point increase in boiler efficiency due to improved fuel quality. Unfortunately, coal cleaning involves a trade-off between the quality and the quantity of saleable coal from mine sites. As such, the demand for higher quality coals will result in higher fuel costs for utilities. In-house estimates indicate that a 1 percentage point “across-the-board” reduction in ash content would likely increase fuel costs by $3-5 per dry ton, depending on the source of the coal feedstock (Bethell, 2013).

Process Instrumentation and Controls

A state-of-the-art power station is comprised of hundreds of components whose minute-by-minute operating states determine plant performance. Using advanced software and instrumentation—known as intelligent or “neural network” concepts—can provide significant payoff in plant efficiency.

These benefits can only be derived with a digital control system, requiring the plant’s legacy control system to be completely replaced. The capital charge for advanced process instrumentation and control systems—assuming an upgrade to digital controls is not required—typically ranges from $0.50 to $0.75 million. An upgrade to a digital control system would incur a minimum cost of at least several million dollars.

The payoff of implementing process instrumentation and controls varies widely depending on the details at the plant. Typically the payback is limited to less than 0.1 percent plant efficiency improvement. The extent of their applicability in Virginia is unknown.

Boiler and Steam Conditions

High steam pressures and temperatures, assuming all other variables are equal, increase generation efficiency. At present, there are no practical retrofit options to increase the steam pressure and temperature from existing units, although some changes could restore boiler performance to original design levels. These are discussed below.

Maximize Utilization of Existing Surface, or Add Surface

The effectiveness of boiler heat transfer surfaces can sometimes be improved. Repairing or replacing failed or excessively fouled surfaces may restore boiler thermal efficiency to near-original design values. Table 3-1 presents an example of the possible benefits in thermal efficiency. Adding surface is an option only if operating experience shows that the boiler is equipped with less surface than can actually be utilized.

Changes to the boiler heat absorbing surfaces is a possibility for Virginia units, but such work historically has been designated by the EPA as qualifying a unit as “reconstructed” and subject to stricter environmental limits. Any changes may simply serve to restore the boiler heat absorption and thermal efficiency to original “new unit” values.

Intelligent Surface Cleaning with Intelligent Sootblowing

Boiler surfaces should be consistently and thoroughly cleaned to improve heat capture. Using so-called “intelligent” sootblowers that are activated only when needed, and operate for the correct duration, maintains clean surfaces with minimal auxiliary power.

As noted in Table 3-1, intelligent surface cleaning can elevate generation efficiency by up to 0.3 percent. Thermal efficiency improvements of 0.2 percent are possible for a capital cost of approximately $0.5 million for a 500 MW plant (S&L, 2009). One study claims that the benefits of optimizing the combustion process with intelligent controls and the use of intelligent surface cleaning can increase thermal efficiency by 0.33 to 0.66 percent (Lehigh, 2009).

Air Heater Performance

The air heater represents the last heat exchanger to collect heat from the boiler prior to gas entering the environmental control system. Replacing air heater seals to reduce leakage presents an additional opportunity to reduce heat losses. Controlling duct leakage and increasing the surface area within an existing air heater will elevate generation efficiency by 0.03 to 0.13 percent, for a capital cost of $0.6-0.7 million for a 500 MW plant. These benefits are temporal in that this expenditure must be incurred on a periodic basis.

Injecting an alkali sorbent to lower flue gas concentration of SO_3 and offset the potentially damaging role of acid condensation could enable greater heat removal from an air heater. Virginia–based units fire bituminous coal and theoretically could benefit from this approach; however, experience injecting alkali sorbent preceding the air heater is limited, and questions remain regarding the survival of air heater surfaces and the accumulation of sulfate-based salts. Table 3-1 reports one estimate that deploying alkali-based sorbent injection and replacing air heater surfaces could theoretically increase efficiency by up to 0.4 percent, for a capital cost between $2.5 and $10 million.

In summary, improving boiler steam conditions to increase heat removal by restoring, improving, or optimizing the cleaning of boiler surfaces is possible, but the applicability to any given unit is unknown.

Steam Path Changes

Changes to the steam path—most importantly the steam turbine—can significantly improve power plant efficiency. These changes, which have already been implemented on many units, include a complete replacement of rotors and inner casings, or upgrades of high-payoff components. Table 3-2 summarizes the range in cost incurred and payoff derived for options that are commercially available. For some units turbine efficiency gains can be achieved by installing improved or new control valves or seals and the use of innovations such as partial arc admission for steam control valves, the latter enabling unit turndown with reduced loss of efficiency.

Many plant owners have already deployed these changes, which in many cases restore the generating efficiency to initial design values. Some actions can improve thermal efficiency beyond the initial design but these are limited in payoff.

The last component in the steam path, the turbine condenser, is equally important. This final heat exchanger is typically cooled by water withdrawn (and returned to) a body of water (such as a river or lake), or by mechanical or natural draft towers. Increasing the amount of heat removed from the condensed steam is potentially a means to increase plant generating thermal efficiency.

Table 3-2: Summary of Cost, Heat Rate Payoff, and Capacity Payoff for Steam Turbine Improvement Options

Action	**Capital Cost, $M *(annual fixed O&M)***	**Heat Rate Improvement (Btu/kWh)**	**Plant Generating Efficiency Improvement (percent)**	**Capacity Increase (percent)/ Comment**
Steam Turbine (General)				
Increase H_2 Purity	0.25	10	0.03	.10
Partial Arc Admission	1	50	0.17	N/A
Replace Control Valves	?	4	0.01	N/A
High Pressure Turbine				
HP Steam Seal upgrade	1	50	0.17	0.75
HP Steam Path Upgrade	6	95-135		1.5
Intermediate Pressure Turbine				
IP Steam Seal upgrade	1	20	0.10	0.50
IP Steam Path Upgrade	5	50-100	0.17-033	0.70
Low Pressure Turbine				
LP Steam Seal upgrade	0.75	120	0.40	0.30
LP Steam Path Upgrade	5	65-225	0.22-0.75	0.65
Cooling system				
Replace cooling tower “pack or fill	3 (125K)	0-70	0-0.25	N/A

Low Temperature Heat Recovery

Using available heat that is designated as "low" temperature (generally considered less than 300 F) historically has been challenging for increasing generating thermal efficiency. The key barriers have been cost and reliability, because heat exchangers of sufficient size to provide reasonable payback incur a high capital cost, and can suffer corrosion from exposure to condensed moisture and SO_3.

Preheating boiler feed water is one option to recover low temperature heat. Increasing the number of feedwater heating steps is possible but requires an array of upgrades for additional heat exchangers and boiler feedwater pumps. Another means to increase boiler feedwater preheating is expanding the economizer section. A second option is recovering low quality heat in the flue gas exiting the particulate collector prior to the FGD. The practicality of this action is limited by heat exchanger and construction materials costs.

Minimizing Auxiliary Power Consumption

The net plant thermal efficiency is directly affected by the consumption of auxiliary power, most of which is used to drive motors that move boiler water, air or combustion products, or other media within a power plant. Variable speed drives (VSD) can minimize power consumption at lower load for inducted draft and forced draft gas fans, circulating water pumps, coal pulverizers, flue gas desulfurization alkali slurry pumps, cooling tower fans, and other major power-consuming motors.

The cost for variable speed drives ranges from $9-11 million for a 500 MW plant, with the range of net thermal efficiency increasing by 0.05-0.50 percent. The wide range in improvement is due to the uncertain baseline of the as-found equipment (S&L, 2009). Depending on the unit, the gas path could be streamlined reducing power consumption by fans by as much as 15-25 percent. Reducing air infiltration into the ductwork, where applicable, minimizes heat losses and can improve plant generating efficiency by up to 0.05 percent. These measures deliver only modest payoff but move in the right direction.

Cooling System Effectiveness

Power stations typically employ cooling systems referred to as once-through (as described previously) or recirculating, the latter typically a wet cooling tower. Improving the performance of once-through cooling systems requires maintenance to clean surfaces exposed to the cooling water, which can be fouled from accumulation of biological materials. Maintaining a clean condenser surface is essential.

Recirculating cooling systems (cooling towers) reject the most heat when the cooling water within the tower is effectively utilized, most notably by the material within the tower that promotes evaporative cooling. Replacing this so-called “pack” with improved materials increases thermal efficiency of generation by up to 0.26 percent. These benefits are greatest in the summer months. The cost to replace the pack can range from $1.5 to 3 million for a 500 MW plant.

Environmental considerations pertaining to water usage have prompted energy producers to consider air cooled systems, which are inherently less efficient. The VCHEC utilizes one of the largest such air-cooled condensers in the world which, although it reduces water consumption, does penalize plant heat rate. It is unlikely that the efficiency of the VCHEC cooling system can be enhanced with any of the previously stated improvements.

Discussion

In many cases the payoff for many of the efficiency improvements discussed in this section are cumulative—such as those minimizing auxiliary power and improving heat rejection. The benefits from other actions, such as economizer modifications, improved air heater performance and low temperature heat recovery, will not be cumulative, because the same low quality heat can only be captured once. All efficiency-improving measures are unit and site-specific and will not always be technically or economically feasible.

A detailed analysis would be required to assess the benefits of multiple actions, as well as their compatibility with New Source Review regulations. A recent discussion of the types of possible improvements estimated that reductions in heat rate (and thereby CO_2 emissions) of 1 to 4 percent are possible outcomes from existing inventory (Gaikwad, 2010). It is not clear how many projects in Virginia would achieve reductions in the range of 1 to 4 percent without a detailed, site-specific analysis.

In summary, efficiency-improving measures are commercially available for use with the existing coal-fired fleet; however, the benefits and costs are highly variable and depend on facility-specific characteristics. Some of these measures may have been already applied on units in the inventory. Steam turbine upgrades (such as rotor replacements) provide some of the highest payoff actions but are frequently deployed as standard practice. Improving heat rejection through the condenser, as aided by design changes to cooling towers or once-though cooling systems, is also possible. Improved materials may reduce fouling of condenser surfaces and thus improve performance, while improved cooling tower designs and materials may increase heat rejection. Low-temperature heat recovery shows promise, but uncertainties presently exist because of the potential for damage from material corrosion. Deployment of the most significant improvements in efficiency may be deterred by concern that equipment changes will be deemed a “major modification” under New Source Review (NSR). The addition of NSR-mandated environmental controls would reduce and perhaps offset any gains in efficiency.

Carbon Capture, Utilization and Storage Technology Assessment

Carbon capture, utilization and storage (CCUS) technologies offer the most promising means of controlling CO_2 emissions while retaining fossil fuels in the power generation portfolio. These technologies, however, are currently cost prohibitive and have yet to be implemented on a commercial scale in the power generating industry. To address this issue, a diverse range of research, development, and demonstration (RD&D) projects are currently underway to overcome the technical, economic, policy, and public acceptance challenges presented by wide-spread commercial deployment of CCUS.

Historically, Virginia power companies have been able to successfully implement environmental control technologies, such as flue gas desulfurization (FGD) to reduce the emissions of SO_2 and selective catalytic reduction (SCR) to reduce NO_x emissions, following a step-by-step development and demonstration process. A similar approach is vital to the successful implementation of CCUS, because of the extensive cost and large quantities of CO_2 that must be managed following capture.

CCUS encompasses the numerous pathways to reduce the emission of CO_2 into the atmosphere by removing CO_2 during power generation (capture) and redirecting it to markets as a sellable product (utilization) or injecting into secure, underground reservoirs for permanent storage. It is essentially, a three-step process that includes:

- Capture of CO_2 from the source (power plants or industrial facilities)
- Transport of the captured and compressed CO_2 (usually in pipelines). Already, approximately 50 million tonnes of CO_2 are transported each year in the US through 3,600 miles of existing pipeline.

- Underground injection and geologic sequestration (also referred to as storage) of the CO_2 in suitable rock formations, mainly deep saline formations and oil and gas reservoirs. These reservoir formations are capable of safely storing the CO_2 and are also overlain by layers of rock with very little permeability or porosity that trap the CO_2 and prevent it from migrating upward.

Underground CO_2 injection can also stimulate the recovery of residual oil or gas in the host reservoir and thus allow additional amounts to be recovered, a process known as Enhanced Oil Recovery (EOR) or Enhanced Gas Recovery (EGR). This ***utilization*** of CO_2 to recover additional resources and maximize well production has created a significant market for CO_2, as the off-take value of this gas can help defray the overall cost of CCS. Other potential beneficial uses for CO_2 are also receiving increased attention. In this context, Carbon Capture, Utilization and Storage (CCUS) is the most attractive option for successful commercial deployment.

Technology Development Paths

The CCUS program (US DOE, 2013) is addressing three categories of research components, 1st Generation Technologies, 2nd Generation Technologies, and 3rd Generation or Transformational Technologies defined as follows:

- **1st-Generation Technologies**—include technology components that are being demonstrated or that are commercially available.
- **2nd-Generation Technologies**—include technology components currently in R&D that will be ready for demonstration in the 2020–2025 timeframe.
- **Transformational Technologies**—include technology components that are in the early stage of development or are conceptual that offer the potential for improvements in cost and performance beyond those expected from 2nd- Generation technologies.

In order to ensure a reasonable probability of success in developing 2nd and 3rd Generation or Transformational Technologies, a relatively large portfolio of laboratory/bench scale studies is necessary because of the risk of failure at the early stages.

In addition to technology development process, a Technology Readiness Level (TRL) is also used as an assessment of technology progress on the path to commercialization. For this reason, 2nd generation technologies are typically in a higher TRL category than transformational technologies, because they are closer to commercial deployment.

Status of CO_2 Capture

Carbon capture from fossil fuel-based power plants involves the separation of CO_2 from flue gas or syngas. Capture of CO_2 from industrial gas streams has occurred since the 1930s using a variety of approaches to separate CO_2 from other gases. Commercially available CO_2 capture technologies are currently being used in various industrial applications, including the natural gas industry, and in the production of food and chemical-grade CO_2; however, in their current state of development, these technologies are not ready for implementation on coal-based power plants because they have not been demonstrated at appropriate scale. Capture in this case requires approximately one-third of the plant's steam and power to operate, operational issues of capture unit integration are not resolved and neither is the practical issue of available real estate to build a capture facility close to a plant (US DOE, 2014).

Though CCS technologies exist, scaling up processes and integrating them with coal-based power generation poses technical, economic, and regulatory challenges. In the electricity sector, estimates of the incremental costs of new coal-fired plants with CCS relative to new conventional coal-fired plants typically range from \$60 to \$95 per tonne of CO_2 avoided (US EPA, 2010). Approximately 70–90 percent of that cost is associated with capture and compression. Some of this cost could be offset by the use of CO_2 for EOR/EGR for which there is an existing market, but such options may not be available for every project, depending on location.

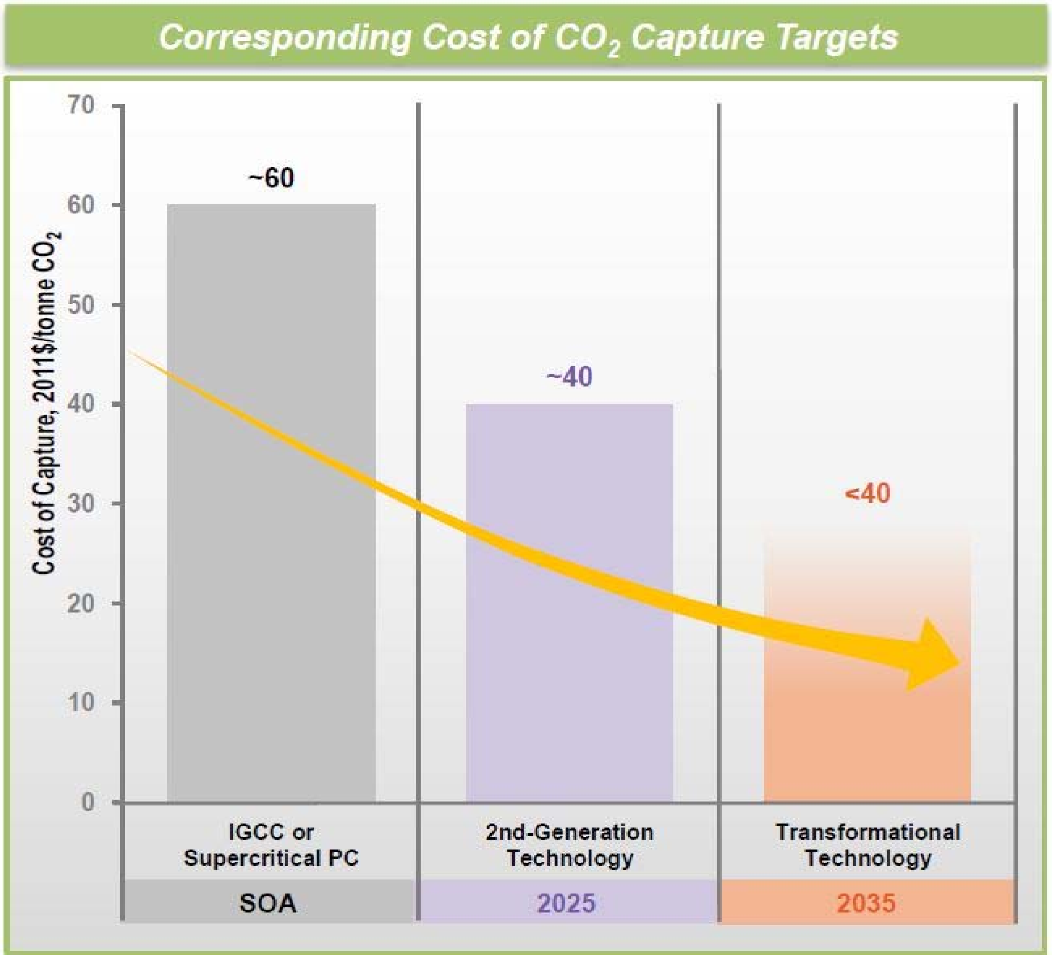
The main approaches pursued for separating CO_2 can be organized into three categories.

1. **Post-combustion**, where CO_2 is removed from fossil-fuel combustion products. Primarily applicable to conventional pulverized coal-fired plants (PC)
2. **Pre-combustion**, where solid fuel (coal) is converted into syngas during coal gasification enabling carbon to be captured before combustion occurs; applicable to Integrated Gasification Combustion Cycle (IGCC) power plants
3. **Oxy-combustion**, where combustion occurs in an oxygen rich atmosphere

Any of these technologies can be applied to new plants, however, post-combustion and oxy-combustion are the main technologies for retrofitting existing units.

According to DOE, 1st Generation Technologies (those tested at present on large-pilot or commercial-scale equipment) require up to 35 percent of the plant's output and can reduce CO_2 at a coat of \$70-90/ton. In contrast, 2nd Generation Technologies, which at present are tested in small-scale environments, can potentially reduce CO_2 at a rate of \$40-50/ton when operating at full scale. For these processes, the commercialization target is in the late 2020s. The timeline of the commercialization path is shown in Figure 3-2.

Figure 3-2: CCS Research Timeline (Source: NETL/DOE)



Status of CO_2 Storage

Carbon sequestration in geologic formations mainly includes saline aquifers, oil and gas reservoirs, and unmineable coal seams. These formations may have stored hydrocarbons, such as oil or natural gas, brine water and/or naturally-occurring CO_2 for millions of years. The injection of CO_2 in a hydrocarbon-bearing reservoir offers the opportunity to enhance the recovery of the hydrocarbons, including oil (EOR) and natural gas (EGR) for commercial use that could off-set the cost of carbon capture and storage.

Carbon storage mechanisms (CO_2 Capture Project, 2014) vary by geologic formations and there are generally multiple processes which may improve storage over time. The primary trapping mechanisms include: physical trapping, residual phase trapping, solubility trapping, and mineral trapping (Benson, LBNL, and US DOE, 2014). An additional mechanism for storage unique to organic rich rocks, like coal or shale, is an adsorption phenomenon, where CO_2 can adsorb on the micropores within a complex matrix. This adsorption process can also unlock large quantities of hydrocarbons that are already adsorbed in the same micropores because the affinity of CO_2 to adsorb is greater.

The US Department of Energy has developed a carbon storage program that focuses on core RD&D for geologic storage technologies; risk assessment; monitoring, verification and accounting (MVA); and infrastructure development through small- and large-scale testing programs. The goals for an effective MVA program include improved understanding of injection and storage processes, evaluation of interactions among CO_2, reservoir fluids, and formation solids, assessment and minimization of environmental impacts, and ensuring that CO_2 storage is “safe, effective, and permanent in all types of geologic formations” (DOE, 2012).

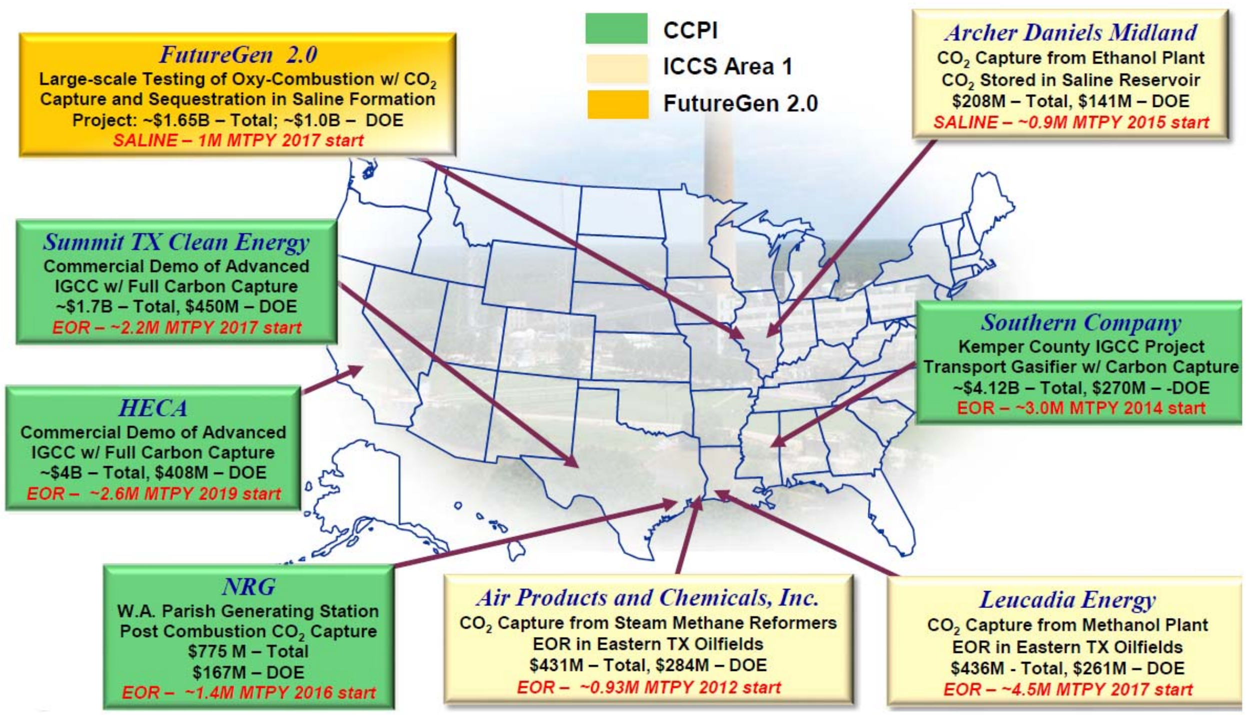
CCUS Demonstration and Pilot Tests

Demonstration and pilot tests of CCUS can be divided into three categories, integrated projects CCS/CCUS projects, large-scale CO_2 storage projects, and small-scale CO_2 storage projects.

Integrated CCS/CCUS Projects

The major CCUS demonstration projects in the US are shown in Figure 3-3 (from NETL). All of these projects have received significant federal support. They include three industrial application projects and five power generation projects. Enhanced oil recovery (EOR) is a key component for these projects to partially offset the cost of the CCUS.

Figure 3-3: Major CCUS Demonstration Projects in the US (Source: NETL)



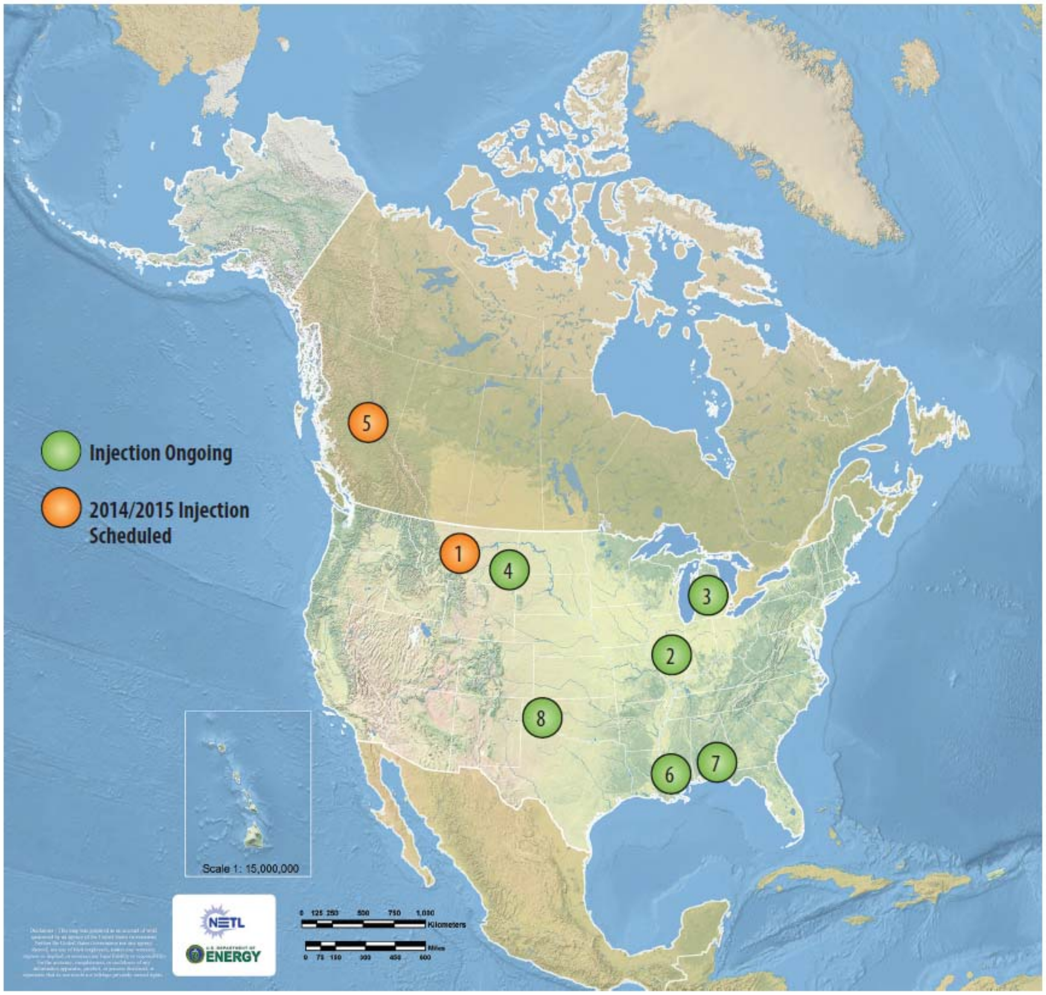
Two North American CCUS projects nearing operation are particularly important because they are the first such projects to be developed at large-scale in the power sector:

- The Boundary Dam Integrated Carbon Capture and Sequestration Demonstration Project in Canada is currently in trial-test mode and expects to begin operations in the fall of 2014.
- The Southern Company's Kemper County IGCC Project in Mississippi is expected to be in operation before the end of 2014.

Large-Scale CO_2 Storage Tests

The US DOE considers large-scale CO_2 storage tests to be those involving injection of greater than 500,000 metric tons per year. There are eight ongoing large-scale CO_2 storage tests funded by the US DOE, including two in the southeast as part of the Southeast Carbon Sequestration Partnership (SECARB), as shown in Figure 3-4.

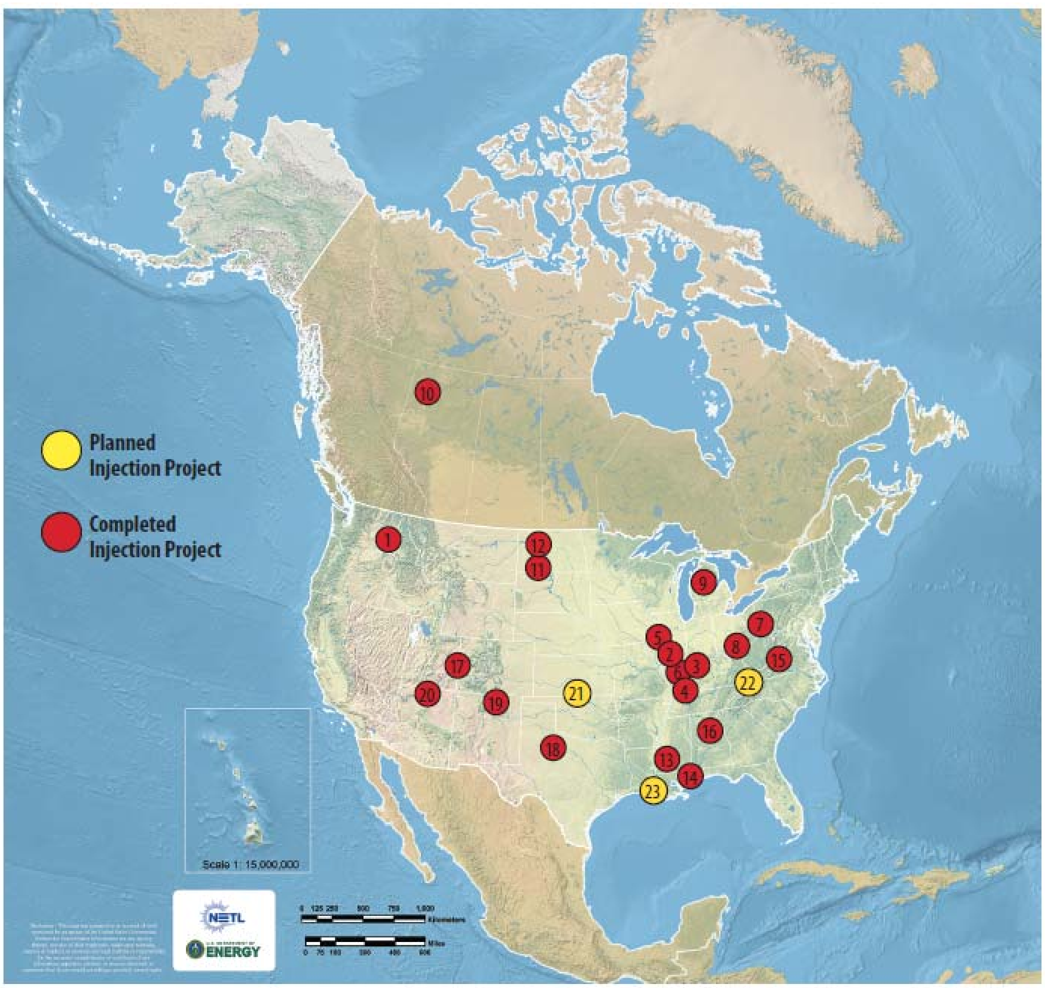
Figure 3-4: Large-Scale CO_2 Storage Tests in the US (Source: NETL)



Small-Scale CO_2 Storage Tests

DOE considers small-scale CO_2 storage tests as those that involve the injection of less than 500,000 metric-tons per year. There have been 20 completed small-scale federally funded projects, with an additional three in the implementation stage (Figure 3-5). SECARB, in conjunction with Virginia Tech researchers, completed a successful small-scale injection project in Russell County, Virginia (#15). Project #22 is an active Virginia Tech-led effort, where two field sites, one in Buchanan County, Virginia, and the other in Morgan County, Tennessee, are utilized for the injection of 20,000 metric tons of CO_2 to test the ability of coal seams and shale gas reservoirs to store CO_2 and enhance gas recovery.

Figure 3-5: Small-Scale CO_2 Storage Tests in North America (Source: NETL)



CCUS in VA

Virginia has been very active in CCUS research, including field tests, primarily through the work of the Virginia Center for Coal and Energy Research (VCCER) at Virginia Tech.

The work completed to date in Virginia has shown that in addition to providing a promising technology for managing CO_2, developing CCUS compatible infrastructure can result in significant long term benefits for Virginia. Such opportunities extend to both western and eastern Virginia. CCUS infrastructure, including retrofitted and newly constructed CCUS-enabled power generating stations (or other industrial facilities), pipelines, compressor stations, and the development of storage facilities, presents an enormous investment that can enable Virginia to retain its existing fleet of coal-fired generating stations. The investment in infrastructure also would enable a value-added utilization of captured CO_2 by facilitating enhanced resource recovery, extending the lifespan of existing gas wells, and reducing the growth of the surface footprint in gas fields.

The development of off-shore oil and gas can be a significant new energy opportunity for Virginia and can enable CCUS with enhanced oil and gas recovery. One step towards this is Governor Terry McAuliffe's action in joining the Outer Continental Shelf Governors Coalition (OCS) on February 24, 2014. Formed in 2011, the OCS consists of coastal state governors who support policies that encourage an expansion of domestic energy, particularly US offshore energy resources (ocsgovernors.org).

Offshore utilization and storage of carbon dioxide (CO_2) in secure geological strata has significant potential for development and offers an attractive alternative to onshore use and storage. Unlike the traditional oil and gas model in which onshore resources were developed long before offshore CCUS opportunities were explored, offshore utilization and geologic storage of CO_2 could be pursued simultaneously. In the case of the offshore areas of the Mid-Atlantic, there is no existing oil and gas infrastructure, so the opportunity exists to include consideration of CCUS during the planning and development stages.

Discussion

There are a number of issues and barriers that must be overcome prior to implementing CCUS at the commercial scale. These issues include technology gaps, funding required for large-scale demonstration testing, legal impediments (e.g. subsurface property rights and long-term liability), public awareness and acceptance, regulatory uncertainty, and a lack of policies and incentives for promoting CCUS commercial deployment. A number of these issues have been resolved in some states and this experience could provide useful examples for charting a path toward a CCUS infrastructure in Virginia. It is also imperative that the public accepts the technology and understands the benefits and risks involved. This will be facilitated by successful and safe large-scale demonstration projects in different regions of the country.

CCUS technology is emerging as a viable option for reducing CO_2 emissions at greenfield power plants, where the requirements for CCUS deployment can be accommodated in the planning phases. Using CCUS technologies to reduce CO_2 emissions from existing power plants, as has been suggested to meet the proposed EPA regulations, would however be difficult because of the challenges involved in retrofitting established facilities. Complications, such as integration with unit operations, reduced design and operational flexibility, fixed locations, and limits on available space, make deployment an unattractive and often uneconomic and/or unrealistic option for many existing plants.

Pursuing the commercial development of CCUS technologies requires continued investment in RD&D and deployment of the best technologies in the field in order to reduce the cost of CCUS. It is imperative that there be integrated full-scale demonstration projects at existing power plants to prove capture technologies and reduce their cost. Once the near-term technologies have been proven on existing plants, they are likely to be implemented at new fossil fuel-fired power plants where the full design of the plant can include CCUS. Virginia should encourage and facilitate the participation of the research community and the private sector in the state in the development of these technologies.

If CCUS is to become a viable technology, then a focused and aggressive effort to overcome the technical, financial, regulatory, and legal barriers must be made by industry, regulators, and technology developers. Recent reports by the National Coal Council, (NCC, 2008 and 2011) as well as the report by the Interagency Task Force on Carbon Capture and Storage, (IATFCCS, 2010) recommended 5-10 MW of commercial scale CCUS demonstrations, and others have suggested that 50 to 100 MW would be needed to prove the technology. Virginia could be a national center for emerging CCUS infrastructure and industry, achieving the state's greenhouse gas reduction goals while simultaneously creating jobs and economic development opportunities for the Commonwealth.

Energy Efficiency Technology

The ability to provide an existing service—of equal and perhaps of greater quality—with reduced electrical power consumption is the basic tenet of energy efficiency. There are various categories of energy efficiency, with demand-side management the best evaluated and broadly deployed.

The Virginia economy can benefit from energy efficiency in many ways. There are a broad array of services, improved methodologies, and improved components which can help all sectors satisfy their energy needs while providing for lower energy usage and lower energy generation.

Means of Improving Energy Efficiency

The means that could be deployed to effect energy efficiency can be categorized by sector: residential, commercial, or industrial. Within each of these sectors are various steps to pursue improving energy efficiency, a sampling of which are described below.

Secure Building Envelope. Any structure—whether residential or commercial—is characterized by a “building envelope,” defined by the external walls, windows, roof, and floor. A basic step in improving energy efficiency is to tighten or secure the envelope to minimize loss of conditioned or heated air into the ambient environment.

The HVAC system provides the heating, cooling, and ventilation in a commercial or residential building. Heating systems are comprised of boilers, furnaces, heat pumps while cooling is provided by air conditioners or heat pumps. The efficiency of electrical use by these systems is key to driving conservation. State-of-art HVAC systems employ the most efficient drive motors and compressors. The use of heat pumps will conserve natural gas for heating, but could increase electrical use due to the need for electrical drive motors.

Cooking and Cleaning. Opportunities for electrical savings in food preparation exist, primarily through selection of energy efficient appliances and improved food preparation practices. Similarly, the use of energy efficient cleaning appliances, such as washers, dryers, and dishwashers, can reduce the electrical demand in both commercial and residential sectors.

Refrigeration. Almost without exception every residence has a refrigerator—and 20 percent of these residences own at least two. Stand-alone freezers are used in 35 percent of residences. The key devices—126 million refrigerators and 38 million freezers in the US operate around the clock and are often the largest power consuming devices in a home. In the commercial sector, refrigeration accounts for about 10 percent of power consumed. Devices such as; commercial refrigerators and freezers, ice makers, water coolers, and beverage vending machines can either be replaced with more efficient models or be used and installed in more efficient ways. These appliances are numerous in office buildings and certain service industries such as hospitals.

Electric Drive Motors in Industrial Applications. Industrial applications comprise a large component of power consumption. The domestic manufacturing sector employs a broad array of power consuming equipment—all driven by electric motors, which consume more power than any other device or application in the US. Some estimates cite that 60 percent of the power generation output is used to drive motors. Analysis suggests that 15-20 percent savings can be achieved by optimizing the performance of motors and wiring, power conditioning, controls, and power transmission.

Deploying Energy Efficiency Steps

There are numerous efforts sponsored by government and utility companies to encourage energy efficiency practices. Almost without exception, deploying energy efficiency requires a capital outlay and/or an outage or loss of the specific service in return for lower power consumption and eventual cost savings. In most cases, the capital outlay necessary for deploying the energy efficiency steps would require a significant payback period before savings are realized. Adoption of energy efficiency could be accelerated if a third-party such as the utility or governing agency provides incentives for energy efficiency actions.

Energy efficiency programs typically employ financial incentives such as rebates or loans, technical services such as energy audits and retrofit of equipment, and campaigns to educate consumers. The details of how utility and governing agencies can provide incentives are beyond the scope of this discussion; however they have been published by the American Council for an Energy Efficient Economy (ACEEE, 2013 and Nowak, 2013)

Payoff

The payoff from energy efficiency programs varies widely, with exemplary programs demonstrating significant benefits. The payoff of an energy efficiency program is typically gauged by three metrics: the technical potential that can be achieved; the economic potential (i.e., the projects that economically make sense), and a maximum achievable potential (i.e., the projects that realistically can be deployed). Several investigators have determined the technical potential to range between 2.3 and 4.1 percent; the economic potential to range between 1.8 and 2.7 percent; and the potentially achievable savings to range from 1.2 and 1.5 percent (Eldridge et al., 2008 and Sreedharan, 2013). Other investigators have found results both below and above the ranges cited.

The payoff in terms of cost savings also varies widely. A recent comprehensive survey conducted by ACEEE addressed the programs in 20 states and concluded that the levelized cost of electricity (LCOE) savings varied between 1.3 -3.3 cents/kWh, averaging 2.6 cents/kWh.

Section 4. Virginia Electricity Generation

It is important to discuss Virginia's generation mix in 2012 and to highlight planned power plant retirements and new generating capacity additions expected before 2020. The year 2012 is used by the EPA as a baseline to calculate the state's target CO_2 emission rates for existing power plants and is also used in the analysis scenario in Section 6 of this report (EPA, 2014c).

The 2012 total generation, which includes all electric energy dispatched to customers in Virginia regardless of the generating unit's physical location or status under the proposed rule, was approximately 118 MWh (Figure 4-1). Approximately 47 MWh of the total disposition was "imported" or generated outside the state, netting an in-state generation of approximately 71 MWh, depicted in Figure 4-2. However, it is worth noting that the designation of "imported" electricity is somewhat misleading, as clarified in a report by the State Corporation Commission:

> *Generally, approximately 85%-90% of the total supply of energy to Virginia's investor owned electric utility ("IOU") customers is produced from facilities under the Commission's rate setting jurisdiction even though some of those facilities are located outside the boundaries of the Commonwealth. Power from jurisdictional plants that may be physically located in another state is not considered "imported" in any relevant definition because, from legal and regulatory standpoints, Virginia consumers have the same claim on such power as they do on power from jurisdictional plants physically located in Virginia.* (VSCC, 2014)

The energy sources that contribute to the CO_2 emissions rate as calculated by the proposed EPA rule include fossil fuels, such as coal, natural gas and petroleum; renewable sources, and a portion of the nuclear generation fleet, as shown in Figure 4-1. The role of imported power is not addressed by the proposed EPA rule, regardless of the fuel source, and does not factor into emissions rate calculations. As such, the 2012 compliance generation accounts for approximately 43 MWh or 36.7% of the total generation of Virginia.

Figure 4-1: Virginia 2012 Total Generation by Source and Regulatory Status

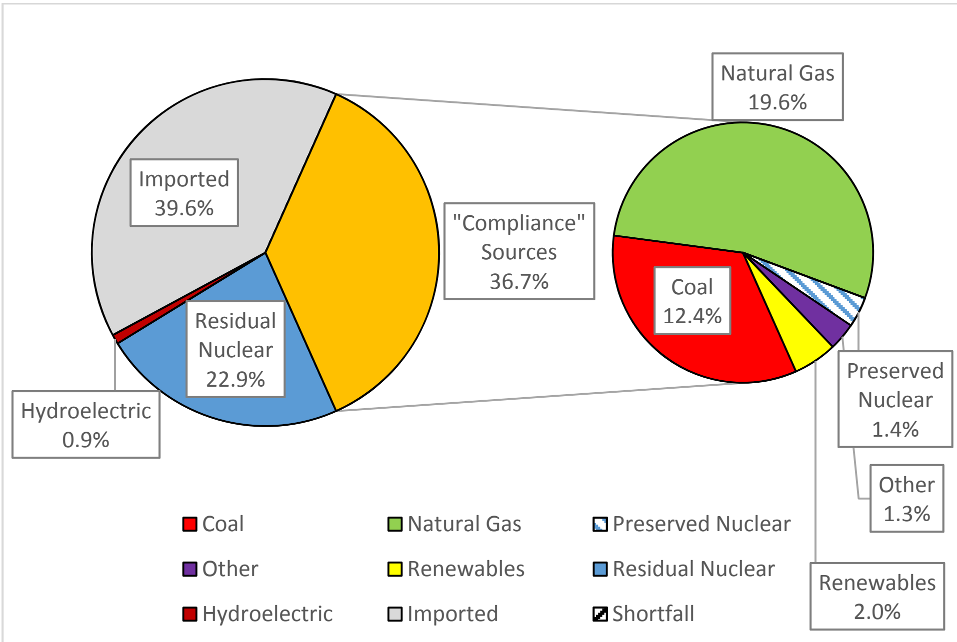
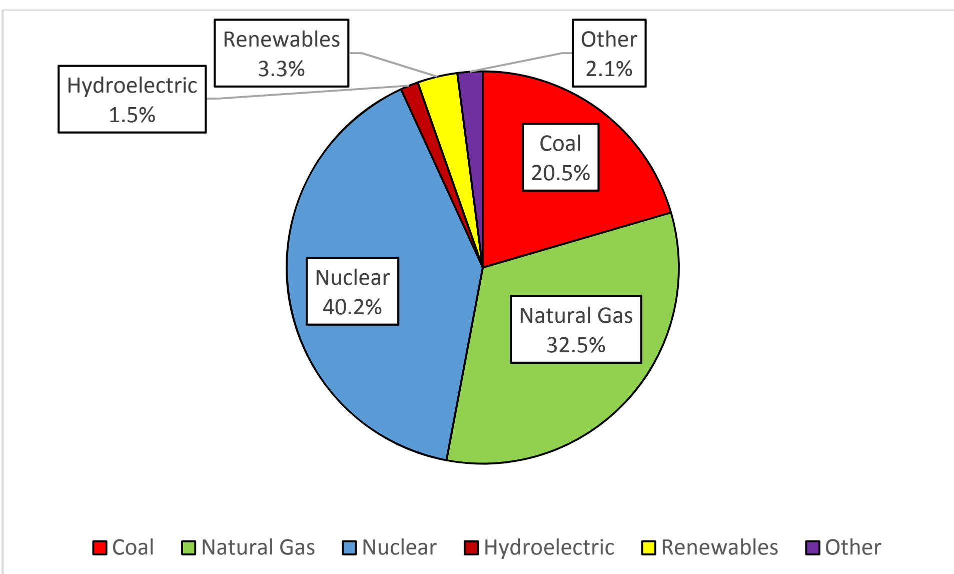
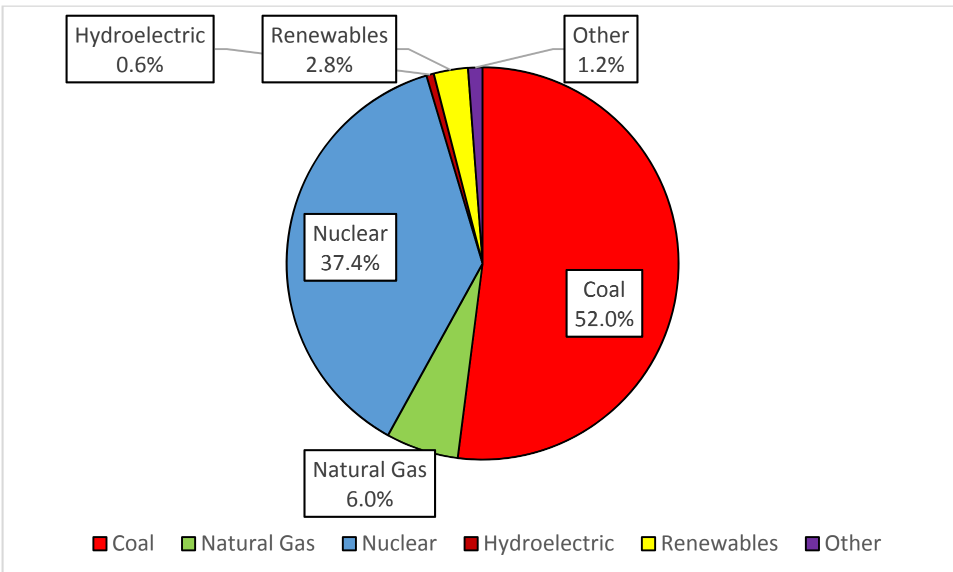


Figure 4-2: Virginia 2012 In-State Generation by Source (Source: EIA, 2014)



In 2012, fossil fuels (coal, natural gas and other hydrocarbon sources such as petroleum) comprised more than 50% of the in-state generation. However, the composition of fossil fuel sources has changed dramatically. Most notably, much of the coal generation capacity, which comprised 52% of the in state generation in 2002 has shrunk to 20.5% in 2012, while natural gas rose from 6% to 32.5% (Figure 4-2 and Figure 4-3). The switch from a coal dominated energy mix to one of greater reliance on natural gas is mostly due to a decrease in natural gas prices. This trend is likely to continue mostly due to expected favorable natural gas prices and also EPA regulations, such as CSAPR, MATS and the new proposal for reducing CO_2 emissions.

Figure 4-3: Virginia 2002 In-State Generation by Source (Source: EIA, 2014)



As Virginia moves forward in making decisions regarding the future fuel sources for its generating facilities, it is important to consider announced plant retirements and capacity additions by power generating entities within the state. This information is presented in Table 4-1 and Table 4-2 and was used for the scenarios presented in Section 6 of this report.

Table 4-1: Virginia Planned Coal Unit Retirements

State of Virginia

Planned Coal Unit Retirements as of July 2014

(as compared to 2012 base case)

	Facility Name	Unit #	MW Size	Primary Fuel
1	Chesapeake	1-4	578	coal
2	Clinch River	1-3	722	coal
3	Glen Lyn	1-2	338	coal
4	Potomac River	1-5	514	coal
5	Yorktown	1-2	323	coal
6	Bremo Bluff	3-4	227	coal
	Totals		2,702	

Table 4-2: Virginia Planned Additional Generating Capacity

Planned New Generating Capacity Additions/Conversions

(as compared to 2012 base case)

	Facility Name	Unit #	MW Size	Primary Fuel
1	Halifax Biomass	1	44	biomass
2	Covington Biomass	1	81	biomass
3	Clinch River	1	242	coal to natural gas
4	Clinch River	2	242	coal to natural gas
5	Bremo Power Sta.	3	71	coal to natural gas
6	Bremo Power Sta.	4	156	coal to natural gas
7	Warren County	1	427	natural gas
8	Warren County	2	427	natural gas
9	Warren County	3	427	natural gas
10	Brunswick County	1	433	natural gas
11	Brunswick County	2	433	natural gas
12	Brunswick County	3	433	natural gas
13	CPV Smyth	1	325	natural gas
14	CPV Smyth	2	325	natural gas
15	Stonewall Green Energy	1	430	natural gas
16	Stonewall Green Energy	2	430	natural gas
18	AltaVista	1	51	coal to biomass
19	Hopewell	1	51	coal to biomass
20	Southampton	1	51	coal to biomass
	Total		5,079	

Existing Fossil Fuel Generation

This study projects the composition of the Virginia generating portfolio to 2030. Given the continued evolution of power generation technology (with variations in the use and availability of fossil fuels and "renewable" or zero-carbon sources, the possible resurgence of nuclear power, and the potential "disruption" from energy storage and enhanced energy efficiency), it is prudent to assume an additional lifetime of not more than 20 years beyond the 2030 target date—thus 2050. However, no end date has been projected or postulated for the units projected for the portfolio in this study.

Most fossil units in the present portfolio will be able to operate effectively up to 2050. This statement assumes that owners of generating units located in Virginia are offered a safe harbor in terms of New Source Review (NSR), enabling them to invest in existing units to maintain high reliability, while not being subject to new source emission limits.

Coal-fired generation is projected to be carried by the following units (with startup dates in parentheses):

- Chesterfield Unit 6 (1969)
- Clover Units 1 (1995) and 2 (1996)
- Birchwood (1995)
- Virginia City Hybrid Energy Center (2011)

With the exception of Chesterfield 6, all of these units (given continued investment to maintain reliability and efficiency without NSR implications) should be able to operate to 2050. Chesterfield 6 is not likely to operate for an extended period, since by 2030 it will have registered a 50-year lifetime which could prohibit further investment. A detailed engineering analysis will be required to assess the condition of Chesterfield 6 prior to that time. If Chesterfield is judged not capable of effectively generating power in 2030, it is likely that the remaining coal-fired units, which started commercial service in the 1990s, can compensate, assuming there are no grid stability issues.

NGCC generation from existing units is projected to be carried by the following (with startup dates in parentheses):

- Bear Garden (2011)
- Bellmeade (1997)
- Chesterfield (1990)
- Doswell Energy Center (1991)
- Gordonsville Energy Partners (1994)
- Hopewell Cogeneration (1990)
- Possum Point (2003)
- Tenaska Virginia (2004)

The oldest of these units—Chesterfield, Hopewell, and Doswell—will be 40 years old in 2030 and will reach 60 years of life by 2050. Given the state-of-art evolution in NGCC technology it is likely these units will not continue in operation until 2050; however, significant investment in new NGCC units, such as Warren and Brunswick County, and the prospect of additional new units will provide adequate inventory from which to generate NGCC power.

In summary, most fossil fuel units not already scheduled for retirement will be able to operate until 2050, assuming the necessary investment to retain reliability is possible without triggering NSR mandates. Some units may be judged incapable of reliable operation to 2030 or 2050, but there are adequate replacement resources available. As a result, unit lifetime does not compromise the results of this analysis.

Natural Gas Generation and Pipeline Requirements

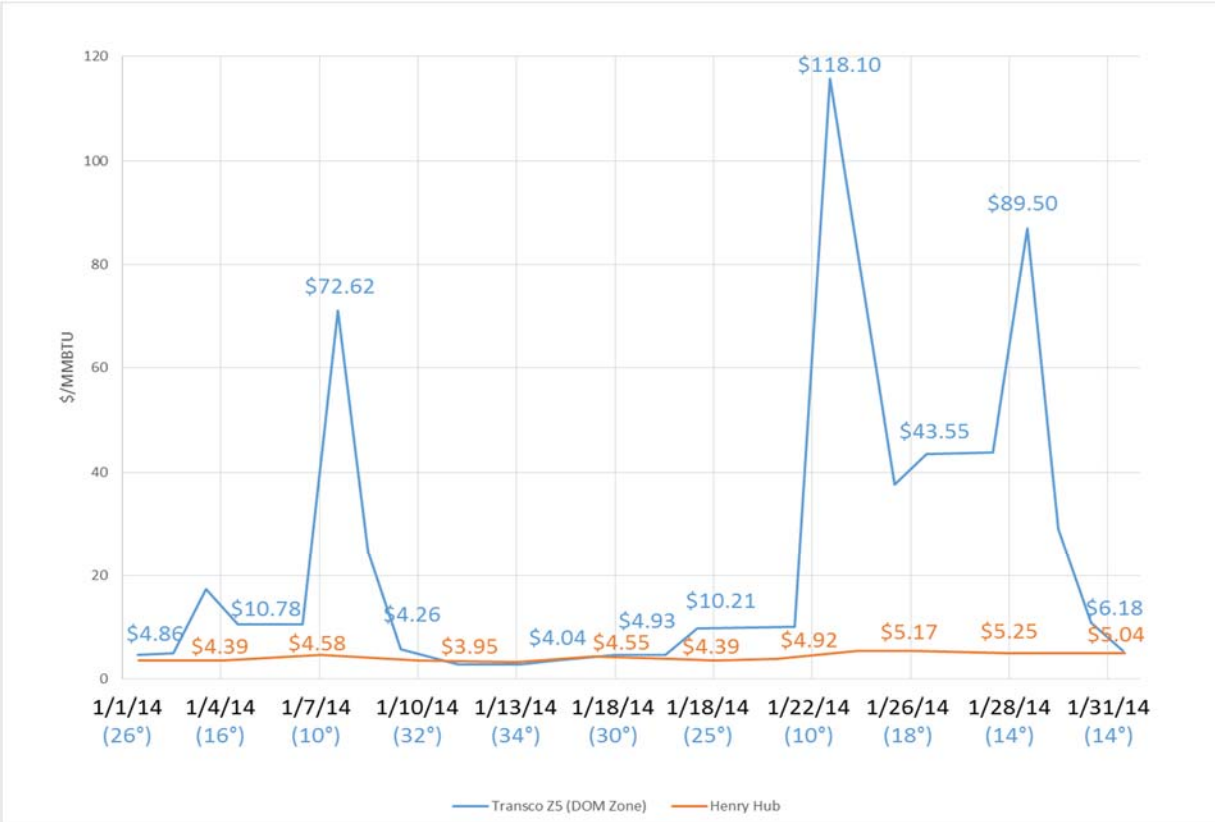
Approximately 2,700 MW of coal-fired generation in Virginia is scheduled for retirement and will be replaced primarily by new natural gas combined cycle units. The 2012 generation mix shows natural gas accounting for 35 percent of Virginia's power generation. Additionally, the various CO_2 compliance scenarios discussed in Section 6 show a significant increase in natural gas demand in Virginia. In fact, some projections suggest a demand exceeding 40 million MWh from natural gas generation in 2030. With new NGCC capacity additions, the potential for natural gas-fired generation will grow substantially by 2020.

The expected increases in demand and capacity for gas-fired generation raise legitimate questions regarding the ability of the natural gas infrastructure to meet the energy demand of Virginia. In fact, natural gas delivery issues already manifested during the "Polar Vortex" of early 2014. According to Robert Blue, the President of Dominion Virginia Power, in a presentation to the Quadrennial Energy Review Task Force (QER) in April 2014:

> *I believe the winter events in PJM and our plans for additional gas generation demonstrate that the QER must recognize the importance of our network of natural gas pipelines and their contribution to our national goals, both in reducing greenhouse gas emissions and improving the resiliency of our energy delivery system.*
>
> *The prices for natural gas during the Polar Vortex days provided clear and even startling evidence of the constraints on our pipeline infrastructure. For example, average gas prices on the Transco Zone 5 hub that serves Virginia on January 6 were $11.14 per MMBtu, but just one day later, on January 7, they surged to $72.62.* [See Figure 4-4] *Capacity on existing pipelines was inadequate to meet residential and commercial heating demands along with power generation requirements. Federal policies must provide a stable and*

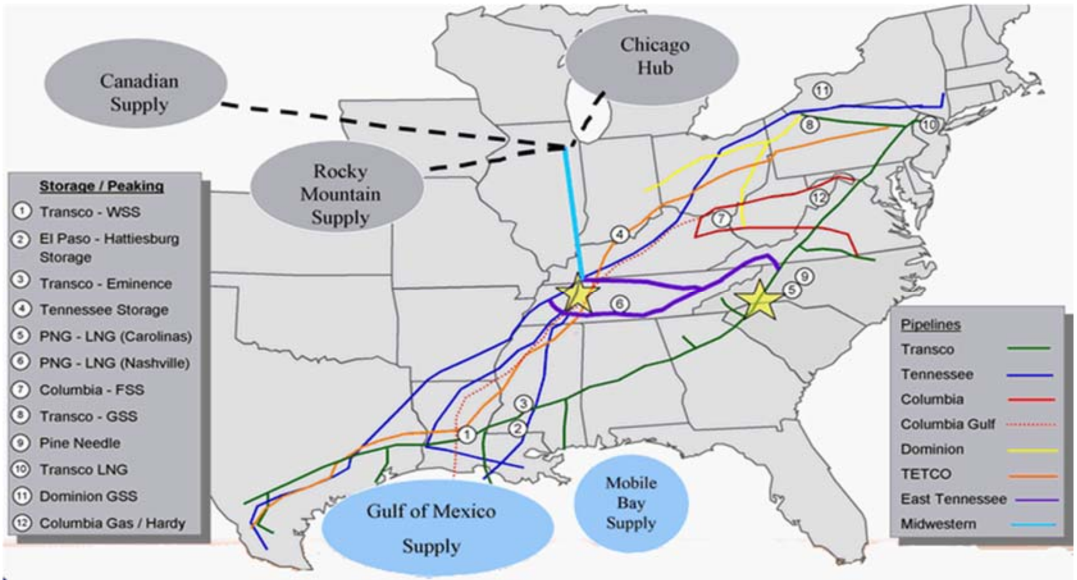
predictable environment where private capital will invest in an expanded pipeline network to move the unprecedented supplies of gas to our population and power load centers.

Figure 4-4: Winter 2014 Natural Gas Markets Stressed



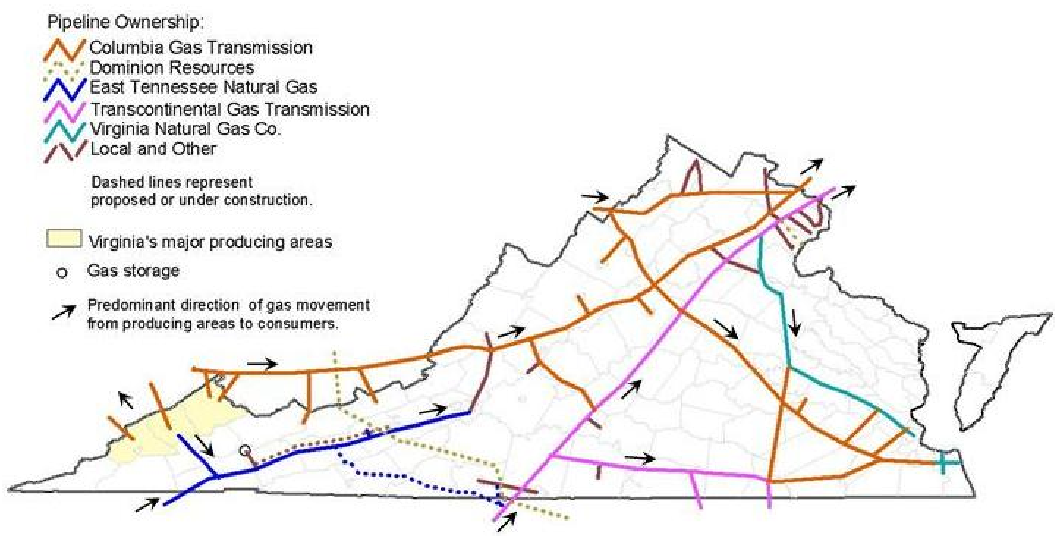
The 2010 Virginia Energy Plan addresses the natural gas pipeline system in the State, as shown in Figure 4-6 which depicts existing routes within Virginia, and Figure 4-5, which shows the state infrastructure in relation to the southeast and mid-Atlantic regions.

Figure 4-5: Natural Gas Pipeline System



Source: Virginia Places, 2014.

Figure 4-6: Virginia Natural Gas Pipeline System



Source: VEPT, 2004.

It should be noted that the projected major shift to natural gas is not limited to Virginia. For example, an operating unit of the Southern Company (Mississippi Power Company) has committed to convert many of its older coal units to natural gas and by 2020 will be a 60 percent gas-fired utility (E&E, 2014).

The increased demand for natural gas generation, both within and outside of Virginia, will have concurrent impacts on the natural gas pipeline network in the state. To adequately review those impacts, in addition to reviewing published material in preparation of this report, discussions were held with the Federal Energy Regulatory Commission (FERC), Dominion Pipeline, and Transco Pipeline System to determine planned expansions within Virginia.

Dominion Energy and its subsidiaries have a number of plans to expand their pipeline assets. For example, to address potential natural gas deliverability issues, Dominion Transmission Inc. initiated its Atlantic Coast Pipeline project. The following is a portion of the description of the project as provided by Dominion:

> *Dominion Transmission is considering the construction of a natural gas pipeline, the [Atlantic Coast Pipeline Project], which is important for the reliability and affordability of natural gas and electric service, for economic development and for cleaner air in West Virginia, Virginia and North Carolina. The pipeline would provide improved supply of natural gas for utilities needing to use cleaner natural gas rather than other fuels to generate electricity, local distribution companies searching for new, affordable natural gas supplies for its residential and commercial customers and industries looking to build or expand their operations. The pipeline could originate in Harrison County, W.Va., go toward Greensville County, Va., and then turn toward southern North Carolina. A lateral pipeline from the Virginia-North Carolina border toward Hampton Roads is also being considered as part of this project.*

Additional expansions of the pipeline network were noted in discussions with the Transco/Williams Pipeline Business Development Group. To address this new demand for natural gas in Virginia, Transco has the following expansion projects:

- Leidy Southeast Project (Figure 4-7)
- Atlantic Sunrise Project (Figure 4-8)
- Virginia Southside Project (Figure 4-9)
- Mid Atlantic Connector Project (in Figure 4-10)

Figure 4-7: Leidy Southeast Pipeline Expansion Project

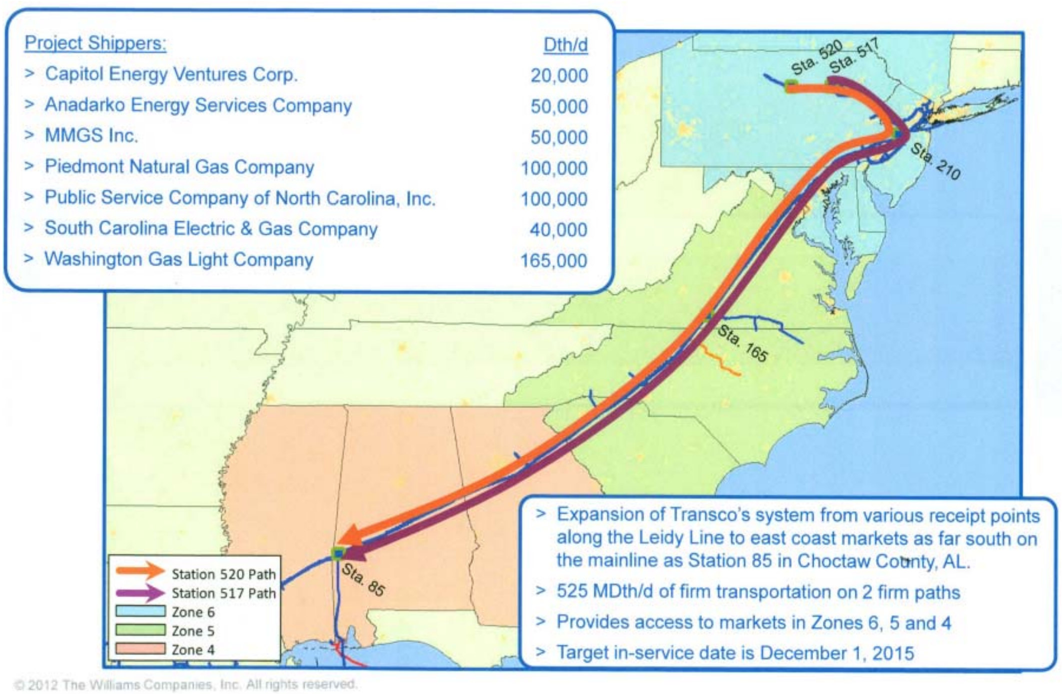


Figure 4-8: Atlantic Sunrise Pipeline Expansion Project

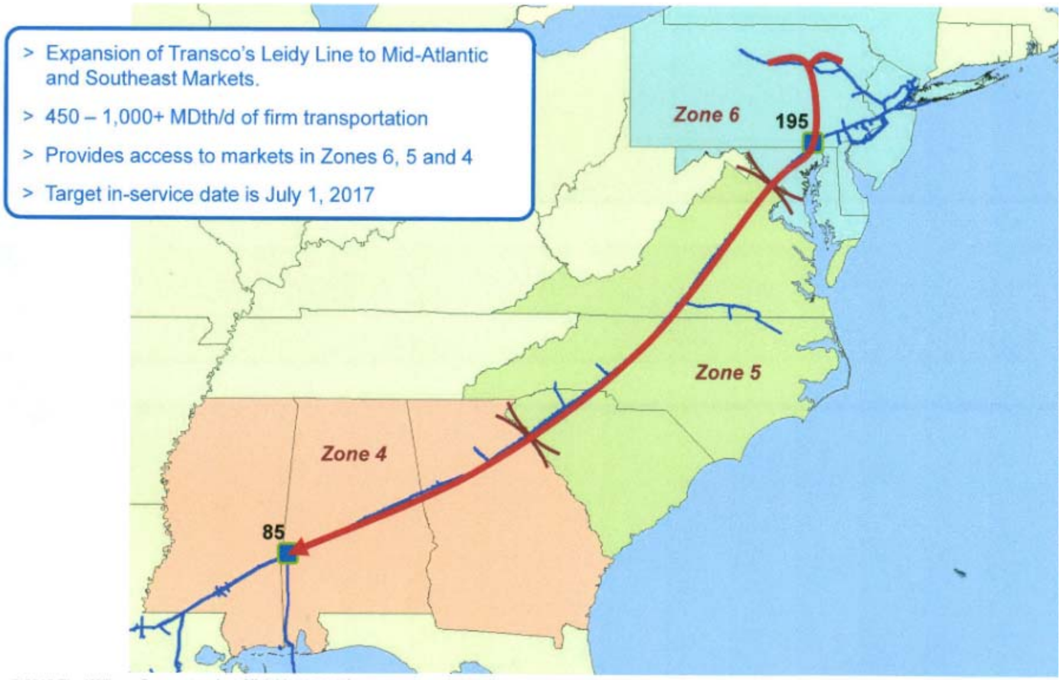


Figure 4-9: Virginia Southside Pipeline Expansion Project

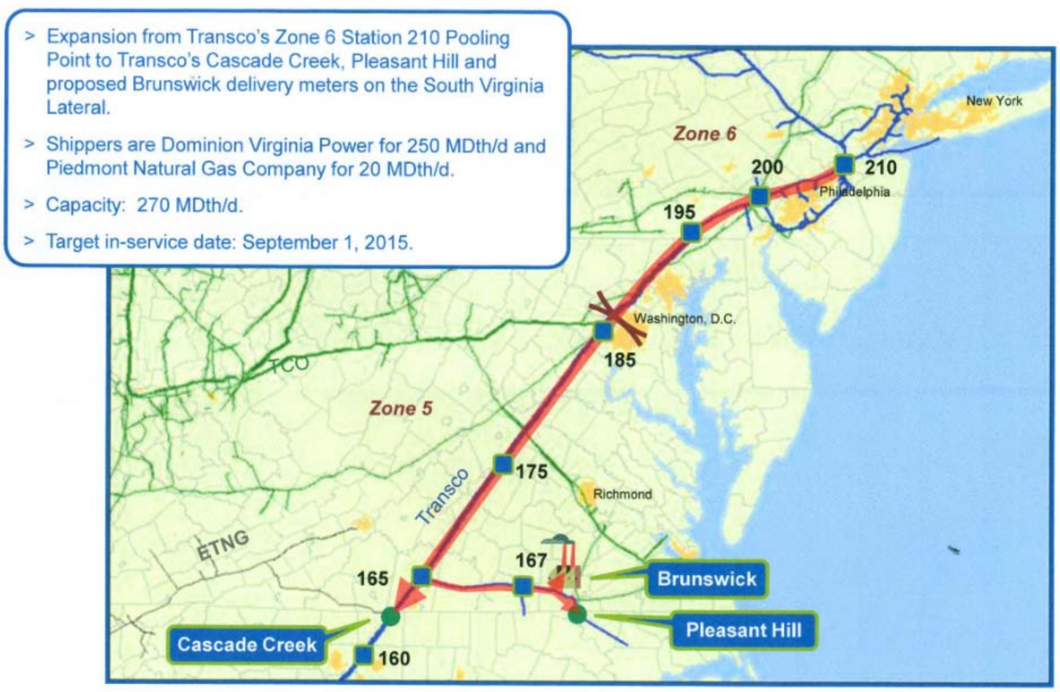
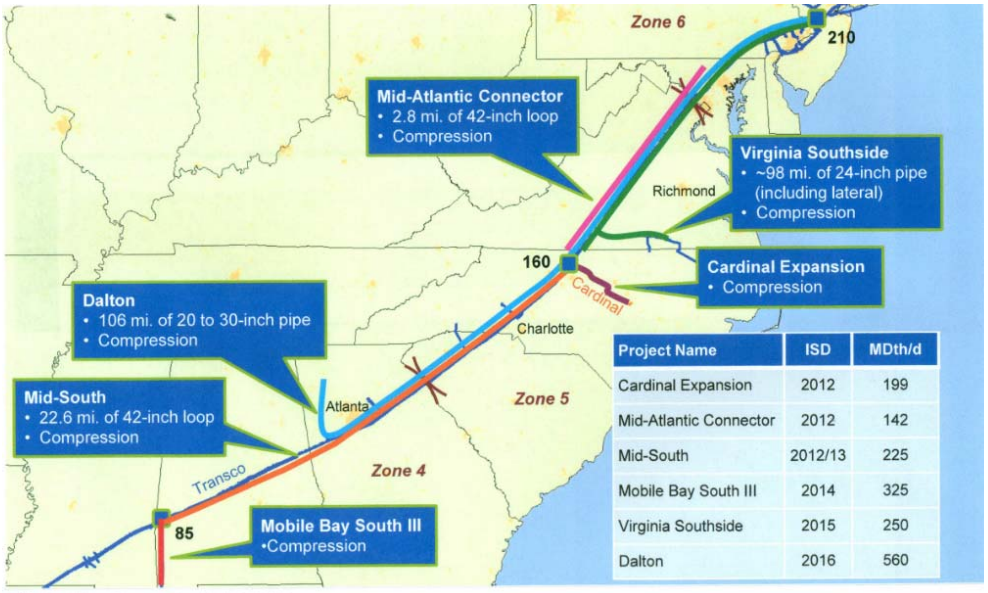


Figure 4-10: Southern Market Area Projects, including Mid-Atlantic Connector



Project Name	ISD	MDth/d
Cardinal Expansion	2012	199
Mid-Atlantic Connector	2012	142
Mid-South	2012/13	225
Mobile Bay South III	2014	325
Virginia Southside	2015	250
Dalton	2016	560

Data from the Federal Energy Regulatory Commission show pipeline projects under review and approved within Virginia, including those described above (FERC, 2014). While some expansion of delivery infrastructure is planned in Virginia, compliance with EPA CO_2 emission targets may require additional capacity. As the winter 2014 price fluctuations demonstrated, pipeline capacity can greatly impact the reliability and resilience of the projected NGCC generation, under the compliance scenarios considered in Section 6.

Nuclear Generation

Virginia's four nuclear power units (North Anna units 1 and 2 and Surry units 1 and 2) currently rank Virginia 14^{th} in the US in net generation from nuclear power.

The units at the North Anna Nuclear Plant are rated at 920 and 943 MW's (summer peak capacity) by the US Department of Energy's Energy Information Administration (DOE/EIA). During 2010, the North Anna units reported average capacity factors of 84 and 80 percent and produced 13.4

million MWh of energy for Virginia consumers. The operating licenses for these units expire in 2038 and 2040.

The units at the Surry Nuclear Plant are rated at 839 and 799 MW's (summer peak capacity) by the DOE/EIA. The Surry units reported average capacity factors of 84 and 99 percent in 2010 and produced 13.2 million MWh of energy for Virginia consumers. The operating licenses for these units expire in 2032 and 2033.

In an effort to meet future power generation requirements for the state, Dominion has sought permission from regulatory authorities to construct a third unit at the North Anna site. In 2007 Dominion submitted an application for a combined operating license to the Nuclear Regulatory Commission (NRC) that included a new, third unit and received an early site permit. Final federal permission and a final management decision are not expected to be made until 2015.

The EPA's proposed rule does not allow Virginia to take full credit for the generation of power at existing and planned nuclear units (over 27 million MWh in 2012). Under the proposal, only 6 percent of nuclear generation can be used in calculating the state's compliance with CO_2 emission targets. The EPA believes this figure for "preserved" nuclear generation is appropriate, due to overall uncertainties related to the relicensing and expected retirement of existing nuclear facilities nationwide. It should be noted, however, that EPA's concerns are not applicable to Virginia, where existing and planned nuclear units would be licensed and operated long after the 2030 compliance targets.

Renewables

Currently Virginia (as shown in Figure 4-11) is one of 29 states that have either an enforceable or voluntary renewables program. Virginia is also one of 20 states currently with an energy efficiency program (Figure 4-12).

Figure 4-11: Renewable Portfolio Standard Policies (Source: www.dsireusa.org)

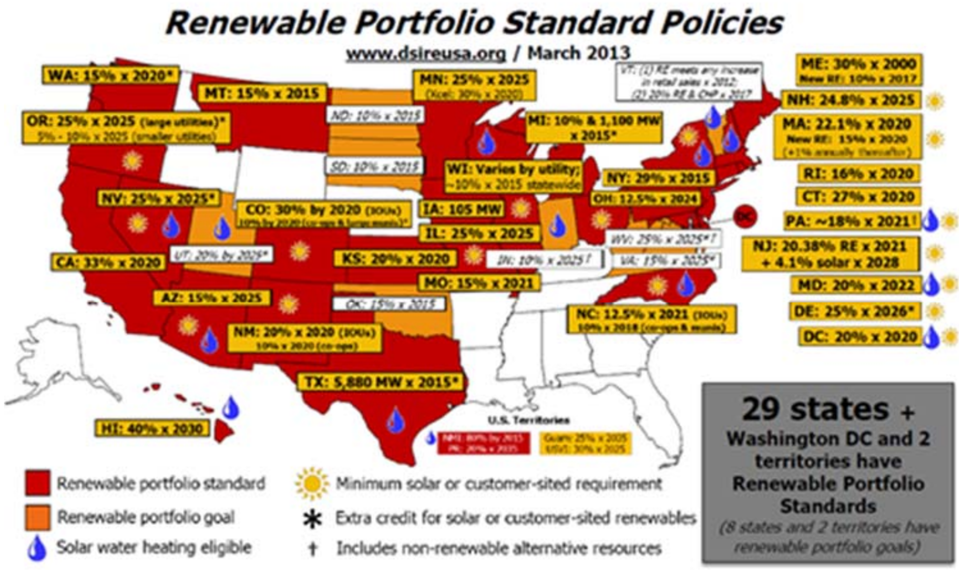
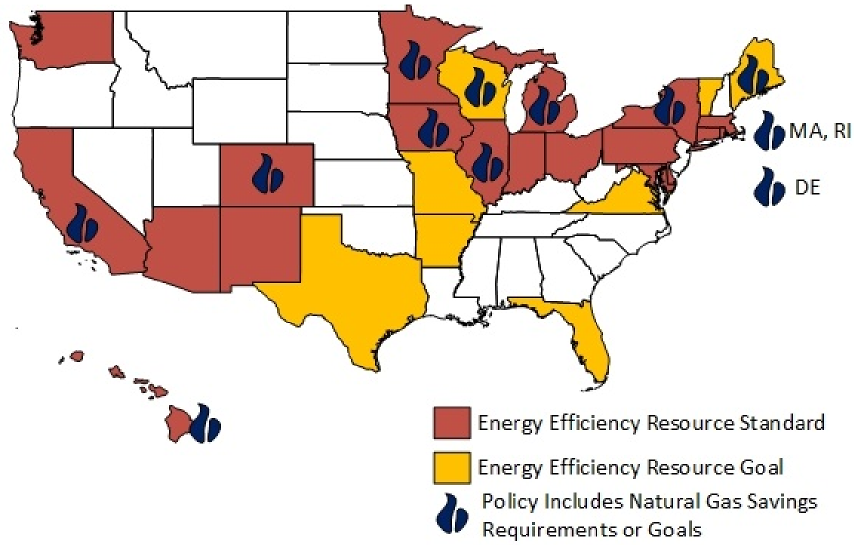


Figure 4-12: Energy Efficiency Resource Standards (Source: www.dsireusa.org)



Virginia's renewable portfolio standards program (RPS) is currently a renewables goal and not a mandatory compliance program. It applies to the investor owned utility (IOU) sector only, with its primary goal being 15 percent renewables (of the base year 2007 sales) by 2025. It includes wind, solar, thermal energy, photovoltaic, landfill gas, biomass, geothermal, waste energy, anaerobic digestion and tide and wave energy. Renewable energy credit (REC) trading is allowed with the most recent authorizing legislation being SB 420 enacted on March 31, 2014.

The EPA's proposed regulations set a target of existing and incremental renewable energy of approximately 4.6 million MWh in 2020. Because Virginia has only voluntary renewable portfolio goals and very little work has been done to demonstrate the renewable energy resource base in Virginia, it is unclear whether this EPA target is practical and achievable. This analysis will therefore construct two sets of cases to address the challenge of meeting renewable energy targets, as well as energy efficiency. One case, the "Incremental Dispatch" is based on marginal cost delivery and will assume that EPA renewable energy generation targets are not met—with only about 50 percent of the targeted value attained for both 2020 and 2030 conditions. A second case, denoted the "Green Dispatch" case, will attain or approach EPA's assumptions for renewable energy.

These options will be discussed in more detail in Section 6 of the report.

Discussion

Virginia's electric generating utilities and IPP's have made recent decisions to retire a number of long standing coal-fired facilities and replace this capacity with newer and cleaner natural gas-fired capacity. This new gas capacity will allow the utilization of the remaining coal units to be cut back substantially and thus help Virginia meet the requirement set forth in the new EPA Clean Power Plan proposed regulations.

However, there remain some significant questions about electrical generation in the Commonwealth and EPA's proposal. The first is whether it is fair and reasonable to calculate

Virginia's emission rates without considering the significant, non-CO_2 emitting nuclear portfolio in the state. The EPA's proposal only allows for 6 percent of the existing generation to be considered, although the nuclear fleet in Virginia has a licensed useful life well beyond 2030. In 2012, the excluded portion of nuclear generation (referred to as residual nuclear) accounted for approximately 23% of the total generation in the state. Additionally, the EPA's proposal does not, at this time, allow for the consideration of additional nuclear generation in the determination of Virginia's CO_2 emission rates, which is likely from a third unit at the North Anna facility.

Partially as a result of this approach to nuclear, Virginia's reliance on natural gas-fired generation would have to grow substantially over a period of decades. Such growth has the potential of creating power supply instability and issues with electrical reliability based on the resulting needs for substantial expansion of natural gas pipelines in the Commonwealth. While some expansion is already slated, whether the fuel supply will be readily available for all new NGCC facilities is uncertain.

The EPA's proposed rules would encourage development of renewable power generation within the state. There have not been adequate studies or analysis to demonstrate the practicality of such expansion within Virginia, and few efforts are currently ongoing which can be used as positive examples of the capability of the Commonwealth to meet demand using renewable sources. A study conducted by Virginia Tech in 2005 assessed various sources of renewable power for Virginia, and concluded that in concept numerous sources can contribute significantly to the generation portfolio (VCCER, 2005). Specifically, sources as varied as onshore wind, offshore wind, landfill gas, biomass, solar photovoltaic, and hydro were reviewed. Each of these sources can be deployed for Virginia, but the specific amount of power that is available will not be known until a detailed assessment is conducted. Furthermore, the cost is only approximated, given the uncertainties in how specifics conditions at each generation site may affect production cost. The generating cost for many of these individual sources (e.g. onshore wind and solar photovoltaic) is decreasing; however, the cost and applicability for Virginia must await a detailed assessment. This study assumes that the renewable portion of the portfolio is equally comprised of on-shore wind, off-shore wind, and solar photovoltaic sources.

As mentioned earlier in this section, approximately 40% of the total generation in Virginia is sourced from generating units physically located outside of the state. At this time, it is not clear how imported electric energy will be affected by the proposed EPA rule and, as such, introduces a great deal of uncertainty as to how the final rule, if and when it is implemented, will affect the energy dispatch strategy of Virginia. Although the contributions of each source will vary over time, it is apparent that interstate imports will likely remain as major contributors to the electrical energy mix of Virginia for years to come.

Section 5. Study Approach, Assumptions, and Limitations

This report was based on the specific requirements of the Virginia Energy Plan, as amended in 2014 and listed in statute, as well as the approach taken by the EPA in its June 18, 2014, proposed rule (EPA, 2014b). Given the short time available to complete this analysis and report, complex modeling exercises were not possible. The analysis was, therefore, based on published data and analyses, augmented by personal interviews and the professional experience of the report team.

To examine the impact in Virginia of complying with the EPA's proposed rules, six scenarios of different power generation portfolios were developed with the input of the Virginia Department of Environmental Quality, the Virginia Department of Mines, Minerals and Energy, the State Corporation Commission, and the Virginia Center for Coal and Energy Research report team.

The Baseline Generation (Scenario 1) and Role of Preserved Nuclear Generation (Scenario 2) cases are straightforward and simply required an accounting of the Virginia power generation portfolio as adjusted by announced retirements, conversions, and new capacity. The data used to construct these portfolios is derived from the baseline data included in the EPA docket for this rulemaking (EPA, 2014c). The capacity factors for all fossil units in Scenarios 1 and 2 were calculated from EPA-provided data for the year 2012. The emissions of CO_2 were determined, and the CO_2 emission rate using the net power output delivered to the grid, were based on EIA reports.

All subsequent Scenarios (3 to 6) require reducing the capacity factor of coal-fired units, oil- and gas-fired steam boilers; increasing the capacity factor of existing NGCC units; and assigning capacity factors for new state-of-the-art units. The objective of these changes to the generation portfolio was to abide by the CO_2 limit designated by EPA, while providing the requisite amount of power for the least possible cost (for the incremental case) or to meet EPA renewable energy targets (for the green case). The study abided by the constraints established in the EPA rule proposal. These constraints included the EPA's definitions of affected units and of new capacity. Based on the publication date of the proposed rule for new sources under the EPA's 111(b) rulemaking, only those facilities for which construction commenced on or before January 8, 2014, are eligible for consideration in Virginia's portfolio and compliance calculations. Additionally, the EPA specified that only 6 percent of existing nuclear generation capacity can be included in compliance calculations. The development of the scenarios was also constrained by the assumptions of the building blocks identified in the EPA's proposal. The implications of these limitations are discussed below.

Assigning Unit Generation

Ideally, unit generation (e.g. prediction of capacity factors) in a study such as this is assigned by an algorithm within a linear-programming model (LPM). The model is instructed to find the least cost generation for the entire system while meeting the CO_2 emission rate. It is likely that an approach using a sophisticated LPM tool will be pursued by the in-state power generators.

The present study did not use an LPM-enabled approach because of the time constraints for completion of this report. As an alternative, this study relied upon significant data collection and the experience of the contributors to identify units that would be included in a Virginia generating portfolio to satisfy the mandates of the Clean Power Plan (CPP), while generating adequate, least cost power. The relative cost of generation of various units reflects the coal-fired, oil- and gas-fired boilers, and NGCC units, enabling generating units to be ranked in approximate order of least to highest generating cost. In general, this ranking demonstrated that coal-fired units were least cost, followed by NGCC units. Finally, oil- and natural gas-fired steam generating units, with higher costs, are also considered.

Ranking of Units by Generation Cost

The capacity factors were assigned by ranking units in terms of generating cost from lowest to highest under the constraint of meeting the CO_2 emissions rate. The complicating factor is that a ranking of units by generating cost is inverse to the ranking of units by CO_2 emissions. Typically, state-of-art NGCC facilities rank lowest in CO_2 emissions, followed by existing earlier-generation and smaller NGCC facilities, then oil-fired and gas-fired steam boilers, with coal-fired units ranking highest in emissions. The challenge is to construct a portfolio of generating options that balances meeting power requirements against complying with the required overall CO_2 emission rates.

As noted, the only approach available within the timeframe to complete this report is not as rigorous or as accurate as employing an LPM model. This study may not identify the same units that would be selected by an LP model for dispatch, but the sum of all units in aggregate, acting as a pool, is believed to be accurate. Notably, all coal units emitted CO_2 at a rate greater than 2,000 lbs per MWh; therefore, these units were forced to accept relatively low capacity factors. As a result, the overall generation that coal contributes to the total is relatively low in each scenario.

CO_2 Reduction From Existing Coal-Fired Units

Two means of reducing CO_2 from existing coal-fired units were adopted in this study—heat rate or efficiency-improving measures, and firing biomass for a fraction of heat input to the Virginia City Hybrid generating station.

Heat Rate and CO_2 Emissions. The commercially available technology section of this report described an array of heat rate and thermal efficiency-improving techniques that could be deployed to obtain a reduction in heat rate and CO_2 emissions. As noted, the CO_2 reduction that can be achieved over the long term is, in the opinion of the study authors, 3 percent. This value, which is less than either the targeted 6 percent or the “alternative” value of 4 percent, is based on a projection of the number of heat rate improving projects that have already been deployed. The 3 percent CO_2 savings represents a long-term average because any single heat rate improving technique may initially deliver 4 percent or more improvement during the first year of operation, but this payoff decreases as equipment deteriorates with use.

Equally important, the value of 3 percent is valid only at a high capacity factor, perhaps greater than 65 percent. Operation at a lower capacity factor significantly compromises heat rate. This analysis credited coal-fired units with a 3 percent heat rate reduction at high load, but lowered that benefit at lower capacity factors. Specifically, it is assumed that operation at 45 percent capacity factor compromised the 3 percent heat rate benefit to 2 percent. Similarly, a further reduction in capacity factor to less than 45 percent would almost eliminate the improvement, but a 1 percent benefit was retained in this case.

The data used in this study reflect the trend in heat rate savings and capacity factor. The study team is confident that the assumptions used in this report (i.e., significantly lower heat rate benefits achievable over the long-term, and the greatly reduced or negated heat rate benefit at extremely low capacity factor), will be confirmed. The assumptions defining the compromise in heat rate for this study are optimistic—that is, in reality the penalty will be greater. Any variance in these specific inputs will not markedly affect the study conclusion; however, a more detailed analysis of the specific units in Virginia, at a later stage, would be appropriate if the proposed rule becomes final.

Co-firing Biomass at the Virginia City Hybrid Energy Center. A second means to reduce CO_2 from the existing coal-fired inventory is to co-fire biomass at the Virginia City Hybrid Energy Center. The state-of-art plant—designated by Power Magazine as the 2012 Plant of the Year (Power, 2012)—is equipped with fluidized bed combustion boilers that are designed for fuels with the properties of biomass. Exploiting this resource to reduce CO_2 should be a high payoff act, pending the availability of adequate supplies of biomass fuels at a reasonable cost. The study assumed that such fuels were available at a price determined in an earlier EPA study to reflect value of woody-residues (EPA, undated).

Other Assumptions

Several other assumptions directly impacted the analysis and interpretation of results. One critical assumption was the rate of growth in electricity demand. Virginia has not established an official growth rate and estimates in the published literature varied from less than 1 percent to over 2 percent. In conducting this study, the projected rate of growth of 1.51 percent, used by Dominion Energy in their official submittals to the states of North Carolina and Virginia, was used to develop demand projections (Dominion, 2013).

In order to ensure that total electrical demand in Virginia is met under all scenarios, additional electrical generation that is not subject to EPA's proposed rule is assumed to continue and to be built as previously announced. This additional generation consists of smaller MW coal-fired units that are projected to produce less than 219,000 MWh annually and thus considered non-affected units by the EPA. This additional generation also includes small biomass generating units, and new generation that commenced construction after January 8, 2014, totaling about 11.5 MWh annually by 2030.

Several assumptions were also made about the costs and availability of fuel, the ability of the transportation infrastructure to deliver fuel, particularly natural gas, as needed for generation, and the reliability and balancing of the electrical grid to deliver the power generated. While investigation of many of those assumptions in depth is beyond the scope of this report, where those assumptions are critical to the analysis, specific reference is made to how those factors may influence the outcomes of the study. Divergences from the EPA's stated assumptions or goals for capacity factors, heat rate, or other efficiency and generation constraints are also noted.

In order to analyze the impacts and benefits of the proposed rules on the public, including environmental and health costs and benefits, the approaches used by the EPA in support of its June 18, 2014, proposal were utilized; there was a lack of other easily-applicable methodology. While additional in-depth research may be warranted if the EPA's regulations are finalized, this should be pursued at a later date. The proportion of emissions reductions in Virginia, compared to the projected national reductions, was used to assign costs and benefits accruing in the Commonwealth based on the EPA's published Regulatory Impact Analysis (EPA, 2014g). Additional data from the US Census Bureau was used to evaluate the possible impacts of changes in the electrical generation mix within Virginia, resulting from implementation of the EPA's proposed rules, on low-income and minority populations.

Section 6. Power Generation Scenarios

This analysis addresses six possible scenarios for Virginia's power consumption and production under the proposed Clean Power Plan (CPP) rule. These six cases reflect a step-by-step progression of power production options aimed at achieving compliance with the CPP. The scenarios considered below establish a baseline framework and subsequently identify the effect of changes in the portfolio of operating plants. Four of the scenarios identify changes to the portfolio for the explicit purpose of complying with the proposed near-term and long-term CO_2 emission rate limits as established by the EPA in its proposed rules.

It should be recognized that, at this stage, these scenarios are offered as discussion topics. A more detailed and comprehensive analysis may be necessary later to complete a thorough evaluation.

The six scenarios account for

1. Changes in generation due to retirement, fuel switch, and new generation (Scenario 1)
2. As in Scenario 1, but including "preserved" nuclear power (Scenario 2)
3. Maintaining selected existing oil/gas units, while including planned new generation from NGCC units (Scenario 3)
4. Adjusting generation as identified by the EPA to meet the *alternative* CO_2 emissions rate (Scenario 4)
5. Converting all fossil generation to NGCC, eliminating coal from the generation mix (Scenario 5)
6. Adjusting generation as identified by the EPA to meet the baseline CO_2 emissions rate (Scenario 6).

As noted previously, and to be addressed subsequently within this report, for Scenarios 4 through 6 both an “Incremental Dispatch” and a “Green Dispatch” case were developed, the latter distinguished by meeting or approaching EPA’s targets for renewable and energy efficiency sources.

Description of Scenarios

The descriptions of the six scenarios in this section provide background information for each case analyzed, including assumptions. A simplified summary of these scenarios and their underlying assumptions is shown in Table 6-2.

Scenario 1: Baseline Analysis

Scenario 1 establishes a baseline operation of key fossil assets in the Virginia power portfolio. This scenario is defined by the existing generation as of 2012, while acknowledging that certain units will be shut down. Any new fossil units can only be included in the inventory if construction commenced by January 8, 2014. The coal-fired unit inventory is retained the same as 2012, minus units expected to be retired, or to be converted to natural gas. The coal-fired units are assumed to operate at the 2012 capacity factor and heat rate. Conversions of coal-fired units to natural gas, retaining the same conventional steam cycle, are included in the inventory and assumed to operate at 2012 coal capacity factors. Existing natural gas/combined cycle (NGCC) inventory is retained the same as 2012, in capacity factor, and heat rate. Also, the inventory and operation of conventional steam boilers that operated in 2012, fired by fuel oil or natural gas are retained at the same capacity factor as in 2012. Announced additions at Warren and Brunswick are included in the scenario and assumed to operate at the floating capacity factors necessary to achieve the total baseline generation for Virginia defined in the EPA’s proposed rules.

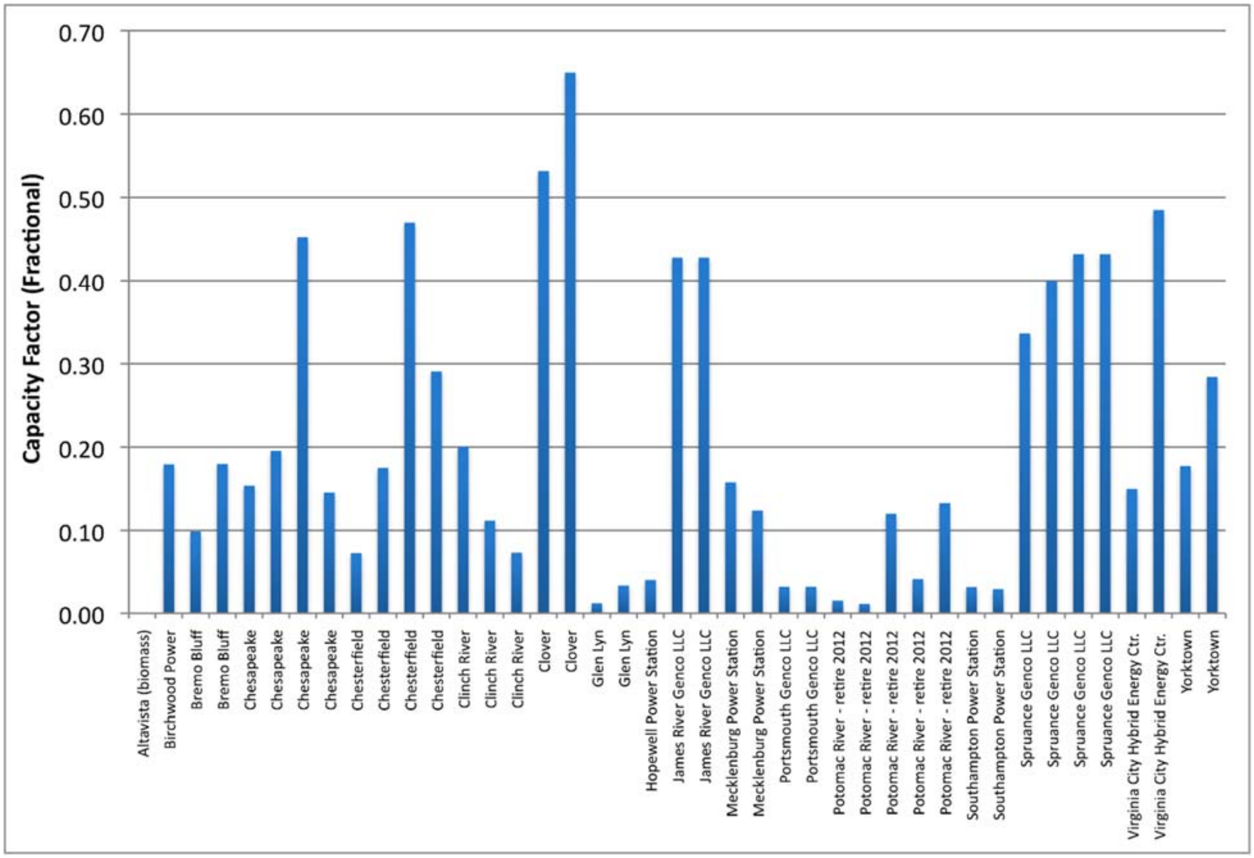
Consistent with EPA assumptions, preserved nuclear generation is not included in the 2012 baseline. Generation derived from renewable sources remains at 2012 levels. Conservation or energy efficiency is not included.

Coal-Fired Generation

A total of 40 coal-fired units operated in Virginia in 2012, ranging in designed generating capacity from 57 MW (multiple units at James River, Spruance, and Portsmouth) to 424 MW (two Clover units). The Virginia Hybrid Energy Center, where coal is augmented by biomass fuel, has a combined output of 610 MW.

Figure 6-1 presents a bar chart depicting the 2012 capacity factors for all these units. As shown in the figure, the 2012 capacity factors range from below 10 percent to 53 and 65 percent for Clover Units 1 and 2.

Figure 6-1: Virginia Coal-Fired Power Stations – 2012 Capacity Factor



The capacity factors vary significantly because of the difference in variable operating cost, defined by fuel prices and plant heat rate, and location within the grid.

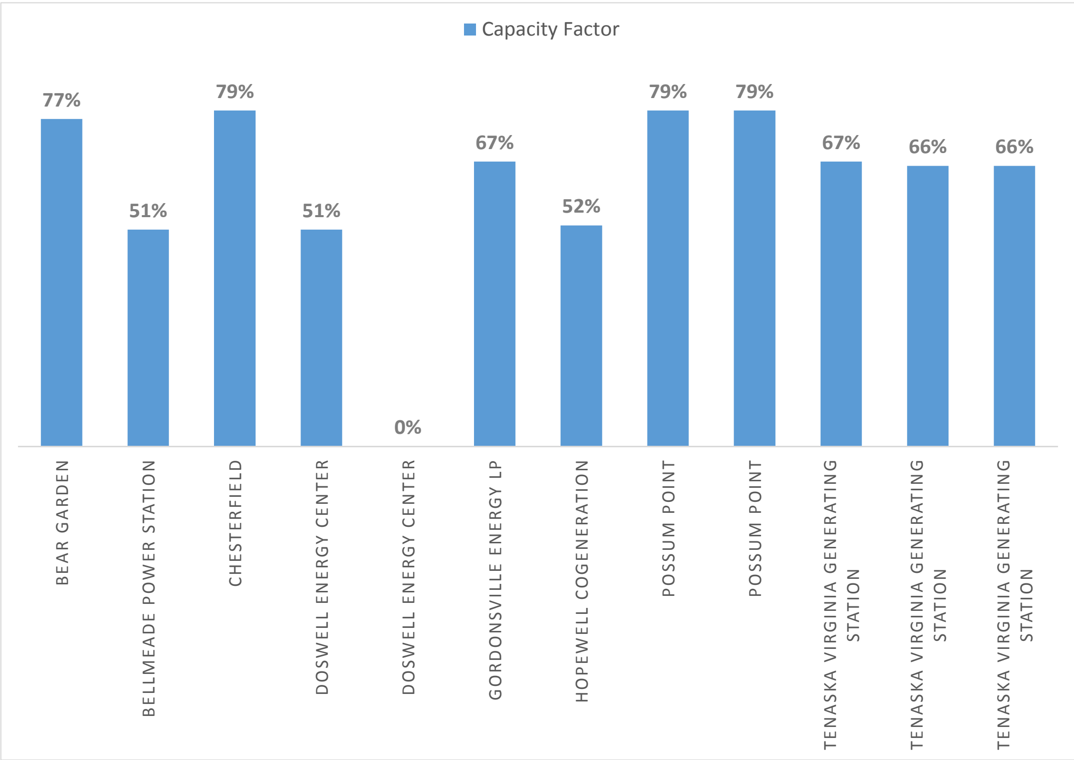
Numerous units have been designated for retirement by 2020. These include all units at the Bremo Bluff, Chesapeake, Clinch River, Glen Lyn, Potomac River, and Yorktown stations. Cumulatively, this will remove a total of 2,793 MW of generating capacity from the coal-fired inventory.

Natural Gas and Oil/Gas Units

Eleven natural gas-fired combined cycle (NGCC) generating units operated in 2012. Two steam boilers firing a mix of fuel oil and natural gas in a conventional steam cycle were also in operation and are discussed below. The NGCC units ranged in generating capacity from 175 MW (Tenaska combustion turbines) to 590 MW (Bear Garden).

Figure 6-2 presents a bar chart depicting the 2012 capacity factors for these units. As shown in the figure, the 2012 capacity factors range to as high as 77-79 percent for units at Bear Garden, Chesterfield, and Possum Point.

Figure 6-2: Natural Gas/Combined Cycle Power Stations – 2012 Capacity Factor



Two large steam stations, Units 3-5 at Possum Point (786 MW) and Yorktown Unit 3 (818 MW), fired a mix of natural gas and fuel oil. These units in 2012 operated at a very small capacity factor—4 percent and 1 percent for Possum Point and Yorktown, respectively.

Other Generation

Three small generators produced the following output:

Hopewell Cogeneration	124,646 MWh
James River Genco, LLC	395,923 MWh
Spruance Genco, LLC	598,719 MWh

Nuclear generation is not accounted for in Scenario 1. Renewable generation is set at 2012 levels of 2,358,433 MWh based on EIA estimates.

New and Converted Units

According to the EPA guidelines, new fossil units are to be included in the scenario if construction commenced by January 8, 2014.

Table 6-1 summarizes new generation (all natural gas-fired combined cycle) for which construction commenced by the January 8, 2014 deadline. A total capacity of 3,045 MW is predicted. Also shown are five relatively small units that converted from coal to natural gas, totaling 747 MW, which will be included in Scenario 1 data. This adds a total of 3,792 MW capacity to the baseline.

Table 6-1: Summary of New Units (begun by 1/8/2014) and Converted Units

Power Station	Unit	Capacity (MW)
Warren County	CT01	427
Warren County	CT02	427
Warren County	CT03	427
Brunswick County	1	433
Brunswick County	2	433
Brunswick County	3	433
Clinch River	1	242
Clinch River	2	242
Bremo Power Station	3	71
Bremo Power Station	4	156
Total		**3,291**

The outcome of Scenario 1 will be estimates of the baseline power production rate (MWh) for 2012 and the associated CO_2 emissions rate (lbs of CO_2/MWh).

Scenario 2: Role of Nuclear Generation

Scenario 2 explores the impact of only one change to Scenario 1: adding preserved nuclear generation to the state power portfolio.

Preserved nuclear generation is assigned the value designated by the EPA in the proposed rule as 6 percent of the 2012 generation. To accommodate the added nuclear generation, the output of the new NGCC units at Warren and Brunswick are proportionally reduced. All other inputs are retained unchanged from Scenario 1. Renewable generation remains at 2012 levels.

The revised average CO_2 emissions rate (lbs of CO_2/MWh) from augmentation by nuclear power will be noted for Scenario 2.

Scenario 3: Role of New Capacity

Scenario 3 explores the impact of actively exploiting the new generating capacity that is included in Scenarios 1 and 2 (specifically the NGCC additions at Warren and Brunswick) to optimally contribute to the Virginia power portfolio and meet the Virginia CO_2 emissions rate target. Scenario 3 is the first scenario where the inventory and/or capacity factor of fossil assets in the Virginia portfolio are adjusted to satisfy the CO_2 emission rates under the proposed rule.

Scenario 3 required that the capacity factors for all units be adjusted to provide the necessary generation while meeting targets for CO_2 emissions of 991 and 810 lbs CO_2 per MWh for 2020 and 2030, respectively. Scenario 3 retains the 2012 coal-fired inventory, but exploits the expanded NGCC inventory to satisfy both power generation needs and the CO_2 emission rate. The capacity factor for the steam boilers firing either fuel oil or natural gas is significantly lowered or equated to zero.

The coal-fired and NGCC capacity factors were selected based on production costs and CO_2 emission rates. Using the most current fuel and CO_2 emission rates, in all cases the least-cost power is generated from coal-fired units so those are dispatched first. Production costs are higher for NGCC units, but CO_2 emission rates are lower. The newest NGCC units provide among the lowest heat rate and the lowest operating cost of this class of assets. Within each asset class, the most efficient (e.g. lowest CO_2 emissions per MWh) units are assigned the highest capacity factors while the least efficient units are assigned the lowest capacity factors.

There are no changes to generation from nuclear, renewable sources, or conservation in this scenario compared to Scenario 2.

The output of Scenario 3 is a portfolio of operating units, including new units, to meet the projected 2020 and 2030 CO_2 emissions rates.

Scenario 4: Comply with Alternative CO_2 Rate

Scenario 4 describes an operating plan to achieve the alternative CO_2 emissions rates of 1,175 and 962 lbs/MWh for 2020 and 2025, respectively. The EPA's concept is to allow a higher CO_2 emissions limit in the near-term (by 2020) but provide a shorter time period (only 5 years) to reach the final CO_2 rate by 2025 (EPA, 2014e). For the analysis of this scenario, the following steps were implemented:

***Retire Selected Coal*.** An additional set of coal-fired units are retired, as determined by plant age, heat rate, and existing or pending environmental control upgrades. To the extent possible, the location of the station is considered (as essential to grid-balancing). In general, the newer, larger, and most efficient units are retained and the smaller, older units retired.

Existing NGCC. Existing NGCC units are retained in the inventory, but the capacity factor of the smaller units with higher heat rate and CO_2 emissions is lowered, consistent with meeting the projected 2020 demand.

New "State-of-Art" NGCC. State-of-art NGCC units, typically more efficient and emitting less CO_2 per MWh than the existing fleet, will provide the largest share of the load.

Preserved "at risk" nuclear generation will remain at the EPA designated value. Both renewable and conservation "negawatts" (generation avoided by conservation actions) will be grown at values that approximate, but are less than the EPA's projections of 13 percent.

The output of Scenario 4 is recommended portfolios of operating units and generation rate, projected for 2020 and 2025, to meet the EPA's alternative CO_2 emission rates for Virginia (EPA, 2014).

The “Incremental Dispatch” case of Scenario 4 employed a fraction of the renewable power targeted by EPA, while the “Green Dispatch” case either met or approached 100 percent of target renewables values.

Scenario 5. NGCC Only

Scenario 5 explores the option of retiring all coal-fired generation and, instead, operating only NGCC fossil units as a means to attain the 2020 and 2030 CO_2 emission targets of 991 and 810 lbs/MWh, respectively.

The capacity factors for the NGCC units were selected to capitalize on the operation of the most efficient and least CO_2 emitting units.

Preserved nuclear was assumed at the EPA’s 6 percent rate (1,645,272 MWh). For the “Incremental Dispatch” case, renewable generation was set at 5,700,000 MWh, slightly less than the EPA’s recommended production rate. The Green Dispatch case met or approached 100 percent of EPA’s targeted value. For the Green Dispatch case energy efficiency also was assumed to be 100 percent of EPA’s target while less for the Incremental Dispatch 2030 case.

Scenario 6. Comply With 2020/2030 CO_2 Rate

Scenario 6 describes an operating portfolio using coal-fired and NGCC assets, supplemented by nuclear, renewable, and conservation, to attain the 2020 and 2030 CO_2 emission targets of 991 and 810 lbs per MWh, respectively.

Coal-fired units will continue to operate, depending on heat rate, location, and environmental controls. NGCC units are retained and their capacity factor is in approximate proportion to their heat rate and CO_2 emissions, perhaps adjusted by location.

Renewable generation for the Incremental Dispatch Case for Scenario 6 is projected to grow to 2,500,000 MWh by 2020 and assumed to increase to 5,700,000 MWh by 2030, as necessary to meet projected load. The “Green Dispatch” case met or closely adopted EPA’s targets. Energy efficiency was set at 100 percent of EPA’s targets for the “Green Dispatch” case, but to a fraction thereof for the “Incremental Dispatch” case. Preserved nuclear remained at the EPA’s established value of 1,645,272 MWh.

The output of this scenario is a recommended portfolio for Virginia that complies with the EPA’s base CO_2 emission rate goals for Virginia (EPA, 2014c).

Table 6-2: Summary Description - Six Scenarios

Unit or Generation Basis	***Scenario 1:* Baseline Generation (2012)**	***Scenario 2:* Role of Nuclear**	***Scenario 3* Role of New Capacity**	***Scenario 4:* Comply w/Alternative CO_2 Rate**	***Scenario 5:* NGCC Only**	***Scenario 6:* Comply with 2020 Rate**
Coal						
- Inventory	Per 2012, minus retirements	Same	Same	Retire select or all units	Retire all	Same
- Capacity Factor	2012	Same	Lower	Lower	Zero	TBD
Existing NGCC Units						
- Inventory	Per 2012	Same	Same	Same	Same	Same
- Capacity Factor	2012	Same	Calculated per load	per CO_2 rate	per CO_2 rate	per CO_2 rate
Oil/Gas Steam						
- Inventory	2012 + conversions	Same	Same	Retire select	Retire	Same
- Capacity Factor	2012	Same	Lower/zero	Lower/zero	Zero	Same
New Generation						
- Inventory	Announced additions	Same	After 1/8/14	Same	Same	Same
- Capacity Factor	Calculated per load	Same	Calculated per load	per CO_2 rate	per CO_2 rate	per CO_2 rate
Nuclear						
- Generation (MWh)	N/A	Include preserved nuclear	Same*	Same	Same	Same
Renewable Generation (MWh)	2012	Same	Same	Partial and achieving EPA target	Same	Same
Conservation "Negawatts" (MWh)	None	None	None	Partial and achieving EPA target	Same	Same

TBD—To be determined in the scenarios.
**Scenario 3A also includes new nuclear generation at North Anna 3.*

Achieving Compliance

This section presents the results of all the Scenarios, beginning with baseline generation (Scenario 1) and the role of nuclear (Scenario 2). Results for achieving compliance with Scenarios 3 through 6 follow.

Scenario 1: Baseline Analysis - 2012

Scenario 1 provides an accounting of generation and CO_2 emissions based on the 2012 operating history, while removing the units designated for retirement. The results show the shortfall in generation that must be accommodated, and the 2012 CO_2 emission rate that serves as the starting point in the analysis. This scenario includes detailed projections to 2020 and 2030, because it is intended to provide a basis for comparison for the other scenarios.

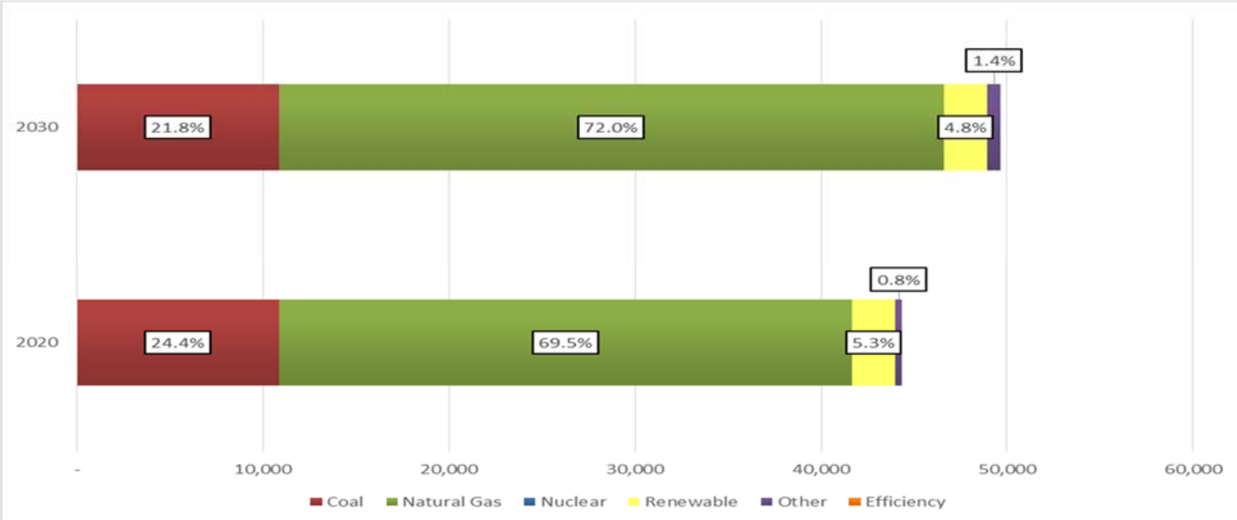
Table 6-3 presents a summary of the results for Scenario 1, which are reflected in Figure 6-3.

Table 6-3: Scenario 1 – Electricity Generation by Source (in 1,000 MWh)

Year	Coal	Natural Gas	Nuclear	Renewable	Other	Efficiency	Total
2020	10,834	30,811	-	2,358	344	-	44,348
2030	10,834	35,748	-	2,358	709	-	49,650

The Glen Lyn, Potomac River, and Yorktown stations, as announced in 2013, are retired. For the remaining units, operation in 2012 entailed relatively low capacity factors at Birchwood (18 percent); Chesterfield unit 3 (8 percent), unit 4 (20 percent), and unit 6 (30 percent); and the Virginia City Hybrid Energy Center (21 percent). Modest capacity factors (50-63 percent) were recorded at Chesterfield unit 5, and Clover units 1 and 2.

Figure 6-3: Scenario 1 – Energy Generation Portfolio



The CO_2 emission rates from these coal-fired units ranged from 2,054 lbs/MWh to 2,617 lbs/MWh, with generation from these units totaling 9,484,189 MWh.

Existing NGCC. All NGCC units operated in 2012 at relatively high capacity factor. With the exception of Hopewell and Bellemeade, all units operated at a capacity factor of at least 63 percent and three (Bear Garden, Chesterfield, and Possum Point) approached 80 percent capacity factor.

New NGCC. New capacity at Warren and Brunswick was added, and capacity factors were adjusted (12-14 percent) to meet baseline generation established by the EPA.

The CO_2 emission rates from the NGCC fleet ranged from 850 to 1035 lbs/MWh, with many units in the 865-870 lbs/MWh range. The generation from these NGCC units totals 23,184,363 MWh.

Several coal-fired units, Clinch River units 1 and 2 and Bremo units 3 and 4, were converted to natural gas firing. These operated at between 10 and 20 percent capacity factor.

Oil/Gas Steam. Possum Point Unit 5 and Yorktown Unit 3 operated at 4 and 1 percent capacity factor, respectively. These units are costly to operate but are maintained on-line to assure availability if needed for grid balancing.

Other. The EPA's suggested "preserved nuclear" generation is not included in the 2012 baseline case, but the 2012 renewable level of 2,538,443 is included.

The units cited above provided a total generation of 39,336,399 MWh, which is nearly identical to the baseline of 39,336,386 MWh actually recorded in 2012. This portfolio of generation produced a CO_2 emissions rate of 1,180 lbs/MWh, exceeding the 2020 standard of 991 lbs/MWh.

If Virginia were allowed to include its 27,421,250 MWh of nuclear generation (based on 2012) as a part of compliance, the CO_2 emissions rate would be approximately 695 lbs/MWh.

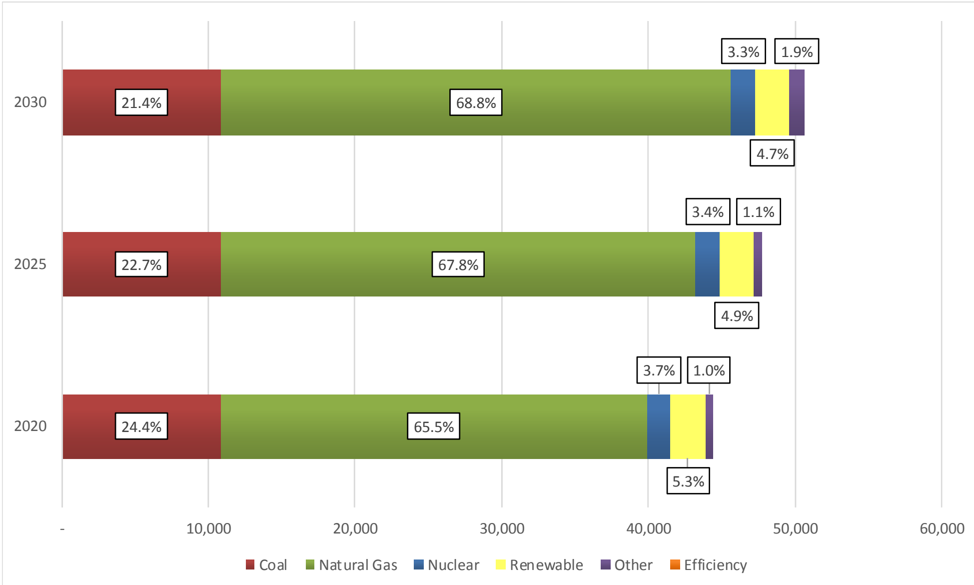
Scenario 2. Role of Preserved Nuclear

The role of nuclear generation is explored for 2020 and 2025. Figure 6-4 shows the generation mix under Scenario 2, which is summarized in Table 6-4Table 6-4: Scenario 2 – Electricity Generation by Source (in 1,000 MWh).

Table 6-4: Scenario 2 – Electricity Generation by Source (in 1,000 MWh)

Year	Coal	Natural Gas	Nuclear	Renewable	Other	Efficiency	Total
2020	10,834	29,050	1,645	2,358	464	-	44,353
2025	10,834	32,381	1,645	2,358	541	-	47,760
2030	10,834	34,805	1,645	2,358	953	-	50,595

Figure 6-4: Scenario 2 – Energy Generation Portfolio



Projections for 2020 and 2030

Scenario 2 is identical to Scenario 1, with the exception that the EPA recommended building block assumption of "preserved" nuclear-derived generation is included in both the projected generation totals and is considered in calculating the CO_2 emissions rate.

The inventory of coal-fired, existing NGCC, oil/gas steam boilers, and renewable sources is identical to Scenario 1 in terms of installed base and capacity factor. The EPA's allocation of 1,645,275 MWh of nuclear generation is included in the 2012 portfolio.

The generation added by including nuclear must be compensated for by a reduction in generation from other sources. The newest NGCC units were selected for decreased generating rates, consistent with the Scenario 1 assumption. As a result, the generating capacity for Warren and Brunswick County units were operated at 7 percent and 5 percent, respectively.

The CO_2 emission rate for Scenario 2 decreases to 1,142 lbs/MWh, still exceeding the 991 and 810 lbs/MWH values for 2020 and 2030, respectively.

Projections for 2025

A portfolio for compliance with 2025 was developed targeting a CO_2 emission rate of 885 lbs/MWh. The portfolio was adjusted by eliminating generation from the new NGCC units and adding renewable resources.

Both of the new NGCC units, in Warren and Brunswick Counties, were assigned a capacity factor of zero. Renewable generation was assumed to be 3,750,000 MWh, 38 percent of the EPA's recommended value for that timeframe.

A generating portfolio system CO_2 emission rate of 1,110 lbs/MWh results, exceeding the target value of 885 lbs/MWh.

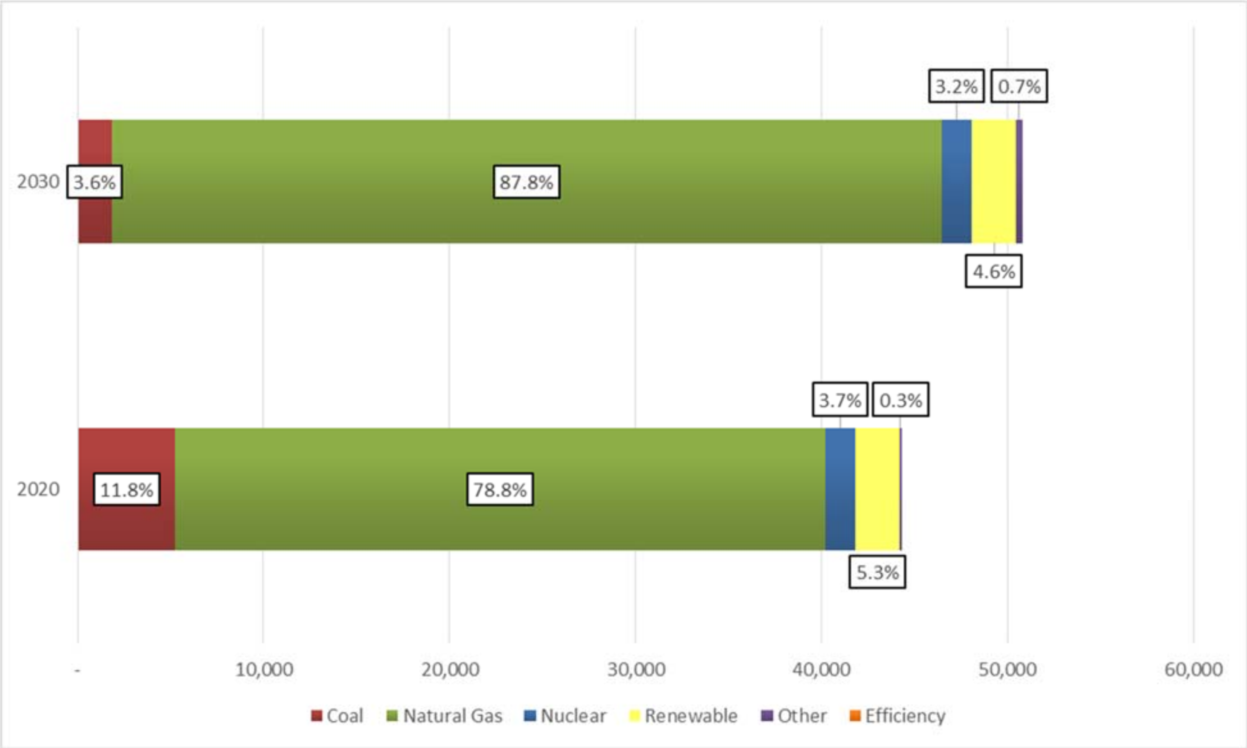
Scenario 3: Role of New Capacity

Scenario 3 evaluates the role of new generating capacity (exclusively NGCC) on generation and CO_2 compliance for 2020 and 2030. The results are considered separately for each of those years. Table 6-5 presents a summary of the results for Scenario 3 and Figure 6-5 shows the projected generation mix under this scenario.

Table 6-5: Scenario 3 – Electricity Generation by Source (in 1,000 MWh)

Year	Coal	Natural Gas	Nuclear	Renewable	Other	Efficiency	Total
2020	5,248	34,932	1,645	2,358	122	-	44,306
2030	1,826	44,619	1,645	2,358	365	-	50,814

Figure 6-5: Scenario 3 – Energy Generation Portfolio



Projections for 2020

The results from this analysis show:

<u>Coal-fired Units</u>. All units at Bremo Bluff, Clinch River, Glen Lyn, Potomac River, and Yorktown are retired. Operations are terminated for Chesterfield Units 3-5 (based on unit capacity and age) and Clover Units 1-2 (based on CO_2 emission rate). Generating capacity is reduced from 2012 levels for Birchwood (to 42 percent), Chesterfield 6 (to 35 percent), and Virginia City Hybrid (to 42 percent). A heat rate improvement of 2 percent is assumed.

The heat rate improvement for Birchwood and Chesterfield, assumed to be 3 percent for historical capacity factors, is reduced to 2 percent because of the average of 40 percent capacity factor. The CO_2 emissions rate at Virginia City Hybrid is lowered by 20 percent based on switching of fuels from waste coals to an eastern bituminous coal, and including up to 20 percent biomass fuel as co-firing.

Existing NGCC. The NGCC units of largest capacity and lowest CO_2 emission rate (Bear Garden, Chesterfield, Possum Point, and Tenaska) were assumed to operate at 65 percent capacity factor. The NGCC units with the highest CO_2 emission rates (Bellmeade, Doswell, and Gordonsville) were assigned low (10 percent) or zero capacity factors.

Oil/Gas Steam. Operation of the Possum Point and Yorktown units was terminated because of a combination of high variable operating cost and high CO_2 emissions.

New NGCC Units. The new NGCC units for which construction commenced by January 18, 2014, (Warren County and Brunswick County) were assigned a 67 percent capacity factor.

Other. “Preserved” nuclear was included at 6 percent of 2012 generation (1,645,275 MWh) and renewable sources assumed to generate 2,358,443 MWh.

Results. These conditions enable Scenario 3 to deliver the required 2020 generation of 39,336,386 MWh with a CO_2 emissions rate of 952 lbs/MWh, meeting the 2020 standard of 991 lbs/MWh.

Projections for 2030

Table 6-5 presents a summary of the results for Scenario 3 for 2030, with Figure 6-5 showing the projected generation mix. The results show:

Coal-fired units. All large coal-fired units subject to the EPA CPP proposed rule will be retired under this scenario, while some small coal plants may remain operational. The high capacity factor of low-emitting NGCC plants results in this change in coal-fired generation.

Existing NGCC. The capacity factor for existing large NGCC units was increased slightly from the 2020 case to 70 percent, while an additional unit at Chesterfield was bought into service. Specifically, the following NGCC units were awarded 70 percent capacity factor: Bear Garden, Chesterfield, Dowell, Possum Point, and Tenaska. Capacity factors of zero were assigned to Bellemeade, Doswell and Gordonsville, as these units operate at lower efficiency with higher CO_2 generation.

Oil/Gas Steam. Operation of Possum Point and Yorktown units is terminated.

New NGCC Units. The capacity factor for the new NGCC units (Warren County and Brunswick County) was increased to 70 percent.

Other. The “preserved” nuclear and renewables contributions were retained at the same values, as Scenario 2: 1,645,275 and 2,358,443 MWh, respectively.

Results. These conditions enable Scenario 3 to deliver the required 2030 generation of 39,336,386 MWh with a CO_2 emissions rate of 800 lbs/MWh, meeting the 2030 standard of 810 lbs/MWh.

In its proposed rules, the EPA assumes that on-going construction at new nuclear facilities in five states will be completed and these are taken into consideration by the EPA in its CO_2/MWh calculations for those states. Virginia’s North Anna #3 nuclear unit is not one of those units identified by EPA. There is currently nothing in the EPA CPP regulation that will allow use of “proposed,” but not yet permitted, nuclear facilities in the calculations. However, if the permit for North Anna #3 were expedited and executed as planned in the proposed seven-year construction window, using all of the planned output of North Anna #3 would lower the CO_2 emissions rate in Virginia to 792 tons of CO_2 per MWh by 2022, even without counting renewable energy, energy efficiency or preserved nuclear power in Virginia’s portfolio.

Scenario 4: Alternative CO_2 Emissions Rate

Scenario 4 evaluates the ability to comply with EPA’s alternative rate: 1175 lbs/MWh in 2020 and 962 lbs/MWh in 2025. The derivation of these EPA alternative CO_2 rates can be found on the EPA

Climate Change web site (EPA, 2014c). The EPA's concept is to allow a higher CO_2 emissions limit in the near-term (by 2020), but provide a shorter time period (only 5 years), to reach the final CO_2 rate by 2025. The slightly higher CO_2 rate changes the relative generation offered for coal-fired versus NGCC-fired assets.

Scenario 4 is addressed with an "Incremental Dispatch" and a "Green Dispatch" case. The discussion focuses on the former and the key differences versus the latter are highlighted.

Table 6-6 presents a summary of the results for the Incremental Dispatch case for Scenario 4 for 2020, Table 6-7 shows the Green Dispatch case, and Figure 6-6 and Figure 6-7 graphically represent the projected generation mix.

Table 6-6: Scenario 4 (Incremental Dispatch) – Electricity Generation by Source (in 1,000 MWh)

Year	Coal	Natural Gas	Nuclear	Renewable	Other	Efficiency	Total
2020	8,961	30,931	1,645	2,358	22	331	44,248
2025	5,096	34,735	1,645	5,055	265	1,162	47,958

Table 6-7: Scenario 4 (Green Dispatch) – Electricity Generation by Source in (1,000 MWh)

Year	Coal	Natural Gas	Nuclear	Renewable	Other	Efficiency	Total
2020	7,102	30,931	1,645	4,459	22	314	44,472
2025	4,802	33,067	1,645	7,000	265	1,090	47,870

Figure 6-6: Scenario 4 (Incremental Dispatch) – Energy Generation Portfolio

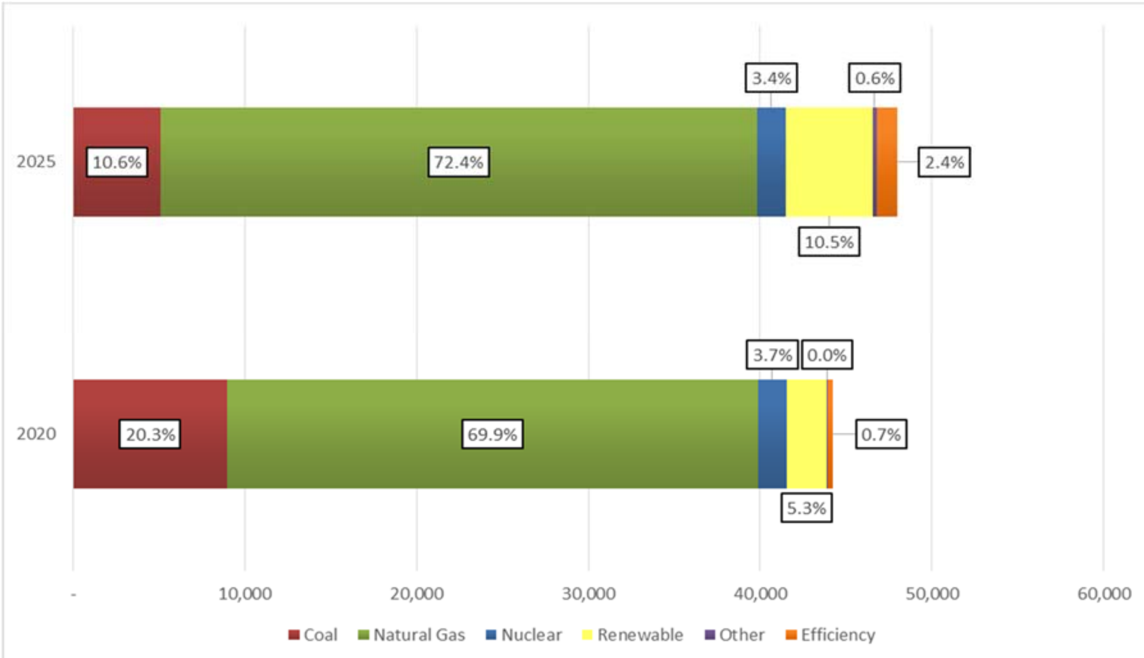
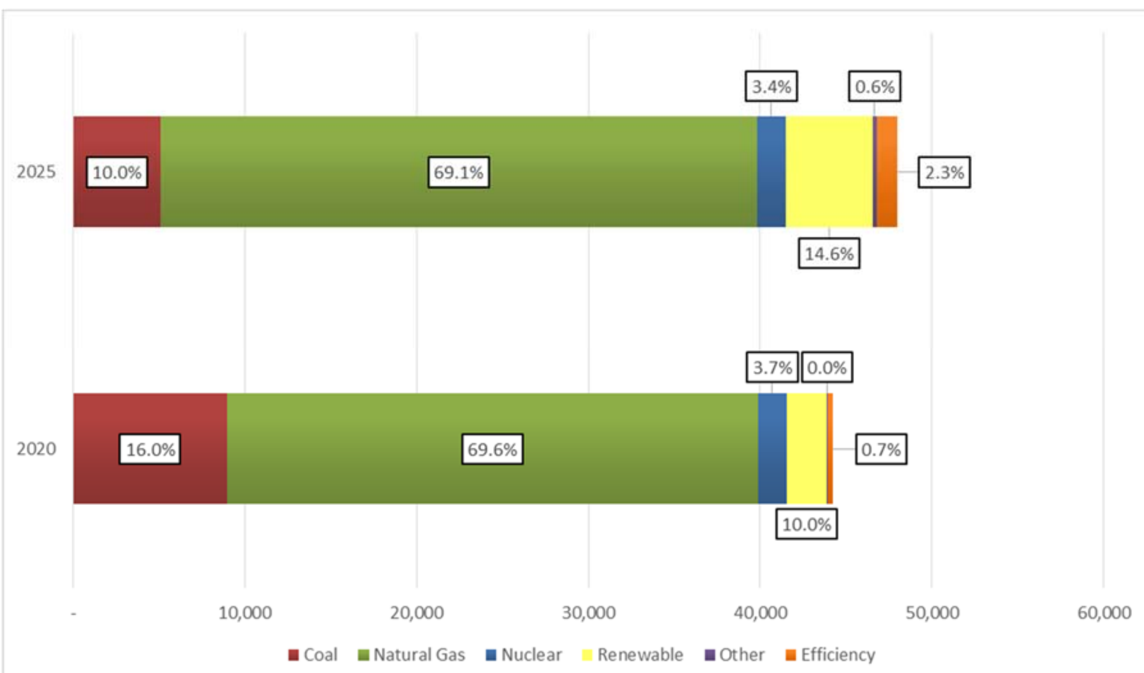


Figure 6-7: Scenario 4 (Green Dispatch) – Energy Generation Portfolio



Projections for 2020

Coal-fired units. All remaining coal-fired units operate between 35 and 42 percent capacity factor, with the generation approximately in inverse order to the CO_2 emissions rate. Operating units are Clover units 1-2 (35 percent), Birchwood (42 percent), Chesterfield units 5 and 6 (45 and 40 percent, respectively), and Virginia City Hybrid Energy Center. The total coal-derived generation is 9,548, 488 MWh. A heat rate improvement of 2 percent is assumed.

Similar to Scenario #3, the heat rate improvement for Birchwood and Chesterfield is 2 percent, limited by the penalty of operating at approximately 40 percent capacity factor. As noted previously, the best payoff in limiting CO_2 emissions is possibly to exploit the fluid bed boilers at Virginia City to fire up to 20 percent biomass and blend mined Appalachian coal with about 20 percent by weight "waste" coal.

Existing NGCC. The NGCC units operate at lower capacity factor than in previous scenarios. Bear Garden, Chesterfield, Possum Point, and Tenaska NGCC units operate at 50 percent capacity factor; units with the highest CO_2 emission rates (Bellmeade, Doswell, Gordonsville, and Hopewell) were assigned low (5 percent) or zero capacity factors.

Oil/Gas Steam. Operation of Possum Point and Yorktown units is terminated due to a combination of high variable operating cost and high CO_2 emissions.

New NGCC Units. The new NGCC units were assigned a 65 percent capacity factor, representing a slight decrease from Scenario 3's 2020 case.

Other. "Preserved" nuclear was included at 6 percent of 2012 generation (1,645,275 MWh). In this Incremental Dispatch case renewables were retained at 2,358,443 MWh and energy efficiency met the 2020 target of 331,215 MWh (0.95 percent of fossil generation).

These conditions enable Scenario 4 to deliver the required 2020 generation of 39,336,386 MWh with a CO_2 emissions rate of 1,069 lbs/MWh, meeting the alternative CO_2 2020 standard of 1,175 lbs/MWh.

Projections for 2025

Table 6-6 presents a tabular summary of the results for the Scenario 4 Incremental Dispatch case for 2025, with the projected generation mix represented in Figure 6-6. The results show:

Coal-fired units. Birchwood and Virginia City Hybrid Energy Center operate at the same capacity factor as projected for 2020 (42 percent). Chesterfield 5 and 6 operate at slightly lower capacity factors—35 percent (versus 40 and 45 percent, respectively). A heat rate improvement of 2 percent is assumed.

Existing NGCC. Capacity factor for the following units increases slightly: Bear Garden, Chesterfield, Possum Point, and Tenaska NGCC units operate at 55-65 percent. As for the 2020 case, zero capacity factors were assigned to Bellemeade, Doswell and Gordonsville.

Oil/Gas Steam. Operation of Possum Point and Yorktown units is terminated.

New NGCC Units. The capacity factor for the new NGCC units (Warren County and Brunswick County) increases slightly to 68-69 percent.

Other. The “preserved” nuclear and renewables contributions were retained at the same values as Scenarios 2 and 3—1,645,275 MWh and 2,358,443 MWh, respectively—with the latter at 53 percent of EPA’s target This case for Scenario 4 assumed energy efficiency met the targeted value at 3.67 percent of fossil generation.

These conditions enable Scenario 4 to deliver the required 2025 generation of 39,336,386 MWh with a CO_2 emissions rate of 857 lbs/MWh, meeting the 2025 alternative CO_2 standard of 962 lbs/MWh.

The Green Dispatch case increased renewable generation to 100 percent of EPA's target for 2020 and 71 percent of the 2025 target—the shortfall with the latter due to the accelerated time frame over which to deploy the yet-to-be defined renewable resources. The Green Dispatch case also assumed the 2025 target for energy efficiency could be attained. As a result, small to modest decreases in capacity factor for several units were absorbed to retain generation at 39,336,386 MWh. The Green Dispatch case lowered CO_2 emissions to 1040 and 857 lbs CO_2/MWh, as shown in Table 6-7 and Figure 6-7.

Scenario 5: NGCC Only

Scenario 5 evaluates the concept of using solely NGCC to comply with EPA's CO_2 rates of 991 and 810 lbs/MWh for 2020 and 2030, respectively, with all coal-fired generation terminated. Renewable generation is set close to the EPA recommended value at 5,750,000 MWh. Both an "Incremental Dispatch" and "Green Dispatch" case were addressed.

Table 6-8 presents a summary of the results for the Scenario 5 Incremental Dispatch case, for 2020, with the projected generation mix shown in Figure 6-8.

Table 6-8: Scenario 5 (Incremental Dispatch) – Electricity Generation by Source (in 1,000 MWh)

Year	Coal	Natural Gas	Nuclear	Renewable	Other	Efficiency	Total
2020	-	35,842	1,645	5,700	751	388	44,327
2030	-	40,114	1,645	5,700	1,311	388	49,158

Table 6-9: Scenario 5 (Green Dispatch) – Electricity Generation by Source (in 1,000 MWh)

Year	Coal	Natural Gas	Nuclear	Renewable	Other	Efficiency	Total
2020	-	36,591	1,645	5,700	49	389	44,373
2030	-	34,948	1,645	9,500	609	2,397	49,099

Figure 6-8: Scenario 5 (Incremental Dispatch) – Energy Generation Portfolio

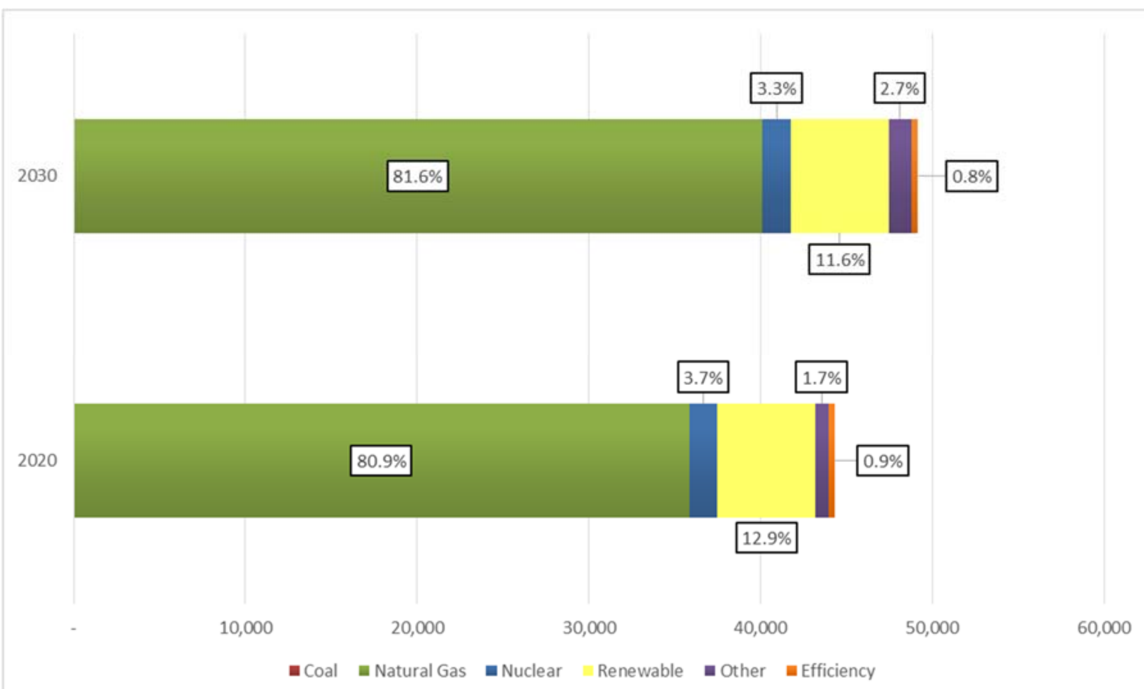
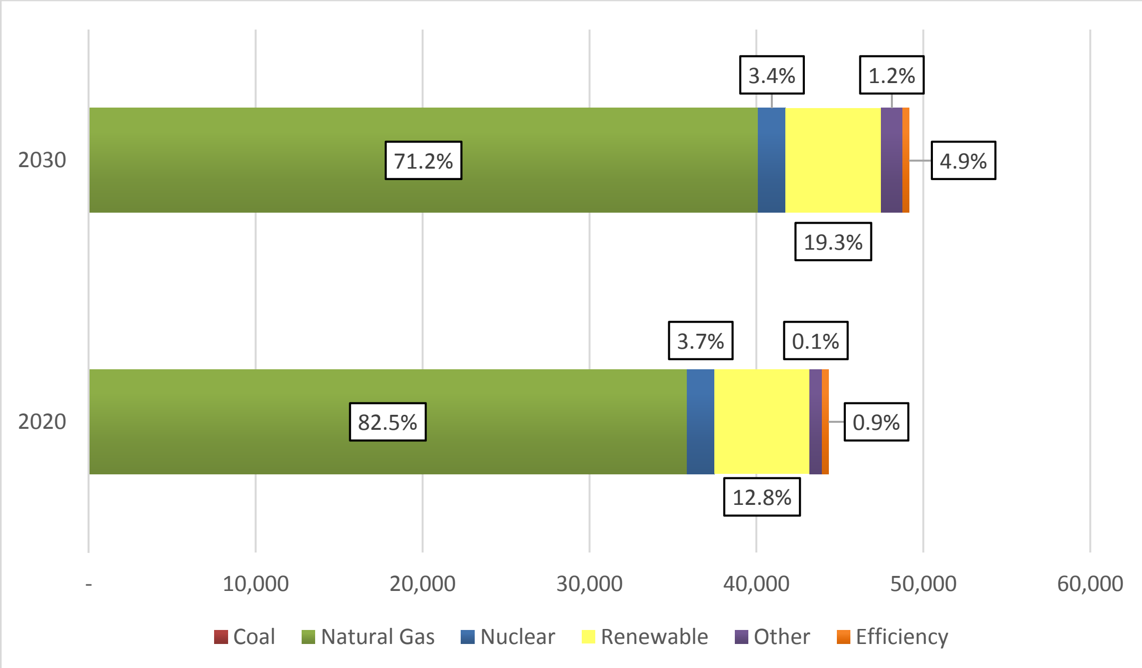


Figure 6-9: Scenario 5 (Green Dispatch) – Energy Generation Portfolio



Projections for 2020

Coal-fired units. All coal-fired units are removed from service.

Existing NGCC. Most existing NGCC units operate at 50-60 percent capacity factor: Bear Garden (60 percent), Chesterfield (50 percent), Possum Point (50 percent), and Tenaska (60 percent). Only Bellmeade, Doswell, Gordonsville, and Hopewell operate at 20 percent or lower capacity factor.

Oil/Gas Steam. Operation of Possum Point and Yorktown units is retained at 5 percent capacity factor in the incremental dispatch case, but in the green case these units are retired.

New NGCC Units. The new NGCC units were assigned a 70 percent capacity factor. In addition, two units each at Clinch River and Bremo were converted to natural gas, and assigned a low capacity factor (10 percent) due to relatively low efficiency and high CO_2 emissions.

Other. “Preserved” nuclear was included at 6 percent of 2012 generation (1,645,275 MWh), renewable generation was set at 5,700,000 MWh, and energy efficiency/demand side management (DSM) deployed at 1.23 percent of generation, equivalent to 388,148 MWh.

These conditions enable Scenario 5 to deliver the required 2020 generation of 39,336,386 MWh with a CO_2 emissions rate of 735 lbs/MWh, well below the CO_2 2020 standard of 991 lbs/MWh.

Projections for 2030

Table 6-8 presents a tabular summary of the results for the Incremental Dispatch case for Scenario 5 for 2030. The results show:

Coal-fired units. All coal-fired units are removed from service.

Existing NGCC units operate at the same capacity factors as for the 2020 case. Specifically: Bear Garden, Chesterfield, Possum Point, and Tenaska all operate at 50 percent. Bellmeade, Doswell, Gordonsville, and Hopewell operate at 20 percent or less capacity factor.

Oil/Gas Steam. Operation of Possum Point and Yorktown units is terminated.

New NGCC Units were assigned a 70 percent capacity factor. The units at Clinch River and Bremo converted to natural gas continue are terminated.

Other. “Preserved” nuclear was included at 6 percent of 2012 generation (1,645,275 MWh), renewables retained at 5,700,000 MWh, and energy efficiency/DSM deployed at 1.23 percent of generation or 385,778 MWh.

These conditions enable Scenario 5 to deliver the required 2030 generation of 39,336,386 MWh with a CO_2 emissions rate of 735 lbs/MWh, well below the CO_2 2020 standard of 810 lbs/MWh.

The Scenario 5 Green Dispatch case increased renewable generation to 100 percent of EPA's target for 2020 and 85 percent of the 2030 target—the shortfall with the latter due to anticipated barriers in raising capital, identifying adequate sites, and financing large projects. The Green Dispatch case also assumed the 2030 target for energy efficiency could be attained. Small to modest decreases in capacity factor were imposed on several units to retain the generation at 39,336,386 MWh. The Green Dispatch case lowered CO_2 emissions to 757 and 572 lbs CO_2/MWh. These results are shown in Table 6-9 and Figure 6-9.

Scenario 6: Compliance with 2020, 2030 CO_2 Emissions Rate

Scenario 6 evaluates the ability of the Commonwealth to comply with EPA's base case target rates of 991 lbs/MWh in 2020 and 810 lbs/MWh in 2030 using the EPA building blocks. Table 6-10 presents a summary of the results for the Incremental Dispatch case for Scenario 6 for 2020. A graphical representation of the generation mix is in Figure 6-10.

Table 6-10: Scenario 6 (Incremental Dispatch) – Electricity Generation by Source (in 1,000 MWh)

Year	Coal	Natural Gas	Nuclear	Renewable	Other	Efficiency	Total
2020	6,476	33,347	1,645	2,500	49	314	44,331
2030	4,227	39,107	1,645	5,700	487	388	51,554

Table 6-11: Scenario 6 (Green Dispatch) – Electricity Generation by Source (in 1,000 MWh)

Year	Coal	Natural Gas	Nuclear	Renewable	Other	Efficiency	Total
2020	6,476	31,456	1,645	4,459	49	406	44,490
2030	4,268	34,379	1,645	9,500	487	1,345	51,624

Figure 6-10: Scenario 6 (Incremental Dispatch) – Energy Generation Portfolio

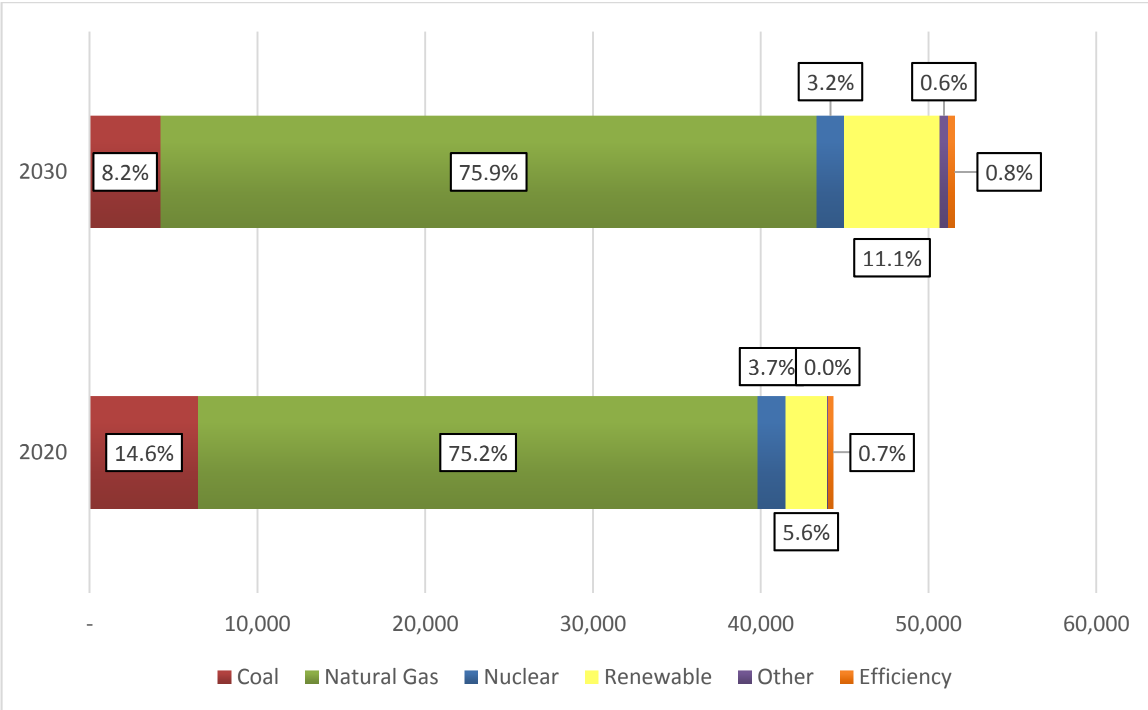
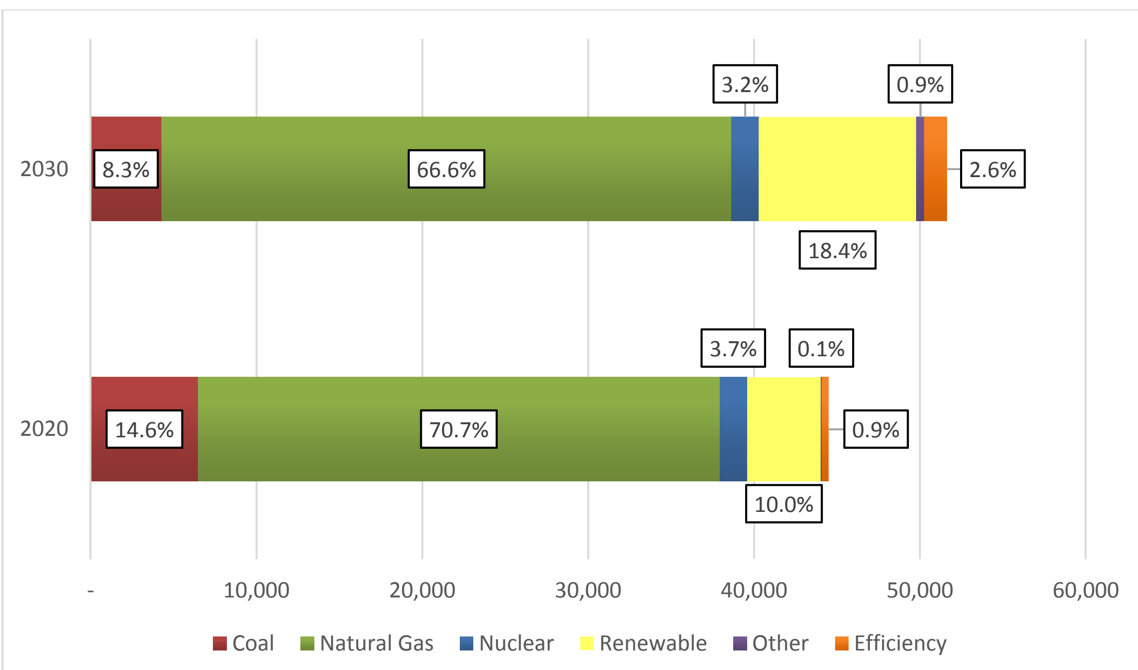


Figure 6-11: Scenario 6 (Green Dispatch) – Energy Generation Portfolio



Projections for 2020

The results show:

Coal-fired units. All remaining coal-fired units operate at 45-47 percent capacity factor. A 3 percent heat rate improvement is assumed. These include Birchwood (47 percent), Chesterfield 6 (45 percent), and Virginia City Hybrid Energy Center (47 percent). The total coal-derived generation is 6,214,870 MWh.

The heat rate improvement for Birchwood and Chesterfield is 3 percent because these units operate near 50 percent capacity factor. As with prior scenarios, the best payoff in CO_2 emissions mitigation is exploiting the fluid bed boilers at Virginia City to fire up to 20 percent biomass and blend Appalachian coal with "waste" coal to lower CO_2 emissions by about 20 percent.

Existing NGCC. Most existing NGCC units operate at capacity factors between 55 and 60 percent. Bear Garden operates at 60 percent, while Chesterfield, Possum Point, and Tenaska NGCC units operate at 55 percent capacity factor. Those with the highest CO_2 emission rates were assigned low (20 percent) or zero capacity factors: Bellmeade, Doswell, Gordonsville, and Hopewell operate at zero to 20 percent capacity factor.

Oil/Gas Steam. Operation of Possum Point and Yorktown units is terminated.

New NGCC Units are assigned a 60 percent capacity factor.

Other. Preserved nuclear is included at 6 percent of 2012 generation (1,645,275 MWh) and renewables are set at 2,500,000 MWh, or 56 percent of EPA's target. Energy efficiency/DSM is assumed to attain 65 percent of EPA's target (313,797 MWh).

These conditions enable Scenario 6 to deliver the required 2020 generation 39,336,386 MWh with a CO_2 emissions rate of 979 lbs/MWh, meeting the alternative CO_2 2020 standard of 991 lbs/MWh.

Projections for 2030

Table 6-10 presents a tabular summary of the results for the Incremental Dispatch case Scenario 6 for 2030, with the projected generation mix shown in Figure 6-10. The results show:

Coal-fired units. Birchwood, Chesterfield 6, and the Virginia City Hybrid operate at extremely low capacity factors of 20-23 percent. The heat rate benefit is reduced to 1 percent.

Existing NGCC stations with the highest CO_2 emission rates are terminated. The remaining units (Bear Garden, Chesterfield, Possum Point, and Tenaska) operate at 55-65 percent.

Oil/Gas Steam. Operation of Possum Point and Yorktown units is terminated.

New NGCC Units. The capacity factor for the new NGCC units (Warren County and Brunswick County) is 68 percent.

Other. The “preserved” nuclear and renewables contributions are set at the same values as in other scenarios, 1,645,275 and renewables increase to 5,700,000 MWh—51 percent of EPA’s target. The Incremental Dispatch case for Scenario 6 includes only 11 percent of the targeted value of energy efficiency/DSM at (388,428 MWh).

These conditions enable the Incremental Dispatch case for Scenario 6 to deliver the required 2030 generation of 39,336,386 MWh with a CO_2 emissions rate of 792 lbs/MWh, meeting the 2030 alternative CO_2 standard of 810 lbs/MWh.

The Scenario 6 Green Dispatch case increased renewable generation to 100 percent of EPA’s target for 2020 and 85 percent of the 2030 target—the shortfall with the latter due to anticipated barriers in raising capital, identifying adequate sites, and financing large projects. The Green Dispatch case also assumed the 2030 target for Energy Efficiency could be attained. Small to modest decreases in capacity factor were imposed on several units to retain generation at 39,336,386 MWh. The Green Dispatch case lowered CO_2 emissions to 922 and 689 lbs/MWh, as shown in Figure 6-11 and Table 6-11.

Impacts of Compliance

The analysis of the scenarios demonstrates that it is possible for Virginia to comply with the requirements of the EPA's CPP proposed regulations in a number of different ways. The analysis also shows that both the EPA's preferred option for an emissions rate of 810 lbs/MWh in 2030 and the alternative compliance standard of 962 lbs/MWh in 2025 can be achieved. Figure 6-12 and Figure 6-13 illustrate the emissions rates under the various scenarios in 2020 and 2030.

Figure 6-12: Virginia's Projected 2020 CO_2 Rate by Scenario vs EPA Target CO_2 Rate (in lbs of CO_2/MWh)

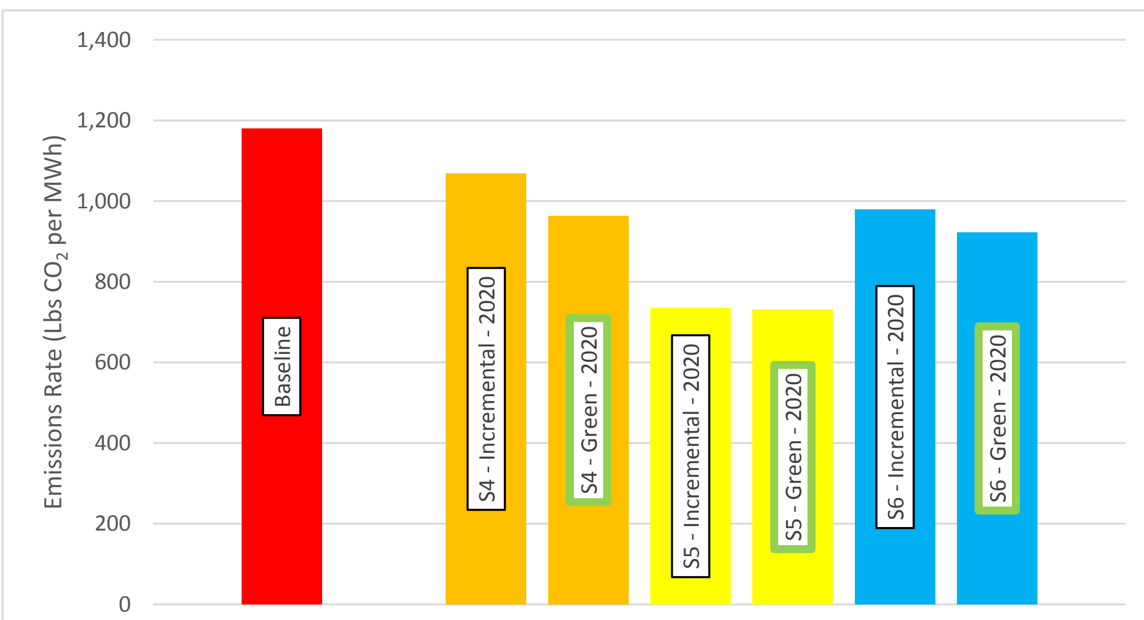
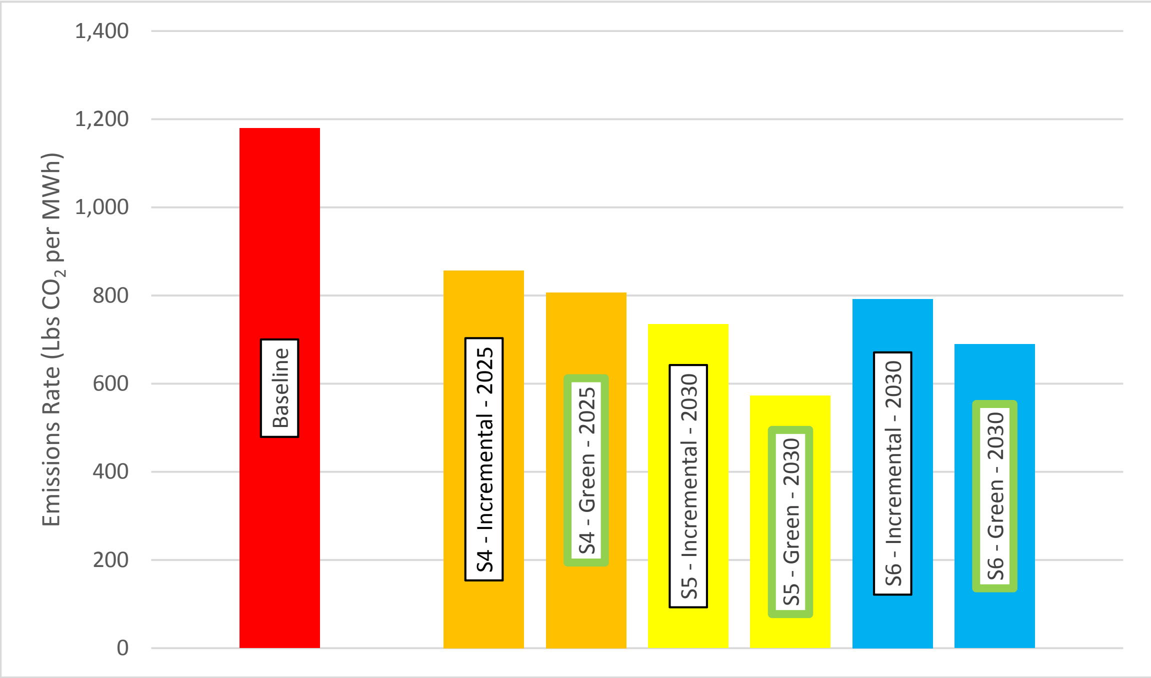
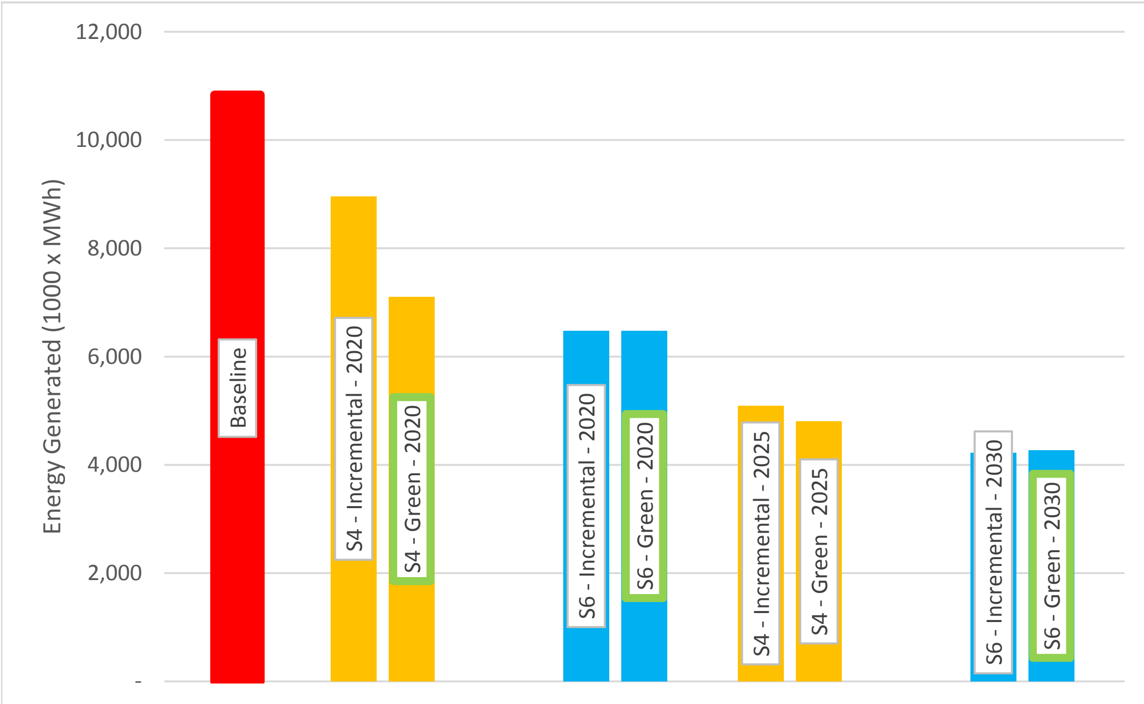


Figure 6-13: Virginia's Projected 2030 CO_2 Rate by Scenario vs EPA Target CO_2 Rate (in lbs of CO_2/MWh)



Each case, however, required significant changes in the generation mix in the Commonwealth. Figure 6-14 shows how the coal generating units in Virginia would be dispatching power in 2020, compared to the 2012 baseline. Dispatched power from each unit is less than half of 2012 rates in all scenarios.

Figure 6-14: MWh of Compliance Coal Units in each Scenario



The analysis shows a very different adjustment for natural gas generating units under all scenarios. Figure 6-15 shows how natural gas generation in Virginia is projected to change under the various scenarios while Figure 6-16 shows the projected change in renewable generation. These increases could be higher than projected, based on the ability of renewable energy and energy efficiency to meet the projected growth.

Figure 6-15: MWh Generated at all Virginia NG Units in 2020 vs EPA 2012 Base (in million MWh)

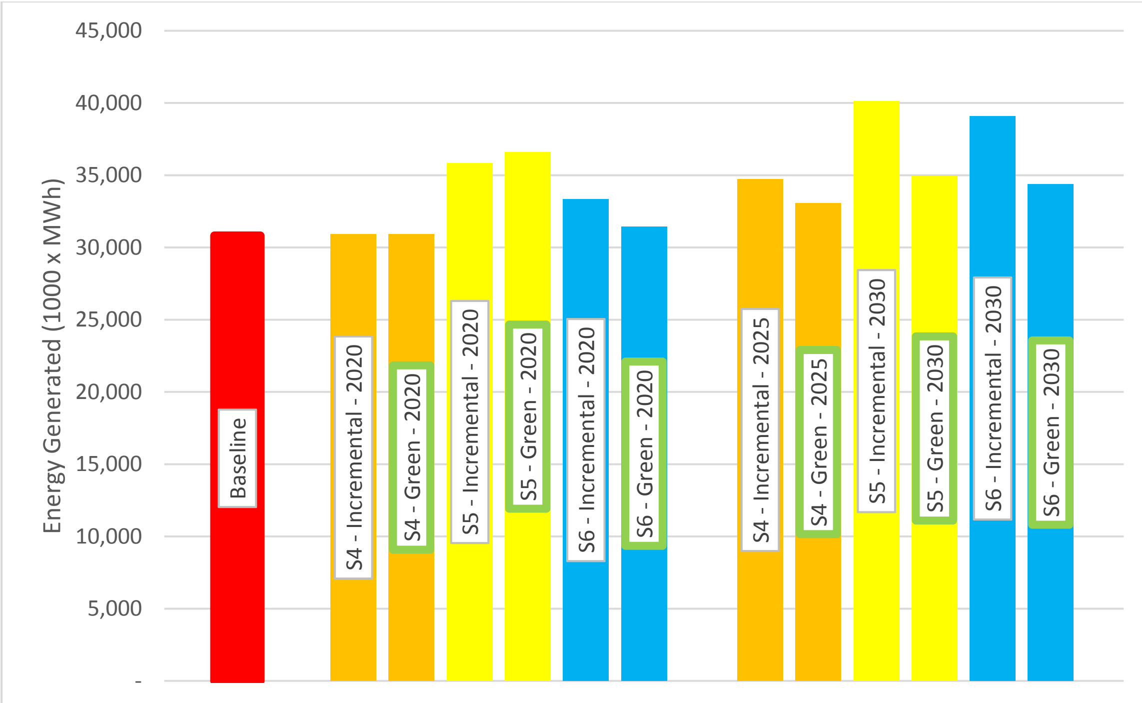
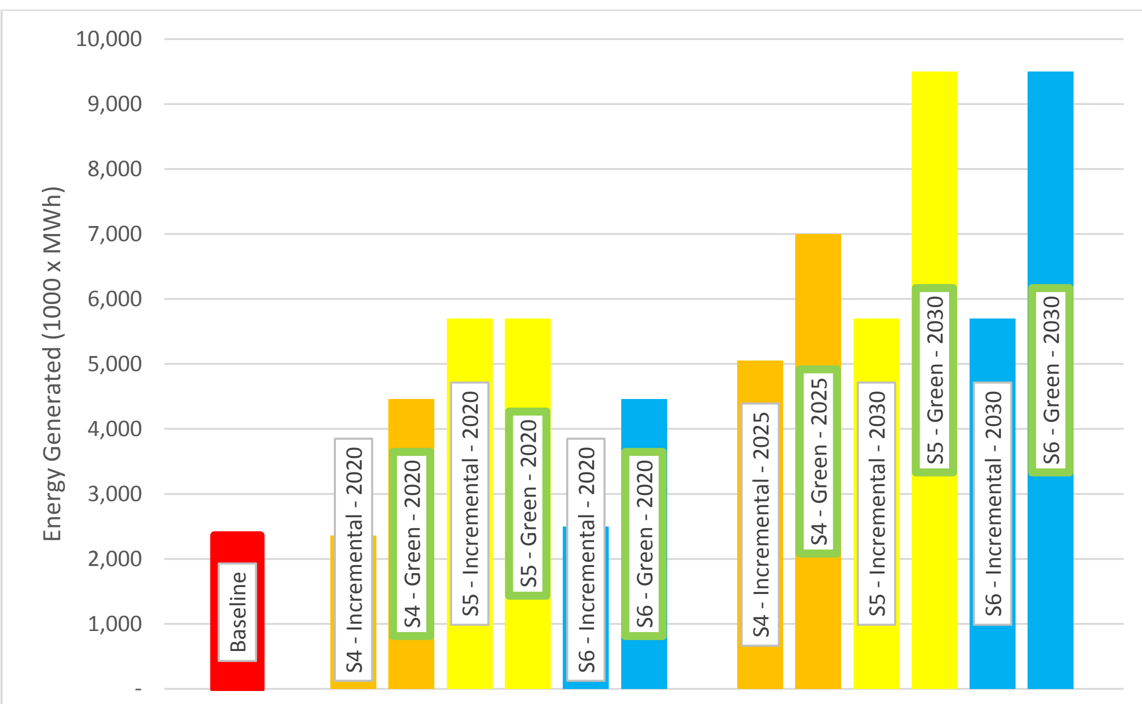


Figure 6-16: MWh of Renewable Generation Units in each Scenario (in million MWh)



The analysis of the scenarios merely demonstrates that compliance with the EPA proposed rules is theoretically possible; however, further consideration of the means of compliance and the costs and benefits is necessary in order to determine the true feasibility and impacts of compliance.

Section 7. Flexibility for the Commonwealth of Virginia

While the EPA's proposed rules provide particular targets which drive future power generation toward a very different mix, the proposal also includes some flexibility. The analysis completed for this report also identified other possible policy options for the Commonwealth, which are discussed in Section 9.

Flexible Mechanisms found in the EPA Clean Power Plan Rule

The primary flexibility in the EPA's proposed rules involves the potential use of multi-state compliance plans. The EPA will allow states to convert their rate-based goals (expressed in pounds of CO_2 per MWh) to what EPA terms "mass-based goals" (i.e., tons of CO_2 allowed) and thus participate in regional CO_2 cap and trade programs. While the EPA encourages a multi-state approach and suggests that it may be more cost effective, the EPA does not offer states a "model trading rule" or any type of model federal trading platform for use in the design of multi-state approaches.

The EPA, in its Clean Power Plan (CPP) "Fact Sheet" of June 2, 2014, provides guidance as to how states may meet their CO_2 goals through measures that reflect their particular circumstances. The EPA says that states may:

1. Look broadly across the power sector for strategies that result in reductions
2. Invest in existing energy efficiency programs or create new ones
3. Consider market trends toward improved energy efficiency and reliance on low emitting power sources
4. Expand renewable energy generating capacity
5. Increase investments being made to upgrade aging infrastructure
6. Integrate their state plans into the existing power sector planning process

7. Design plans that use innovative cost effective regulatory strategies
8. Develop a state-only plan or collaborate with others to develop a plan on a multi-state basis.

In this section of the report, we will focus on the potential to utilize the collaborative or multi-state flexibility approach as found in option number eight above.

Background—Cap and Trade Programs

Two notable cap and trade programs could serve as models, the US Acid Rain Program and the Regional Greenhouse Gas Initiative.

US Acid Rain Program

The most widely known and successful cap and trade program was the US Acid Rain Program established by Title IV of the 1990 Amendments to the Clean Air Act. This nationwide program took baseline heat input (1985-1987 average) and then applied a standard US EPA SO_2 factor to each affected unit's historic baseline to calculate the number of tons or allowances that would be granted to each unit, in other words its SO_2 emission cap.

Electronic continuous emission monitors (CEMS) were installed before the program commenced. Compliance was then tested once a year. Emitting units were required to hold a number of allowances in their compliance accounts equal to or greater than the annual SO_2 emissions reported to the EPA by the CEMS. If a unit did not hold sufficient allowances then it was fined and future allowance allocations were deducted. If a unit held excess allowances, these could be sold to others who found themselves in a shortfall position. Thus, this SO_2 trading program introduced the economic concepts of incentives and compliance flexibility into the environmental compliance arena. In the 1980s, utility sector SO_2 emissions totaled over 18 million tons per year. Today, as a result of the SO_2/Acid Rain cap and trade program, these emissions have fallen to well below 5 million tons nationwide.

The US Congress did not provide a mechanism for changing or modifying future caps, and as the EPA attempted to make these caps more stringent via regulation and not via legislation, the changes were challenged in court, which brought about massive market uncertainty. Participants began to lose confidence in its future viability and prices plummeted. SO_2 allowances that traded at a price of over $1,500 per ton in early 2006 today trade at approximately $1 per ton. Further details on the SO_2 allowance marketplace can be found in literature (Napolitano, et al., 2007).

Regional Greenhouse Gas Initiative

In 2003 the state of New York commissioned a study of the potential for a regional CO_2 trading program in the northeast. In 2005, a Memorandum of Understanding was created by the Regional Greenhouse Gas Initiative (RGGI) group, to be signed by each state choosing to participate. States had to enact enabling legislation to become full participants. RGGI was eventually established in 2009, with each state's program based upon its own statutory and/or regulatory authority. Guided by the RGGI Model Rule, each state's regulations limit emissions of CO_2 from electric power plants, establish participation in CO_2 allowance auctions, create CO_2 allowances, and determine appropriate allowance allocations.

Currently, nine northeastern states comprise the RGGI: Connecticut, Delaware, Massachusetts, Maine, Maryland, New Hampshire, New York, Rhode Island and Vermont. Conceptually, this program is set up as a cap and trade program, where fossil fueled power plants greater than 25MW’s are assigned a cap on their CO_2 emissions. Regionally the initial cap was set at 165 million tons for the period 2009 through 2014, but after a review of criticism of over-allocation in the program, the regional cap was lowered by 45 percent to 91 million tons in 2014.

Electricity generators in the RGGI states must purchase needed allowances from quarterly auctions, but, unlike the US Acid Rain Program, compliance is measured on a three-year basis rather than annually. Because of over-allocation, allowance prices in the first phase of the program hovered just below $3 per ton. Today, even with the lower overall allocation levels, offers to sell RGGI allowances were at $4.90 in late July 2014. One major issue the designers of RGGI had to contend with was the concept of how to deal with power being generated outside the RGGI footprint and brought into RGGI with no associated CO_2 penalty. This was called “leakage” by the RGGI group, and continues to be an issue when considering CO_2 emissions for power imports into RGGI states.

A wide array of opinions have been offered regarding RGGI’s success. According to some, the program has been very effective in meeting its goals. Others (Stavins in Legrand, 2013) have noted, “*what RGGI is today is a relatively modest electricity tax that is being used to fund energy efficiency programs in the states*.” However, RGGI indicates that the auction proceeds to date have resulted in a return of “more than $2 billion in lifetime energy bill savings” to regional electric customers (RGGI, 2014). RGGI indicates that the investments offset 8.5 million MWh of electrical generation and reduce CO_2 emissions by 8 million tons.

Like the US Acid Rain Program, the RGGI program has encountered changes in mid-stream through allowance reallocations, discounting of banked allowances, and states withdrawing from the program. These types of occurrences do not contribute to overall market confidence for long term compliance assurance.

Potential for Multi-State Collaborations

Collaborative or multi-state flexibility has been discussed by EPA in the Technical Supporting Document (TSD) titled “Projecting EGU CO_2 Emission Performance in State Plans,” dated June 2014. Any state that opts to use this multi-state compliance concept must still file a compliance plan in June 2016, but will also be allowed to file for extensions due to requirements to finalize other items such the state authorizing legislation and state regulatory procedures associated with a multi-state compliance program.

The state must convert the CO_2 rate goal to a tonnage goal for a specified time period. To accomplish this, according to the EPA's TSD, a mass-based CO_2 performance goal is calculated by projecting the tons of CO_2 that would be emitted during a state plan performance period (i.e., from 2020 to 2029) by the affected electric generating units (EGUs) in the state as if they were hypothetically meeting the state rate-based CO_2 goal established by EPA. The translation of a rate-based goal to tons is based upon a projection of affected EGU utilization and dispatch mix.

Note that the calculation suggested by EPA assumes the total absence of any state-specific emission reduction programs. The main issue addressed by EPA is what would happen to EGU CO_2 emissions if one applied the EPA rate goals (found in in the emission guidelines) instead of the measures in the state compliance plan. The EPA's TSD goes into some detail (pages 6-12) as to the virtual necessity of using a large scale dispatching model to project CO_2 emissions under a mass-based conversion and this complete process must be fully explained in the compliance plan submitted to EPA for approval. If Virginia chooses to pursue a mass-based tonnage compliance program, then the state could get access to entities that have experience with, and access to, such modelling tools in order to develop the required compliance plan.

The EPA strongly recommends that large computer-based electricity dispatch models be employed to calculate these mass-based tons for the State Implementation Plan (SIP); however, for simplicity's sake, an attempt has been made to manually estimate the conversion using available EPA data for Virginia for 2020. The simple reverse conversion formula (from the rate calculation) would be:

*Mass = rate limit * (2012 Affected Unit Generation + preserved nuclear*

+ any new nuclear + renewable generation + electrical efficiency (EE) savings).

From this formula, the estimated mass for Virginia in 2020 was calculated to be approximately 26.9 million tons of CO_2. Other estimates project different tonnage caps for Virginia for the year 2020.

Issues to Consider Before Embarking on a Tonnage Regional Compliance Program

In addition to the flexible mechanism of a mass-based tonnage trading program, the EPA CPP would also allow (a) a Flexible CO_2 intensity program and (b) a carbon price assignment program administered by an Independent System Operator (ISO). Alternative (a) would require the establishment of a state or multi-state regulatory compact that formally establishes the procedures to administer emissions reductions (in pounds per MWh) and to potentially establish a CO_2 credit (not allowance) trading program in the state or region. Alternative (b) most likely would require enabling legislation in each state to grant compliance responsibility to the regional ISO and enable the ISO to set an ever-changing CO_2 penalty (like an allowance price of CO_2) and this would be included in the dispatch algorithm for all affected EGUs. Carbon revenues must be addressed in the state enabling laws and in the operating procedures of the ISO under this flexibility alternative.

A recent paper (Gifford et al., 2014) addressing state implementation of CO_2 rules provides a guide to critical areas that states must consider, as they craft a compliance plan for this proposed EPA regulation:

- States will have little time to make crucial decisions regarding this CPP rule.
- Carbon Integrated Resource Plans (IRPs), will require new institutional arrangements and legislation.

- All EGU's must be involved in development of a State Carbon IRP, as well as non-regulated independent power producers (IPP's).
- Carbon driven planning could result in reintegration of restructured markets.
- Multi-state SIPs, while attractive, present legal and practical issues.
- Default Federal Implementation Plans may put state regulators in an awkward position.

Virginia and the RGGI

In order to better understand what involvement of Virginia in RGGI would entail, inquiries were made to senior officials of RGGI Inc. in New York City and to state commissioners serving on the Board of Directors of RGGI. From these discussions, the following criteria were highlighted pertaining to any state wishing to join RGGI:

- Must participate in the quarterly auction
- Must return proceeds to consumer benefit (renewables or efficiency, etc.)
- Must not dilute the strength of the RGGI cap
- State allowances must be transferable to others in RGGI

In addition, the state must sign the most recent RGGI MOU and have passed enabling legislation documenting the distribution of the proceeds to the various sectors.

Discussion

The EPA in the release of the Clean Power Plan suggests that there is a real possibility that states, through the use of flexible trading programs, have the potential to lower overall CO_2 compliance costs. Based on the analysis of existing emission trading programs and the opportunities for the Commonwealth to comply with EPA's proposed regulations contained in this report, Virginia should initially chart a course of independent compliance with the EPA proposed regulations.

Factors such as quickly identifying reciprocal states for partnering, enabling legislation, complex conversion from rate based compliance to mass based tons and other required legal actions make this a rational policy choice at this time. Another very large factor to further support this near term policy choice is the timing of the submittal of a Virginia CO_2 SIP Compliance Plan to the EPA in less than 24 months (June 2016). Many of the proposed flexible mechanisms as discussed in this section would require enabling legislation on the part of Virginia, or substantial changes to the regulatory compact that currently exists with the EGU's that the state regulates. Given that it took RGGI from 2003 when studies were begun until its first compliance year in 2009, a similar time frame does not adequately conform to the submission of a detailed compliance plan to EPA for this CO_2 regulation.

Virginia may want to consider the initiation of a parallel CO_2 compliance study that would look with greater detail into the implementation of a mass-based tonnage trading system. In addition, Virginia may wish to have state officials conduct preliminary exploratory discussions with neighboring states regarding the formation of such a program in the longer term.

Section 8. Implications of the EPA's Clean Power Plan

Based on the analysis and considerations previously discussed there are a number of implications of the EPA's proposed regulations under the CPP for the Commonwealth of Virginia. These implications relate to the reliability of electricity, the economic impacts of changes that may be required by the regulatory proposal, and environmental and health impacts of the proposed regulations.

Energy Markets and Reliability

One major consideration in ensuring system reliability is the preservation of a diverse energy portfolio for Virginia. Over reliance on one fuel makes Virginia's electrical system vulnerable to market fluctuations and supply disruptions. As a result, in looking at the scenarios presented in this report, it is critical to consider not only compliance with CO_2 emission targets, but also the full mix of generation in order to evaluate the impacts on energy markets and reliability.

The scenarios consider only "compliance generation", that is within the constraints of the EPA CPP. Scenarios 1 and 2, as examinations of baseline generation in 2012, do not bring the State of Virginia into compliance and therefore are not considered for system reliability. The remaining scenarios, 3 through 6, bring Virginia into compliance with the EPA CPP under both the Incremental Dispatch and Green Dispatch cases. This compliance generation was achieved primarily through greater reliance upon natural gas-fired electric power generation facilities.

Although the scenarios considered the total energy needs of the state, it should be stressed that the scenario generation mixes only dealt with compliance generation and not the total generation portfolio mix, which would include the entire nuclear generation output for the state. Because nuclear generation will still be available to 2030 and beyond, for approximately 40 percent of the total generation mix (without counting new nuclear from North Anna 3), it is a critical part of system reliability and source balance. Subsequent calculations show that natural gas could provide between 42 and 52 percent of the total electric power generation. This would represent a substantial change in the fuel generation mix for Virginia in 2020 and beyond.

Economic Impacts

Evaluating the economic impacts of these substantial changes must include consideration of the costs of compliance and sensitivity to fuel pricing. The cost of obtaining capital (e.g., interest on loans, bonds, etc.) and rates of return were not considered in the analysis below. Costs and savings are presented as annualized costs for the stated compliance years (2020, 2025 and 2030). Actual costs and savings in other years will vary.

Compliance Cost Estimation for the Incremental Dispatch Case

Since the EPA regulation was written specifically for existing power plants, it is not surprising that electricity producers in Virginia are expected to be affected the most under the different scenarios. To comply with the EPA target for new CO_2 emission, electricity producers in Virginia can choose different scenarios, with each of those resulting in different estimates for compliance cost.

Typically, electricity producers can use a variety of different strategies to meet the EPA target. The first method is fuel-switching. The electricity producer can reduce or retire power plants with higher CO_2 emission (in this case, most of them coal), while increasing the production from fuels with lower CO_2 emission, such as natural gas or renewable energy sources such as wind and solar. Reducing or retiring coal-fired plants can provide cost savings in terms of operation and maintenance (O&M) cost for such plants.[1] This study used national electricity generation costs from various fuel sources in estimating compliance cost (see Table 8-1, EIA, 2014a).[2]

Table 8-1: National Generation Cost

National Generation Cost ($/MWh 2019 Cost in 2012 Dollars)					
	Levelized Capital Cost	**Fixed O&M**	**Variable O&M (including fuel)**	**Transmission Investment**	**Total**
Nuclear	$71.40	$11.80	$11.80	$1.10	$96.10
Coal	$60.00	$4.20	$30.30	$1.20	$95.60
Natural Gas	$14.30	$1.70	$49.10	$1.20	$66.30
Biomass	$47.40	$14.50	$39.50	$1.20	$102.60
Renewable	$124.20	$18.70	$1.30	$4.20	$148.40
Source: EIA of Department of Energy					

When a coal plant is retired, however, the electricity producer incurs decommission costs, which arise from dismantling the plant and equipment and shipping them to waste treatment facilities. Industry research indicates that the cost of decommissioning varies, but the median cost in 2013 was $18.9 million for coal plants between 350 and 500 megawatts in size, which is equivalent to $44,470 per megawatt (E&E, 2013).

As shown in the analysis of generation scenarios (Section 6) electricity producers in Virginia need to expand electricity production to meet demand in plants using cleaner fuels, with natural gas,

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[1] In this study, capital cost was considered only when such plants have not started operation following the 2012 baseline. In the case of coal, since all plants are in operation, capital investment is considered a sunk cost. But for new renewable and certain natural gas plants, these costs can be substantial. This document is available at: http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf.

[2] Cost for renewables are the average of wind, off-shore wind, solar PV, solar thermal, and hydroelectric,. Only a small portion of Virginia electricity is produced via oil. The O&M cost is assumed to be $247, based on a study that indicates the O&M cost for oil is 10 times of that of nuclear. http://instituteforenergyresearch.org/analysis/electric-generating-costs-a-primer/.

biomass, and renewables as expansion candidates. For electricity producers, there are two main types of cost. Using NGCC plants as an example, if increased electricity output comes from existing plants by increasing the capacity factor, incremental cost will come from O&M as the plants purchase more fuel and other supplies to generate electricity. If the electricity producer also plans to construct new power plants that use cleaner fuels, the cost will also include capital expenditures (EIA, 2014a)[,3].The same method also applies to biomass and renewable generation.

For existing coal plants, electricity producers can also invest in new technology to increase the heat rate, which will result in lower CO_2 emissions per MWh. Nationally, the capital cost to install such technology is assumed to be $100/KW for 4 to 6 percent improvement in heat rate. Capital cost will be recovered over the lifespan of this technology. The levelized capital cost of heat rate improvement is $2.10 per MWh (EPA, 2014d). This study uses a capital cost of heat rate improvement of $67/KW, which is levelized to annual capital costs. After increasing heat rate, the plant can realize O&M cost savings because it will burn less coal, while producing the same amount of electricity. The O&M cost savings is negligible, however, due to a low capacity factor, as previously discussed in this report. Virginia City plant is a special case, and is excluded from heat rate improvements, since it is already uses a hybrid of coal and biomass.

Finally, the EPA proposal requires that states also reduce emissions by implementing demand conservation efforts. Those practices include encouraging consumers to use energy efficient appliances, upgrade windows, and improve building insulation. Based on a study by the EPA, the cost of levelized conservation is assumed to be 7.8 cents per KWh in 2020, and 9.2 cents per

[3] In this study, capital cost was considered only when such plants have not started operation following the 2012 baseline. This study used levelized capital cost, assuming the plant life is 30 years.

KWh in 2030 (in 2011 dollars). It is assumed that this cost is split in half between electricity producers and consumers such as individuals and businesses (EPA, 2014g).

Under Scenarios 1 and 2, the electricity generation mix will be at the 2012 baseline, with the addition of known changes in the generation mix from plant retirements and fuel switches. Under those two scenarios, Virginia will not be able to meet the EPA CO_2 emission target. Under Scenarios 3, 4, and 5, Virginia will be able to meet the EPA targets with different combinations of compliance strategies. Table 8-2 shows the total reduction in millions of tons of CO_2 emissions in the compliance years based on implementing those strategies.

Table 8-2: Total Reduction in CO_2 emissions compared to Scenario 2 (millions of tons)

Scenario	2020		2025		2030	
	Emissions	**Change**	**Emissions**	**Change**	**Emissions**	**Change**
2	22.49					
3	18.70	-3.79			15.75	-6.74
4	20.94	-1.54	16.94	-5.55		-
5	14.44	-8.05			14.44	-8.05
6	19.24	-3.25			15.57	-6.92

Table 8-3 presents the estimated compliance cost of the other scenarios, as compared with Scenario 2. For example, in Scenario 3, the total compliance cost is estimated to be $368.0 million (measured in 2012 dollars) in 2020. Only three coal-fired plants will be in operation, with the rest retired. Retired coal plants can provide O&M cost savings of $290.4 million (including cost of Virginia City), but decommissioning plants will incur a cost of $136.8 million. In addition, the cost of heat rate improvement for coal plants is estimated to be $10.3 million. Electricity output from biomass plants will be reduced, providing O&M cost savings. To meet demand, electricity production will increase from the use of natural gas, with increased cost (both O&M and levelized capital cost) estimated at $514.4 million. These estimated costs result in a cost $97 per ton of CO_2 reduced. In 2030, all coal-fired and oil-fired plants will be decommissioned, increasing both

O&M cost savings and decommissioning cost. Expanded production in NGCC plants could increase the cost further to $719.1 million. The total compliance cost in 2030 is estimated to be $499.9 million in 2012 dollars, or $74 per ton of CO_2 reduced.

Table 8-3: Estimated Annualized Compliance Costs and Savings for Electricity Producers

Estimated Compliance Costs and Benefits for Electricity Producers (2012 Dollars)								
	Scenario 3		**Scenario 4**		**Scenario 5**		**Scenario 6**	
	2020	**2030**	**2020**	**2025**	**2020**	**2030**	**2020**	**2030**
Costs and Benefits to Coal/Oil Plant ($Million)								
Coal/Oil O&M Cost Saving	-$290.4	-$405.7	-$155.3	-$295.3	-$312.7	-$312.7	-$246.7	-$323.8
Coal/Oil Decommissioning Cost	$136.8	$205.2	$82.9	$121.8	$133.9	$133.9	$136.8	$136.8
Cost and Benefit for other Fuel Source ($Million)								
Natural Gas	$514.4	$719.1	$300.9	$323.0	$579.7	$481.4	$410.4	$431.4
Biomass	-$3.0	-$18.6	-$10.1	$2.2	-$8.6	$0.0	-$8.6	-$9.3
New Renewables			$0.0	$383.5	$475.2	$475.2	$20.1	$475.2
Coal Heat Rate Improvement	$10.3		$18.4	$12.6			$10.3	$10.3
Conservation Costs			$13.0	$50.2	$15.5	$18.1	$12.5	$18.1
Totals								
Total Compliance Costs ($Million)	**$368.0**	**$499.9**	**$249.8**	**$598.1**	**$883.0**	**$795.8**	**$334.8**	**$738.8**
CO_2 **Emission Reduction (million short-tons)**	**3.79**	**6.74**	**1.54**	**5.55**	**8.05**	**8.05**	**3.25**	**6.91**
Cost per Shor-ton Reduction ($)	**$97**	**$74**	**$162**	**$108**	**$110**	**$99**	**$103**	**$107**
Note: Comparison are made with respect to Scenario 2								
Source: Chmura								

In Scenario 4, total compliance cost in 2020 is estimated to be $249.8 million (measured in 2012 dollars), a reduction of $162 per ton of CO_2. Similar to Scenario 3, the main driver of compliance cost comes from retiring some coal-fired plants, providing O&M cost savings and incurring decommissioning cost. In addition, the cost of heat rate improvement for coal plants will add to the compliance cost. Electricity output from biomass plants will be reduced, providing O&M cost savings. To meet demand, electricity production will increase using natural gas plants, resulting in incremental cost. In 2025, in addition to the above approaches, electricity producers will also implement demand conservation programs. This ambitious goal of decreasing electricity demand by 3.7 percent will cost $50.2 million in 2012 dollars. This scenario also includes expanding the generation from renewable sources, adding costs significantly. The total compliance cost in 2025 is estimated to be $598.1 million in 2012 dollars, or equivalent to $108 per ton of CO_2 reduction.

In Scenario 5, the total compliance cost in 2020 is estimated to be $883.0 million (measured in 2012 dollars), a reduction of $110 per ton of CO_2. In this scenario, all coal-fired plants (but not oil-fired plants) will be retired, providing O&M cost savings and incurring decommissioning cost. Electricity production will increase from natural gas plants (with increased cost). Another major compliance cost is the increased capacity of electricity production from renewable sources. As Table 8-1 shows, renewable sources of electricity are associated with higher capital cost, resulting in significant incremental cost for Virginia electricity producers. In 2030, similar strategies apply and the total compliance cost is estimated to be $795.8 million in 2012 dollars ($99 per ton of CO_2 reduction).

In Scenario 6, the total compliance cost in 2020 is estimated to be $334.8 million (measured in 2012 dollars), the equivalent of $103 per ton of CO_2 emissions reduction. In this scenario, some coal-fired plants and oil-fired plants will be retired, providing O&M cost savings and incurring decommissioning cost. In addition, the cost of heat rate improvement for coal plants will add to the compliance cost. Electricity output from biomass plants will be reduced, providing O&M cost savings. Electricity production will increase from both natural gas and biomass plants. This scenario also considers both increased capacity for renewable energy and demand conservation programs. In 2030, similar strategies apply with a significant increase in renewable capacities—significantly increasing compliance cost. The total compliance cost is estimated to be $738.8 million in 2012 dollars ($107 per ton of CO_2 emissions reduction).

Sensitivity to Gas Prices

The calculations above rely on EPA's assumptions about gas prices through 2030. If the price of natural gas were to increase by 50 percent over those assumed values, the cost per ton of CO_2 reduced increases significantly, demonstrating the sensitivity of costs to gas prices. Table 8-4 gives the cost per ton of CO_2 reduced in the various scenarios analyzed, using the costs shown in Table 8-1 above as a basis for the analysis.

Table 8-4: Cost per ton of CO_2 emissions reduction with 50 percent increase in gas prices

Scenario	Cost per ton of CO_2 emissions reduction (2020)	Cost per ton of CO_2 emissions reduction (2030)
3	$1369	$110
4	$193	$119*
5	$131	$115
6	$136	$122
*Cost is in 2025 for Scenario 4		

Benefit to Electricity Producers

The benefit to Virginia's electricity producers is that the measures outlined in Scenarios 3 through 6 will reduce their CO_2 emission, allowing them to be in compliance with EPA regulations. As a result, the benefit is measured as the reduction in CO_2 emission. In Scenario 2, CO_2 emission is calculated to be 1,142 pounds per MWh (lbs/MWh) in both 2020 and 2030, failing EPA targets of 991 lbs/MWh in 2020 and 810 lbs/MWh in 2030.

In Scenario 3, strategies taken can reduce CO_2 emission by 190 lbs/MWh in 2020 and 342 lbs/MWh in 2030, which are equivalent to 3.8 million and 6.7 million tons of reduction in emission (Table 8-2). That implies the cost to reduce each short-ton of CO_2 emission (cost/benefit ratio) is $97 in 2020 and $74 in 2030. For other scenarios, the cost/benefit ratio varies between $99 and $162 per ton of CO_2 emission reduction.

Consumer and Business Cost

Because the methodology of estimating consumer and business costs is the same, these impacts are summarized together. As with the costs presented earlier, these are annualized and vary per year. As 2020 and 2030 (or 2025 in the case of Scenario 4) are compliance years, these are used as example years.

The strategies taken by Virginia electricity producers to be in compliance with new EPA CO_2 emission targets will also affect residential and business customers in Virginia. These effects will mostly be felt by consumers and businesses through change in electricity prices. It is assumed that electricity producers will attempt to recoup compliance cost via electricity price increases. If demand conservation programs are implemented, consumers and businesses will also share the cost of implementing such programs.

The determination of the price of electricity is a complex matter, affected by market demand, generation cost, and government regulations and policies. In Virginia, any electricity rate change needs to be approved by the State Corporation Commission. As a result, the rate does not always reflect market supply and demand. Sometimes, electricity producers choose to absorb a portion of compliance cost rather than request a rate increase. Because of this complexity, the national study conducted by EPA economists on how the EPA's Clean Power Plan can affect national and regional electricity price was used as a basis. This study estimates that the CPP would increase electricity price by 2.4 percent in 2020 and 3.0 percent in both 2025 and 2030 (EPA, 2014g).

In 2012, Virginia had 3.7 million retail electricity customers. Among those, an estimated 3.3 million were residential customers and the rest were business customers. In 2012, the electricity price was 9.1 cents per KWh—11.1 cents for residential customers and 7.7 cents for business customers (EIA, 2013). Based on historic data, it is assumed that Virginia's customer base will grow 0.8 percent per year, and the nominal electricity price will increase by 3.2 percent per year.

Combining price change assumptions from the EPA's Clean Power Plan, Virginia's electricity customer base, and conservation cost estimated above, the resulting consumer and business cost is shown in Table 8-5. As an example, in Scenario 3, where there are no conservation programs; the cost to Virginia businesses and consumers will come from the increased electricity price due to the CPP. Estimated total cost of increased rates for residential customers would reach $132.4 million (in 2012 dollars) in 2020, averaging $37.40 annually per residential customer. For businesses, the total cost of increased electricity rates are estimated to be $130.2 million (in 2012 dollars) in 2020, averaging $342.10 annually per business customer.

The consumer and business cost for other scenarios can be interpreted similarly from Table 8-5. In Scenarios 5 and 6 and in the 2025 case of Scenario 4, however, demand conservation programs are implemented. Those programs can reduce total demand, and consequently the electricity cost for customers. But customers are expected to share half the cost of implementing such programs (EPA, 2014g). The total cost reflects both the electricity bill savings as well as customers' share of the program implementation cost. This estimate does not, however, include all of the costs to utilities outlined above.

Table 8-5: Estimated Cost to Consumers and Businesses ($Millions)

Estimated Costs to Consumers and Businesses (2012 Dollars)								
	Scenario 3		Scenario 4		Scenario 5		Scenario 6	
	2020	2030	2020	2025	2020	2030	2020	2030
Residents								
Electricity Cost	$132.4	$221.1	$115.5	$222.0	$112.5	$198.1	$116.3	$198.1
Conservation Cost	$0.0	$0.0	$0.0	$20.3	$6.3	$7.3	$5.1	$7.3
Residents Cost Total	$132.4	$221.1	$115.5	$242.2	$118.8	$205.4	$121.4	$205.4
Business								
Electricity Cost	$130.2	$205.7	$113.5	$212.3	$110.7	$184.3	$114.4	$184.3
Conservation Cost	$0.0	$0.0	$0.0	$30.0	$9.2	$10.8	$7.5	$10.8
Business Costs Total	$130.2	$205.7	$113.5	$242.2	$119.9	$195.0	$121.9	$195.0
Total Costs to Customers	**$262.6**	**$426.8**	**$229.0**	**$484.5**	**$238.7**	**$400.4**	**$243.3**	**$400.4**
Note: Comparison are made with respect to Scenario 2								
Source: Chmura, 2014								

Effect on Households with Different Income Levels

Households across the state may be impacted differently when bearing the increased cost of electricity or conservation programs. Households with higher incomes may easily absorb this cost, but households with lower incomes and tight budgets may find it difficult to accommodate even a small increase in electricity price. To understand the various degrees to which households with different incomes are affected by the EPA's proposed regulations, Virginia households were divided into five groups based on household income. Household income and electricity spending in 2012 as a baseline were also investigated (BLS, 2012). The residential cost estimated above was distributed into households in different income groups based on their electricity usages.

Table 8-6 summarizes the increased consumer cost per household in different income groups under each of Scenarios 3 through 6. For example, in Scenario 3, the average household will see an increased cost of $37.40 in 2020. For households in the lower 20 percent income bracket, they will see a per-household cost increase of $26.60 in 2020. But for households in the highest 20 percent income bracket, their per-household cost increase is estimated to be $51.80 in 2020. The reason is that they use more electricity because of habits and lifestyle choices, including larger houses and additional electronics and electric appliances. Scenarios 5, 6, and the 2025 case of Scenario 4 have conservation programs built in. Despite paying for half the cost of conservation programs, consumers can realize cost savings by using less electricity. The net result is that electricity cost per household is lower than in Scenario 3, where no such programs exist.

Table 8-6: Increased Consumer Cost per Household

Increased Consumer Cost Per Household (2012 Dollars)								
	Scenario 3		Scenario 4		Scenario 5		Scenario 6	
Income Bracket	**2020**	**2030**	**2020**	**2025**	**2020**	**2030**	**2020**	**2030**
Lowest 20 Percent	$26.60	$42.50	$23.20	$47.60	$23.80	$39.50	$24.40	$39.50
Second 20 Percent	$32.80	$50.60	$28.60	$57.70	$29.50	$47.00	$30.10	$47.00
Third 20 Percent	$37.50	$58.70	$32.70	$66.40	$33.60	$54.60	$34.40	$54.60
Fourth 20 Percent	$39.40	$57.70	$34.30	$67.50	$35.30	$53.60	$36.10	$53.60
Highest 20 percent	$51.80	$82.30	$45.20	$92.50	$46.50	$76.50	$47.50	$76.50
Average	**$37.40**	**$57.30**	**$32.60**	**$65.50**	**$33.50**	**$53.30**	**$34.20**	**$53.30**
Note: Comparisons are made with respect to Scenario 2								
Source: Chmura, 2014								

As mentioned above, these costs are annualized and vary by year. Table 8-7 shows an example of how costs would change per year for a typical household.

Table 8-7: Cost of Electricity per Year under Scenario 6

Household Cost Per Year, Scenario 6, no pass-through from utilities			
Year	Electricity Cost Household Without Compliance (Scenario 2)	Electricity Cost with CPP (Scenario 6, Incremental Dispatch)	Annual Additional Cost per Household
2012	$1,388	$1,388	$0
2013	$1,408	$1,412	$4
2014	$1,429	$1,437	$8
2015	$1,450	$1,462	$12
2016	$1,471	$1,487	$16
2017	$1,492	$1,513	$20
2018	$1,514	$1,539	$25
2019	$1,536	$1,566	$29
2020	$1,559	$1,593	$34
2021	$1,581	$1,617	$36
2022	$1,604	$1,642	$38
2023	$1,628	$1,667	$39
2024	$1,652	$1,693	$41
2025	$1,676	$1,719	$43
2026	$1,700	$1,745	$45
2027	$1,725	$1,772	$47
2028	$1,750	$1,799	$49
2029	$1,776	$1,827	$51
2030	$1,802	$1,855	$53

Table 8-8 summarizes the consumer cost per household with respect to household incomes. For example, in Scenario 3, the average household will see an increased electricity cost of $37.40 in 2020, which is equivalent to 0.05 percent of household income. For households in the lowest 20 percent income bracket, the increase will take up 0.27 percent of their household income. But for households in the highest 20 percent income bracket, the cost increase is an estimated 0.03 percent of household income. Despite having a higher consumer cost on a per-household basis, the highest 20 percent bracket will see a lower relative impact. This is because of having higher household income and the expectation that their income will grow faster than in lower-income households.

Table 8-8: Increased Consumer Cost as a Percentage of Household Income

Increased Consumer Cost as a Percentage of Household Income (2012 Dollars)								
	Scenario 3		Scenario 4		Scenario 5		Scenario 6	
Income Bracket	**2020**	**2030**	**2020**	**2025**	**2020**	**2030**	**2020**	**2030**
Lowest 20%	0.27%	0.44%	0.24%	0.49%	0.24%	0.41%	0.25%	0.41%
Second 20%	0.11%	0.16%	0.10%	0.19%	0.10%	0.15%	0.10%	0.15%
Third 20%	0.08%	0.12%	0.07%	0.13%	0.07%	0.11%	0.07%	0.11%
Fourth 20%	0.05%	0.07%	0.04%	0.08%	0.04%	0.07%	0.05%	0.07%
Highest 20%	0.03%	0.04%	0.02%	0.05%	0.03%	0.04%	0.03%	0.04%
Average	**0.05%**	**0.08%**	**0.05%**	**0.09%**	**0.05%**	**0.07%**	**0.05%**	**0.07%**
Note: Comparisons are made with respect to Scenario 2								
Source: Chmura, 2014								

Costs to Consumers and Business with 100 percent Compliance Costs

The above analysis uses EPA's assumed price for electricity (EPA, 2014g). That assumption does not consider the electricity rate process in Virginia, where under the existing law, the State Corporation Commission decides on the rate, based on applications from electricity producers. While electricity producers desire to pass all compliance costs to their customers, the degree to which they can achieve such a goal is uncertain. Further, the cost of capital and rates of return have not been included in these financial analyses, but could be passed to the consumer given regulatory approval. To illustrate this, Table 8-9 presents the costs of consumers and businesses, assuming 100 percent of the compliance costs could be passed through to customers. Table 8-10 presents the same information as it impacts Virginia households of different income levels.

Table 8-9: Estimated Annualized Increased Cost to Consumers and Businesses

Estimated Costs to Consumers and Businesses (Million 2012 Dollars)								
	Scenario 3		**Scenario 4 (Economic)**		**Scenario 5 (Economic)**		**Scenario 6 (Economic)**	
	2020	2030	2020	2025	2020	2030	2020	2030
Residents								
Electricity Cost	$132.4	$221.1	$115.5	$222.0	$112.5	$198.1	$116.3	$198.1
Conservation Cost	$0.0	$0.0	$0.0	$20.3	$6.3	$7.3	$5.1	$7.3
Compliance Cost (100 percent pass-through)	$185.5	$259.0	$125.9	$299.0	$439.4	$408.2	$167.1	$378.9
Residents Cost Total	$317.9	$480.1	$241.4	$541.3	$558.2	$613.6	$288.5	$584.3
Business								
Electricity Cost	$130.2	$205.7	$113.5	$212.3	$110.7	$184.3	$114.4	$184.3
Conservation Cost	$0.0	$0.0	$0.0	$30.0	$9.2	$10.8	$7.5	$10.8
Compliance Cost (100 percent pass-through)	$182.4	$240.9	$123.8	$299.0	$443.5	$387.6	$167.7	$359.8
Business Costs Total	$312.7	$446.6	$237.4	$541.3	$563.4	$582.6	$289.6	$554.9
Total Costs to Customers	**$630.6**	**$926.7**	**$478.8**	**$1,082.5**	**$1,121.7**	**$1,196.3**	**$578.1**	**$1,139.2**
Note: Comparison are made with respect to Scenario 2								
Source: Chmura, 2014								

Table 8-10: Estimated Annualized Increased Electricity Cost per Household by Size of Household

Increased Electricity Bill per Households, with Compliance Cost (2012 Dollars)								
	Scenario 3		Scenario 4		Scenario 5		Scenario 6	
	2020	2030	2020	2025	2020	2030	2020	2030
Lowest 20 Percent	$63.8	$92.3	$48.5	$106.4	$112.1	$118.0	$57.9	$112.4
Second 20 Percent	$78.8	$109.9	$59.8	$128.9	$138.4	$140.4	$71.5	$133.7
Third 20 Percent	$90.0	$127.5	$68.3	$148.4	$158.0	$163.0	$81.7	$155.2
Fourth 20 Percent	$94.6	$125.3	$71.8	$150.8	$166.0	$160.1	$85.8	$152.5
Highest 20 percent	$124.5	$178.8	$94.5	$206.6	$218.5	$228.5	$112.9	$217.6
Average	**$89.7**	**$124.5**	**$68.1**	**$146.4**	**$157.4**	**$159.1**	**$81.4**	**$151.5**
Note: Comparison are made with respect to Scenario 2								
Source: Chmura								

Economic Impact of the Clean Power Plan

Economic impact is measured in terms of total economic output (sales) as well as number of jobs. Differing from cost to electricity producers, businesses, and households, this analysis evaluates the effect of the Clean Power Plan on the state and/or regional economy. In economic impact studies, there are three types of economic impact. Using electricity generation as an example, the direct impact is measured as total sales of electricity producers plus total employment hired by power stations. Ripple effects, categorized as indirect and induced impacts, measure secondary benefits that can be supported by electricity generation. The indirect impact refers to increased sales and employment occurring for Virginia businesses that sell supplies and services to power plants, such as fuel producers and truck transportation. The induced impact refers to increased sales and employment that occur in Virginia when power station workers spend their wages in the region. The benefactors of the induced impact are primarily consumer-related businesses such as retail stores, restaurants, and hospitals.

Statewide Employment Impacts on the Power Industry

To comply with the EPA's proposed rule, there are several factors that can affect total sales and direct employment of electricity producers; those two elements may also move in opposite directions. In terms of total sales (revenue), under each scenario, total output is maintained to meet state demand, and electricity price will increase. As a result, total revenue for electricity producers for all scenarios will increase. However, employment is a different matter. To meet the EPA's CO_2 emission target, many coal-fired plants will be retired, and workers at those plants could lose their jobs. Also, those lost jobs may not be offset by employment at natural gas plants where production expands. If increased electricity output is realized by increasing the capacity factor of existing natural gas plants, employment in those plants may not change since labor is considered a fixed O&M cost. Even if new natural gas or renewable energy plants are built, data have shown that for the same level of electricity production, plants using natural gas and renewable energy sources employ fewer workers than coal plants. As a result, while total sales (revenue) may increase, employment will decline in all compliance scenarios.

For direct employment in fossil fuel generation plants, the following steps are used to estimate employment. Based on estimated data from JobsEQ[4], total employment in Virginia fossil fuel power generation was slightly over 1,700 in 2012. Those numbers were distributed to each existing fossil-fuel plant based on generation capacity and fuel sources. For example, there is 0.16 job associated with each megawatt capacity of coal-fired plants, and 0.07 job associated with each megawatt capacity of natural gas plant. For new fossil-fuel plants, employment was estimated using the above assumptions. In this analysis, plant employment was treated as a fixed O&M cost; this means as long as a plant is producing electricity, its employment is set at a certain level regardless of output. However, if the plant is retired, its employment is set to zero.

Employment in renewable plants was estimated using the following methodology. Firstly, employment data from JobsEQ indicate that total power generating jobs in renewable plants in Virginia was less than 90 in 2012, including jobs in hydroelectric and wind plants. In 2012, the total renewable electricity output in Virginia was 2.36 million MWh. Secondly, those data imply that each renewable job is associated with 26,600 kW annual electricity output. Thirdly, using that assumption, new renewable jobs can be estimated based on expanded generating capacities in renewable sources.

Table 8-11 summarizes the economic impact of Scenarios 3 through 6, as compared with Scenario 2. Using the year 2020 in Scenario 3 as an example, total direct economic impact

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[4] JobsEQ is a proprietary technology platform developed and maintained by Chmura.

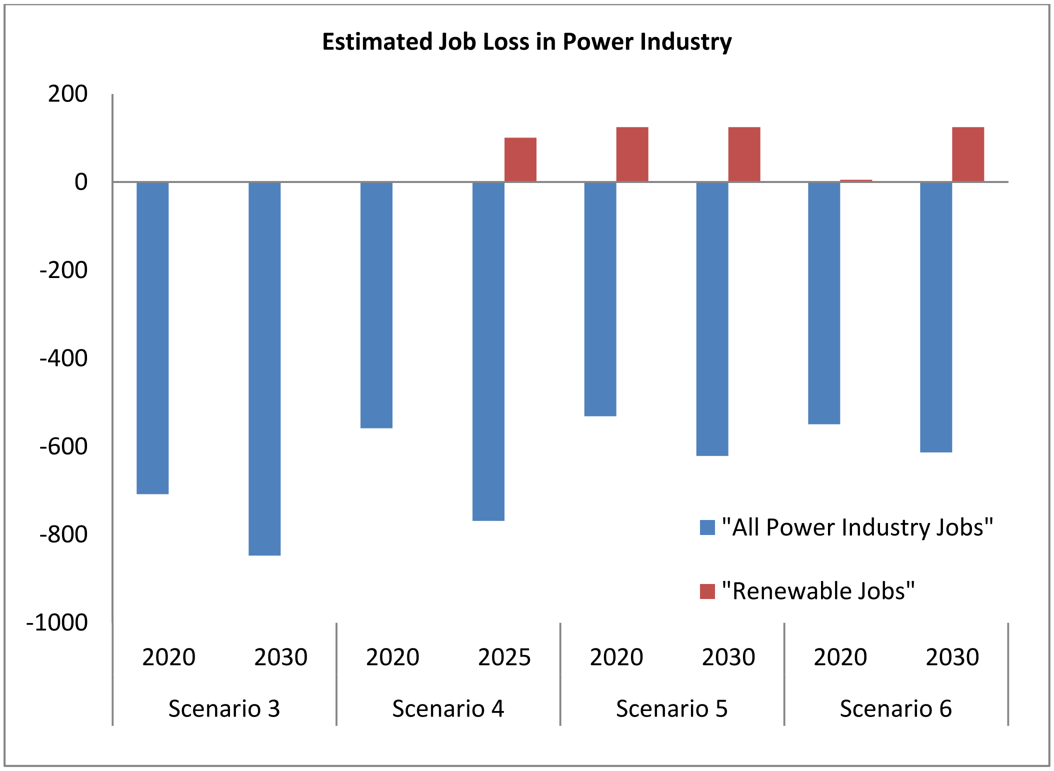
measured as total sales (revenue) will reach $59.4 million in 2020. An additional annual indirect impact of $11.7 million jobs will benefit other Virginia businesses that support power generation. Since the induced impact results from household spending, with anticipated jobs losses in the power industry, the annual induced impact is estimated to be a negative $162.6 million. Because this scenario involves shutting down several coal-fired plants, and additional generation is achieved mainly through capacity improvement for natural gas plants, it is estimated that the state power industry will lose 708 jobs in 2020. While shutting down coal-fired plants will negatively impact employment in Virginia coal-mining industries, in terms of indirect employment impact, increased use of natural gas and biomass implies Virginia businesses in those industries will add jobs. Those additional jobs, however, will not offset job losses in the coal industry, and other business in Virginia will lose 1,176 jobs from indirect impact. The induced impact is negative as well, because direct job loss in the power industry reduces total household income. Adding ripple effects, total job losses in Virginia are estimated to be 2,706 in 2020. The economic impact of other scenarios can be interpreted similarly. The key drivers in employment changes will be the retirement of certain coal-fired plants and the addition of new plants using natural gas, biomass, and renewable sources. In scenarios where demand conservation programs are implemented, the indirect impact also includes energy efficiency jobs in industries such as construction.

Table 8-11: Virginia Economic Impact Summary

Virginia Economic Impact Summary (2012 Dollars)						
			Direct	Indirect	Induced	Total
Scenario 3	**2020**	Spending ($Million)	$59.4	$11.7	-$162.6	-$91.6
		Employment	-708	-1,176	-821	-2,706
	2030	Spending ($Million)	$113.6	$22.4	-$277.4	-$141.4
		Employment	-848	-1,589	-983	-3,419
Scenario 4	**2020**	Spending ($Million)	$71.3	$14.1	-$127.7	-$42.4
		Employment	-558	63	-648	-1,143
	2025	Spending ($Million)	$82.6	$16.3	-$207.1	-$108.2
		Employment	-768	-511	-891	-2,171
Scenario 5	**2020**	Spending ($Million)	$60.6	$12.0	-$122.6	-$50.0
		Employment	-531	-2,600	-616	-3,747
	2030	Spending ($Million)	$2.5	$0.5	-$226.2	-$223.3
		Employment	-621	-2,082	-721	-3,424
Scenario 6	**2020**	Spending ($Million)	$60.9	$12.0	-$126.7	-$53.8
		Employment	-550	-690	-637	-1,877
	2030	Spending ($Million)	$163.3	$32.2	-$224.4	-$28.8
		Employment	-613	-655	-711	-1,979
Note: Comparisons were made with respect to Scenario 2						
Source: IMPLAN 2012 and Chmura, 2014						

Figure 8-1 summarizes the direct jobs impact in Virginia's power industry. In this chart, overall job changes in the power industry are represented by the blue columns. Under all scenarios, jobs in Virginia's power industry will shrink, mostly as a result of the retirement of coal plants, but there will be growth in jobs in renewable electricity generation.

Figure 8-1: Direct Jobs Changes in Virginia's Power Industry vs 2012

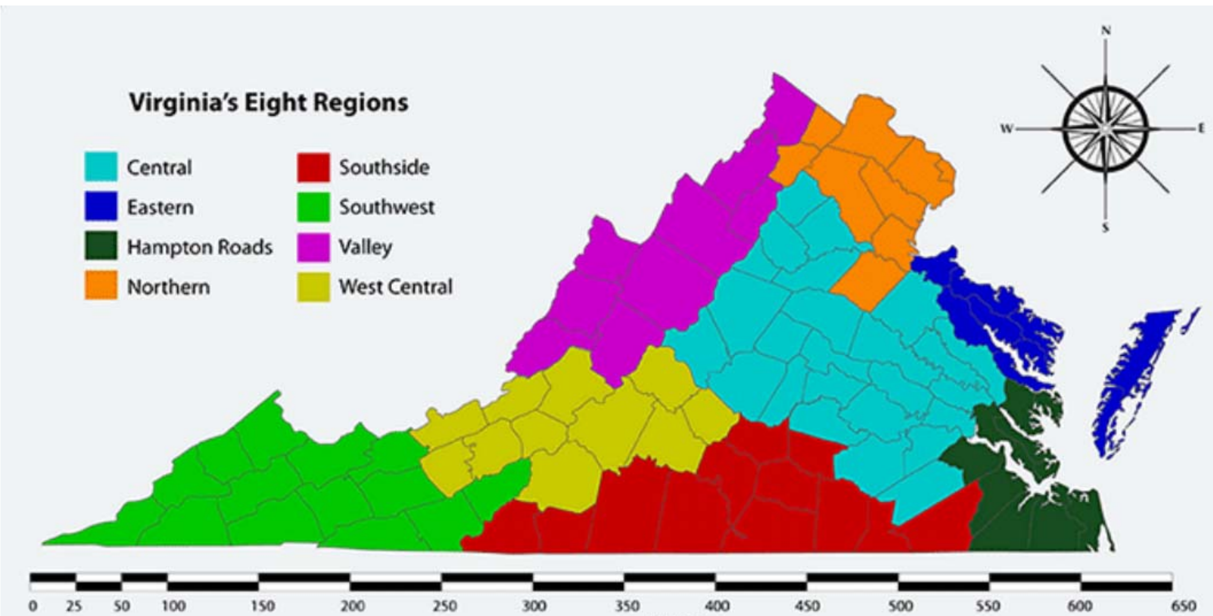


To estimate the number of those jobs, we first evaluate the current renewable generation and number of renewable jobs in Virginia in 2012 (BLS, 2014). We then estimate the jobs proportionally based on the output of electricity from renewable sources. From Figure 8-1, it can be concluded that addition in renewables generating jobs will not offset job losses in retired coal-fired plants.

Regional Employment Impacts on the Generation Sector within Virginia

Because creating jobs is the paramount goal for state and local economic development, the direct employment impact in different regions of the Commonwealth was also analyzed. The regional definitions from the Council on Virginia's Future, which divides the state into 8 regions, were used for this analysis. A map of the regions is shown in Figure 8-2

Figure 8-2: Virginia's Economic Regions



Source: Council for Virginia's Future, http://vaperforms.virginia.gov/Regions/regionsMap.php

As Table 8-12 shows, these regions will be impacted differently in Scenarios 3 to 6. In all scenarios, the Central region will experience the largest number of job losses. The reason is that many large coal-fired plants in the region, such as Chesterfield and Bremo, are candidates for retirement under various scenarios, resulting in job losses. The Southside region will also see sizable job losses, with plants such as Brunswick possibly retired. Regions like Northern Virginia and Hampton Roads will also experience various degrees of job losses.

Table 8-12: Direct Employment Impact by Region

Direct Employment Impact by Region								
Region	**Scenario 3**		**Scenario 4**		**Scenario 5**		**Scenario 6**	
	2020	**2030**	**2020**	**2025**	**2020**	**2030**	**2020**	**2030**
Central	-313	-450	-244	-414	-404	-434	-215	-353
Eastern	0	0	0	0	-42	-42	0	0
Hampton Roads	-65	-77	-95	-95	12	-18	-47	-61
Northern	-105	-105	-105	-105	0	0	-105	-105
Southside	-178	-141	-37	-178	-178	-178	-141	-141
Southwest	-78	-75	-78	-78	-75	-75	-78	-78
Unknown	0	0	0	101	125	125	5	125
Valley	0	0	0	0	0	0	0	0
West Central	30	0	0	0	30	0	30	0
Grand Total	**-708**	**-848**	**-558**	**-768**	**-531**	**-621**	**-550**	**-613**
Note: Comparisons were made with respect to Scenario 2								
Source: Chmura, 2014								

On the other hand, several regions could see increased employment in their power generation industries. The West Central region will experience modest increases in employment while the Valley region will see no changes. The incremental jobs for the region identified as “Unknown” are mostly due to expanded power generation from renewable sources. In Scenarios 5 and 6, the capacities of renewable generation are expanded, but no specific locations were given.

Employment Impact on the Fuel and Energy Efficiency Sectors

While the indirect impact summarized in Table 8-11 provides the overall impact for other industries in Virginia that could be affected by the Clean Power Plan, this section highlights three key industries that are closely associated with power plants in Virginia—the coal mining and natural gas extraction industries[5] and the energy efficiency industry.

[5] This is the same approach taken by EPA for its Regulatory Impact Analysis (EPA, 2014g).

Based on 2012 employment data, Virginia's coal mining industry employed approximately 5,000 workers while the natural gas production industry employed fewer than 50 workers. While Virginia coal-fired plants use a significant amount of Virginia coal, a large percentage of the natural gas used by Virginia natural gas plants comes from out of state. As a result, the Clean Power Plan will affect the state's coal industry disproportionally, while having little effect on the natural gas industry. Changes in the natural gas production industry within Virginia are projected to be negligible, although expansion of coal bed methane production or shale gas production in response to increased demand could result in additional jobs in the sector.

National data indicate that 93 percent of coal output was sold to electricity producers as of 2014 (EIA, 2014a). As a result, any reduction in coal-powered electricity will have a sizable impact on this industry. As Table 8-13 shows, under the scenario where all coal-fired plants are retired (Scenario 5), Virginia coal mining industries would lose 3,305 jobs, or approximately 70 percent of direct coal mining jobs (2012) in Virginia. Based on typical indirect and induced employment multipliers for coal mining jobs of about 4, this would potentially create indirect and induced job losses of over 12,000 jobs, for a total of over 15,000 jobs impacted. Although other scenarios in this study implied less severe impacts, a significant portion of coal-mining employment nevertheless will be lost under all scenarios. Since 98 percent of Virginia coal mining employment is located in southwest Virginia, almost all jobs lost in the coal industry will be located in the Southwest Region.

Based on available information, the natural gas industry would experience almost no change in overall employment in 2020 and 2030.

One industry sector, however, will benefit from the effort to be more energy efficient. As businesses and consumers implement energy efficiency practices, those investments will generate jobs in construction and other industries. To estimate possible jobs in those industries, prior studies were used to formulate the assumptions. For example, a study in Washington State, citing data from American Council for an Energy Efficient Economy (ACEEE), indicated that the investment-to-job ratio in the energy efficiency industry was $184,049 per job in 2004 (WSU, 2009). Inflating that figure to 2012 dollars, it is estimated that additional energy efficiency jobs could range from 116 to 466 under different scenarios in Virginia.

Table 8-13: Employment Impact on Coal and Natural Gas Industries

Employment Impact on Other Industries								
	Scenario 3		**Scenario 4**		**Scenario 5**		**Scenario 6**	
	2020	**2030**	**2020**	**2025**	**2020**	**2030**	**2020**	**2030**
Coal Industry	-1,736	-2,748	-626	-1,782	-3,305	-3,305	-1,367	-2,024
Natural Gas Industry	3	5	1	0	3	2	2	2
Energy Efficiency	0	0	120	466	144	168	116	168
Net Change	**-1,733**	**-2,743**	**-505**	**-1,316**	**-3,158**	**-3,135**	**-1,249**	**-1,855**
Note: Comparison are made with respect to Scenario 2								
Source: Chmura, 2014								

Compliance Cost Estimation for Green Dispatch Energy Scenarios

In addition to considering the impacts of the Incremental Dispatch option as is done above, this section presents the economic analysis of the Green Dispatch Scenarios, which were alternative approaches under Scenarios 4, 5 and 6 where electricity generation from renewable energy sources meets, or at least approaches, the EPA target in the CPP proposed rules.

Table 8-14 presents the compliance costs and benefits for Virginia's electricity producers. Since in all scenarios except for Scenario 5 for the year 2020, there is significantly more electricity generated from the renewable sources, it is not surprising that total compliance costs of Green Dispatch scenarios are higher than those presented in Table 8-3. For Scenario 5 in 2020, both the Green Dispatch scenario and the Incremental Dispatch case has 5.7 million MWh electricity production from renewable, but the Green Dispatch scenario utilizes more natural gas and less coal, resulting in greater cost savings.

Table 8-14: Estimated Annualized Compliance Costs and Benefits for Electricity Producers, Green Dispatch Scenarios ($ Million)

Green Dispatch Scenario-Compliance Cost						
	Scenario 4		Scenario 5		Scenario 6	
	2020	2025	2020	2030	2020	2030
Costs and Benefits to Coal/Oil Plant ($Million)						
Coal/Oil O&M Cost Saving	-$224.4	-$306.5	-$470.3	-$470.3	-$246.7	-$321.7
Coal/Oil Decommissioning Cost	$82.9	$121.8	$133.9	$133.9	$136.8	$136.8
Cost and Benefit for other Fuel Source ($Million)						
Natural Gas	$300.9	$228.7	$616.1	$198.6	$307.8	$159.2
Biomass	-$10.1	$2.2	-$8.6	$0.0	-$8.6	-$9.3
New Renewables	$298.7	$660.1	$475.2	$1,015.7	$298.7	$1,015.7
Coal Heat Rate Improvement ($Million)	$18.4	$12.6			$10.3	$10.3
Conservation Costs ($Million)	$12.3	$50.2	$15.5	$111.6	$16.2	$170.3
Total Compliance Costs ($Million)	**$478.7**	**$769.2**	**$761.8**	**$989.4**	**$514.5**	**$1,161.2**
CO_2 Emission Reduction (million short-tons)	**3.50**	**6.58**	**8.11**	**11.26**	**4.29**	**8.91**
Cost per Ton Reduction ($)	**$137**	**$117**	**$94**	**$88**	**$120**	**$130**
Note: Comparison are made with respect to Scenario 2						
Source: Chmura, 2014						

In terms of cost-benefit ratio under the Green Dispatch scenarios, for Scenarios 4 and 6, cost-benefit ratio increased mainly due to incremental cost from renewables. But in Scenario 5, the cost-benefit ratio decreases, as the result of a larger CO_2 emission reduction. Overall, the cost/benefit ratio varies between $88 and $120 per ton of CO_2 emission reduction.

The consumer and business cost for Green Dispatch scenarios are summarized in Table 8-15. There are two notable changes as compared to Scenario 2. First, the demand conservation efforts have an effect of reducing electricity usage for consumers and businesses. As a result, electricity payment will be lower in scenarios with aggressive demand conservation programs. Another change is the costs of conservation. Those costs are higher in scenarios with aggressive programs (notably Scenarios 5 and 6, 2030).

Table 8-15: Estimated Annualized Cost to Consumers and Businesses ($ Million)

Cost to Consumers and Businesses – Green Scenarios						
	Scenario 4		Scenario 5		Scenario 6	
	2020	2025	2020	2030	2020	2030
Residents						
Electricity Cost	$116.4	$225.9	$112.5	$79.1	$111.6	$4.4
Conservation Cost	$0.0	$19.0	$6.3	$45.0	$6.5	$68.7
Residents Cost Total	$116.4	$245.0	$118.8	$124.2	$118.2	$73.1
Business						
Electricity Cost	$114.4	$216.1	$110.6	$73.6	$109.8	$4.1
Conservation Cost	$0.0	$28.1	$9.2	$66.5	$9.7	$101.5
Business Costs Total	$114.4	$244.2	$119.9	$140.1	$119.4	$105.6
Total Residents and Business Costs	**$230.8**	**$489.1**	**$238.7**	**$264.2**	**$237.6**	**$178.7**
Note: Comparison are made with respect to Scenario 2						
Source: Chmura, 2014						

Table 8-16 summarizes the consumer cost per household in different income groups under the Green Dispatch scenarios. For example, in Scenario 4, the average household will see an increased cost of $32.80 in 2020. For households in the lower 20 percent income bracket, they will see a per-household cost increase of $23.40 in 2020. But for households in the highest 20 percent income bracket, their per-household cost increase is estimated to be $45.60 in 2020.

Table 8-16: Increased Annualized Consumer Cost per Household

Green Dispatch Scenarios – Increased Consumer Cost per Household						
	Scenario 4		Scenario 5		Scenario 6	
	2020	2025	2020	2030	2020	2030
Lowest 20 Percent	$23.4	$48.1	$23.8	$23.9	$23.7	$14.1
Second 20 Percent	$28.8	$58.4	$29.4	$28.4	$29.3	$16.7
Third 20 Percent	$32.9	$67.2	$33.6	$33.0	$33.5	$19.4
Fourth 20 Percent	$34.6	$68.2	$35.3	$32.4	$35.2	$19.1
Highest 20 percent	$45.6	$93.5	$46.5	$46.2	$46.3	$27.2
Average	**$32.8**	**$66.3**	**$33.5**	**$32.2**	**$33.3**	**$19.0**
Note: Comparison are made with respect to Scenario 2						
Source: Chmura, 2014						

When compliance costs are passed through from electricity producers to consumers and business customers, the overall costs will be much higher, as presented in Table 8-17. Accordingly, per-household costs will also be much higher for households in all income groups (see Table 8-18).

Table 8-17: Estimated Annualized Cost to Consumers and Businesses, with Compliance Cost ($ Million)

Green Dispatch Scenario – Estimated Costs to Consumers and Business, with Compliance Cost (2012 Dollars)						
	Scenario 4		Scenario 5		Scenario 6	
	2020	2025	2020	2030	2020	2030
Residents						
Electricity Cost	$116.4	$225.9	$112.5	$79.1	$111.6	$4.4
Conservation Cost	$0.0	$19.0	$6.3	$45.0	$6.5	$68.7
Compliance Cost (100% pass-through)	$241.4	$385.2	$379.1	$464.9	$255.9	$475.1
Residents Cost Total	$357.7	$630.2	$497.9	$589.0	$374.1	$548.2
Business						
Electricity Cost	$114.4	$216.1	$110.6	$73.6	$109.8	$4.1
Conservation Cost	$0.0	$28.1	$9.2	$66.5	$9.7	$101.5
Compliance Cost (100% pass-through)	$237.3	$384.0	$382.7	$524.6	$258.6	$686.1
Business Costs Total	$351.8	$628.2	$502.6	$664.7	$378.1	$791.7
Total Resident and Business Costs	**$709.5**	**$1,258.3**	**$1,000.4**	**$1,253.7**	**$752.1**	**$1,339.9**
Note: Comparison are made with respect to Scenario 2						
Source: Chmura, 2014						

Table 8-18: Estimated Annualized Cost per Household, with Compliance Cost

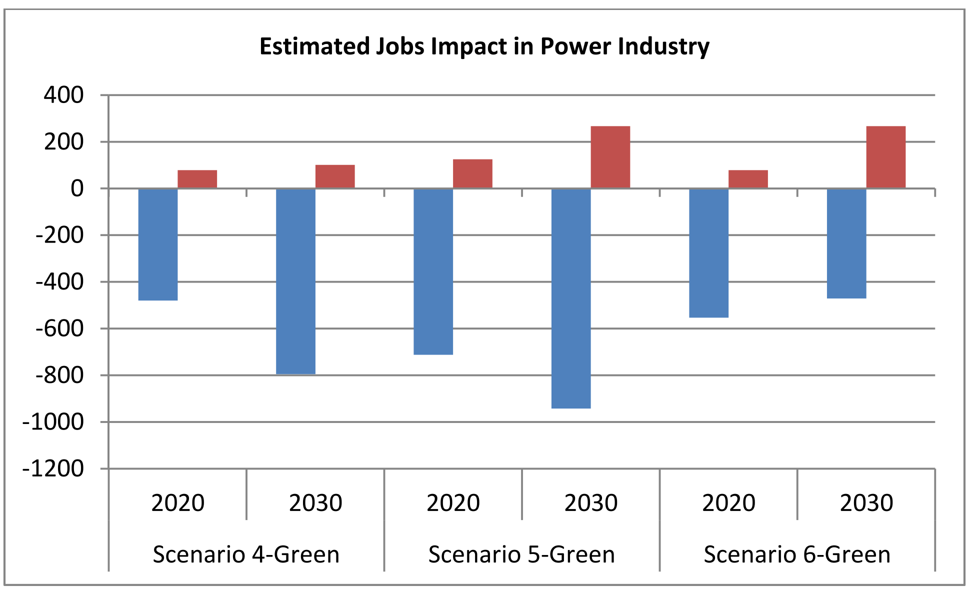
Green Dispatch Scenario-Increased Cost per Household						
	Scenario 4 (Green)		Scenario 5 (Green)		Scenario 6 (Green)	
	2020	2025	2020	2030	2020	2030
Lowest 20%	$71.8	$123.8	$100.0	$113.3	$75.1	$105.4
Second 20%	$88.7	$150.1	$123.4	$134.8	$92.7	$125.5
Third 20%	$101.3	$172.8	$141.0	$156.5	$105.9	$145.6
Fourth 20%	$106.4	$175.6	$148.1	$153.7	$111.3	$143.1
Highest 20%	$140.0	$240.6	$194.9	$219.3	$146.4	$204.1
Average	**$100.9**	**$170.4**	**$140.4**	**$152.8**	**$105.5**	**$142.2**
Note: Comparison are made with respect to Scenario 2						
Source: Chmura, 2014						

Table 8-19 summarizes the economic impact of Green Dispatch Scenarios 4 to 6, as compared with Scenario 2. Under the Green Dispatch scenarios, while increasing production will certainly result in more jobs in renewable generating facilities, that increased capacity also means reduced production or even retirement in coal-fired or oil-fired plants, resulting in job losses. The net impacts are a decline in employment in the power industries in all Green Dispatch scenarios, despite large numbers of jobs created in renewable units (Figure 8-3).

Table 8-19: Virginia Economic Impact Summary, Green Dispatch Scenarios

Virginia Economic Impact Summary (2012 Dollars)						
			Direct	Indirect	Induced	Total
Scenario 4	**2020**	Spending ($Million)	$71.3	$14.1	-$109.9	-$24.6
Green		Employment	-480	-499	-557	-1,536
	2025	Spending ($Million)	$82.6	$16.3	-$213.2	-$114.3
		Employment	-795	-629	-922	-2,346
Scenario 5	**2020**	Spending ($Million)	$60.6	$12.0	-$163.5	-$90.9
Green		Employment	-713	-2,599	-826	-4,138
	2030	Spending ($Million)	$2.5	$0.5	-$298.9	-$295.9
		Employment	-943	-1,217	-1,094	-3,254
Scenario 6	**2020**	Spending ($Million)	$60.9	$12.0	-$127.6	-$54.7
Green		Employment	-554	-657	-642	-1,853
	2030	Spending ($Million)	$163.3	$32.2	-$192.3	$3.3
		Employment	-471	767	-546	-250
Note: Comparisons were made with respect to Scenario 2						
Source: IMPLAN 2012 and Chmura, 2014						

Figure 8-3: Direct Jobs Changes in Virginia's Power Industry



Regional distribution of affected jobs are similar to those presented in previous sections of the report (see Table 8-20).

Table 8-20: Direct Employment Impact by Region

Direct Employment Impact by Region						
Region	Scenario 4-Green		Scenario 5-Green		Scenario 6-Green	
	2020	2030	2020	2030	2020	2030
Central	-244	-441	-404	-638	-292	-353
Eastern	0	0	-42	-42	0	0
Hampton Roads	-95	-95	-65	-95	-47	-61
Northern	-105	-105	-105	-105	-105	-105
Southside	-37	-178	-178	-178	-141	-141
Southwest	-78	-78	-75	-153	-78	-78
Unknown	79	101	125	267	79	267
Valley	0	0	0	0	0	0
West Central	0	0	30	0	30	0
Grand Total	-480	-795	-713	-943	-554	-471
Note: Comparisons were made with respect to Scenario 2						
Source: Chmura, 2014						

Compared with Table 8-11, increasing renewable generation will result in more job losses in Scenario 4 in coal industries (see Table 8-21). There are limited changes in Scenario 5 and 6 because the adjustments to accommodate new renewables are from non-coal-fired plants. But Virginia generally will see more jobs in energy efficiency industries where more aggressive demand conservation programs will be implemented under the Green Dispatch scenarios.

Table 8-21: Employment Impact on Coal and Natural Gas Industries

Green Dispatch Scenario-Jobs Impact in Other Industries						
	Scenario 4 (Green)		Scenario 5 (Green)		Scenario 6 (Green)	
	2020	**2025**	**2020**	**2030**	**2020**	**2030**
Coal Industry	-1,182	-1,869	-3,305	-3,305	-1,367	-2,012
Natural Gas Industry	1	-1	3	0	1	0
Energy Efficiency	114	437	144	1,035	150	1,579
Total	**-1,067**	**-1,433**	**-3,157**	**-2,270**	**-1,216**	**-433**
Note: Comparison are made with respect to Scenario 2						
Source: Chmura, 2014						

Environmental Impacts and Benefits

One of the significant concerns leading to the promulgation of regulations and the analysis in this report are the health and environmental impacts of CO_2 emissions and the benefits of limiting those emissions. The EPA prepared a detailed Regulatory Impact Analysis (RIA) that accompanied the release of the June 18, 2014, proposed rule. In the RIA, the EPA develops a means of identifying and monetizing the environmental and health impacts and benefits of CO_2 emissions and reductions possible under the proposed rule (EPA, 2014g). The EPA notes that the climate benefits presented in its RIA are associated solely with CO_2 emissions.

The EPA quantifies the impacts of CO_2 emissions using an economic valuation of the Social Cost of Carbon (SCC). SCC is a metric that can be used to estimate, in monetary terms, the marginal changes in CO_2 emissions on an annual basis. According to the EPA, it is based on consideration of anticipated global climate impacts, including agricultural, human health, property damage, and energy systems costs. Their rationale for using this metric and development of the number are given in another EPA publication from 2010 (EPA, 2010a). It should be noted that the Government Accountability Office and a number of other entities have criticized the EPA's methodology (GAO, 2014).

Using a 3 percent discount rate, the EPA estimates the global SCC for CO_2 emissions as averaging $39/metric ton in 2015; $46/metric ton in 2020; and, $55/metric ton in 2030. Discounting the 2015 value to 2012 yields an SCC for Virginia's CO_2 emissions of $36/per metric ton or approximately $940 million in that year (EPA, 2014g). Using the estimated CO_2 emissions in 2030 under Scenario 6, which corresponds to EPA's Option 1 and requires an emissions rate of less than 810 tons of CO_2 per megawatt hour, the projected SCC in Virginia is approximately $780 million, a reduction of $160 million.

Since the EPA agrees that the SCC is only a partial accounting of the total climate impacts, they developed another monetized metric of "estimated global climate benefits of CO_2 reductions" for the proposed rule. These values differ by year and also include the use of various discount rates to monetize the benefits. The EPA's values are national, based on total tonnage reductions projected under the various options identified in the proposed rule. The EPA states that the use of regional compliance strategies, involving regional trading agreements, produce slightly smaller reductions in CO_2, and as a result, smaller benefits. There is an acknowledgement that the costs and benefits are not uniformly distributed. In order to provide some estimate of the magnitude of those benefits in Virginia, a proportional factor was assigned based on CO_2 emissions reductions in the Commonwealth versus nationally, using the scenarios examined in this report.

For ease of comparison, a summary of the estimated emissions reductions and benefits provided by Scenarios 4, 5, and 6 (as compared to 2012) is shown in Table 8-22

Table 8-22: Summary of Estimated Emission Reductions and Benefits for Selected Scenarios versus 2012 Emissions

Summary of Estimated Emission Reductions and Benefits for Selected Scenarios					
Scenario	**Year**	**Estimated Reduction in CO_2 Emissions versus 2012 (tons)**		**Estimated Benefits**	
		Virginia	**US**	**Virginia**	**US**
Scenario 4	2020	6.45 million	295 million	$310 million	$14 billion
	2025	9.07 million	376 million	$458 million	$19 billion
Scenario 5	2020	12.9 million	383 million	$606 million	$18 billion
	2030	12.9 million	555 million	$721 million	$31 billion
Scenario 6	2020	8.54 million	383 million	$400 million	$18 billion
	2030	11.9 million	555 million	$660 million	$31 billion

Under Scenario 6, which corresponds to the EPA's Option 1, Virginia's emissions reductions total 8.54 million metric tons. The EPA's chart shows total national reductions under that option as 383 million metric tons. Virginia's share of the $18 billion national climate benefits (using the 3 percent discount rate) are estimated at $400 million ($42.48 per ton of CO_2 reduction). Using the same methodology to calculate the benefits in 2030, the benefits based on Virginia's reduction are estimated at $660 million ($50.30 per ton of CO_2 reduced).

For Scenario 4, which evaluates the EPA's Option 2, the reduction required is lowered, but the final compliance timeframe is accelerated to 2025. Using the methodology outlined above, Virginia's benefit in 2020 is estimated as $310 million ($43.59 per ton of CO_2 reduction). The benefit to Virginia in 2025 is estimated at $458 million, or $45.80 per ton CO_2 reduction.

For Scenario 5, which eliminates all coal-fired electrical generation in Virginia, the benefits are estimated as $606 million in 2020 ($42.61 per ton CO_2 emission reduction) and $721 million in 2030 ($50.69 per ton of CO_2 emissions reduction), using the same methodology.

Health Impacts and Benefits

A detailed health investigation was beyond the scope of this report. Instead, EPA's estimates in the RIA for the proposed rule were used. While the SCC outlined above includes some estimate of health costs associated with CO_2 emissions, the EPA's RIA outlines several metrics for health benefits of the proposed rule based on "health co-benefits." The EPA states that implementing the proposed rule guidelines will result in reductions of particulate matter ($PM_{2.5}$), ozone and other atmospheric emissions that can have a negative impact on human health (EPA, 2014g). It should be noted that a number of organizations have criticized EPA's approach, since the majority of the health benefits are realized not for CO_2 reductions under this proposed rule, but rather for pollutants regulated under another section of the Clean Air Act.

In order to monetize the health impacts of the reductions in discharges of these and other air pollutants, the EPA has considered both avoided premature deaths and avoided morbidity effects of numerous non-fatal endpoints. Based on analysis of those factors, the EPA published summaries of national and regional health benefits per ton of reduced emissions from electrical generation units. The EPA recognizes differences on a regional basis, based in part on the differences in specific fuels used in different regions. The EPA warns, *"Great care should be taken in applying these estimates to emissions reductions occurring in any specific location, as these are all based on broad emissions reductions scenarios…"* (EPA, 2014g). As a result, EPA concludes that the health co-benefits may be either over- or under-estimated. It should be noted that this analysis does not include any health co-benefits that may accrue as a result of lowered exposures to hazardous air pollutants, ecosystem effects and visibility impairment (EPA, 2014g).

In order to estimate the co-benefits in Virginia, the proportion of CO_2 reduction expected in the Commonwealth under the scenarios previously considered (average 2.2 percent) was assumed to be the proportional reduction in other emissions. Given these assumptions, the health benefits in Virginia are estimated to range from $300 million to $880 million in 2020; $400 million to $900 million in 2025; and, $600 million to $1.4 billion in 2030 (EPA, 2014g).

Table 8-23 combines the costs and benefits discussed above. It should be noted that the methodology for determining cost and benefit numbers are not the same and these numbers may not be have similar levels of accuracy or confidence. The cost numbers do not include the cost of raising capital and supporting interest on bonds or loans, capital costs associated with infrastructure (such as natural gas pipelines) and some other unquantifiable capital and O&M costs borne by utilities in fuel switching and building new generating plants. Capital costs are levelized over a 30 year period. Although it anticipated that utilities will pass costs to consumers, this is not reflected in the table, due to uncertainties in the timing of approval for cost recoveries. Benefits are based on the methodology outlined by EPA and are based primarily on global "social cost of carbon" reductions and health "co-benefits" derived from the reduction of other emissions from coal-fired power plants, and are derived from the proportion of Virginia reductions to estimated national reductions.

Table 8-23: Summary of Costs and Benefits ($ per ton of CO_2 Emissions Reduction)

Summary of Costs and Benefits ($ per ton of CO_2 Emissions Reduction)					
	Increased Cost to utilities	**Increased Cost to consumers**	**Benefit from reduced social costs**	**Health benefits**	**Net benefit or cost**
Scenario 4 Incremental	108	87	82	72 to 162	-41 to 49
Scenario 4 Green	117	88	82	72 to 162	-51 to 39
Scenario 5 Incremental	99	50	90	75 to 174	16 to 115
Scenario 5 Green	88	33	90	75 to 174	44 to 143
Scenario 6 Incremental	107	58	95	87 to 202	17 to 132
Scenario 6 Green	130	26	95	87 to 202	26 to 141
Note: Net cost indicated by a minus sign (-)					

It is worth noting that, due to the wide variance of projected health benefits, the impact of implementing the Scenario 4 (both the Incremental and Green dispatch cases) compliance strategy indicates a potential net loss of economic value to Virginia residents.

A recently published, EPA-funded study at MIT, examined the air quality co-benefits of carbon management policies (MIT, 2014). The study showed a wide variation in the value of co-benefits derived from air quality improvements, ranging from 26 to 1,050 percent of the costs of policy implementation. The study also indicated that “cap-and-trade” policies were less costly than sector-specific programs, such as the CPP. The article also reinforced the uncertainties of both costs and benefits based on year-to-year meteorological variability, regional variability, and basic uncertainties in both health and economic models.

It should be noted that the EPA analysis does not include any health co-benefits that may accrue as a result of lowered exposures to hazardous air pollutants, ecosystem effects and visibility impairment (EPA, 2014g).

Section 9. Considerations for Policy Options

As drafted, the EPA Clean Power Plan (CPP) will require that all State Implementation Plans (SIPs) be submitted to the EPA for approval in June 2016. Currently, 2020 is projected as the first year that states must begin to comply with the EPA interim CO_2 rates. Thus, it is critical that Virginia considers policies that will allow for the implementation of the CPP regulations and the changes required for electrical generation in the Commonwealth. Because of the time needed for utilities, energy providers, state agencies and the legislature to plan, develop, approve and legislate, the proposed rule timetable is very aggressive. Highlighting the urgency, Gifford et al. (2014) noted, *"…the issues that must be debated and decided among and between states to determine what institutional structures must be in place to even begin deciding how the carbon reduction mandates will be reached must occur over the next several months, not years.*"

Broad Areas of Policy

There are several broad areas where Virginia must ensure that policies exist or are developed to implement the CPP. These include:

1. Examine legislation to promote and implement the CPP requirements at the state level.
2. Develop standards of performance for all EGUs in Virginia, including fossil fuel generation, nuclear generation, and renewable generation, to ensure that the mandates of the CPP can be achieved while meeting electricity demands.
3. Determine institutional structures necessary to enable changes in generation mix, including legal framework and regulatory responsibilities. Identify areas requiring legislation to establish funding and assignment of liability for issues such as storage/sequestration of CO_2, development of fuel distribution (i.e., gas pipelines), and other necessary infrastructure.

4. Engage all electrical generation utilities, including investor-owned, member cooperative, and public, in discussions, as well as pipeline companies, coal mining companies, natural gas companies, regulatory agencies and the State Corporation Commission, to determine what structural changes are necessary and what challenges must be overcome to ensure fuel availability and uninterrupted generation.
5. Provide financial incentives for adoption of low- and zero-carbon generating facilities demonstrating and deploying new technologies that could benefit ratepayers, the economy and the environment.
6. Begin discussions with neighboring states to determine possibilities and options for partnerships to implement trading programs and other necessary areas of cooperation. Detailed consideration of the need for multiple-state compacts and multi-state enforcement mechanisms are critical.
7. Evaluate the CPP impacts on the reliability of the electrical distribution network in the state and in neighboring states, including appropriate involvement of regional grid organizations, such as the PJM.
8. Institute carbon management resource planning measures, such as the most appropriate renewable energy portfolios and support for electrical efficiency and demand-side management programs.
9. Ensure that state implementation plans incorporate all electrical generating units, including all nuclear generating units, small “non-affected” units, and planned new generation, to ensure that the electrical demands of the Commonwealth can be met reliably at the lowest possible dispatch costs to residential and business customers.
10. Encourage the development of new technologies for electrical efficiency, CCS/CCUS, and modernized grid, through support of research and demonstration projects.

11. Determine the needs of small rural electric cooperatives and public utilities in developing integrated resource plans to ensure that all utilities in the state are able to file plans at the same time to meet statewide goals and mandates.
12. Develop mechanisms to deal with negative economic impacts, including addressing regional unemployment in the coal mining sector and indirect and induced impacts on small businesses and industries across the state.
13. Policy should recognize that 4-6 percent CO_2 reduction is not likely to be attainable long-term for the existing coal-fired fleet, particularly when units are forced to operate at extremely low capacity factor.
14. Provide relief from New Source Review. The most effective improvements to power plant heat rate will require investment that, depending on EPA interpretation of actions, could impose additional environmental requirements which further increase CO_2 emissions. These units are already complying with federal and local emissions mandates. Imposing new-source limits restricts investment options.
15. Recognize that natural gas supply limits NGCC operation. Much of the CO_2 reductions achieved come from substituting more costly natural gas-fired generation for coal. The extent to which existing and new proposed NGCC facilities can provide power will depend on a reliable natural gas supply. Expanding pipeline access and eliminating bottlenecks is key.

Specific Policy Options for Virginia

This study has dealt in broad terms with the implications of EPA's June 18, 2014, proposed rules for Virginia. Throughout this report, a number of specific policy issues have been discussed. The listing below consolidates these policy considerations under a number of topical areas.

Power Plants

- Work with utilities to ensure that necessary building blocks, including efficiency improvements and changes to generation can be completed in accordance with final mandates. Seek a means of allowing credit for previous improvements (2005-2012), particularly those that inhibit meeting new mandates.
- Allow for continuation of generation that uses waste coal and biomass to further other environmental goals with a negative impact on CO_2 emissions (e.g., VCHEC).
- Develop regulatory mechanisms to allow for efficiency improvements at existing facilities without requiring “new source” standards or “major modification” requirements.

Pipelines and Infrastructure

- Improve reliability and extent of Natural Gas (NG) pipeline networks and facilitate permitting of pipeline expansions and changes. Encourage development of NG storage at Electric Generating Units (EGUs) and provide for redundancy and alternative transportation of NG in emergency situations to ensure reliability of electrical supply.
- Establish annual communication update meetings between state regulators, gas transportation entities and EGUs to ensure that electric consumers are considered in pipeline planning decisions.
- Encourage grid modernization and enhancement and necessary changes to power dispatch and distribution networks.

CCS/CCUS

- Understand the timeframes and technology development horizon for adoption of CCUS, because, notwithstanding EPA’s assertion that the technology is “proven and available,” CCUS may not be ready in time to meet the mandates of the regulatory proposal.

- Support a diverse range of R&D, demonstration and field projects to develop commercially and economically viable CCUS, including development of CCUS and use of CO_2 in Enhanced Oil Recovery (EOR) and Enhanced Gas Recovery (EGR), both onshore and offshore, in Virginia.
- Provide incentives and remove legal impediments for adoption of CCUS in Virginia, including determination of pore space and CO_2 ownership and short- and long-term liability issues.

Environment

- Consider legislation for renewable portfolio standards, market efficiency improvements, emissions trading, etc.
- Address the timing of implementation of EPA's CPP regulations, particularly in light of current and potential legal challenges to ensure that Virginia is prepared as necessary.

Technology Development and Research

- Support research into the technical limitations on implementation of efficiency improvements at EGUs. Support research evaluating the benefits of implementation of multiple efficiency improvement technologies, including their compatibility with the legal environment and the possibility of unintended consequences.
- Encourage research into the development of technologies for renewable power generation in Virginia, including demonstrations of practicality and opportunities to take advantage of existing resources.
- Support research for improvement of the electrical grid and dispatch of power from various EGUs, including detailed dispatch modeling and linear programming model studies.

- Support studies aimed at determining the true costs and benefits for reduction of CO_2 emissions in Virginia. Determine the applicability of the methodology used by the Federal government, including EPA, to determine the “societal cost of carbon.”
- Support the conduct of Virginia-specific health studies to help identify the cost and benefit of CO_2 emission regulation for citizens of the Commonwealth.

Employment and Economics

- Support the conduct of an in-depth study of the potential direct, indirect and induced employment impacts of changes to the electrical generation mix within Virginia.
- Examine the impact of increased electrical cost that may result from CO_2 emissions reduction regulations on small- and medium-sized businesses and resulting employment impacts.

Consumer protection

- Ensure that EGU’s recovery of the costs to comply with any CO_2 emissions regulations do not result in undue burden on electrical consumers, particularly moderate- or low-income consumers.
- Ensure that conservation programs are implemented in a way that protects the interests of electrical consumers. Provide funding to assist electrical consumers in the adoption of renewable energy and conservation technologies.

Closing Remarks

This report has attempted to identify compliance strategies, as directed by the General Assembly of Virginia in Item 8 (§ 67-201. Development of the Virginia Energy Plan. Subsection B). Effort was focused on satisfying the requirements of this legislation 1) by reporting on Virginia's energy policy positions relevant to the EPA's June 2014 proposal for additional carbon emissions regulations based on section 111(d) of the Clean Air Act for existing power plants; 2) by reviewing and reporting on Virginia's historical fuel portfolio and projected changes to this portfolio under various scenarios to meet the requirements of the proposed EPA regulations; and 3) by assessing the impacts of estimated energy price increases on consumers within the Commonwealth. In doing so, this report has identified options and measures that will further the interests of the Commonwealth and its citizens as it plans for Virginia's energy future and for compliance with the proposed federal regulations.

Fuel and technology diversity have historically been key strengths of the electricity generation sector serving Virginia, the region, and the US as a whole and have helped to ensure stable prices, a reliable electrical system, technology innovation, effective resource planning and integration, environmental protection, job creation, and strong economic growth. Diversity of fuels and technology in the electricity portfolio is fundamental to a properly functioning electricity system. It is crucial that the Commonwealth of Virginia recognize the importance and value of fuel and technological diversity and work with the electric power generation sector and its suppliers to preserve portfolio diversity, while at the same time addressing the challenges of CO_2 emission reductions.

Glossary of selected terms

absorption	the process of being taken up through chemical or molecular action
adsorption	the process of being gathered on the surface in a condensed layer
alkali sorbent	a substance which reacts with acids and readily gathers gases and liquids on its surface through absorption, adsorption or a combination of the two processes
aquifers	geologic formations containing or conducting ground water, especially those that supply water for wells, springs, etc.
base load operation	an operation used to meet some or all of a given region's continuous energy demand and produce energy at a constant rate, usually at a low cost relative to other available generation
boiler heat transfer surfaces	the parts of a boiler system where heat is transferred from the burning of a fuel to water or air to produce energy
capacity factors	the ratio of a power plant's actual output over a period of time to its potential output if it could operate non-stop at full capacity. Usually expressed in a percentage.
carbon capture	a chemical or physical process to entrap carbon dioxide in order to prevent its release into the atmosphere
carbon capture, utilization and sequestration/storage	a system of processes designed to prevent the release of carbon dioxide into the atmosphere which includes utilizing the CO_2 for a beneficial purpose and/or placing in a geologic formation for temporary or long-term storage
Clean Power Plan	EPA's series of actions designed to implement President Obama's climate change policies
coal drying	a process where moisture is removed from coal prior to use
coal rank	the classification of coal based on its heat value and other geologic factors. Coal rank includes: subbituminous, bituminous and anthracite.

coal switching	the use of a different coal rank or coal source in a power plant, done for the purposes of achieving a beneficial goal
commercial availability	referring to pollution control technology, the quality of being economically and technically feasible for use
cooling tower pack or fill	the solid or liquid material used to lower the temperature of water used in boilers or of gaseous emissions from combustion
demand side management	paired with “energy efficiency” as measures used by electrical consumers to lower the need for electrical generation while meeting other needs
direct impact	with regard to economic impacts or job losses, those impacts that are experienced within the specific industry or business sector that must comply with a new regulation or experiences some other change
dispatch	the determination of how much electrical output from a particular generating unit will be used to meet the system load, given economic, transmission, generation capacity or other constraints
electrical generating units	the specific equipment, such as turbines, boilers, etc. at a power generating station used to generate electricity. Often, one power plant may have many separate electrical generating units, fueled by the same or different materials
electronic continuous emissions monitors	automated systems for the collection of data on the composition of gaseous emissions from combustion of fuels
energy efficiency	processes or systems designed to decrease the amount of energy necessary to accomplish a given task. For example, energy efficiency includes using LED lighting to lower the amount of electricity necessary to produce a given amount of illumination
enhanced gas recovery	processes designed to increase the amount of natural gas recovered from the earth at any given well or deposit
enhanced oil recovery	processes designed to increase the amount of petroleum recovered from the earth at any given well or deposit

environmental control technologies	processes designed to manage the environmental impacts of any activity. For example, electrostatic precipitators to remove particulates from gaseous emission streams
flue gas desulphurization	processes designed to remove sulfur-containing ions and compounds from gaseous emissions
forced draft	use of a flow of air or air forced through a pipe or system of pipes by fans or blowers
gasification	the conversion of a solid, such as coal, to a gas
greenfield	a project that lacks any constraints imposed by prior work
heat rate	the percentage of the total energy in a fuel that is converted to electricity
indirect impact	with regard to economic impacts or job losses, those impacts that are experienced within businesses associated with the specific industry or business sector that must comply with a new regulation or experiences some other change (but not within the industry or business sector itself), such as those felt by equipment or material suppliers
induced impact	with regard to economic impacts or job losses, those impacts that are experienced within the specific region of a business that must comply with a new regulation or experiences some other change, such as those felt by restaurants, hotels, retail shops, etc.
inducted draft	the use of a flow of air produced by suction stream jets or fans at the point where air or gases leave a unit
integrated gasification combined cycle	a system where coal and other carbon based fuels are turned into a gas, impurities are removed, and then the gas is combusted to produce heat for electrical generation
Integrated Planning Model	a software model developed by ICF International, used to develop total systems optimization of electrical power generation and dispatch
investor owned utility	a business providing a product or service, such as electricity, managed as a private for-profit enterprise
landgas or landfill gas	A complex mix of gases, including methane, produced by microbial action in a landfill

linear programming model	a mathematical method for determining the solution to a decision problem that contains multiple variables
mass-based goals	goals based on the total quantity or mass of a given substance, such as carbon dioxide
morbidity effects	incidences of ill health, such as disease
natural gas combined cycle	an assemblage of heat engines that work in tandem from the same source of heat, converting it into mechanical energy and then into electricity
negawatts	used to describe the reduction in electricity generation as a result of energy conservation, energy efficiency or other demand side management actions
new source review	A regulatory process where newly-constructed power plants are examined to ensure compliance with the most recent, and usually most stringent requirements for environmental performance and efficiency
non-fatal endpoints	health outcomes from morbidity that do not result in death
once-through	a heat engine where the fuel is used to drive only one mechanical process
outer continental shelf	the offshore area of the United States that falls outside the territorial limits of the individual states
partial arc admission	the process of admitting steam into a turbine only along a partial arc of its circumference
particulate matter	the solid and pre-solid fine material that is often emitted with gases. In EPA’s regulation under the Clean Air Act, of particular concern are particles smaller than 2.5 micrometers, which can be inhaled into the human lung
permeation	the process of penetrating through the pores or interstices of a substance
phase separation	a process for isolating the solid, liquid and gaseous phases, usually of waste stream

polar vortex	a large-scale persistent cyclone that circles either of the planet's geographic poles and creates weather phenomena. A large polar vortex in the Winter of 2014 created significant weather issues in North America.
preserved nuclear	under EPA's Clean Power Plan, the portion of existing nuclear generation (6 percent) that can be accounted for in a state's calculation of CO_2 emission rates. Preserved nuclear is based on EPA's analysis of the potential for retirement of existing nuclear capacity
primary base load generation	the electrical generating units that are most likely to be used to meet some or all of a given region's continuous energy demand and produce energy at a constant rate, usually at a low cost relative to other available generation
rate-based goals	goals that are based on the amount of a pollutant emitted per unit of energy generated, such as carbon dioxide emissions per MWh
renewable energy credit	an incentive or tax credit offered to encourage the installation and operation of renewable energy systems such as wind turbines or solar panels
renewable portfolio standard	a regulation or law that mandates increased production of energy from renewable sources, such as solar and wind. Often, these standards require utilities to produce a set percentage of their total generation from these sources
renewables or renewable energy	energy (or energy sources) that are naturally replenished on a human timescale and are used at a lesser rate than the possible maximum. These include sunlight, wind, rain, tides, waves and geothermal heat.
research and development	the process of investigating the science and creating the technology to implement a process
research, development and demonstration	the expansion of research and development to include a final step that shows the practical use and feasibility of the process
selective catalytic reduction	a means of converting nitrogen oxides to nitrogen gas and water
sequestration	the process of isolating or storing a substance to prevent its interaction with the environment

slagging or fouling	the build-up of ash or other vitreous residue from combustion or other high-temperature processes
social cost of carbon	a metric derived from a variety of disciplines, aimed at monetizing the impacts of carbon dioxide emissions
solubility trapping	capturing of a substance, such as carbon dioxide, based on dissolution into another substance
state implementation plan	the regulatory framework developed by a state to implement federal Clean Air Act requirements
steady state	having properties that are unchanging over time
syngas	a gas created by the gasification of coal or in an integrated gasification combined cycle unit
technology readiness level	measure used to assess the maturity of evolving technologies during their development and early deployment
thermal efficiency	a measure of the performance of a heat engine, determined by the ratio of work output to the heat input, expressed in the same units of energy
tonnes	metric tons
trapping	a physical or chemical process for isolating or capturing a substance
unit	see “electrical generating unit”
unmineable coal seams	coal which cannot be mined due to depth, thickness, quality, geologic setting, economic value, land use restrictions or other legal prohibitions
variable speed drives	electrical or other motors that can be operated at a number of different speeds based on desired output

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