Virginia Energy Plan

October 1, 2014

Commonwealth of Virginia

Department of Mines, Minerals and Energy

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The Commonwealth would also like to thank all of the citizens and businesses that submitted comments and input on the 2014 Virginia Energy Plan. Civic engagement and public participation are critical in ensuring government is working on behalf of all residents of the Commonwealth. The Commonwealth is grateful for this public involvement.

Commonwealth of Virginia
Office of the Governor

A Letter from Governor Terence R. McAuliffe

Grow. Strengthen. Diversify. These words are at the foundation of my administration's efforts to build a New Virginia Economy. They are also the words that guided the process that my staff and I undertook as we developed this quadrennial Virginia Energy Plan. If we are going to build the economy Virginia families deserve, we must begin by giving them the energy plan our economy demands.

The 2014 Virginia Energy Plan will lead our efforts to grow, strengthen, and diversify Virginia's economy in four ways:

1. **We will diversify our economy by strategically growing the energy sector**. There is tremendous untapped potential in many areas of the energy sector including wind and solar generation, biofuels, offshore energy development, and nuclear technology. We have an opportunity to create tens of thousands of jobs and generate hundreds of millions of dollars and bring new companies to Virginia.

2. **We will innovate to reduce greenhouse gas emissions and lower energy consumption throughout the Commonwealth.** The cleanest and cheapest energy is the energy that is not consumed. Strong energy efficiency measures in government, businesses, and residences will reduce energy consumption and diminish the need for new power plants. Converting more large-scale vehicle fleets to alternative fuel technology will lower greenhouse gas emissions and make Virginia more energy independent. Focusing on zero carbon-emitting energy sources will help our Commonwealth become a leader in fighting climate change.

3. **We will strengthen our business climate by investing in reliable and resilient energy infrastructure.** Access to low-cost power in every corner of the Commonwealth is a critical tool in promoting economic development, particularly in areas of high unemployment and a shrinking economic base.

4. **We will prepare Virginia's workforce to drive the energy economy into the future.** Coordination and collaboration with higher education institutions, research laboratories, and career technical centers is imperative in filling the impending gap in the energy sector created by an aging and retiring workforce.

The goals and recommendations set forth in this plan are by no means exhaustive. With many uncertainties in the energy landscape, including proposed federal regulations intended to reduce carbon emissions, we must remain flexible and adaptive. On other issues, like combating the effects of climate change and finding a path to a stronger portfolio standard, we have more work to do.

But if we work together, we can look back four years from today and say unequivocally that ours is an economy that is stronger, less dependent on externalities, and fueled by cleaner and more abundant Virginia energy. That is my administration's goal – and our efforts begin with this Energy Plan for a New Virginia Economy.

Terence R. McAuliffe

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Introduction

The 2014 Virginia Energy Plan is intended to provide a strategic vision for energy policy in the Commonwealth. This plan has been developed in accordance with Chapter 2 of Title 67 of the Code of Virginia. Per the statute, the Division of Energy of the Department of Mines, Minerals and Energy is the agency tasked with releasing the Virginia Energy Plan.

On June 4, 2014 Governor Terry McAuliffe signed Executive Order 16 establishing the Virginia Energy Council. As stated in EO 16, the Energy Council was formed to advise on the development and implementation of the 2014 Virginia Energy Plan. Maurice A. Jones, Secretary of Commerce and Trade, is the Convener and Chair of the Virginia Energy Council.

The Energy Council is comprised primarily of private sector, non-profit and higher education representatives with extensive knowledge and expertise about the energy industry in Virginia. As part of its duties, the Energy Council held two formal meetings in Richmond to review drafts of the plan and provide recommendations on policy strategies to be included in the plan. The Energy Council also spent significant time reviewing public comments and stakeholder input submitted to the Division of Energy during the public comment period. The Energy Council will remain convened for the duration of Governor McAuliffe's Administration and will meet annually to receive updates on implementation progress, provide strategic guidance, and assist in the interim update to be released in October of 2016.

The Division of Energy provided a 60-day public comment period that included a series of public listening sessions, as well as a web page housed in the website of the Secretary of Commerce and Trade. Six listening sessions were conducted in different regions of the Commonwealth to give the public an in-person forum to provide comments and input about what should be included in and excluded from the plan. The table below shows the location and number of attendees and speakers at each listening session.

2014 Virginia Energy Plan Listening Sessions		
Locations	**Attendees**	**Speakers**
University of Mary Washington (City of Fredericksburg)	30	11
Northern Virginia Community College – Annandale Campus (Fairfax County)	41	17
Southern Virginia Higher Education Center (Town of South Boston)	27	12
Virginia Highlands Community College (City of Abingdon)	72	29
Old Dominion University (City of Norfolk)	44	15
James Madison University (City of Harrisonburg)	67	28
Total	**281**	**112**

An online form was created to give the public an additional mechanism to provide comments and input outside of the listening sessions. One hundred and forty four individuals and organizations submitted comments online.

The 2014 Energy Plan is composed of an executive summary, twelve sections and two appendices. Sections 1-11 provide a snapshot of current energy assets in the Commonwealth.

The technical sections include:

- Consumption patterns of the population
- In-state and imported generation
- Transmission, storage and distribution infrastructure
- Energy-related education institutions and programs
- Resiliency and assurance protocols
- Energy source types
- Energy efficiency

Section 12 of the plan outlines a series of action-oriented recommendations that is intended to shape the Commonwealth's energy policy during Governor McAuliffe's Administration and beyond.

The plan also fulfills the statutory language added during the 2014 General Assembly session requiring analysis of any proposed rule promulgated by the Environmental Protection Agency related to the regulation of carbon emissions at existing fossil fuel power generating stations. The analysis can be found in the Appendix A.

The 2014 Virginia Energy Plan has been constructed to provide a comprehensive view of where Virginia has been and currently is in terms of its energy assets, and it charts a path forward for energy policy in the Commonwealth.

Executive Summary

ENERGY IN A NEW VIRGINIA ECONOMY – DIVERSIFY TO COMPETE

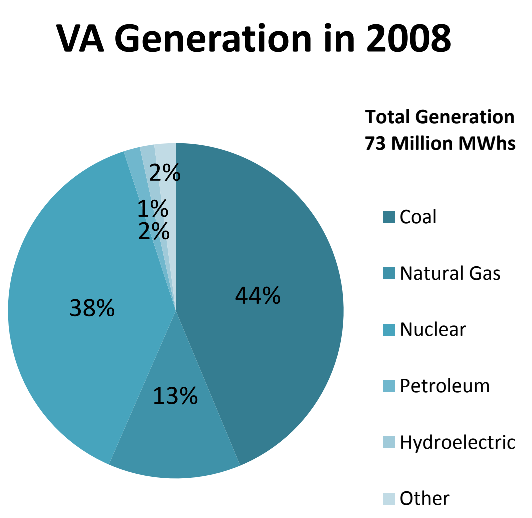
The Commonwealth of Virginia's energy industry is a source of great pride, prosperity, and potential. Historically, Virginia has ensured reliable and affordable energy, helping businesses and consumers thrive. The Commonwealth boasts tens of thousands of energy-related jobs, including miners, gas well crews, manufacturing workers, engineers, mechanics, computer programmers, accountants, and managers. While Virginians can and should be proud of the energy industry, a changing energy market and environment requires decisive action to position the Commonwealth to be a leader in innovative energy generation and utilization. Virginia must continue to leverage its business-friendly climate, high-quality research and educational institutions, and varied energy resources to attract businesses and create jobs.

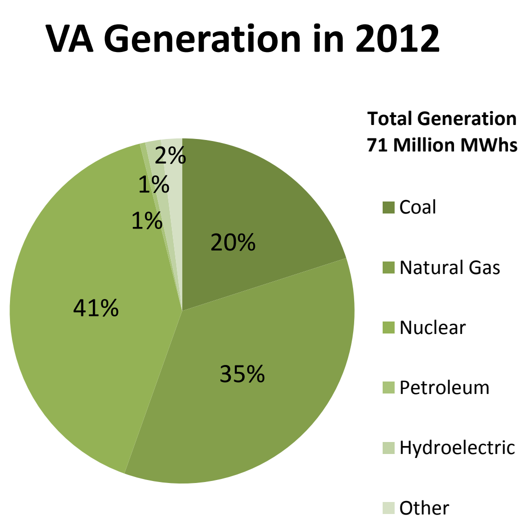
Virginia must implement policies that promote a genuine "all of the above" strategy that includes traditional energy sources, renewable sources, and energy efficiency. Broadening the number of sources utilized and consumed in Virginia will make the Commonwealth less reliant on imported energy, increase economic development and provide a hedge against future volatility that may affect particular resources and be detrimental to the Virginia economy.

The recommendations set forth in the 2014 Virginia Energy Plan are laid out in the form of four themes. Each theme contains a series of specific action items that, when implemented, will accomplish the overarching goal of transitioning to a New Virginia Economy.

Strategic Growth in the Energy Sector

Increasing renewable generation in Virginia is vital to ensuring a healthy and diverse fuel mix. The energy generation mix in Virginia continues to change as natural gas becomes more abundant and available, less expensive and prices become less volatile. Total generation in the Commonwealth has shifted from 82% of total megawatt hours (MWh) deriving from coal and nuclear in 2008 to 76% of total MWh's deriving from natural gas and nuclear in 2012.





One consistent trend is the low percentage of renewable generation contributing to the overall fuel portfolio in Virginia.

2010 Renewable Generation Deployed in Virginia		
Type	Installed Capacity (MW)	Percent of State Total
Hydro	866	3.6
Solar	16	<1 (.0007)
Wind	<1	<1 (.00004)
Wood/Wood Waste	331	1.4
MSW/Landfill Gas	290	1.2

Given the relatively small deployment of renewable generation in Virginia, this industry has the potential to grow substantially and increase diversity within the energy sector specifically and the overall economy generally.

Virginia must create a regulatory and business environment that allows renewable energy development to prosper. A signal must be sent that Virginia is supportive of and enthusiastic about the role of renewable energy in the economy.

Localities must be prepared to address zoning and permitting uncertainties before projects are proposed in their communities. The Commonwealth must increase or lift caps on the size of renewable projects, both at the commercial and residential levels. Virginia citizens should be given the opportunity to work together to develop projects that increase renewable generation in their communities. And the Commonwealth should continue to aggressively support the timely development of offshore wind off the coast of Virginia.

The New Virginia Economy must be based on diversity and inclusion. The renewable industry holds significant economic potential in the Commonwealth, and energy policies should reflect a desire to see this potential reached.

Energy efficiency is considered by many to be the largest and least costly energy resource available today. Virginia must be committed to reducing energy consumption in both the public and private sectors. This will decrease costs to consumers, lessen the need to construct costly generation plants, and spur significant economic development.

Aggressive implementation of energy efficiency measures in both the public and private sectors will grow the existing energy efficiency industry in Virginia. One study estimates that robust energy efficiency policy in Virginia could increase the Gross State Domestic Product by $286 million and increase employment by 38,000 jobs by 2030.

Estimated Employment and Economic Impacts of Energy Efficiency in Virginia		
Type	**2020**	**2030**
Annual Increase Employment (ACEEE Calculator)	28,500	38,000
Change in Gross State Product (in Million $ 2007)	$178	$296

The Commonwealth is committed to leading by example on energy efficiency. Pursuing energy efficiency within state government will set an example for localities and the private sector and highlight the tangible benefits of increasing the productivity of the energy consumed.

The Governor will appoint a Chief Energy Efficiency Officer within the Administration to focus on maximizing opportunities in the public sector to increase energy efficiency, decrease energy consumption and be responsible stewards of taxpayers' dollars.

The Governor will also convene an energy efficiency board comprised of leaders in the energy efficiency industry to develop a strategic plan for meeting the 2007 voluntary goal of a 10% reduction in retail energy consumption in Virginia. The Board will develop a mechanism of measurement and verification to determine where the Commonwealth currently stands in terms of meeting the goal and recommend policies that will accomplish the goal by 2020, two years faster than originally proposed. The Board will continue to robustly monitor progress.

Businesses in many sectors of the Virginia economy have placed an increased emphasis on tapping international markets to diversify their client base and expand their global footprint. This focus on diversification holds much economic potential for certain parts of the Commonwealth that have traditionally catered to a domestic or Virginia-specific clientele.

The coal industry supply chain, including those businesses based in Southwest Virginia, has developed significant and distinct expertise supporting the coal industry in Virginia. There are emerging economies in many parts of the world where this type of mining support experience and expertise would be valuable. The key is connecting these Virginia businesses with international markets that may be in need of their goods and services.

Traditionally, the Commonwealth has developed programs to help connect Virginia businesses with international markets. Now is the time to make these efforts a priority in Southwest Virginia. The first step is to increase educational outreach to the coal industry supply chain to ensure businesses understand potential opportunities in international markets.

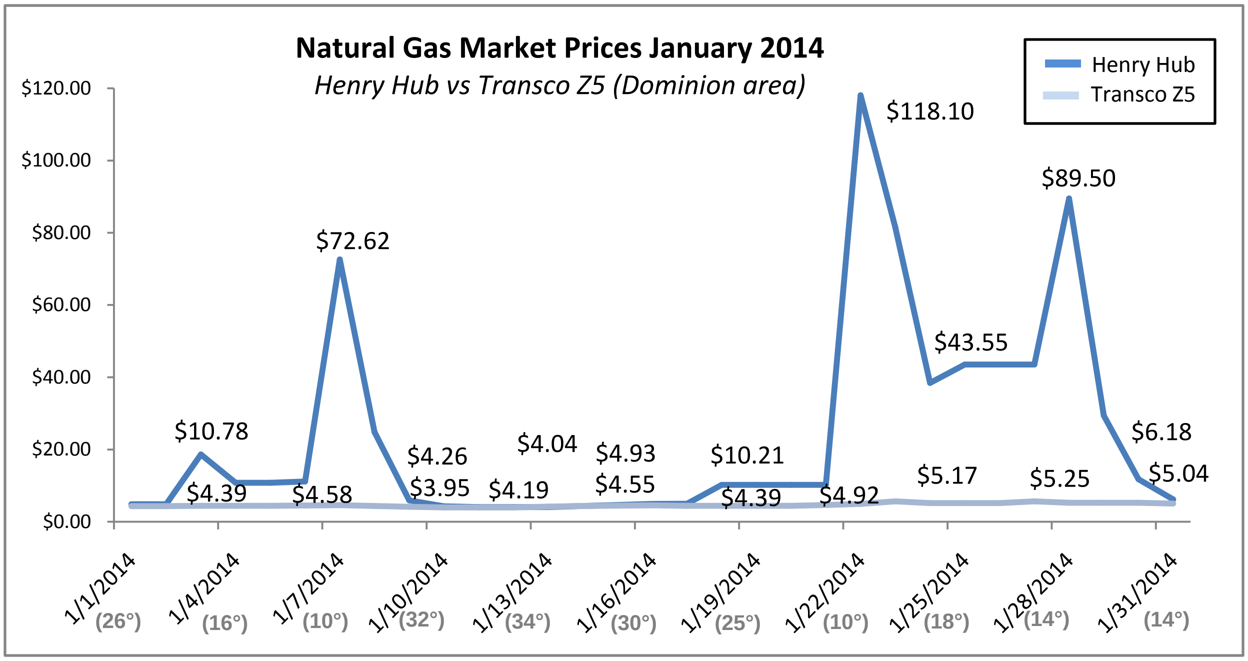
Current Virginia statute on offshore energy development favors permitting the production of offshore oil and natural gas resources 50 miles or more off of the coastline. It is critical that the development of these resources be conducted in a safe manner that is protective of Virginia's coastal environment and its broad economic and ecologic base.

Expand Best-in-Class Energy Infrastructure

A system of energy and electricity transmission and distribution that is reliable, resilient and cost-effective is the backbone of any healthy economy. This requires appropriate investments by the private sector, as well as responsible support and policies by the public sector. In many areas of Virginia, access to natural gas can mean the difference between a growing and vibrant economic base and one of stagnation. Virginia must be committed to giving localities throughout the Commonwealth all of the economic development tools they need to attract new businesses and grow existing businesses. A modern transmission and distribution system that provides the capacity needed in all parts of Virginia is an important component of building a truly diverse economy.

Collaboration between the state and local governments must be a priority in developing policies at all levels of government that chart a long-term path toward resilient, reliable and affordable access to energy. The winter of 2014 offered an important case study in how natural gas transmission constraint can be costly to consumers.

Multiple days of very low temperatures placed a nearly unprecedented amount of pressure on the natural gas transmission system in many parts of Virginia. Due to the lack of sufficient



transmission infrastructure in the Commonwealth, market prices for natural gas prices spiked during the polar vortexes.

It is also important to take advantage of increased natural gas transmission capacity by increasing the fueling infrastructure for automobile and transport vehicles that are converting to Liquid Natural Gas (LNG) and Compressed Natural Gas (CNG). Virginia must work with local partners in areas of the Commonwealth where the potential for high volume alternative fuel vehicle fleet deployment exists and deploy the necessary fueling infrastructure to supply these fleets. Alternative fuel technologies can be significantly more cost-effective for both the private and public sectors. For the private sector, fuel-cost savings means more money to reinvest and grow. For the public sector, using taxpayer dollars as efficiently as possible must be a priority to make each taxpayer dollar go further.

Given the nuclear industry's important role in the Commonwealth's economy, Virginia must continue to be a leader in nuclear generation, research, education and workforce development. Created in 2013, the Virginia Nuclear Energy Consortium is Virginia's primary resource for interdisciplinary study, research, and information on nuclear issues. The Consortium will play a critical role in providing the nuclear industry in Virginia with a viable, long-term and innovative strategic path forward.

Advanced Vehicle Technology and Alternative Fuels

Not only is promoting an increase in fuel mix diversity an important strategy in energy generation, it is also an impactful strategy in the area of vehicle fuel consumption. Virginia uses an enormous quantity of imported petroleum while falling behind other states with state-funded deployment programs for alternative fuel vehicles. Virginia's transportation sector is responsible for more than 50% of Virginia's greenhouse gas emissions. Creating a strategy to promote alternative fuel and advanced technology vehicles makes economic sense, diversifies the transportation fuel mix for improved energy security and resiliency, utilizes domestic resources and has the potential to substantially reduce air emissions, especially in areas of high population density.

The availability of non-traditional vehicle fuels and the advancements in vehicle technology provide an opportunity for significant diversification of the fuels consumed by the transportation sector in the Commonwealth. This diversity promotes growth in emerging sectors of the economy and can create a welcoming business environment for entrepreneurs with innovative ideas and business models. The Commonwealth can achieve great benefits by leading by example and emphasizing the use of more fuel-efficient vehicles and the deployment of a more diverse transportation fuel infrastructure. Virginia must show leadership by accelerating the conversion of its vehicle fleets to alternative sources of fuel.

As a leader in public private partnerships (P3), Virginia must look to previous P3 successes for best practices and apply that knowledge to the alternative vehicle fuels space. Working with the private sector, Virginia can find ways to increase deployment of fueling infrastructure in areas where large vehicle fleets are housed. Combining resources can reduce costs for both the public and private sectors and send a signal that Virginia is finding creative solutions to reducing fuel-costs and greenhouse gas emissions.

Virginia must also use existing resources to increase the conversion of state and local vehicle fleets to alternative fuels. Deploying existing state and federal resources in a creative manner will help lower initial capital costs for agencies and localities in purchasing alternative fuel vehicles that will increase fuel-cost savings in the long-term.

Talent Development in the Energy Sector

The Commonwealth must devise a long-term, comprehensive plan to equip Virginia's workforce with in-demand skill sets that will retain and attract businesses.

With 40 percent of the nation's energy workforce either eligible for retirement or departing their jobs due to of attrition during the next five years, the energy sector needs to work to develop programs to attract and train new workers. The expansion of the Troops to Energy program is imperative to filling these upcoming vacancies. This initiative will train veterans in the skills needed in the energy sector. In addition, it credits military experiential training in the attainment of a degree.

Clean energy jobs are the next generation of employment opportunity. The U.S. Bureau of Labor Statistic's Virginia green workforce estimates are skewed heavily to U.S. military and federal government employment. With these jobs removed, the Commonwealth's green jobs concentration drops to an unremarkable 2.6 percent share of workforce, or roughly 100,000 people. Not having a properly trained and ready workforce has prevented some clean energy companies from moving their businesses to Virginia.

With new technology and an emerging renewable energy field, Virginia should be a global leader and be ready to compete in this new Virginia economy.

SECTION 1 - GENERAL ENERGY INFORMATION

Quick Facts About Energy in Virginia

- Energy - for lighting, heating, cooling and transportation uses- is generated for Virginians from the following sources:
  - 34% from petroleum
  - 20% from electricity generated outside Virginia
  - 18% from natural gas
  - 13% from nuclear-based electricity generation
  - 9% from coal
  - 6% from hydro, biomass, and other renewable sources[1]
- Virginia's net energy balance is negative, which also is the case for most other states. The Commonwealth imported about 55 percent of total energy used in 2012, producing 1,047 trillion Btu, but consuming 2,356 trillion Btu[2]
- Electricity generated in Virginia in 2013, the most recent year in which data is available, came from a variety of sources including:
  - 35.7% from nuclear
  - 29.7% from natural gas
  - 28.7% came from coal
  - 4.5% from renewables
  - 1.2% from hydroelectric
  - 0.2 % petroleum[3]

Virginia's utilities imported about 37 percent of the state's 2012 electricity consumption from generation facilities outside of Virginia.[4] However, much of the generating capacity located outside Virginia geographical borders is owned by utilities that serve Virginia customers. That generation falls under Virginia State Corporation Commission (SCC) rate setting jurisdiction. Between 85 and 90 percent of the total supply of energy to Virginia Investor Owned Utilities is produced from facilities under SCC rate setting jurisdiction.

- The Commonwealth is the 19th largest primary energy producer of the states, including coal, natural gas, hydro, biomass, and other renewables.[5] Virginia's mining companies produce nearly 4.5 percent of U.S. coal east of the Mississippi River from underground and surface mines in Southwest Virginia. Virginia processed over 38 percent of U.S. coal exports in 2012. Virginia has nearly 7,843 natural gas wells that produce approximately 50 percent of the natural gas the state consumes. Two Virginia coal bed methane fields and the Nora and Oakwood fields in Southwest Virginia are among the top 100 natural gas fields in the United States.
- Virginia is home to a robust energy infrastructure including:
  - 115 coal, nuclear, natural gas, hydro, oil, and biomass fueled electric power plants
  - The southern end of the PJM Interconnection System with approximately 60,000 miles of transmission lines and approximately 6,000 substations, connected to an extensive network of local distribution lines reaching customers in almost every corner of Virginia
  - Approximately 3,000 miles of natural gas transmission pipelines[6], approximately 3,200 miles of natural gas gathering pipelines[7], and approximately 20,000 miles of distribution pipelines[8]
  - Two petroleum product pipelines moving gasoline, diesel, and other fuels from the Gulf of Mexico to Virginia; piers to receive water-borne petroleum products; and four major petroleum terminal hubs

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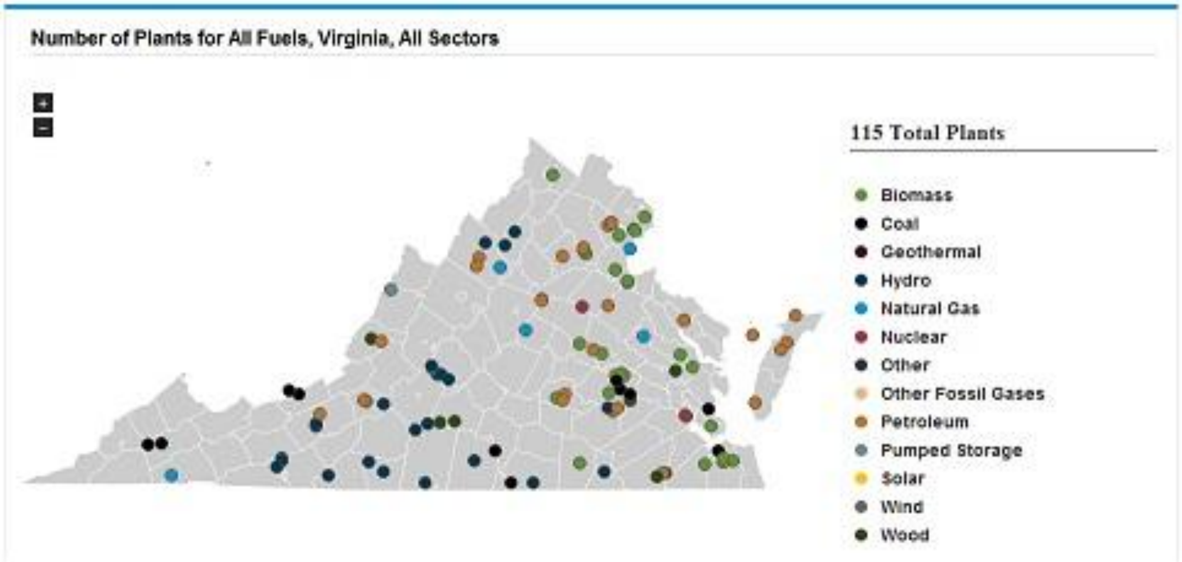
[1] EIA, SEDS, Virginia State Energy Profile
[2] EIA, SEDS, Virginia State Energy Profile
[3] EIA, SEDS, Virginia State Energy Profile
[4] EIA, Sources and Uses
[5] EIA, SEDS, Virginia State Energy Profile
[6] PHMSA Pipeline Safety Program, http://primis.phmsa.dot.gov/comm/reports/safety/VA_detail1.html?nocache=9885#_OuterPanel_tab_1, June 22, 2010
[7] DMME, Division of Gas and Oil, June 23, 2010
[8] PHMSA Pipeline Safety Program, http://primis.phmsa.dot.gov/comm/reports/safety/VA_detail1.html?nocache=9885#_OuterPanel_tab_1, June 22, 2010.

Location of Electric Power Generation Plants in Virginia



- Virginia uses energy more efficiently than the nation, consuming 295 million Btu per capita while the nation consumes an average of 312 million Btu per capita.

Energy Consumption

- Virginians use electricity, natural gas, fuel oil, and other fuels to light, heat, cool, and operate their homes, stores, offices and factories. Gasoline, diesel and a growing market of alternative fuels are used to power cars, trucks, buses, airplanes, ships, and trains.
- Energy is used in different ways and in differing quantities by residential, commercial, industrial, and transportation customers.
  - The transportation sector is the largest user of energy in Virginia. Residential and commercial use about equal amounts of energy, with industry using only slightly less.

Compared to the average state, Virginia uses more energy for transportation and commercial use and less for industrial use.

Figure 1-1: Virginia Total Energy Consumption by Sector, 2012[9]

[9] EIA, SEDS, Virginia State Energy Profile

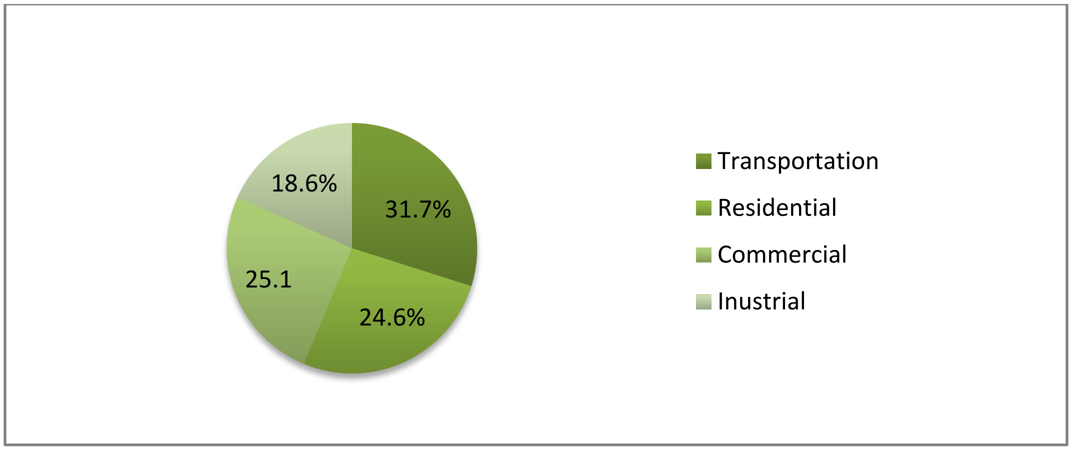
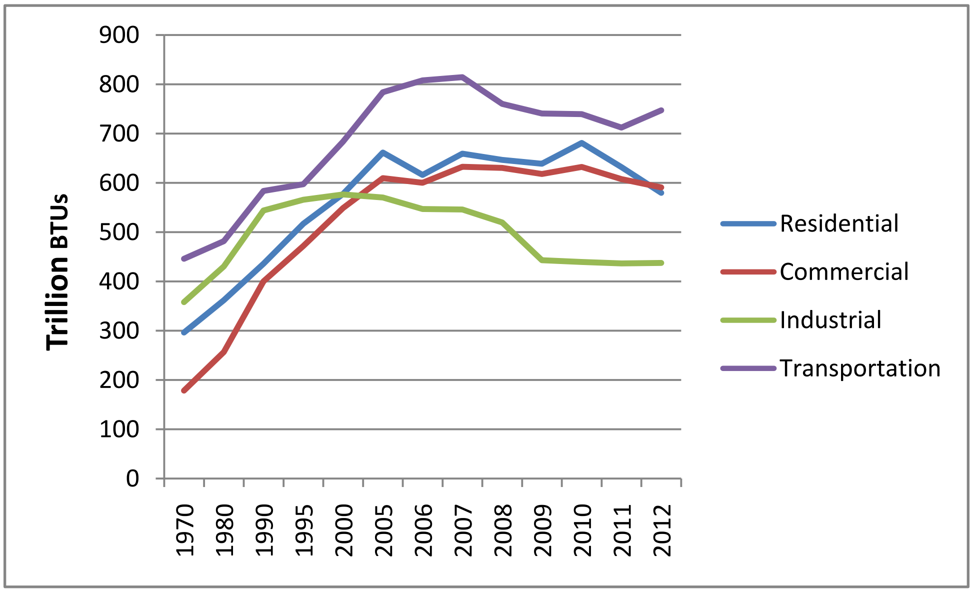


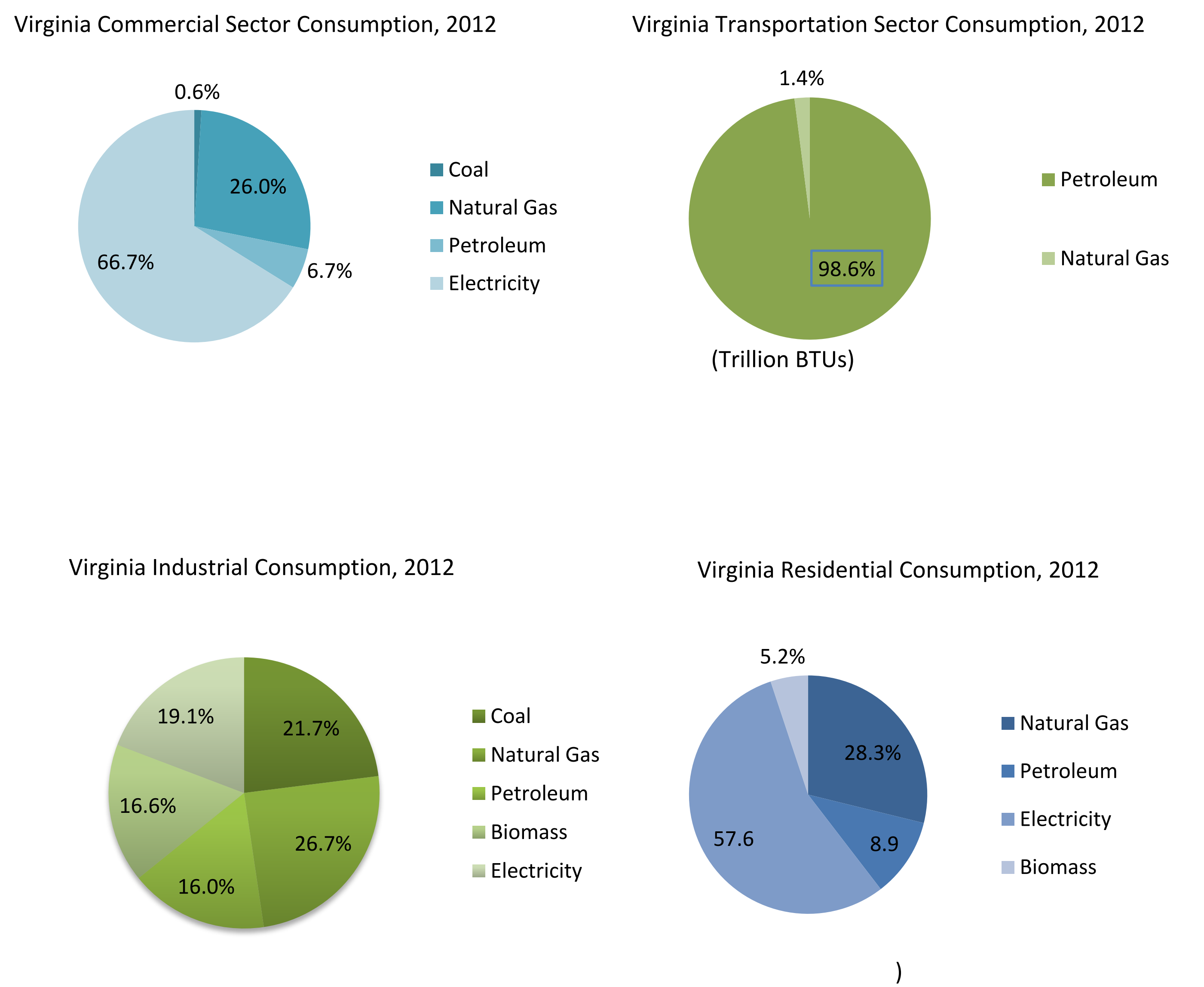
Figure 1-2: Virginia's Total Energy Consumption by Sector, 1970–2012[10]



- Electricity delivers 84 percent of all energy to the commercial sector, 77 percent to the residential sector, 40 percent to the industrial sector, and less than 2 percent to the transportation sector. In contrast, petroleum delivers 98 percent of energy used by the transportation sector and less than 5 percent used by the commercial sector.[11]

[10] EIA, SEDS, Virginia State Energy Profile
[11] EIA, SEDS, Virginia State Energy Profile

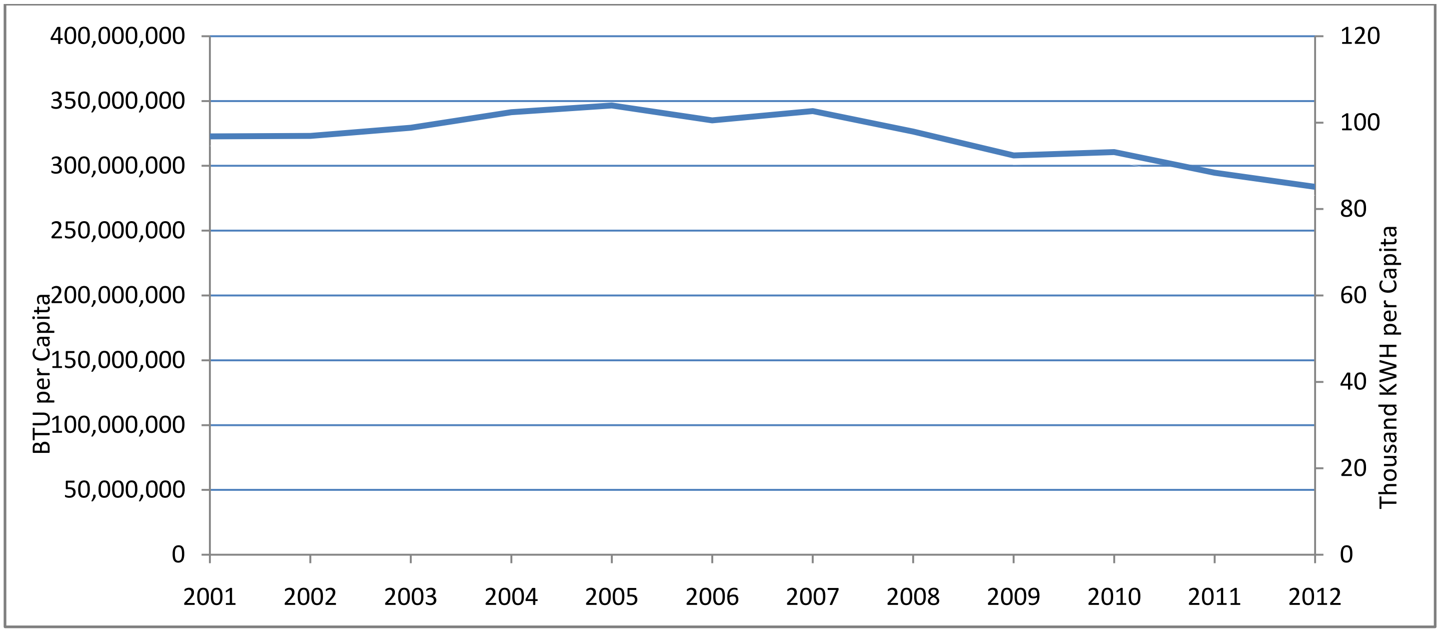
Figure 1-3: Virginia's Energy Consumption by Sector, 2012[12]



Energy use generally before 2005, over the long term, had increased gradually due to increases in energy used for transportation and as consumers used more energy-consuming devices in their homes and businesses. This long-term trend appears to have changed since about 2005. Since then, per capita energy use in the Commonwealth generally has decreased for a number of reasons, including the following: consumers are driving fewer miles per person; economic activity has been slow; and, energy efficiency improvements have been realized.

[12] EIA, SEDS, Virginia State Energy Profile

Figure 1-4: Virginia's Per Capita Energy Use, 2000-2012[13]



Energy Balance – Imports and Exports

- Virginia has a net negative energy balance, importing 55 percent of the total amount of energy the state uses.[14] However, the SCC has rate setting jurisdiction over between 85 and 90 percent of total energy supplied to Investor Owned Utilities because some generation facilities outside of Virginia's geographical boundary are owned by utilities that serve Virginia customers. The Commonwealth is a net exporter of coal and a net importer of all other fuels.

- In 2009, Virginians spent $26.74 billion to purchase energy.[15] On a net basis, this included $13.7 billion on imported fuels and electricity.

[13] EIA, SEDS, Virginia State Energy Profile
[14] EIA, SEDS, Virginia State Energy Profile
[15] EIA, SEDS, Virginia State Energy Profile

Figure 1-5: Virginia's Net Energy Imports/(Exports), 2012[16] (Trillion BTUs)

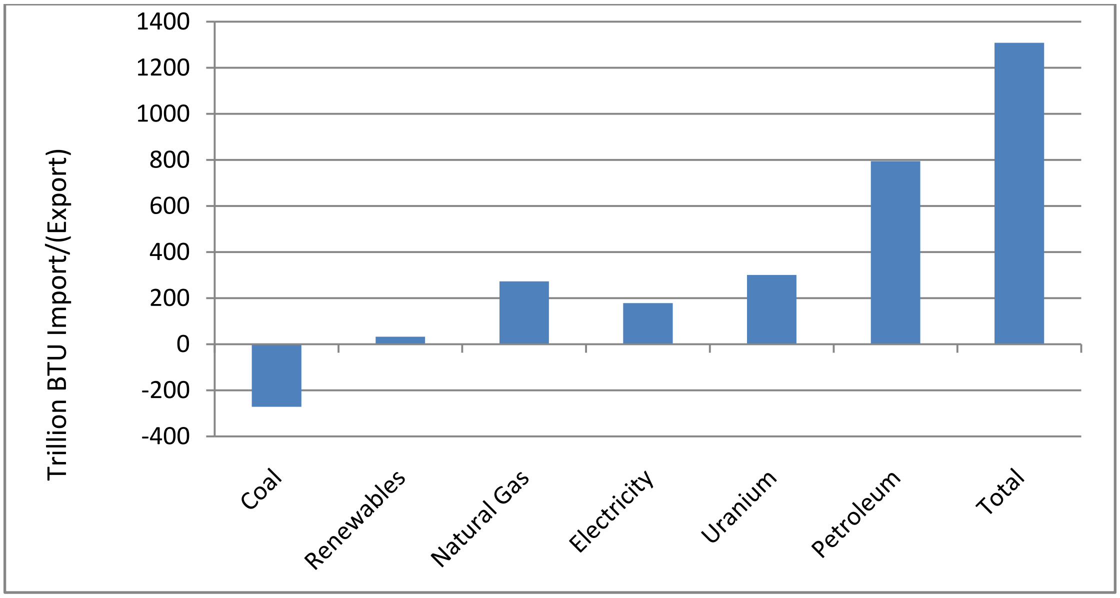


Table 1-1: Virginia's Estimated Net Energy Imports/(Exports), 2012[17] (Trillion BTUs)

Fuel	Production[18]	Consumption[19]	Net Imp/(Exp)
Coal	493.4	222.2	(271.2)
Renewables	101.6	134.5	32.9
Natural Gas	151.4	424	272.6
Electricity from nuclear[18]	301	479.4	178.4
Uranium (converted to Trillion Btu equivalent)[19]	0	301	301
Petroleum	0.1	794.6	794.6
Total	1047.5	2355.7	1308.2

[16] EIA, SEDS, Virginia State Energy Profile
[17] EIA, SEDS, Virginia State Energy Profile
[18] EIA, SEDS, Virginia State Energy Profile
[19] EIA, SEDS, Virginia State Energy Profile

Figure 1-6: Virginia's Net Energy Imports/(Exports) by Fuel, 2000–2012[18]

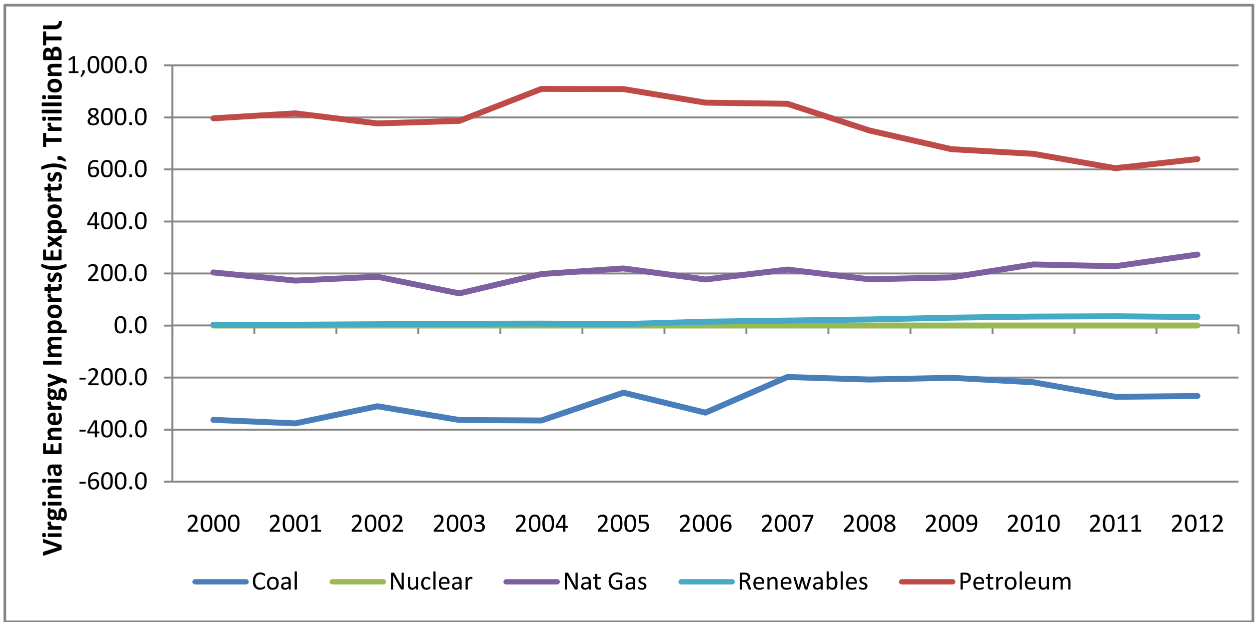


Table 1-2: Energy Production and Consumption History for Virginia (Trillion BTUs) [19]

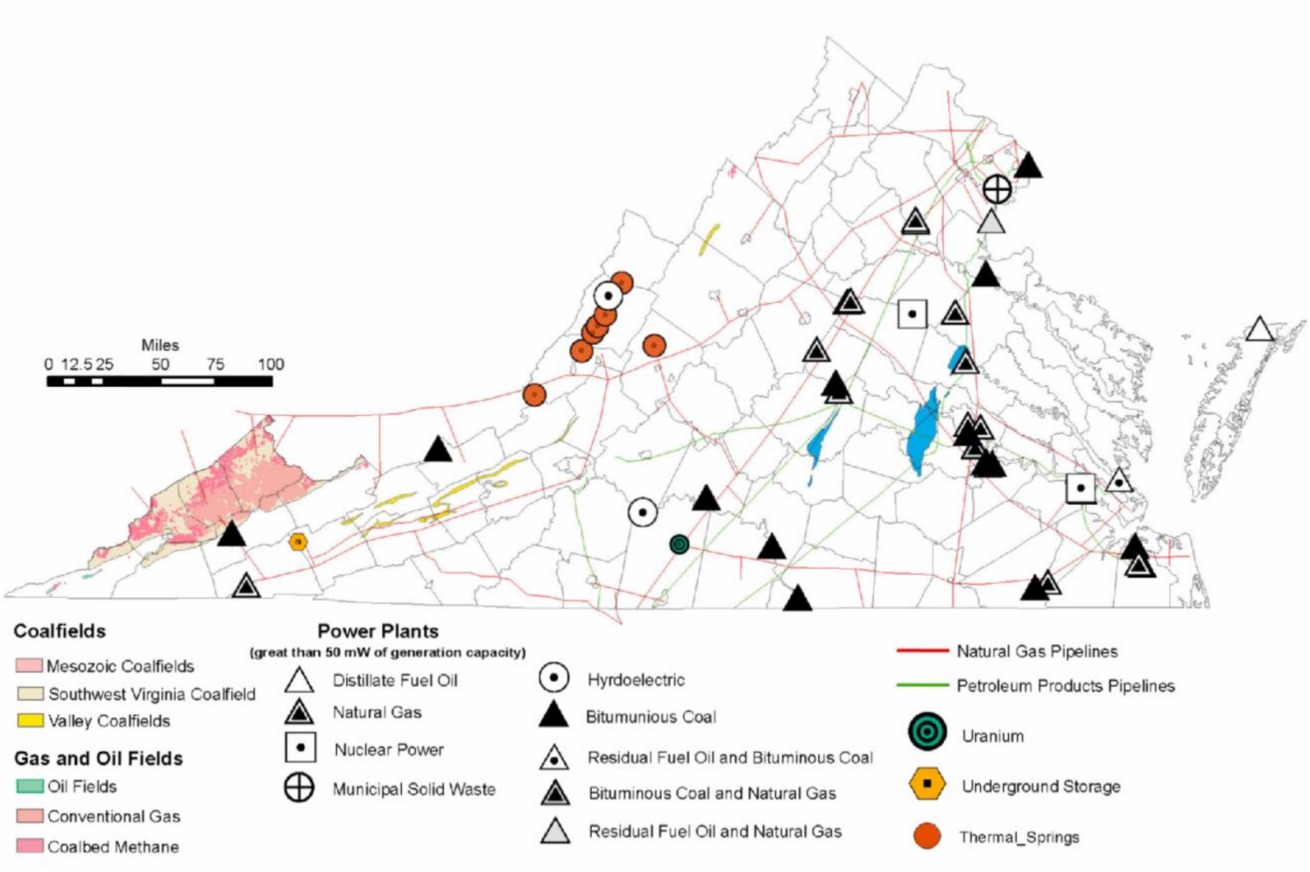
Year	Consumption	Growth	Primary Production	Growth	Gap/Imports	Growth
1995	2152.5		1355.5		797.0	
1996	2209.2	2.63%	1415.7	4.44%	793.5	-0.4%
1997	2205.5	-0.17%	1425.1	0.66%	780.4	-1.7%
1998	2231.7	1.19%	1374.5	-3.55%	857.2	9.8%
1999	2290	2.61%	1346	-2.07%	944.0	10.1%
2000	2386.8	4.23%	1353.9	0.59%	1032.9	9.4%
2001	2322.9	-2.68%	1300.1	-3.97%	1022.8	-1.0%
2002	2354.1	1.34%	1235.7	-4.95%	1118.4	9.3%
2003	2426.8	3.09%	1339.7	8.42%	1087.1	-2.8%
2004	2552	5.16%	1312	-2.07%	1240.0	14.1%
2005	2625.8	2.89%	1227.1	-6.47%	1398.7	12.8%
2006	2571.1	-2.08%	1281.9	4.47%	1289.2	-7.8%
2007	2652.4	3.16%	1175.2	-8.32%	1477.2	14.6%
2008	2557.2	-3.59%	1166.3	-0.76%	1390.9	-5.8%
2009	2440.9	-4.55%	1091.7	-6.40%	1349.2	-3.0%
2010	2492.6	2.12%	1097.2	0.50%	1395.4	3.4%
2011	2388.5	-4.18%	1087.8	-0.86%	1300.7	-6.8%
2012	2356.0	-1.36%	1047.4	-3.71%	1308.6	0.6%

Energy Infrastructure

A robust infrastructure is needed to deliver affordable, reliable energy supplies to energy users. Virginia's energy infrastructure (see Figure 1-7) includes facilities required for:

- Electricity generation, transmission, and distribution
- Natural gas production, transmission, and storage
- Petroleum production, transportation, and distribution
- Coal mining, transportation, and export
- Propane transportation, and distribution
- Wood/biomass production and transportation

Figure 1-7: Virginia's Energy Infrastructure[20]



[20] EIA, SEDS, Virginia State Energy Profile

State Rankings

As shown in the following comparisons of states, the Commonwealth has an economy that ranks among the top tier of states, while using energy more efficiently than the majority of states.

- According to the 2010 U.S. Census, Virginia was home to 8.0 million people, the 12th largest of the states.[21]
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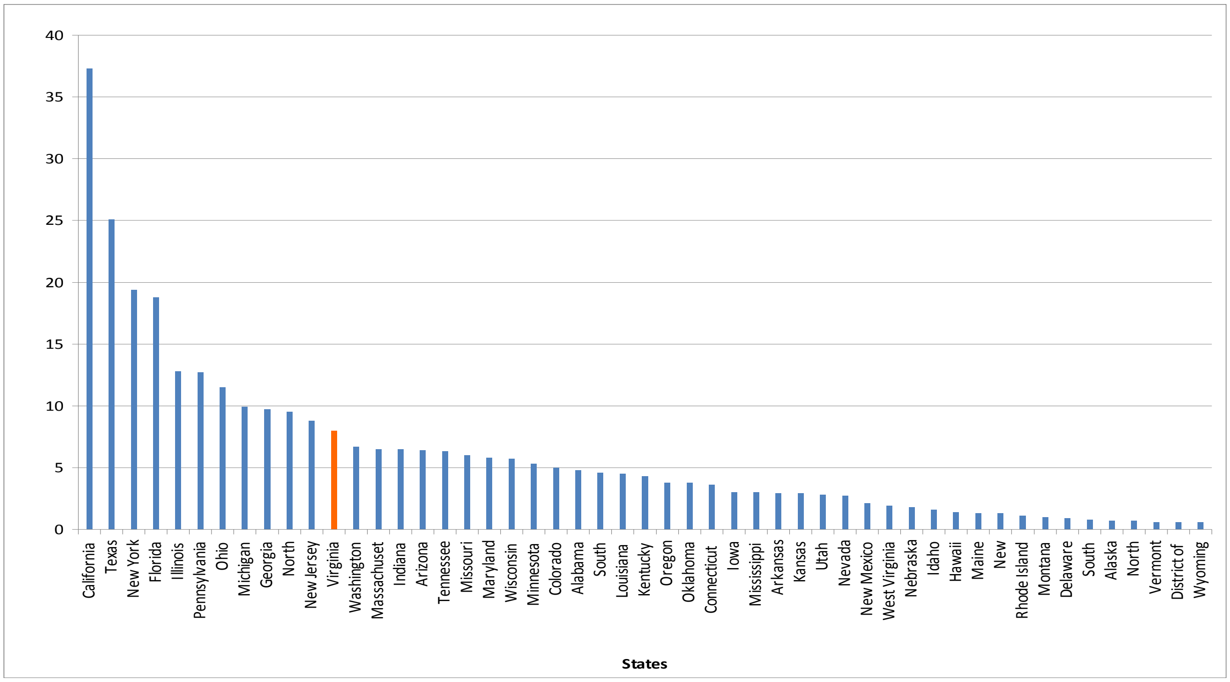
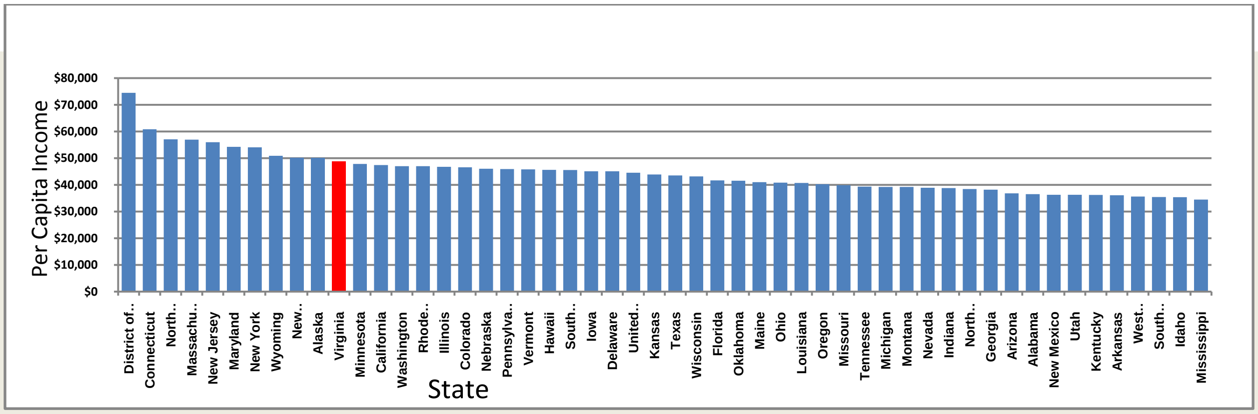
Figure 1-8: State Rankings – Population, 2011[22]



- In 2013, Virginia's per capita personal income was $48,773, the 11th highest of the states (including the District of Columbia).[23]

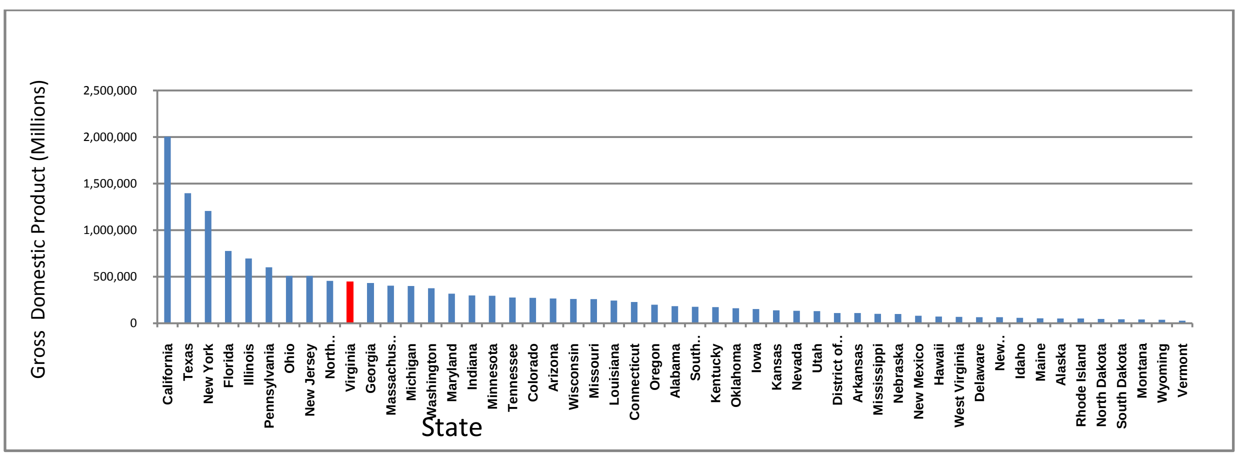
[21] EIA, SEDS, Virginia State Energy Profile
[22] EIA, SEDS, Virginia State Energy Profile
[23] Ibid

Figure 1-9: State Rankings – Per Capita Income, 2013[24]



- In 2013, Virginia's gross domestic product (GDP) was $445,876 billion - making it the 10th largest state economy of the nation.[25]

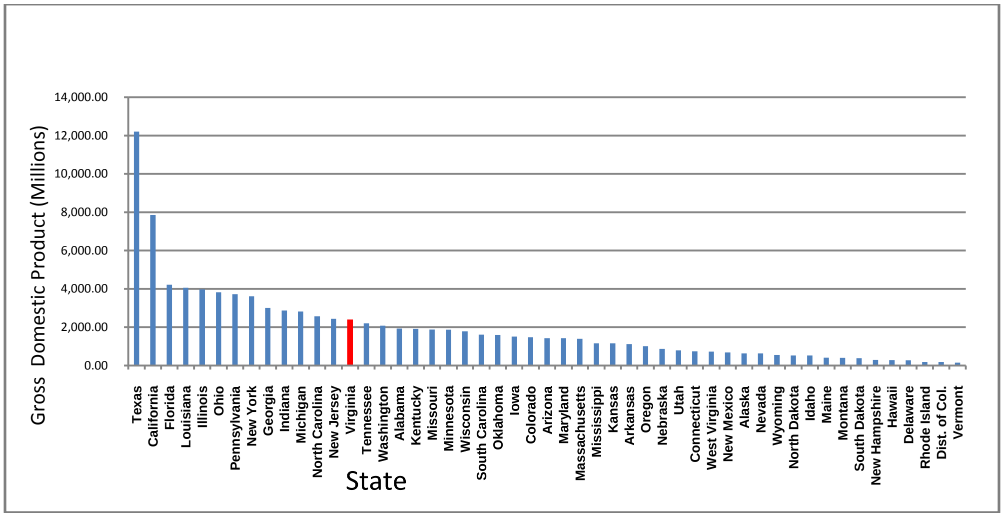
Figure 1-10: State Rankings – Gross Domestic Product, 2013[26]



[24] EIA, SEDS, Virginia State Energy Profile
[25] EIA, SEDS, Virginia State Energy Profile
[26] EIA,SEDS, Virginia State Energy Profile

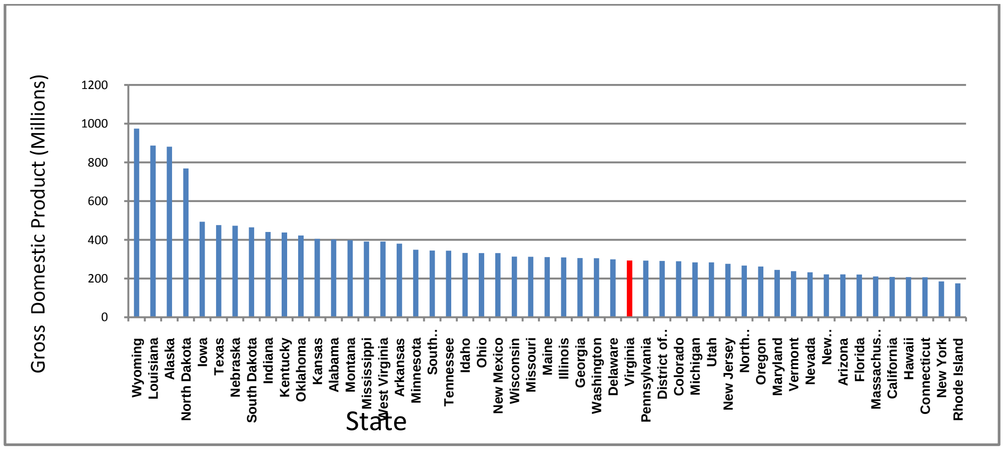
- In 2011, Virginia ranked 14th in total energy consumption, using 2,386 trillion Btu's of energy, or 2.5 percent of the total energy used in the U.S.[27]

Figure 1-11: State Rankings - Total Energy Consumption, 2011[28]



- In 2009, Virginia ranked 29th in energy use per capita among the states, using 303 million Btu's per person, 5 million Btu's less than the national average.[29]

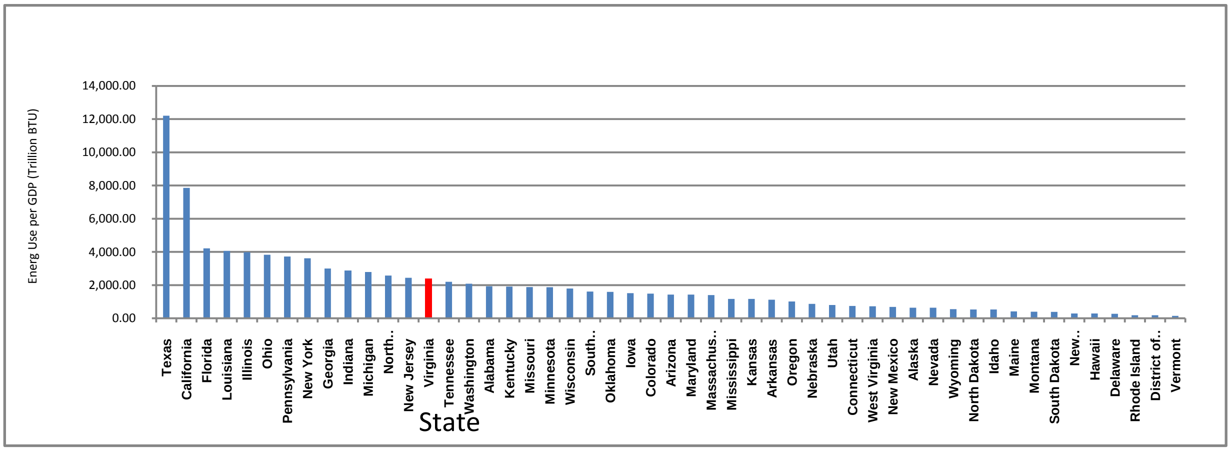
Figure 1-12: State Rankings - Energy Use Per Capita, 2011[30]



[27] EIA, SEDS, Virginia State Energy Profile
[28] EIA, SEDS, Virginia State Energy Profile
[29] EIA, SEDS, Virginia State Energy Profile
[30] EIA, SEDS, Virginia State Energy Profile

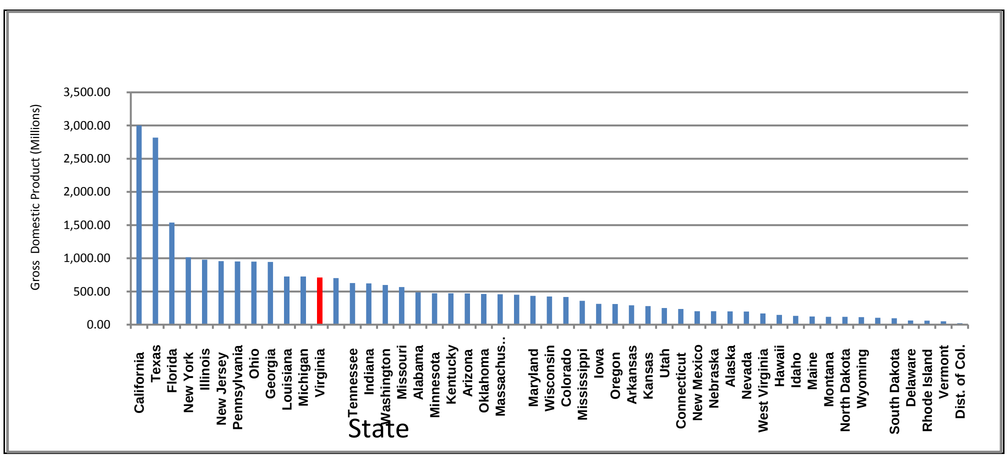
In 2011, Virginia ranked 14th, behind New Jersey, in energy use per gross domestic product (GDP), using 6,500 BTUs per dollar of GDP. This is slightly below the U.S. average of 7,300 BTUs per dollar of GDP.[31]

Figure 1-13: State Rankings - Energy Use Per Real Dollar of Gross Domestic Product (GDP), 2011[32]



- In 2009, Virginians used 745,455 billion BTU of energy for transportation. This was greater than for any other sector, ranking Virginia 10th amongst the states in terms of total energy used for transportation.[33]

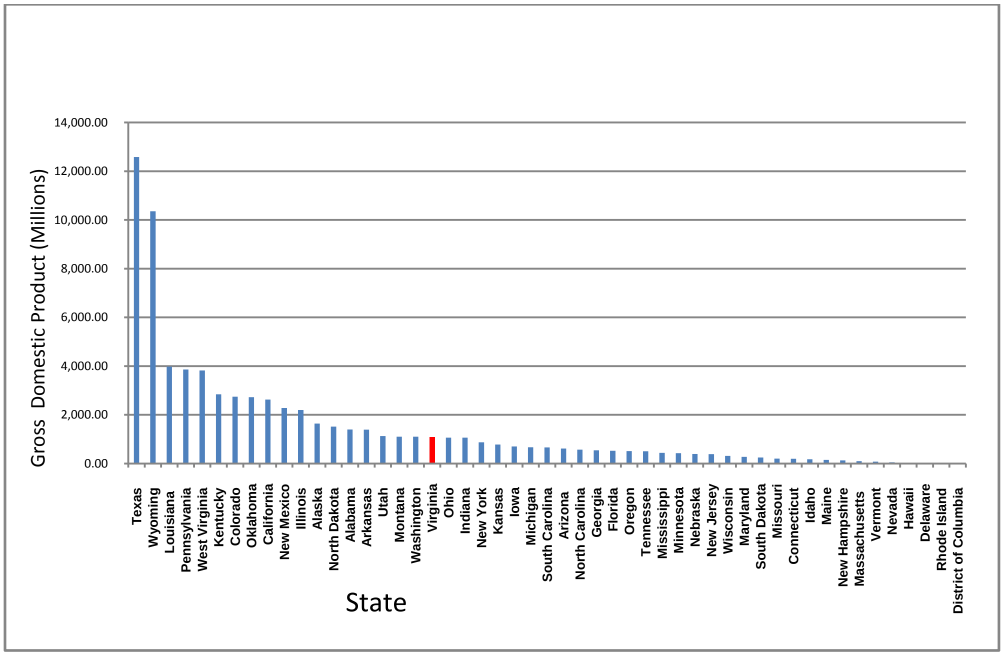
Figure 1-14: State Rankings – Energy Use for Transportation, 2011[34]



[31] EIA, SEDS, Virginia State Energy Profile
[32] EIA, SEDS, Virginia State Energy Profile
[33] EIA, SEDS, Virginia State Energy Profile
[34] EIA, SEDS, Virginia State Energy Profile

- In 2009, Virginia produced 1,092 trillion Btu, ranking it 15th among the states in terms of total energy production.[35]

Figure 1-15: State Rankings – In-State Energy Production, 2011[36]



[35] EIA, Sources and Uses
[36] EIA, Sources and Uses

SECTION 2 - ELECTRICITY

Selling Electricity in Virginia

Retail

With limited exceptions, retail sale of electricity in Virginia is provided by Virginia's regulated and public utilities. Utilities serve exclusive territories and have an obligation to serve customers who request service in their territories. Rates and terms of service for retail providers are subject to State Corporation Commission (SCC) review and approval.[1]

The electric cooperatives together are well over a million, the second largest provider of electricity in Virginia.

- Utilities are entitled to recover their reasonable and prudent costs plus a reasonable rate of return on their capital investment
- Rates of investor-owned utilities base rates are reviewed by the SCC every two years
- Additions to base rates are permitted through application for rate adjustment clauses (RACs) or other mechanisms to recover the costs of
    - Fuel and purchased power (fuel adjustment clause)
    - Transmission, as approved by the Federal Energy Regulatory Commission, and demand response programs
    - Environmental and reliability improvements
    - Energy efficiency programs and peak shaving programs
    - Cost of new nuclear or offshore wind generation facilities; and
    - Financial emergencies

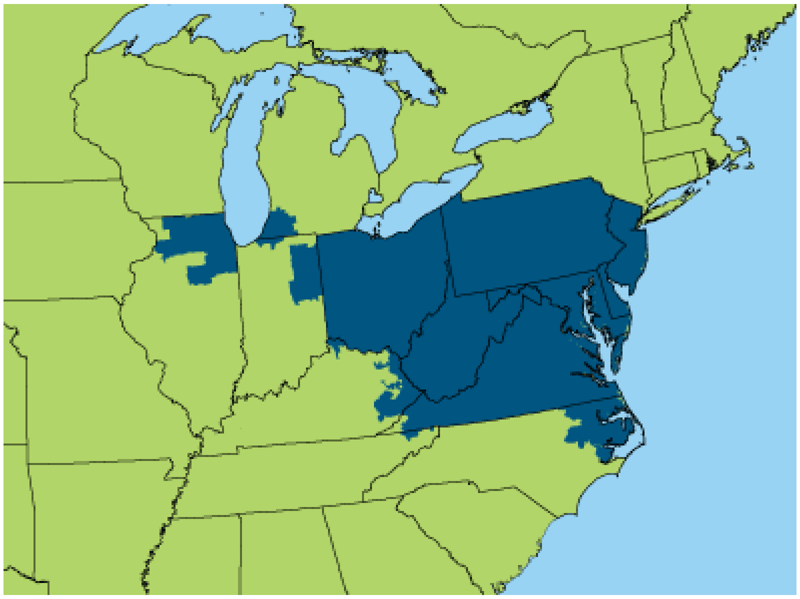
Electric utilities include three investor-owned electric utilities Dominion Virginia Power serves approximately 2.4 million customers, Appalachian Power Company (APCO) serves approximately 500,000 customers in Southern and Southwest Virginia, and Old Dominion Power (a subsidiary of Kentucky Utilities), serves customers in Wise and Dickinson Counties. In addition to investor-owned electric utilities, customers are also served by 13 electric cooperatives and 16 municipal electric providers. The electric cooperatives together serve well over a million customers, serving as the second largest provider of electricity in Virginia.

The two largest investor-owned utilities are statutorily required to be members of a regional transmission organization (RTO). PJM Interconnection is the RTO that includes Virginia. PJM operates the largest centrally dispatched electric grid in the world by coordinating the movement of electricity in thirteen states. In addition to Virginia, PJM coordinates the movement of electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, West Virginia and the District of Columbia.

[1] Virginia Electric Utility Regulation Act, Chapter 23 of Title 56 of the Code of Virginia, http://leg1.state.va.us/cgi-bin/legp504.exe?000+cod+TOC56000000023000000000000 June 19, 2010

Wholesale Electricity Markets

Figure 2-1 Map of PJM Service Territory[2]



RTOs such as PJM operate electricity “spot markets” in which generators sell and utilities or customers buy energy. These energy markets operate every day and participants in the market establish a price for electricity by matching supply (what generators want to sell) and demand (what utilities and customers want to buy).

RTO spot markets function at the “wholesale” level. Utilities and competitive retailers who purchase energy from these wholesale energy markets then resell it to final consumers at retail rates set by state regulators.

Distributed Generation

Distributed generation is defined as any small-scale power generation technology that provides electric power at a site closer to customers than central station generation. These decentralized energy technologies potentially offer significant advantages over conventional grid electricity sources and can be sited in areas where traditional generation would not be feasible. Additionally, distributed power is well suited for the use of solar, biomass, landfill gas, small hydroelectric, and small wind powered energy technologies that can be located closer to the user and can be installed incrementally to match the load requirement of the consumer.

Virginia law requires operators to connect retail customers who use distributed generation to the grid. The most common arrangement for distributed generation is for customers to net meter, that is to generate energy (typically through rooftop solar) to net against their own electric bill. As of July, 2014 there are 969 net metering customers for Dominion Virginia Power, 350

[2] http://www.pjm.com/about-pjm/who-we-are/territory-served.aspx

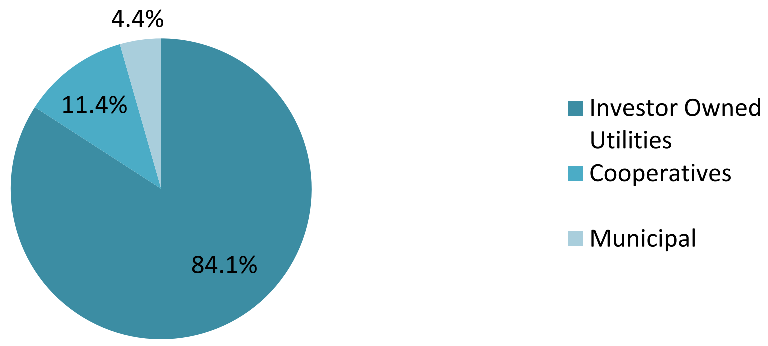
customers for APCO Virginia, and 388[3] for the electric cooperatives. In 2013, the SCC approved Dominion Virginia Power's Solar Purchase Program, which provides an additional avenue for customers to sell energy produced through distributed solar generation. Most of Virginia's electric cooperatives also offer rate riders enabling their member-consumers to purchase 100% renewable electric service through a purchase of undifferentiated energy plus the retirement of cooperative-purchased renewable energy certificates.

While residential net metering customers with systems up to 10 kW receive full retail reimbursement for the energy that they generate, proper and equitable cost recovery for utilities remains a concern regardless of the installation's size. Virginia law also allows utilities to collect a monthly standby charge from those residential customers with a system with a capacity greater than 10 kW and less than 20kW (who can partially meet their electricity needs from their own sources such as solar panels.[4] The standby charge is approved by the SCC and allows utilities which have approved standby charges to recover only the portion of infrastructure costs that are properly associated with those customers. In 2010 and 2011, the SCC examined the benefits and costs of net metering on the electric grid. The SCC also considered this question in 2011, before they established the stand-by charge referenced above.

Buying Electricity in Virginia

Virginia's retail electric customers are served by three investor-owned utilities (IOUs), thirteen electric cooperatives and sixteen municipal utilities.[5]

Figure 2-2 Retail Providers of Electricity in Virginia, 2012[6]



[3]Electric cooperative net metering customers based on best-available 2013 data, and exclude other distributed generators not operating under the net metering rules. For electric cooperatives, the overwhelming majority of these accounts (over 80 percent) are residential member-consumers. Not included in this number are the net metering customers of Powell Valley Electric Cooperative ("PVEC"). PVEC's net metering customers participate in net metering through a unique, three-party arrangement involving the federal Tennessee Valley Authority, PVEC's wholesale power supplier.
[4] http://lis.virginia.gov/cgi-bin/legp604.exe?000+cod+56-594
[5] http://www.eia.gov/electricity/state/virginia/ Table 9. Retail Electricity Sales Statistics, 2012
[6]http://www.eia.gov/electricity/state/virginia/ Table 9, Retail Electricity Sales Statistics, 2012.

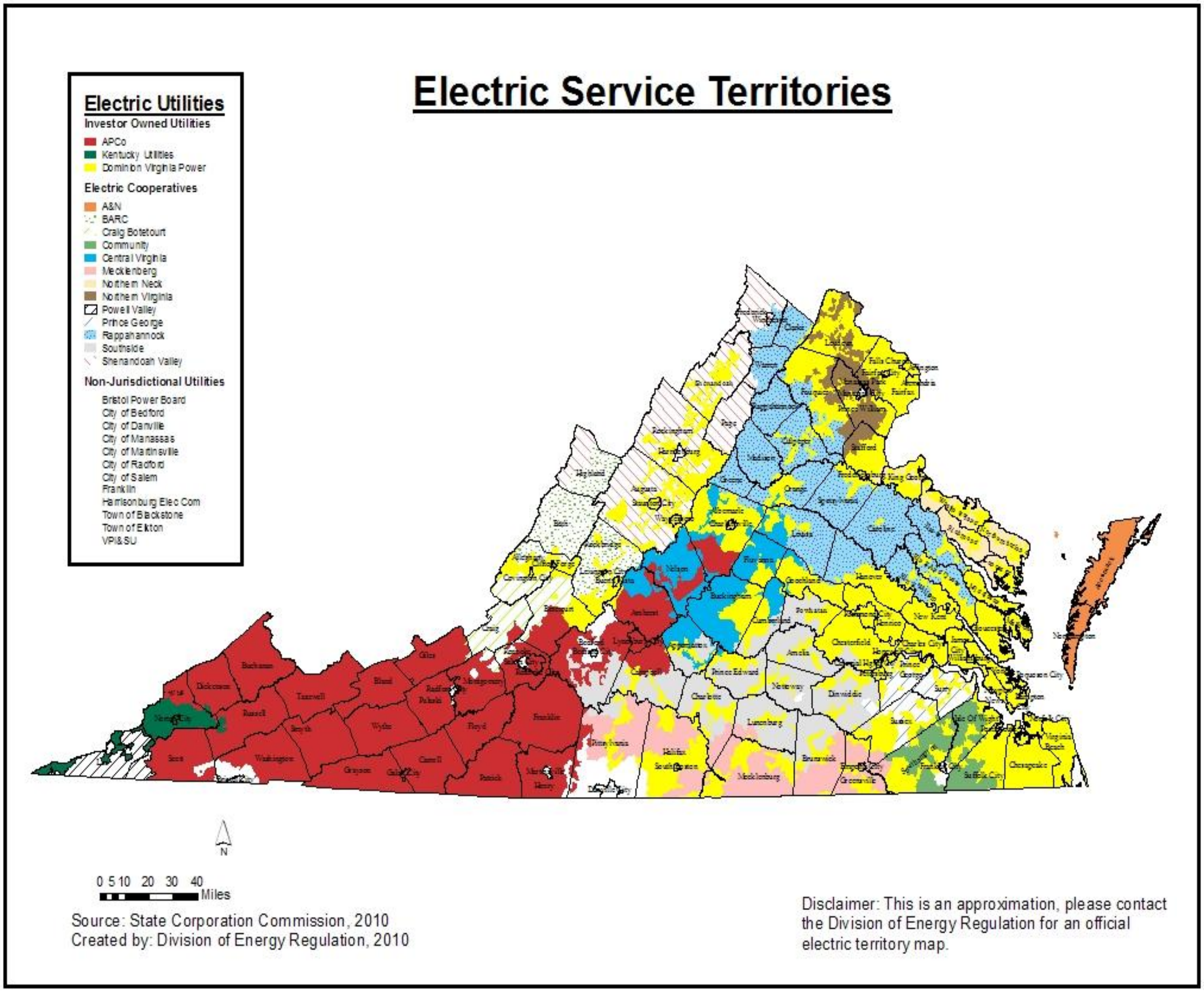
In June 2010, the service territory of a fourth investor-owned utility, Allegheny Power, was split and sold to two cooperatives – Rappahannock Electric Cooperative and Shenandoah Valley Electric Cooperative. Allegheny no longer provides retail electric service to Virginians.

Member owned electric cooperatives[7] are A&N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, Community Electric Cooperative, Craig-Botetourt Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Northern Virginia Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative, Southside Electric Cooperative, and Powell Valley Electric Cooperative. Ten of these are served by the wholesale Old Dominion Electric Cooperative.[8]

The 16 municipal electric utilities[9] serving customers located in their localities are the Cities of Bristol, Danville, Franklin, Harrisonburg, Manassas, Martinsville, Radford, and Salem; the Towns of Bedford, Blackstone, Culpeper, Elkton, Front Royal, Richlands, and Wakefield; and Virginia Tech (serving the Town of Blacksburg).

[7] Electric cooperatives are authorized to increase or decrease rates by 5 percent in a three-year period (not including the fuel factor adjustments) without SCC approval.
[8] Powell Valley Electric Cooperative ("PVEC") is organized pursuant to the laws of the Commonwealth and serves approximately 8,100 member-owners in Virginia in addition to its members in Tennessee. PVEC is regulated by the Commission as to service, and by the federal Tennessee Valley Authority as to rates.
[9] Rates and terms of service for municipal electric utilities are set by each City or Town Council.

Figure 2-3: Electric Utility Service Territories[10]



Electricity Rates

Virginia's rates have generally been below the national average, but in recent years have moved closer to that number, though there is significant variation among rates by electric provider within Virginia.

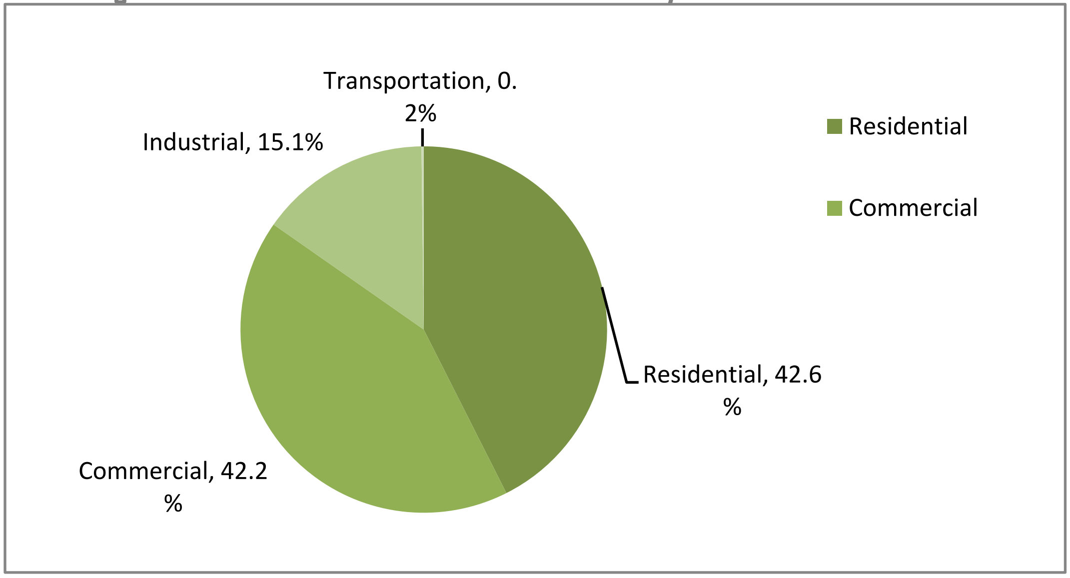
Electricity Consumption[11]

- Virginians purchased 107,794,985 megawatt hours of electricity in 2012

[10] SCC, https://www.scc.virginia.gov/pue/elec/el_map.pdf2010.
[11] Adapted from EIA, Virginia Electricity Profile**, Table 8.**, *Retail Sales, Revenue, and Average Retail Price by Sector, 2000 and 2004 Through 2010*, http://www.eia.gov/cneaf/electricity/st_profiles/virginia.html., January1990- 2012. http://www.eia.gov/electricity/state/virginia/. June 10, 2014.

- The residential sector consumed more electricity than other sectors in 2012 - over 43 million megawatt hours of the total
- The commercial sector used 43.4% in 2012, including major military bases, one of the largest ports in the United States, and a large share of the computer infrastructure supporting the Internet and centralized computing
- The industrial sector used 16.1% of electricity in 2012

Figure 2-4: Percent of Retail Electric Sales by Customer Class, 2012[12]

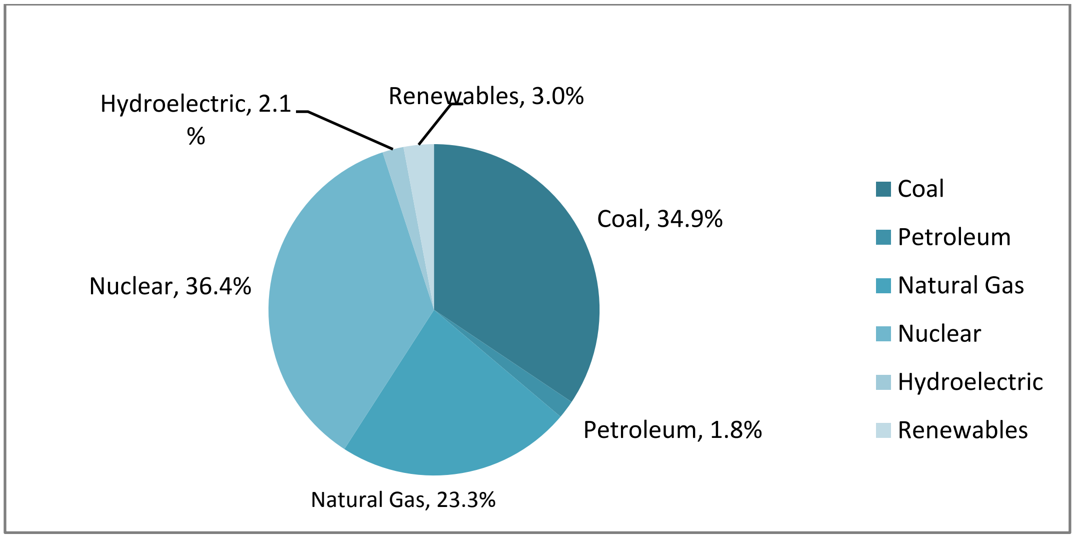


Electric Generation Capacity and Energy Serving Virginia

- Electric generation is measured two ways, net (or actual) generation (energy) and generation capacity. Energy is the amount of electricity generated over time. It is expressed in megawatt hours (MWh). Capacity is the amount of electricity that can be generated at any one time. It is expressed in megawatts (MW). In order to meet customer demand, Virginia's utilities own in-state and out-of-state generation facilities, and make contractual purchases of electricity from in-state and out-of-state producers, and spot purchases of electricity from the PJM wholesale market.
- Electricity generation facilities located in Virginia produced 70,739,235 megawatt hours of electricity in 2012.[13]
    - 56,188,401 megawatt hours (79 percent) were generated in plants owned and operated by electric utilities
- 14,550,834 megawatt hours (21 percent) were generated in plants operated by independent power producers and industrial combined heat and power facilities. Electricity generated in Virginia relies on a diverse portfolio of fuels. That portfolio includes nuclear, natural gas, coal, biomass and other renewables and hydroelectric power.

[12] Ibid.
[13] As compared to 107,794,985 megawatt hours consumed by Virginia users in 2012, per the Energy Information Administration.

Figure 2-5: Actual Electric Power Generation by Primary Source, (Megawatt hours)[14] 2012

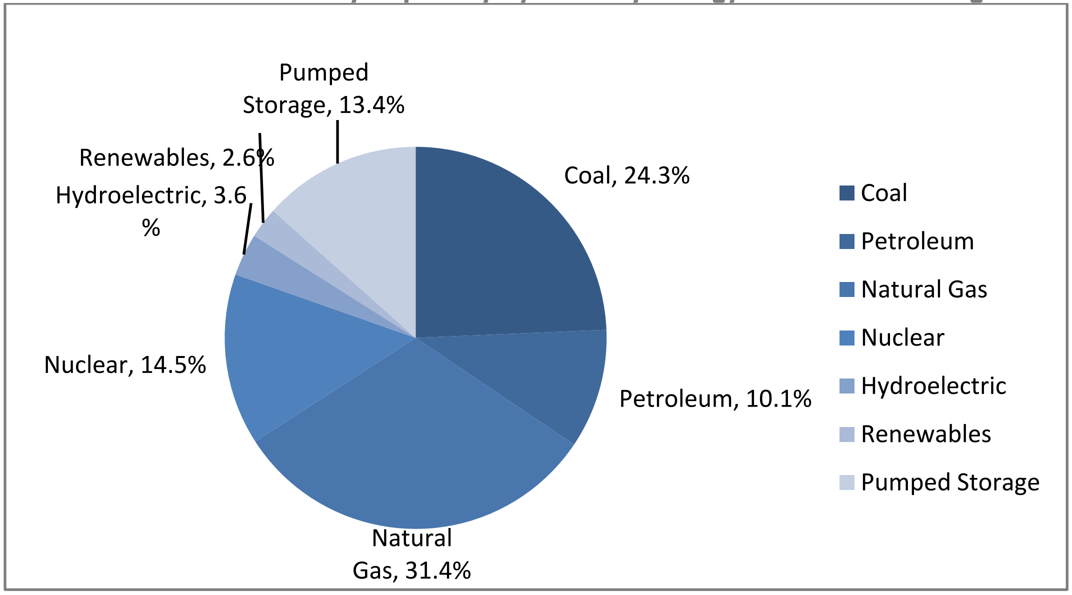


The total net summer generation capacity in Virginia is 24,849 megawatts.[15]

Of that:

- Electric utilities own 20,626 megawatts of generation capacity, and
- Independent power producers and combined heat and power facilities offer 4,223 megawatts

Figure 2-6: Electric Power Industry Capability by Primary Energy Source, 2012 (Megawatts)



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[14]Adapted from EIA, Virginia Electricity Profile, Table 5. Electric Power Industry Generation by Primary Energy Source, 2000 and 2004 through 2010, http://www.eia.gov/cneaf/electricity/st_profiles/virginia.html , January 2012

[15] EIA, Virginia Electricity Profile, Table 4. Electric Power Industry Capability by Primary Energy Source, 1990 Through 2012 (Megawatts) http://www.eia.gov/electricity/state/virginia/June 2014.

Table 2-2: Ten Largest Plants by Generation Capacity, 2012, in Virginia[16]

	Plant	Primary Energy Source	Operating Company	Net Summer Capacity (MW)
1	Bath County	Pumped Storage	Virginia Electric & Power Co	3,003
2	North Anna	Nuclear	Virginia Electric & Power Co	1,887
3	Possum Point	Natural Gas	Virginia Electric & Power Co	1,733
4	Surry	Nuclear	Virginia Electric & Power Co	1,676
5	Chesterfield	Coal	Virginia Electric & Power Co	1,650
6	Yorktown	Petroleum	Virginia Electric & Power Co	1,141
7	Tenaska Virginia Generating Station	Natural Gas	Tenaska Virginia Partners LP	926
8	Clover	Coal	Virginia Electric & Power Co	865
9	Doswell Energy Center	Natural Gas	Doswell Ltd Partnership	814
10	Ladysmith	Natural Gas	Virginia Electric & Power Co	783
	Total			14,478

Voluntary Renewable Energy Goals

Virginia established voluntary renewable energy goals for investor-owned utilities and for several years provided an incentive for achieving those goals.[17] The goals are measured against 2007 base load sales (less sales attributable to nuclear generation). The goals are:

- 4 percent by 2010
- 7 percent by 2016
- 12 percent by 2022 and
- 15 percent by 2025

- Investor-owned were met. Energy produced from onshore wind, solar power, and facilities in Virginia fueled primarily from animal waste receive double credit toward meeting renewable energy goals.[18]
- Energy produced from offshore wind receives triple credit toward meeting renewable energy goals.[19]

[16] EIA, Virginia Electricity Profile, Table 2. Ten Largest Plants by Generation Capacity, .2012http://www.eia.gov/electricity/state/virginia/, , June 2014.
[17] See § 56-585.2 of the Code of Virginia: http://leg1.state.va.us/cgi-bin/legp504.exe?000+cod+56-585.2
[18] Ibid.
[19] Ibid.

Dominion Virginia Power (Dominion)

- The SCC approved Dominion's Application to participate in the Renewable Portfolio Standard program on May 18, 2010.[1]

- According to its November 1, 2010 Annual Report to the SCC on Renewable Energy, Dominion projects that it will meet or exceed its 2010 VA RPS Plan renewable target of 1,732,746 MWh through implementation of its RPS Plan approved by the SCC.
- On January 31, 2011, McGuireWoods LLP submitted documentation on Dominion Virginia Power's behalf to confirm that it had indeed met the 2010 RPS Goal I established under § 56-585.2 of the Code of Virginia.
- Dominion's 2011 Annual Report was filed November 1, 2011 describing Dominion's ongoing efforts to meet the RPS goals.

- Verification of compliance with Dominion's 2011 goal was included as part of the 2012 Annual Report filed on November 1, 2012.

- On November 1, 2013 Dominion filed its Annual Report describing the Company's efforts to support renewable energy development as well as advances in renewable generation technology. The 2013 Annual Report also contains verification of Dominion's compliance with its 2012 RPS goals.

- Hydroelectric power accounts for about 57 percent of Dominion's RPS renewable energy mix, with the remainder 43 percent by waste wood biomass.[20]
- Dominion has other renewable programs besides its RPS. Dominion is currently in the process of implementing its 30 MW Solar Partnership Program, approved by the State Corporation Commission pursuant to 2011 legislation. The company is purchasing 3 MW of solar at a feed-in tariff rate from small systems, and has a new rate schedule through which large users may purchase renewable power from third-party producers through a contract with Dominion to 2011 legislation.

Appalachian Power Company (APCo)

- Appalachian Power Company (APCo) was initially approved to participate in the RPS program on February 7, 2008 by the SCC, with the Final Order issued on August 11, 2008.[21] [22]

- By Commission order in the Biennial Filing Case No. PUE-2011-00037, the Company met Goal I for 2010.

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[1] Case No. PUE-2009-00082
[20] Ibid
[21] Commonwealth of Virginia State Corporation Commission Docket Search, "Case Summary for Case Number: PUE-2008 00003",http://docket.scc.virginia.gov/vaprod/main.asp, June 24, 2011
[22] Commonwealth of Virginia State Corporation Commission, "Report to the Commission on Electric Utility Regulation of the Virginia General Assembly", http://www.scc.virginia.gov/comm/reports/2010_veur.pdf, June 24, 2011

- APCo Annual Reports on November 1, 2012 and November 1, 2013 describing the Company's ongoing efforts to meet the RPS Goal II for the respective years 2011 and 2012.[23]

Appalachian Power has utilized a combination of purchased power wind and company-owned hydro generation in its ongoing effort to meet renewable goals.

Electricity Imports in Virginia

- Virginia utilities do not own in-state generation capacity sufficient to meet their territory's peak load plus the reserve required by the Federal Energy Regulatory Commission.
- In 2012, 34 percent of the electricity consumed was purchased on the wholesale market pursuant to existing contracts.[24]
- All three of Virginia's investor-owned utilities and the wholesale power provided to many of Virginia's electric cooperatives comes from out-of-state generation facilities dedicated to serving their Virginia customers.
- In 2007, the law adopted to re-regulate electricity generation included incentives available to investor-owned utilities for building new generation facilities. Several of these incentives were repealed by 2013 legislation, with the only incentives remaining being for capital intensive projects such as, offshore wind and nuclear power.

PJM Wholesale Electricity Pricing Systems

- Wholesale electric prices in the PJM system are affected by the cost and availability of generation and the availability of transmission capacity to carry power from generating plants to load centers. This method of wholesale power pricing is called Locational Marginal Pricing (LMP).
- Wholesale prices are higher in areas that do not have sufficient local generation, long-distance transmission capacity or demand response to meet peak electric loads as the demand in these areas must be met by local, more costly generating plants.
- LMP in coastal areas with more congestion, such as Virginia, generally runs higher than in areas to the west, such as Illinois or Kentucky. Congestion refers to heavy use of the transmission system in a particular area.
- Electric service providers that purchase wholesale power to serve demand in generation- and transmission-constrained areas pass higher LMP along to their customers through higher retail rates.
- Pricing in the PJM wholesale market changes on a real time basis in response to demand capacity.

[23] http://scc.virginia.gov/pue/renew.aspx
[24] EIA, Virginia Electricity Profile, Table 10. Supply and Disposition of Electricity, 1990-2012, .http://www.eia.gov/electricity/state/virginia/, June 2014

Table 2-3: Average Retail Price of Electricity to Ultimate Customer by State (Cents per Kilowatt hour), 2013-2014[25]

State	Jan-14	Jan-13	Difference as Percent of Jan-13
Hawaii	34.08	34.87	2.32%
Alaska	16.87	15.72	-6.82%
Connecticut	16.82	15.54	-7.61%
New York	16.51	15.20	-7.93%
New Hampshire	15.49	14.50	-6.39%
Vermont	14.47	14.21	-1.80%
Massachusetts	14.71	13.59	-7.61%
Rhode Island	17.41	13.50	-22.46%
California	14.08	13.25	-5.89%
New Jersey	14.53	13.16	-9.43%
Maine	13.79	12.45	-9.72%
District of Columbia	12.83	11.78	-8.18%
Maryland	12.35	11.23	-9.07%
Delaware	11.65	10.98	-5.75%
Michigan	11.05	10.86	-1.72%
Wisconsin	10.44	10.42	-0.19%
Florida	10.66	10.29	-3.47%
Pennsylvania	10.72	9.94	-7.28%
Tennessee	9.20	9.32	1.30%
Colorado	9.54	9.22	-3.35%
Kansas	9.42	9.10	-3.40%
Arizona	9.36	9.08	-2.99%
Minnesota	9.37	9.07	-3.20%
South Carolina	9.76	8.96	-8.20%
Georgia	10.07	8.93	-11.32%
North Carolina	9.15	8.90	-2.73%
Ohio	9.27	8.84	-4.64%
Alabama	9.25	8.77	-5.19%
Virginia	8.89	8.72	-1.91%
New Mexico	9.05	8.70	-3.87%
Mississippi	9.38	8.62	-8.10%
Texas	8.79	8.60	-2.16%
Montana	8.64	8.35	-3.36%

[25] Energy Information Administration, Sources & Uses, Table 5.6.A. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector

State	Jan-14	Jan-13	Difference as Percent of Jan-13
Oregon	8.80	8.35	-5.11%
Indiana	8.76	8.34	-4.79%
South Dakota	8.56	8.32	-2.80%
Nevada	9.14	8.24	-9.85%
West Virginia	7.83	7.95	1.53%
Illinois	8.27	7.82	-5.44%
Nebraska	8.06	7.81	-3.10%
Iowa	7.85	7.79	-0.76%
Missouri	7.94	7.79	-1.89%
Louisiana	7.51	7.71	2.66%
Utah	7.73	7.53	-2.59%
Arkansas	7.25	7.52	3.72%
Wyoming	7.52	7.39	-1.73%
North Dakota	7.60	7.28	-4.21%
Kentucky	8.19	7.21	-11.97%
Washington	7.33	7.15	-2.46%
Idaho	7.52	7.13	-5.19%
Oklahoma	7.29	6.74	-7.54%
U.S. Total	10.13	9.66	-4.64%

Generation Under Construction in Virginia

Virginia's utilities and regulators consider a variety of factors when deciding to build or approve a new generation facility. Many of the same factors considered at the micro level also can be aggregated and averaged at a macro (national) scale to express the levelized cost of power of different fuel sources and technologies. Levelized cost of power generation assets represents the present value of the total cost of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments and expressed in terms of real dollars to remove the impact of inflation. Levelized cost is theoretical and does not reflect the cost of new generation facilities as those costs will be reflected in rates.

Table 2-4. Estimated Levelized Cost of New Generation Resources, 2019[26]

		U.S. Average LCOE (2012 $/MWh) for Plants Entering Service in 2019						
Plant Type	Capacity Factor	Capital Cost	Fixed O&M	Variable O&M (including fuel)	Trans-mission	Total System LCOE	Subsidy	Total LCOE including Subsidy
Dispatchable Technologies								
Conventional Coal	85	60.0	4.2	30.3	1.2	95.6		
Integrated Coal-Gasification Combined Cycle (IGCC)	85	76.1	6.9	31.7	1.2	115.9		
IGCC with CCS	85	97.8	9.8	38.6	1.2	147.4		
Natural Gas-fired								
Conventional combined Cycle	87	14.3	1.7	49.1	1.2	66.3		
Advanced Combined Cycle	87	15.7	2.0	45.5	1.2	64.4		
Advanced CC with CCS	87	30.3	4.2	55.6	1.2	91.3		
Conventional Combustion Turbine	30	40.2	2.8	82.0	3.4	128.4		
Advanced CombustionTurbine	30	27.3	2.7	70.3	3.4	103.8		
Advanced Nuclear	90	71.4	11.8	11.8	1.1	96.1	-10.0	86.1
Geothermal	92	34.2	12.2	0.0	1.4	47.9	-3.4	44.5
Biomass	83	47.4	14.5	39.5	1.2	102.6		
Non-Dispatchable Technologies								
Wind	35	64.1	13.0	0.0	3.2	80.3		
Wind – Offshore	37	175.4	22.8	0.0	5.8	204.1		
Solar PV[2]	25	114.5	11.4	0.0	4.1	130.0	-11.5	118.6
Solar Thermal	20	195.0	42.1	0.0	6.0	243.1	-19.5	223.6
Hydroelectric[3]	53	72.0	4.1	6.4	2.0	84.5		

Meeting Future Electric Demand

- Demand in Dominion's service territory is expected to grow an average 1.8 percent[27] per year over the next 10 years. This is among the highest growth expected in the 13-state PJM region.
- Demand in Appalachian Power's service territory is predicted to grow by 0.5 percent per year over the next 10 years.
- Demand in electric cooperative service territories is predicted to grow by 1 to 2 percent per year over the next 10 years based on these growth rates, Virginia utilities must add

[26] DOE EIA 2014 Annual Energy Outlook. Estimated Levelized Cost of New Generation Resources entering service in 2019, http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf, April 2014
[27] PJM Load Forecast Report (January 2014, revised February 2014), http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx, June 2014

generation (or reduce demand?) by over 14,000 megawatts of new generation capacity by 2024 to keep up. A megawatt represents enough energy to serve approximately 250 homes.

- These growth forecasts may change in the future as the state and national economy continues to recover, and as the electric market changes due to electric cars, added computing capacity, and other factors such as the effects of conservation and efficiency measures.

- A combination of a long permitting process and the high cost of some technologies make it more difficult to finance the large capital investments required for many types of generating facilities.

- To help reduce the financial risk, Virginia provides, subject to SCC approval, for investor-owned utilities:
    - An increased rate of return on equity for utility investments in new, nuclear and offshore wind generating plants; and
    - Construction work in progress (CWIP) cost recovery to reduce the regulatory lag in recovering capital investments in new plants

Integrated Resource Plans

- Investor-owned electric utilities are required to complete a 15-year Integrated Resource Plan (IRP) that describes how the utilities expect to meet future demand for electricity and maintain adequate and reliable service.[28] IRPs must be updated every two years.[29] As a practical matter, Dominion files an IRP every year, as it is required to file one in Virginia in odd-numbered years and one in North Carolina in even-numbered years with updates required to be filed with the and both sets of regulators in the years it is not required to be filed.

- Dominion's 2013 Integrated Resource Plan recommends a path forward to follow the least-cost methodology of the Base Plan, while concurrently continuing forward with reasonable development efforts of the Fuel Diversity Plan.
    - New generation capacity will come from Warren County Power Station (1,337 MW) and the Brunswick County Power Station (1,375 MW), which are currently under construction. Previously coal-fired Altavista, Southampton, and Hopewell Power Stations (153 MW total) were repowered with primarily wood waste biomass at the end of 2013.
    - The Base Plan includes approximately an additional 4,120 megawatts (MW) of generation and 544 MW of demand side management programs by 2028. In

[28] Electric Utility Integrated Resource Planning, Chapter 24 of Title 56 of the Code of Virginia, http://leg6.state.va.us/cgi-bin/legp604.exe?000+cod+TOC56000000024000000000000,
[29] IRPs for all investor-owned utilities can be downloaded from the SCC's website: http://docket.scc.virginia.gov/vaprod/main.asp

addition to traditional supply- and demand-side options, the Base Plan includes a 20 MW biomass non-utility generation (NUG), and a renewable 15 MW solid waste NUG, both in 2015. The Base Plan also includes a 50 MW solar NUG and 24 MW from the Solar Partnership Program. Due to the Base Plan's almost exclusive reliance on natural gas, the reasonable development efforts of the additional resources of the Fuel Diversity Plan include 220 megawatts of solar, 1,453 megawatts of nuclear, 12 MW from an offshore wind demonstration project and 247 megawatts of onshore wind, while removing the need for a 1,375 MW of new natural gas combined cycle plant in the Base Plan.

- Appalachian Power's 2013 Integrated Resource Plan (IRP) included provisions pending before the Virginia State Corporation Commission and the West Virginia Public Service Commission that required the company to file an update to the IRP in 2014. Appalachian Power filed with the State Corporation Commission an Updated 2014 Integrated Resource Plan on March 11, 2014.
    - The IRP includes by mid-2015 the retirement of 1,245 MW of older coal-fired power plants. Two of the plants are located in Virginia – Glen Lyn (325 MW) and Clinch River unit 3 (230 MW).
    - Added generation capacity to Appalachian Power comes from the transfer of unit 3 of Amos (867 MW – Appalachian already owns units 1 and 2) and the expected conversion of Clinch River units 1 and 2 to natural gas (484 MW).
- In addition to traditional resources, Appalachian Power's preferred plan also includes "non-traditional" resources from demand-side management as well as distributed solar generation and utility-scale wind and solar generation.
- Multiple federal, state, and local approvals are required:
    - The SCC must certify the need for and approve the location of the project.
    - The Department of Environmental Quality (DEQ) is responsible for necessary air, water, and waste discharges permits
    - The Department of Conservation and Recreation (DCR) is responsible for erosion and sediment control and storm water management;
    - The Departments of Game and Inland Fisheries (DGIF) and Agriculture and Consumer Services are responsible for threatened or endangered plant, animal, or insect species;
    - The Department of Historic Resources (DHR) is responsible for state and federally-protected historic or other natural or cultural resources;
    - The Department of Transportation is responsible for access to public highways;
    - The Virginia Marine Resources Commission is responsible for state waters;
    - Multiple federal agencies are responsible for environmental controls, such as:
        - The Environmental Protection Agency (EPA);
        - The Army Corps of Engineers;
        - The U.S. Fish and Wildlife Service; and
        - The U.S. Forest Service.

- Local governments must approve the land use and enforce building codes for many electric generating facilities.

- Virginia has taken a number of actions to facilitate permitting of new electric infrastructure.
    - The state natural resource agencies (DEQ, DCR, DHR, DGIF) offer a pre-application planning and review process to provide for an efficient and coordinated review of the proposed project. The plan includes:
        - A list of the permits or other approvals likely to be required based on the information available;
        - A specific plan and preliminary schedule for the different reviews;
        - A plan for coordinating those reviews and the related public comment process; and
        - Designation of points of contact, either within each agency or for the Commonwealth as a whole, to facilitate this coordination.
    - Renewable energy projects of 100 megawatts or less may take advantage of a Permit by Rule (PBR) process.
        - A PBR is an expedited permitting process created by statute that ensures the proper balance between development of renewable energy projects and environmental protection.[30]
    - The SCC, in considering its Certificate of Public Convenience and Necessity for electric generating plants and associated facilities, cannot impose additional conditions with respect to environmental protection, building codes, transportation plans, and public safety when a separate permit is granted by a federal, state, or local government entity.

Transmission and Distribution of Electricity

- Electricity is delivered to end users through a network of high-voltage transmission and local distribution lines.[31]

- Transmission is regulated by the Federal Energy Regulatory Commission, pursuant to federal law. FERC, together with the Regional Transmission Organizations, review and approve proposed new transmission projects and set rates of recovery for those projected developments.
    - PJM is charged with the responsibility of assuring the reliability of the transmission grid in its territory.
    - Dominion Virginia Power, Appalachian Power, Delmarva Power, and Allegheny Power own and maintain transmission facilities in Virginia.

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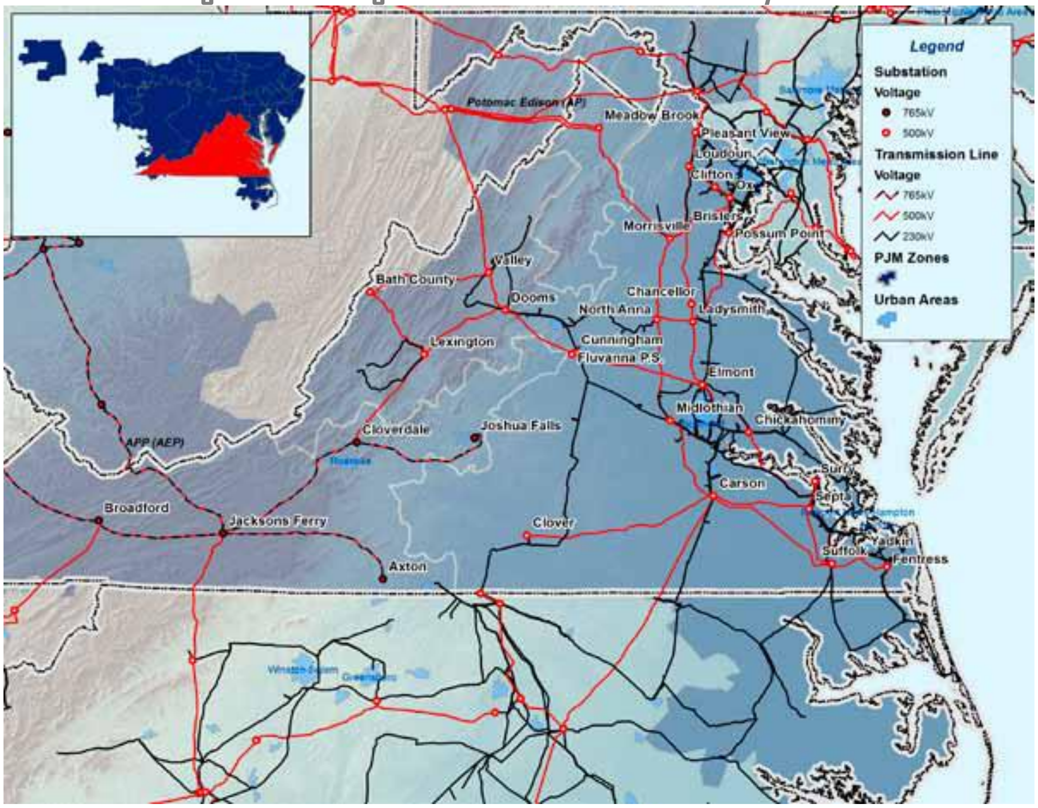
[30] See 10.1-1197.6 of the Code of Virginia: http://lis.virginia.gov/cgi-bin/legp604.exe?000+cod+10.1-1197.6

[31] PJM 2009 RTEP Report – Section 12.12, Virginia, http://www.pjm.com/documents/reports/~/media/documents/reports/2009-rtep/2009-section12-12-va.ashx, June 18, 2010

Figure 2-7. Virginia's Electric Transmission System[32]



- PJM publishes annually a Regional Transmission Expansion Plan (RTEP) to identify the need for new transmission resources.[33] The RTEP process involves a 15 year planning window to address transmission investments to ensure grid reliability and improve economic efficiency.
  - Allegheny and Dominion's 500 kV Trans Allegheny Interstate Line (TrAIL) runs from the 502 Junction in western Pennsylvania to Loudoun County; this line was completed and energized on May 19, 2011.
  - Dominion's 500 kV Carson to Suffolk line was placed into service on June 1, 2011.
  - PJM continues to assess the ongoing reliability of transmission facilities throughout the Commonwealth. This includes examination of such aging infrastructure as the Cloverdale-Lexington and Mt. Storm-Dobbs 500 kV transmission lines.[34]
- The Virginia SCC must certify the need for and approve the location of proposed new electric transmission lines. For a transmission line of 138 kV, a public utility has the option to seek SCC approval or seek approval from the locality or localities in which the 138 kV transmission line will be located.

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[32] PJM. PJM 2011 Regional Transmission Expansion Plan, Section 13.0, Virginia RTEP Overview, Map 12-53, Page 267
[33] PJM Fact Sheet, http://www.pjm.com/documents/~/media/about-pjm/newsroom/fact-sheets/rtep-fact-sheet.ashx, March 2012.
[34] PJM 2011 RTEP, Book 5, Page 270. http://pjm.com/~/media/documents/reports/2011-rtep/2011-rtep-book-5.ashx

Within the electric system, transmission lines carry bulk power from power stations to substations. Substations “step-down” voltages from the very high voltages used in the bulk power system to lower voltages needed to serve retail customers. Distribution lines carry power from substations to individual homes and businesses. These lines include main lines and smaller “tap” lines. These lines are owned and operated by the incumbent electric utility serving the areas in which they are located.

Since the early 1990s most neighborhood tap lines have been placed underground as a matter of course to improve reliability. In 2014, the Virginia General Assembly approved legislation to place up to 20 percent of the worst performing neighborhood lines underground, in order to reduce the frequency and duration of electricity outages in neighborhoods served by overhead distribution lines. It should be noted that placing distribution lines underground is less expensive than doing the same for transmission lines. Transmission lines are typically placed overhead unless doing so is infeasible from an engineering standpoint, due to the high costs of undergrounding transmission lines compared to overhead alternatives. Virginia had implemented a pilot program to assess the cost and effectiveness of placing transmission lines underground. The pilot program was ended due to the large cost of placing the lines underground.

SECTION 3 - NATURAL GAS

Natural Gas in Virginia

- The major uses for natural gas are residential and commercial uses such as space heating, water heating and cooking, and industrial uses such as process heating and chemical feedstock, transportation, and electric power generation.
- Natural gas was first produced in Scott County, VA in 1931. Presently, natural gas is produced in Buchanan, Dickenson, Russell, Lee, Scott, Tazewell and Wise Counties. Coal bed methane (CBM) is also produced in Buchanan, Dickenson, Russell, Tazewell and Wise counties. Virginia natural gas and CBM wells have produced 1.63 trillion cubic feet of gas since 1950.
- In 2010, a total of 18 companies operated gas wells that included 5,617 CBM wells, 1,838 conventional wells and 15 wells producing both conventional natural gas and CBM. These 7,470 wells produced 147.3 billion cubic feet (BCF) of natural gas. Buchanan County accounted for the largest share of production, about 54 percent of the total.

The major uses for natural gas are residential and commercial uses such as space heating, water heating and cooking, and industrial uses such as process heating and chemical feedstock, transportation, and electric power generation.

Natural Gas Market

Natural Gas Consumption

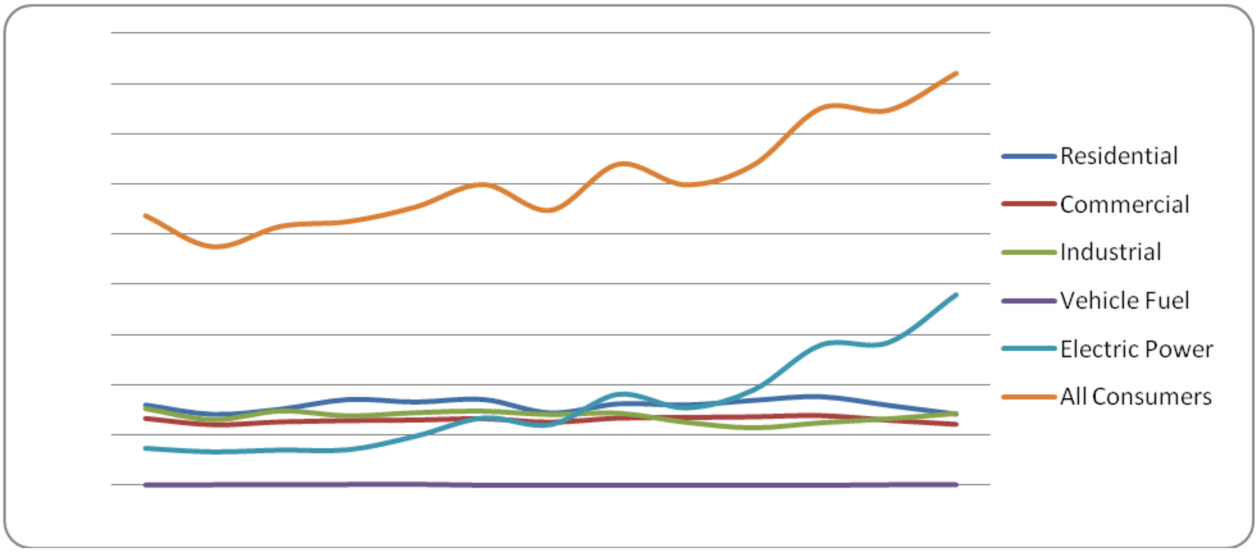
- In 2012, Virginia consumers used 392.3 (BCF) of natural gas. An additional 17.8 was consumed in the operation of pipelines, primarily in compressors, and in well, field, and lease operations, such drilling operations, heaters, dehydrators, and field compressors.[1]
- Natural gas use increased by 56 percent over the last decade. Growth was primarily attributable to new customer growth and use of natural gas for electric generation.
- The growth pattern changed for commercial and industrial, primarily attributable to the economic downturn. Electric power consumption increased due to fuel-on-fuel competition and residential demand dropped by nearly 6 ½ percent from 2007 and 2008 due to warmer than normal winter weather.

[1] EIA. Natural Gas Navigator. http://www.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SVA_a.htm. June 29, 2011

Table 3-1: Natural Gas Consumption, 2000-2012 (million cubic feet)[2]

Year	All Consumers	Residential	Commercial	Industrial	Vehicle Fuel	Electric Power	Avg. Price per Mcf
2000	268770	79701	66098	76263	212	36700	$8.78
2001	237853	70249	59809	65231	263	33118	$10.66
2002	258202	75476	62699	73973	268	34936	$8.49
2003	262970	85330	64004	69090	328	35256	$10.66
2004	277434	82755	64518	72250	368	48784	$11.59
2005	299746	85355	65838	73741	158	66951	$13.50
2006	274175	71693	62352	70420	168	60321	$14.33
2007	319913	80957	66444	71736	154	90573	$13.71
2008	299364	79725	67006	62642	141	76983	$14.50
2009	319134	84445	67709	57144	140	94829	$12.07
2010	375421	88157	68911	62243	142	139755	$11.14
2011	373444	79301	64282	66147	267	142284	$11.21
2012	410108	70438	60217	71486	267	189848	$10.60

Figure 3-1: Natural Gas Consumption, 2000-2012 (million cubic feet)[3]



[2] Ibid.
[3] Ibid.

- Natural gas consumption in Virginia is likely to grow over the next ten years.
    - Dominion has included construction of six new natural gas fired generation plants through 2020 in its 2013 Integrated Resource Plan.
    - Non-utility producers may also construct new natural-gas fired plants to serve Dominion and other electricity markets.
    - Additional retail consumers will hook up to natural gas distribution systems as Virginia's population grows.
    - Transportation uses may increase demand for natural gas. Transportation may create new markets for Virginia natural gas if the number of refueling facilities is expanded.
        - Virginia fleets have nearly 1000 CNG vehicles on the road. Nearly all of them are located in the Hampton Roads, Richmond and Northern Virginia areas.
        - Virginia's largest CNG fleets are operated by the U.S. Navy, VA Dept. of General Services and the Washington Metro Area Transit Authority.

Virginia Natural Gas Production

- Virginia's 21 natural gas exploration and production companies produced 147.3 BCF of natural gas from 7, 400 wells in 2013.[4] [5]
    - This amount is equal to 39 percent of the natural gas consumed in Virginia in 2010[6].
    - CNX Gas Company LLC produced 86 BCF of natural gas or 58 percent of total state production in 2010. The second highest producer, EQT Production Company, produced 47 BCF of natural gas equaling 32 percent of total state production.
    - Virginia produces both conventional natural gas and coal bed methane in the Central Appalachian Basin, which covers the State's western panhandle. Conventional gas is produced from Devonian (354 to 417 million years old) shale's, and Mississippian (323 to 354 million years old) limestones and sandstones of the Appalachian Basin, in the Appalachian Plateaus Province. CBM is produced from coal seams in the Norton, Lee (New River), and Pocahontas Formations of Pennsylvanian age (290 to 323 million years old) in the same physiographic region.
    - Most of Virginia's natural gas production comes from coal bed methane fields, two of which are among the 100 largest natural gas fields in the United States.[7]
    - Virginia currently has 33 landfills that are capturing, converting and using landfill gas (LFG) as an energy source. Twenty-five of these landfills are generating electricity and have a combined capacity of 94.5 megawatts. Three LFG projects are under construction and 38 landfills are either candidates or potential sites for

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[4] Virginia Department of Mines, Minerals and Energy, 2030 Gas and Oil Production.
[5] EIA, "Virginia-Data", http://www.eia.gov/state/state-energy-profiles-data.cfm?sid=VA#Reserves, June 29, 2011.
[6] EIA, "Natural Gas-Natural Gas Consumption by End Use http://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_VC0_mmcf_a.htm, June 29, 2011, Virginia Department of Mines, Minerals and Energy, 2010 Gas and Oil Production Summary by County
[7] EIA, "Virginia-Analysis",http://www.eia.gov/state/state-energy-profiles-analysis.cfm?sid=VA, June 29, 2011

projects. LFG projects are operational, under construction or planned in 54 counties from Eastern Shore to Southwest Virginia.[8]

Figure 3-2: Appalachian Basin Coal bed Methane Formations

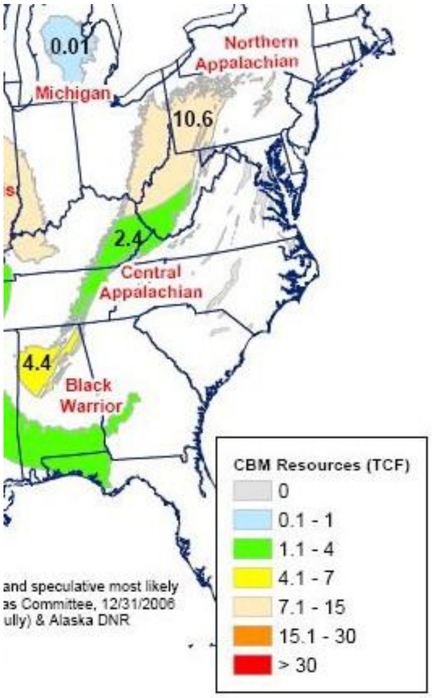
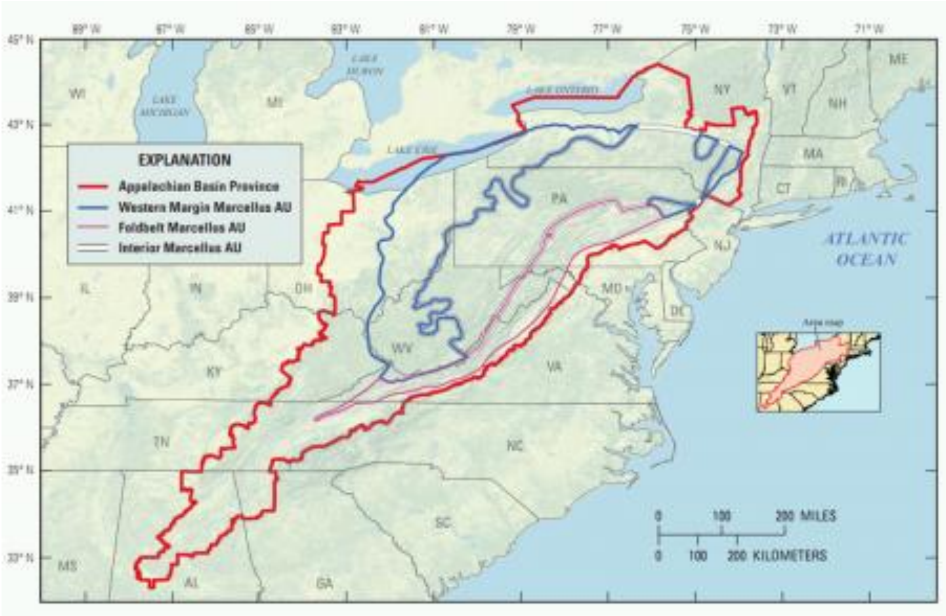


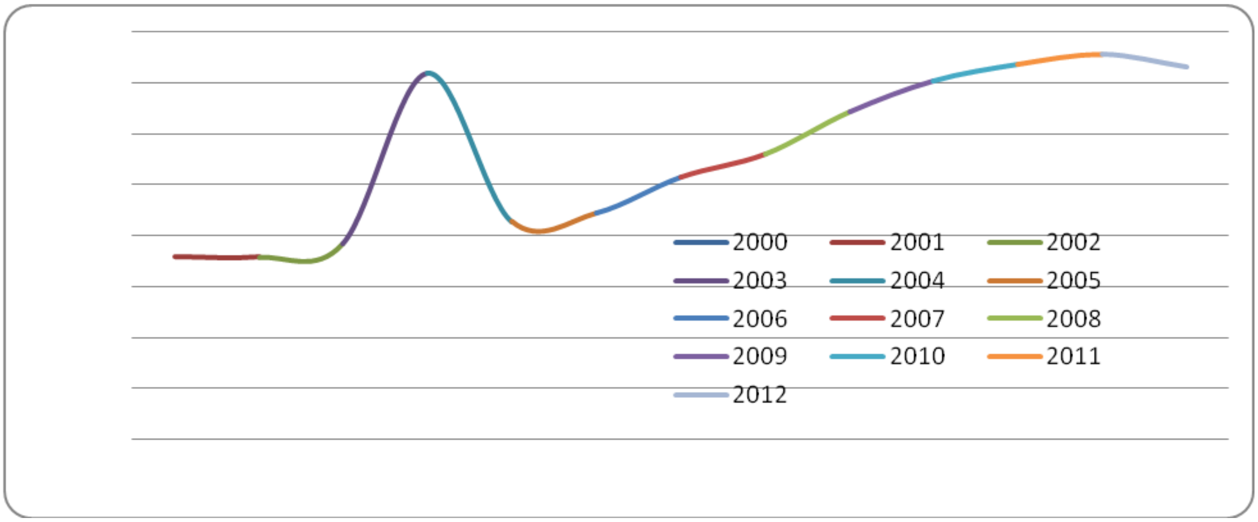
Figure 3-3: Appalachian Basin Natural Gas Shale Formations



[8] EPA, Landfill Methane Outreach Program; http://www.epa.gov/lmop/index.html

- In 2010, a record total of 147.3 BCF of natural gas was produced in Virginia, with an estimated value of $659 million. This value is based on the average wellhead price reported by the U.S. Energy Information Administration (EIA) of $4.48 per thousand cubic feet (MCF). According to the EIA, Virginia ranked 17th in the nation among all states that produced natural gas in 2010. CBM accounted for roughly 82 percent of the total production (about 121 BCF) and conventional gas accounted for about 18 percent (about 26 BCF).
- Gas production has experienced an upward trend since 1980, and has increased 104 percent from 1999 (72 BCF) to 2010 (147 BCF). The increase was related to growth in CBM production, which reached a record level in 2010. Most of the increased production occurred in Buchanan County, where gas production increased from 42 BCF in 1999 to 78.6 BCF in 2010.

Figure 3-4: Natural Gas Withdrawals in Virginia 2000–2012[9]



- Natural gas produced in Virginia is collected in gathering pipeline systems. These systems include low pressure pipelines from wells to compression facilities where the gas is cleaned and compressed. After being compressed, the gas is fed into the interstate pipeline network where it is delivered to customers.

- Natural gas produced in Virginia is sold in Southwestern Virginia and other interstate markets because there is limited pipeline capacity to deliver gas from Southwestern Virginia to the Central and Eastern Virginia markets.
- The capacity to deliver Virginia produced natural gas to the Northern, Central, and Hampton Roads regions

[9] VEPT. Virginia Total Historic Gas Production. http://www.energy.vt.edu/vept/naturalgas/historic_production.asp, June 29, 2011.

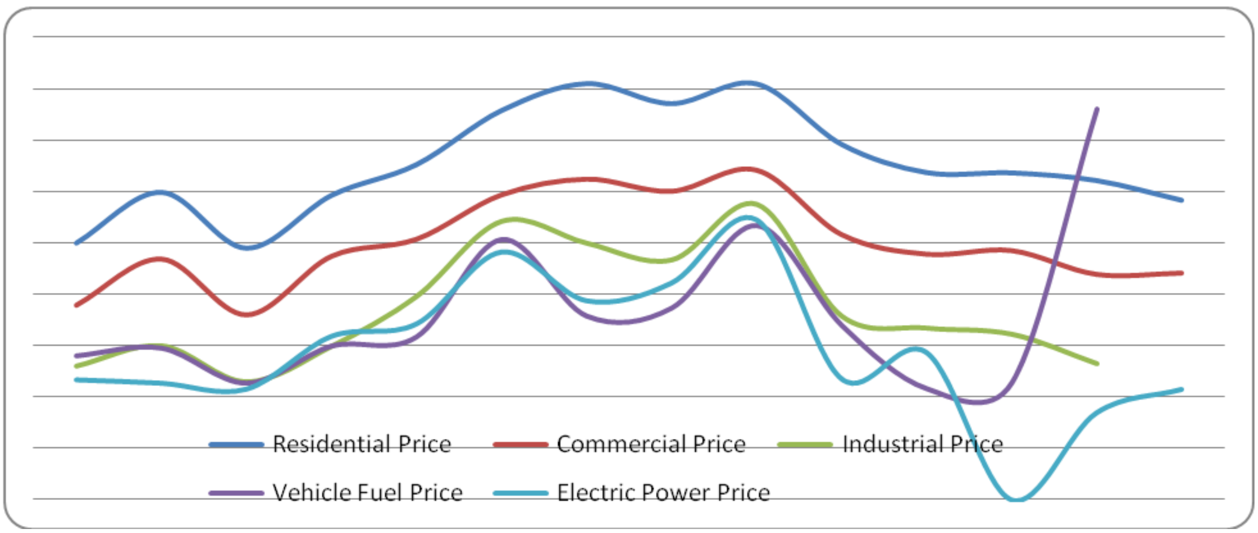
of Virginia increased with the connection of the Spectra Patriot Pipeline to the Transco interstate pipeline.

- As shown in Figure 3-7, the EIA projects natural gas prices at Henry Hub will increase annually over the next decade, increasing from $.3.74/per MCF in 2014 to $5.23 in 2025.[10]

Natural Gas Prices

- Virginia's residential consumers paid on average $11.65/thousand cubic feet (MCF) in 2013. Commercial customers paid on average $8.82/MCF in 2013, and industrial consumers paid on average $5.29/MCF in 2012.[11]
- Since 2009, these prices reflect a 15.7 percent decrease for residential consumers, a 14 percent decrease for commercial consumers, and a 25.9 percent decrease for industrial consumers.

Figure 3-5: Average Natural Gas Price by Sector[12]



- Natural gas prices in Virginia have traditionally been higher than in areas that are closer to natural gas production. The higher price is attributable to the need to transport the natural gas long distances to Virginia.
- In 2013, abundant supply and low prices characterized natural gas markets. Prolific production from East Texas, Mid-Continent, Marcellus and Utica Shale's contributed to stabilize prices.

Average annual natural gas prices have remained relatively low over the past several years as a result of the availability of abundant domestic resources and the application of improved production technologies.

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[10] EIA, Annual Energy Outlook 2010. Natural Gas Supply, Disposition, and Prices. http://www.eia.doe.gov/oiaf/aeo/excel/aeotab_13.xls. May 16, 2010.
[11] EIA, "Natural Gas – Natural Gas Prices", http://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PRS_DMcf_a.htm June 27,2014
[12] Ibid.

Supply

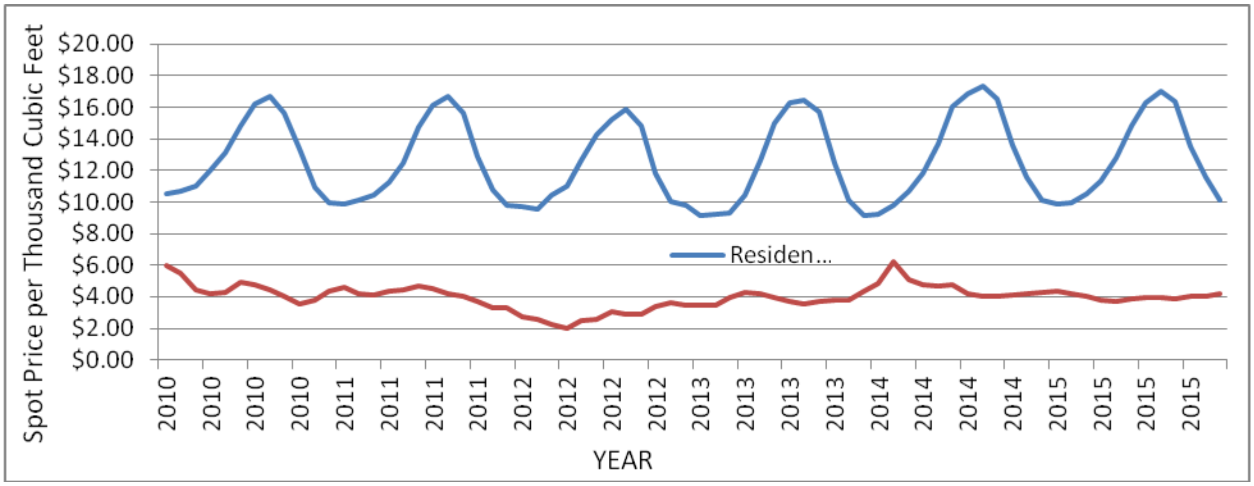
In 2013, marketed production of natural gas in the U.S. reached 25.6 trillion cubic feet (TCF), its highest recorded annual total.

Production of natural gas from shale and tight sand formations continued to increase. These production increases were the result of more efficient, cost-effective drilling techniques, notably in the production of natural gas from shale formations.

Additionally, shale gas has been the primary source of recent growth in technically recoverable natural gas resources in the United States. For example, the Marcellus Shale encompasses 104,000 square miles, ranging in depth from 4,000 to 8,000 feet, and is estimated to contain more than 410 trillion cubic feet of natural gas.

The evolution of fracking and horizontal drilling technology has led directly to a proliferation of wells drilled in the Marcellus Shale. The Energy Information Administration estimates that by 2035, 24 percent of total natural gas production will come from shale formations such as Marcellus. The bulk of Marcellus drilling activity has occurred in Pennsylvania, Ohio and West Virginia. One gas company is expressing interest in drilling one exploratory Marcellus well in Rockingham County, VA and leasing is taking place in Rockingham and other counties. Another potential area of development is in the Taylorsville Basin Shale which extends through several counties including Caroline, King George, Westmoreland, King and Queen, King William, others.

Figure 3-6. EIA Natural Gas Price History 2010 – August 2014 and Projection for 2015

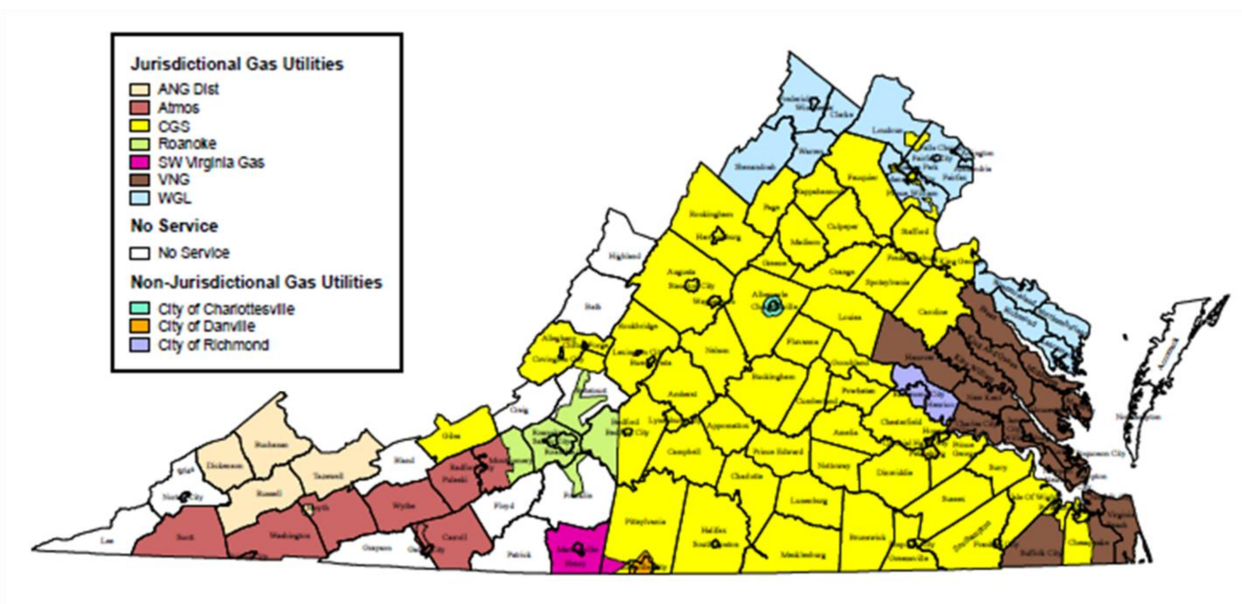


INFRASTRUCTURE

Virginia's Natural Gas Providers

- Natural gas transmission companies move natural gas from production areas to population centers through transmission pipelines. Local Distribution Companies (LDCs), which are utilities regulated by the SCC, distribute the gas to end users.
- A total of ten natural gas LDCs serve Virginia customers in assigned territories; seven are investor owned LDCs, and the remaining three are municipal LDCs.
  - Virginia's investor-owned LDCs are Columbia Gas of Virginia, Washington Gas, Virginia Natural Gas, Roanoke Gas, Atmos Energy, Appalachian Natural Gas Distribution Company, and Southwestern Virginia Gas Company.
  - The municipals are in the Cities of Richmond, Charlottesville, and Danville.
- LDCs primarily sell gas to the residential and commercial markets. Large natural gas users can contract directly for natural gas purchases under Federal Energy Regulatory Commission (FERC) rules. In 2012, Virginia gas users were 92.2 percent residential, 7.7 percent commercial and 0.1 percent industrial.[13]
- The LDCs serve approximately 37 percent of U.S. households and 90,000 commercial natural gas customers.
- The LDCs operate approximately 20,000 miles of distribution pipelines nationally.

Figure 3-7: Service Areas of Virginia Natural Gas Distribution Companies[14]



Natural Gas Transmission

- Natural gas consumed in Virginia is transported by four primary interstate pipelines:

[13] EIA: http://www.eia.gov/naturalgas/annual/pdf/table_016.pdf
[14] State Corporation Commission, http://www.scc.virginia.gov/pue/gas/map.aspx. June 23, 2010.

- Transco Pipe Line provides access to supply sources from Texas, the Gulf of Mexico and other southern locations.
- East Tennessee Gas Pipeline provides access to supply sources from Virginia and other Appalachian natural gas production areas, from Texas and other southern locations via the Tennessee Gas Pipeline system.
- Columbia Gas Transmission provides access to supply sources from Appalachian Marcellus and Utica Shale, and Texas, the Gulf of Mexico, and other southern locations via the Columbia Gulf Transmission system.

- Dominion Transmission provides access to supply sources from Appalachian Marcellus and Utica Shale production, and LNG imports through the Cove Point Liquefied Natural Gas (LNG) import facility in Maryland.
- There are approximately 2,950 miles of natural gas transmission pipelines in Virginia.

Figure 3-8: Major Natural Gas Transmission Pipelines in Virginia[15]

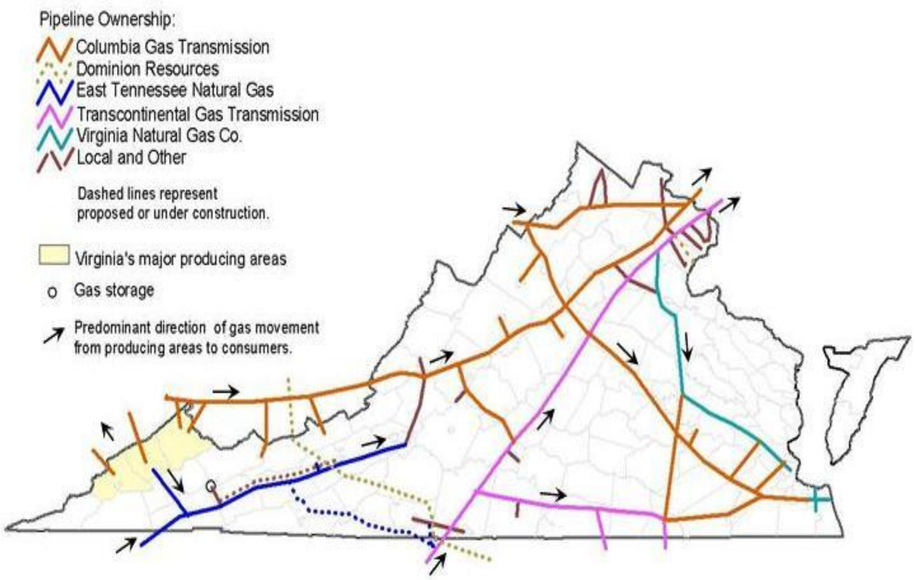


Table 3-2: Principal Natural Gas Pipeline Companies Serving Virginia

Pipeline Name	Principal Supply Source(s)
Interstate & Importing Pipelines	
Columbia Gas Transmission Co	Appalachia. Marcellus and Utica Shale, and upstream sources from Columbia Gulf Transmission

[15] Modified from VEPT. Major Natural Gas Pipelines. http://www.energy.vt.edu/vept/naturalgas/NG_pipelines.asp. June 28, 2011

Dominion Cove Point LNG LP	Upstream sources from Columbia Gas Transmission, Dominion Transmission, Transco Gas Pipe Line and LNG imports
Dominion Transmission Corp	Appalachia, Marcellus and Utica Shale
East Tennessee Natural Gas Co	Appalachia and upstream sources from Tennessee Gas
NORA Gas Transmission Co	Appalachia
Transcontinental Gas Pipeline Co	Texas, the Gulf of Mexico and other southern supply sources
*Intrastate Pipelines**	
Virginia Natural Gas Co	Upstream sources from Dominion Transmission

- Natural gas companies have added new pipeline capacity across the state in recent years, including:
  - Virginia Natural Gas' HRX pipeline that provides a third pipeline water crossing in Hampton Roads;[16]
  - Spectra's East Tennessee Line to Southside Virginia and North Carolina;[17] and
  - Spectra's Jewell Ridge Pipeline to deliver natural gas from Southwest Virginia's gas production areas to the East Tennessee line and Saltville natural gas storage facility.[18]

Natural Gas Storage

- Virginia is home to two underground natural gas storage facilities, the Spectra salt cavern storage facility in Saltville and the Early Grove underground storage field in Scott and Washington Counties.[19]
- Other underground natural gas storage services located in various areas and the market area available to Virginia utilities and consumers throughout the interstate pipeline system. Dominion is one of the largest operators of these underground natural gas storage facilities in the United States.

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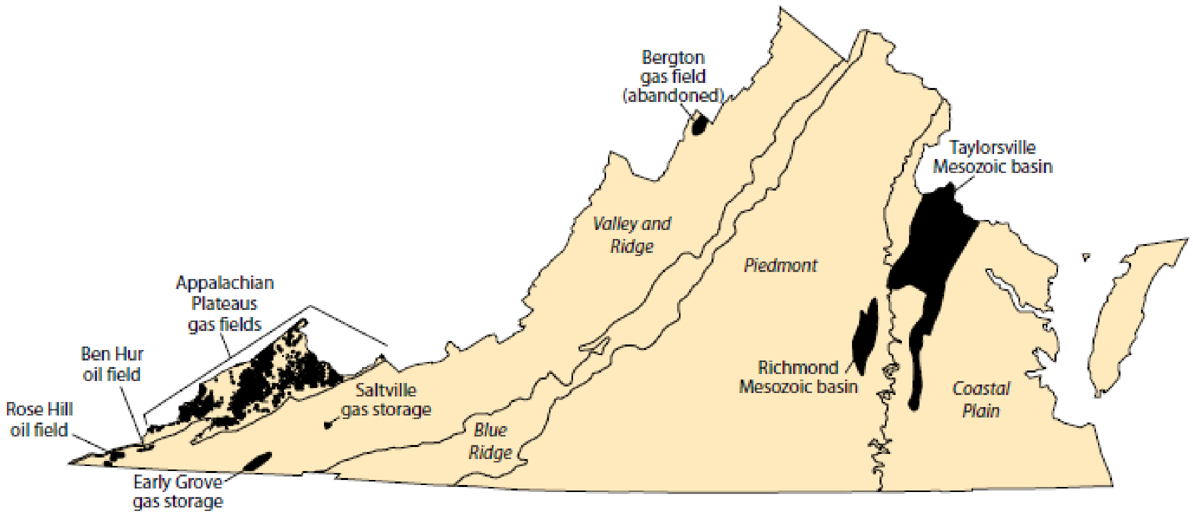
[16] Virginia Natural Gas, "Hampton Roads Crossing Pipeline", http://www.virginianaturalgas.com/Universal/AboutUs/InOurCommunity/HamptonRoadsCrossingPipeline.aspx, June 29, 2011.

[17] Spectra Energy, "U.S. Transmission-East Tennessee Natural Gas" http://www.spectraenergy.com/Operations/US-Transmission/Pipeline-Assets/East-Tennessee-Natural-Gas/, June 29 2011.

[18] Ibid.

[19] Spectra Energy, "U.S. Transmission-Saltville Gas Storage", http://www.spectraenergy.com/Operations/US-Transmission/Pipeline-Assets/Saltville-Gas-Storage/, June 29, 2011.

Figure 3-19: Underground Natural Gas Storage Facilities



- Virginia LDCs operate peak shaving natural gas storage facilities near their local distribution networks.
  - These facilities include compressed natural gas tanks, liquefied natural gas tanks, propane storage tanks and one underground propane storage cavern.
  - Companies store gas in these facilities when demand is low and inject gas into the pipeline system during times of peak demand.

FEDERAL AND STATE LAW AND REGULATIONS

Virginia's Natural Gas Utility Regulatory Structure

- Virginia's statutory scheme for the regulation of gas utilities provides that, LDCs are required to offer service at just and reasonable rates and have the opportunity to earn a maximum rate of return set through rate cases before the State Corporation Commission (SCC).
- Starting in 2000, LDCs were authorized to offer all customers direct access to natural gas suppliers, called retail supply choice.
  - Washington Gas Light Company and Columbia Gas of Virginia offer this choice to all customers.
  - In 2009, 8.4 percent of eligible residential customers and 23.3 percent of eligible commercial customers participated in choice programs.[20]

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[20] Ibid.

- LDCs have the opportunity to be governed by performance-based ratemaking (PBR) agreements that allow higher rates of return contingent upon the LDC meeting defined performance standards. Columbia Gas and Washington Gas have used SCC approved PBR plans.
- Natural gas LDCs are authorized to undertake Conservation and Ratemaking Efficiency (CARE) programs and if they do, to decouple earnings from the volume of gas sold. Rate decoupling is conditioned upon adoption of an SCC approved plan for promoting and investing in conservation and efficiency by the company's customers.
  - As of summer 2014, Virginia Natural Gas and Columbia Gas have implemented CARE plans.
- Virginia enacted the Steps to Advance Virginia's Energy Plan (SAVE) program in 2010 to provide timely cost recovery for large-scale replacement of aging local distribution pipeline infrastructure.
- Virginia enacted legislation that seeks to create a regulatory framework for natural gas utilities to invest in upstream reserves, where those investments are reasonably expected to yield lower delivered cost of gas to customers, mitigate price volatility, or mitigate supply risk. This bill went into effect July 1, 2014.

Adequacy of Supply

- Natural gas production in the coalfield region should rise incrementally as producers continue to drill new coal bed methane and conventional shale wells in Southwest Virginia.
- Virginia's natural gas reserves were estimated in 2009 to be 3,091 BCF.[21] Given current removal rates, this reserve would support production for about 22 years.
- Additional reserves and potential production are available in the Marcellus Shale areas west of the Shenandoah Valley and offshore.
- A growing amount of out of state supply is available from shale production areas in Pennsylvania, Ohio, West Virginia, and elsewhere.
- The federal Energy Information Administration predicts there should be adequate supplies from new domestic production for expanded uses of natural gas.[22]
- Potential disruptions of natural gas production or interstate transmission pipelines are unforeseen but may occur and could possibly affect multiple states including Virginia. States will need to work with the federal Department of Energy to coordinate responses to such possible supply disruptions.

[21] http://www.eia.gov/state/state-energy-profiles-data.cfm?sid=VA
[22] EIA. Annual Energy Outlook, 2010. http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2010).pdf. May 16, 2010.

Offshore Natural Gas

- There is an estimated 1.66 TCF of natural gas reserves in federal waters in the Virginia administrative boundary areas offshore.
- The value of natural gas in the Virginia offshore administrative boundary areas could total more than $10 billion (1.66 TCF at $6/MCF).
    - The value will depend on the actual amount of recoverable resources, cost of developing gas and the price of natural gas when it comes to market.
    - Offshore natural gas production would support infrastructure expansion in Hampton Roads, attracting new business and creating jobs in the supply chain and exploration and production.
- Developing offshore natural gas resources is dependent on an extensive federal lease sale and permitting process.
    - There is currently a new lease authorization for 2017-2022.
- Offshore extraction will need to be compatible with U.S. Department of Defense operations in Virginia offshore waters and commercial maritime activity. Federal-state cooperation can lead to developing a compatible exploration and production plan.
- Virginia’s coastal regions may hold producible methane hydrate resources offshore. The technology to produce these resources is not expected to be developed in the 10-year term of this Plan.

SECTION 4 - RENEWABLES

Renewable energy is defined by Virginia statute to include:

- Solar
- Wind
- Hydroelectric, not including pumped storage
- Biomass
- Energy from waste, including municipal solid waste
- Landfill gas
- Wave motion and tides
- Geothermal

Virginia's viable and existing renewable resources include:

- Biomass
- Waste-to-energy, landfill and waste water treatment gas
- Wind, both offshore and on-shore
- Hydroelectric, not including pumped storage
- Low temperature geothermal (not including geothermal heat pumps)
- Solar thermal for heating air and water
- Solar photovoltaic

In 2010, these resources provided about 6.2 percent of the electricity capacity in Virginia and about 5.1 percent of the electricity generated.[1] Virginia is ranked 26th in the nation for renewable capacity, with just under 1.5 gigawatts of net summer renewable generating capacity.[2]

Most forms of renewable energy emit zero carbon dioxide in the production of electricity. Therefore, the use of these sources as a substitute to high carbon producing coal will significantly reduce Virginia's carbon intensity.

Electricity generated from renewables in Virginia is used in several ways.

- The primary use of renewable electricity has been on-site distributed generation using primarily grid connected solar photovoltaic or small wind systems. While exact counts are not available, a small number of off-grid homes use solar and/or small wind systems coupled with battery storage. Typically, however, even systems with battery storage are grid connected and the batteries add a measure of energy security in the event of power outages.
- Virginia's electric utilities own renewable generation assets, or purchase renewable energy from non-utility renewable energy projects to meet their service obligation and Virginia's voluntary renewable energy portfolio goals.

[1] Energy Information Administration Virginia Renewable Energy Profile 2010 http://www.eia.gov/renewable/state/virginia/

[2] Energy Information Administration, State Renewable Electricity Profiles: http://www.eia.gov/renewable/state

Financial incentives such as state or federal tax credits can significantly affect the levelized cost estimate.

Cost of Renewables Compared to Other Generation

Table 4.1 provides the average national levelized costs for the generating technologies represented in the U.S Energy Information Administration's 2014 *Annual Energy Outlook*.

Financial incentives such as state or federal tax credits can significantly affect the levelized cost estimate. For example, new solar and wind power systems are eligible to receive a 30-percent investment tax credit on capital expenditures if placed in service before the end of 2016, and 10 percent thereafter.

New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive from the federal government $21.50 per MWh ($10.70 per MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30-percent investment tax credit, if under construction before the end of 2013 .

Table 4-1: Estimated Levelized Cost for New Generation Resources Entering Service in 2019[3]

	U.S. average levelized costs (2012 $/MWh) for plants entering service in 2019							
Plant type	Capacity factor (%)	Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system LCOE	Subsidy[1]	Total LCOE including Subsidy
Dispatchable Technologies								
Conventional Coal	85	60.0	4.2	30.3	1.2	95.6		
Integrated Coal-Gasification Combined Cycle (IGCC)	85	76.1	6.9	31.7	1.2	115.9		
IGCC with CCS	85	97.8	9.8	38.6	1.2	147.4		
Natural Gas-fired								
Conventional Combined Cycle	87	14.3	1.7	49.1	1.2	66.3		
Advanced Combined Cycle	87	15.7	2.0	45.5	1.2	64.4		
Advanced CC with CCS	87	30.3	4.2	55.6	1.2	91.3		
Conventional Combustion Turbine	30	40.2	2.8	82.0	3.4	128.4		
Advanced Combustion Turbine	30	27.3	2.7	70.3	3.4	103.8		
Advanced Nuclear	90	71.4	11.8	11.8	1.1	96.1	-10.0	86.1
Geothermal	92	34.2	12.2	0.0	1.4	47.9	-3.4	44.5
Biomass	83	47.4	14.5	39.5	1.2	102.6		
Non-Dispatchable Technologies								
Wind	35	64.1	13.0	0.0	3.2	80.3		
Wind-Offshore	37	175.4	22.8	0.0	5.8	204.1		
Solar PV[2]	25	114.5	11.4	0.0	4.1	130.0	-11.5	118.6
Solar Thermal	20	195.0	42.1	0.0	6.0	243.1	-19.5	223.6
Hydro[3]	53	72.0	4.1	6.4	2.0	84.5		

[1]The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2019, which include a permanent 10% investment tax credit for geothermal and solar technologies, and the $18.0/MWh production tax credit for up to 6 GW of advanced nuclear plants, based on the Energy Policy Acts of 1992 and 2005. EIA models tax credit expiration as in current laws and regulations:Â new solar thermal and PV plants are eligible to receive a 30% investment tax credit on capital expenditures if placed in service before the end of 2016, and 10% thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $21.5/MWh ($10.7/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30% investment tax credit, if they are under construction before the end of 2013.

[2]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2014*, April 30, 2014, DOE/EIA-0383(2014).

[3] Energy Information Administration, *Annual Energy Outlook 2014*, April 30, 2014, DOE/EIA-0383(2014)

Because of regional differences in the cost of labor, fuel, and other factors that affect the levelized generation cost, the cost for generation technologies will vary by location. Table 4.2 gives the range in the levelized cost based on these regional differences.

Table 4-2: Regional Variation in Levelized Cost of New Generation, 2017[4]

	Range for total system LCOE (2012 $/MWh)			Range for total LCOE with subsidies[1] (2012 $/MWh)		
Plant type	Minimum	Average	Maximum	Minimum	Average	Maximum
Dispatchable Technologies						
Conventional Coal	87.0	95.6	114.4			
IGCC	106.4	115.9	131.5			
IGCC with CCS	137.3	147.4	163.3			
Natural Gas-fired						
Conventional Combined Cycle	61.1	66.3	75.8			
Advanced Combined Cycle	59.6	64.4	73.6			
Advanced CC with CCS	85.5	91.3	105.0			
Conventional Combustion Turbine	106.0	128.4	149.4			
Advanced Combustion Turbine	96.9	103.8	119.8			
Advanced Nuclear	92.6	96.1	102.0	82.6	86.1	92.0
Geothermal	46.2	47.9	50.3	43.1	44.5	46.4
Biomass	92.3	102.6	122.9			
Non-Dispatchable Technologies						
Wind	71.3	80.3	90.3			
Wind-Offshore	168.7	204.1	271.0			
Solar PV[2]	101.4	130.0	200.9	92.6	118.6	182.6
Solar Thermal	176.8	243.1	388.0	162.6	233.6	356.7
Hydro[3]	61.6	84.5	137.7			

[1]Levelized cost with subsidies reflects subsidies available in 2019, which include a permanent 10% investment tax credit for geothermal and solar technologies, and the $18.0/MWh production tax credit for up to 6 GW of advanced nuclear plants, based on the Energy Policy Acts of 1992 and 2005.

[2] Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: Wind – 31% to 45%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydroelectric – 30% to 65%. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2014*, April 30, DOE/EIA-0383(2014)

[4] Energy Information Administration, Annual Energy Outlook 2014, April 30, 2014, DOE/EIA-0383(2014)

Table 4.3 shows a comparison of estimated capital cost for new generation capacity for various technologies. It should be noted that even though there are no utility-scale photovoltaic systems in Virginia, the cost reduction for residential sized systems has shown to be comparable to those shown in Table 6.3. In the two-year period between 2010 and 2012 that the Virginia Solar and Wind Power Rebate Program was active[5] the installed cost for residential and small commercial photovoltaic systems went from an average of $8.20 per watt installed to $5.70 per watt, or around a 30 percent reduction.

Table 4-3: Comparison of 2011 Updated Plant Costs to 2010 Plant Costs[6]

	Overnight Capital Costs (2012 $/kW)		
	2013 Report	2010 Report	% Difference
Coal			
Single Unit Advanced PC	$3,246	$3,292	-1%
Dual Unit Advanced PC	$2,934	$2,956	-1%
Single Unit Advanced PC with CCS	$5,227	$5,300	-1%
Dual Unit Advanced PC with CCS	$4,724	$4,760	-1%
Single Unit IGCC	$4,400	$3,706	19%
Dual Unit IGCC	$3,784	$3,348	13%
Single Unit IGCC with CCS	$6,599	$5,559	19%
Natural Gas			
Conventional CC	$917	$1,017	-10%
Advanced CC	$1,023	$1,043	-2%
Advanced CC with CCS	$2,095	$2,141	-2%
Conventional CT	$973	$1,012	-4%
Advanced CT	$676	$691	-2%
Fuel Cells	$7,108	$7,105	0%
Uranium			
Dual Unit Nuclear	$5,530	$5,546	0%
Biomass			
Biomass CC	$8,180	$8,205	0%
Biomass BFB	$4,114	$4,012	3%
Wind			
Onshore Wind	$2,213	$2,534	-13%
Offshore Wind	$6,230	$6,211	0%
Solar			
Solar Thermal	$5,067	$4,877	4%
Solar Photovoltaic (7 MW)	N/A	$6,289	N/A
Solar Photovoltaic (20 MW)	$4,183	N/A	N/A
Solar Photovoltaic (150 MW)	$3,873	$4,943	-22%
Geothermal			
Geothermal – Dual Flash	$6,243	$5,798	8%
Geothermal – Binary	$4,362	$4,304	1%
Municipal Solid Waste			
Municipal SolidWaste	$8,312	$8,557	-3%
Hydroelectric			
Conventional Hydroelectric	$2,936	$3,197	-8%
Pumped Storage	$5,288	$5,816	-9%

[5] Implemented by the Virginia Department of Mines, Minerals and Energy and funded through the American Recovery and Reinvestment Act (ARRA).
[6] U.S. Energy Information Administration | Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants | April 2013

Virginia currently has several programs and policies intended to enable the growth of renewable energy, including:

Voluntary Renewable Energy Standard

- Voluntary renewable energy goals calling for 15 percent of 2007 base-line electric production to come from renewable sources by 2025. Utilities are eligible to receive an enhanced rate-of-return for investments in renewable electric generating facilities. Both onshore wind and solar power count as double credit toward meeting a utility's renewable energy goals. Offshore wind counts as triple credit.

Net Metering

- Under Virginia's *net metering* law, residential electric consumers may generate up to 20 kilowatts (kW) of grid-connected renewable power to offset their load. Non-residential consumers may generate up to 500 kW, with an option to generate more at the discretion of the non-residential customer's electric utility.

For both residential and non-residential renewable generators, excess electricity generated at the end of the monthly billing period is credited to the customer at the retail rate. Upon the written request of the net metering customer, the customer's electric supplier must enter into a power purchase agreement for any excess generation at the end of the net metering period (the anniversary of the date of interconnection). Consumers entering into a power purchase arrangement with their utility are not paid the retail rate, but what is essentially the utility's' wholesale rate.

In 2012, the legislature amended the net metering law to allow utilities to charge stand-by fees to residential net metering customers. Retail electric rates include charges for transmission and distribution infrastructure. To avoid cross subsidization of transmission and distribution infrastructure by all other ratepayers, residential consumers with a system capacity greater than 10 kilowatts must now pay $2.79 a kW in monthly distribution standby charges and $1.40 kW in monthly transmission standby charges. Non-residential consumers with grid-connected renewable generation are exempt from these additional charges. Advocates of distributed generation, from renewables such as solar or small wind power argue that the standby charges are a disincentive and that the value of solar generation in particular - especially at peak times, more than makes up for any lost transmission and distribution fees.

In 2013 the net metering law was again amended to allow for *agricultural net metering,* for certain types of energy production systems, thereby allowing the output of a renewable energy system up to 500 kilowatts in capacity to be shared with multiple metered facilities at contiguous sites on the agricultural facility's property.

Sale of Renewable Energy Credits

Renewable energy system owners can sell their Renewable Energy Credits (RECs) as an additional revenue stream. Renewable energy credits, also known as renewable energy certificates, green certificates, green tags, or tradable renewable certificates, represent the environmental attributes of the power produced from renewable energy projects and are sold separate from commodity electricity. Customers can buy green certificates whether or not they have access to green power through their local utility or a competitive electricity marketer. And they can purchase renewable energy certificates without having to switch electricity suppliers.

At one time, Virginia citizens could sell their solar RECs, also known as SRECs, in North Carolina, Maryland, Pennsylvania and Washington, DC, to help electric utilities in those states and the District meet their renewable portfolio mandates. However, at this time, Maryland and the District of Columbia no longer allow out-of-state SRECs, and limit SREC's to those generated within their borders, or to solar energy energy systems connected to a distribution feeder serving them.

One-Stop Permitting

In 2009, the Virginia General Assembly enacted legislation directing the Department of Environmental Quality to develop regulations for the construction and operation of renewable energy projects in Virginia. A Regulatory Advisory Panel (RAP) made up of key stakeholders developed a streamlined Permit by Rule (PBR) processes for the review and approval of renewable energy projects 100 megawatts and smaller, or up to 20 megawatts for combustion projects such as biomass, landfill gas or municipal solid waste.

The PBR process is intended to offer project developers regulatory certainty and a finite time frame for permit issuance.

The first PBR tackled by the RAP was for wind energy projects in 2009-10 and went into effect in December 2010.

The solar PBR became effective on July 18, 2012.

The combustion PBR for renewables such as biomass, landfill gas and municipal solid waste became effective on August 28, 2013.

After careful consideration of the issues, the Water-Related Regulatory Advisory Panel recommended, and the DEQ director agreed, that it is not necessary or appropriate at this time and under current conditions for DEQ to develop a PBR regulation for projects that generate electricity from falling water, wave motion, tides, or geothermal resources.

Siting of Renewable Energy Projects

Virginia local governments bear the chief responsibility for siting renewable energy projects. In response to questions raised by local governments and others, the Virginia Department of Environmental Quality convened an informal stakeholder group comprised of representatives from state and local government, planning officials, industry, and non-governmental organizations, and others to develop model ordinances and other information that local governments may choose to consult when addressing the issue of where to locate renewable energy facilities. A model utility scale wind ordinance and other resources are available at http://www.deq.virginia.gov/Programs/RenewableEnergy/ModelOrdinances.aspx.

Other Supporting Policies

- In 2014, the legislature passed legislation allowing commercially owned solar energy property to be classified as pollution control equipment, thereby exempting it from state and local taxation.
- Also in 2014, the General Assembly passed a bill making it easier for homeowners in community associations to install solar panels on their property. Homeowners Associations can only ban solar panels if the ban is contained within their original recorded declarations.

Virginia has an onshore wind resource potential of 1,793 MW at an 80 meter "hub height"[1] Capable of providing clean renewable power to thousands of Virginia homes and businesses.

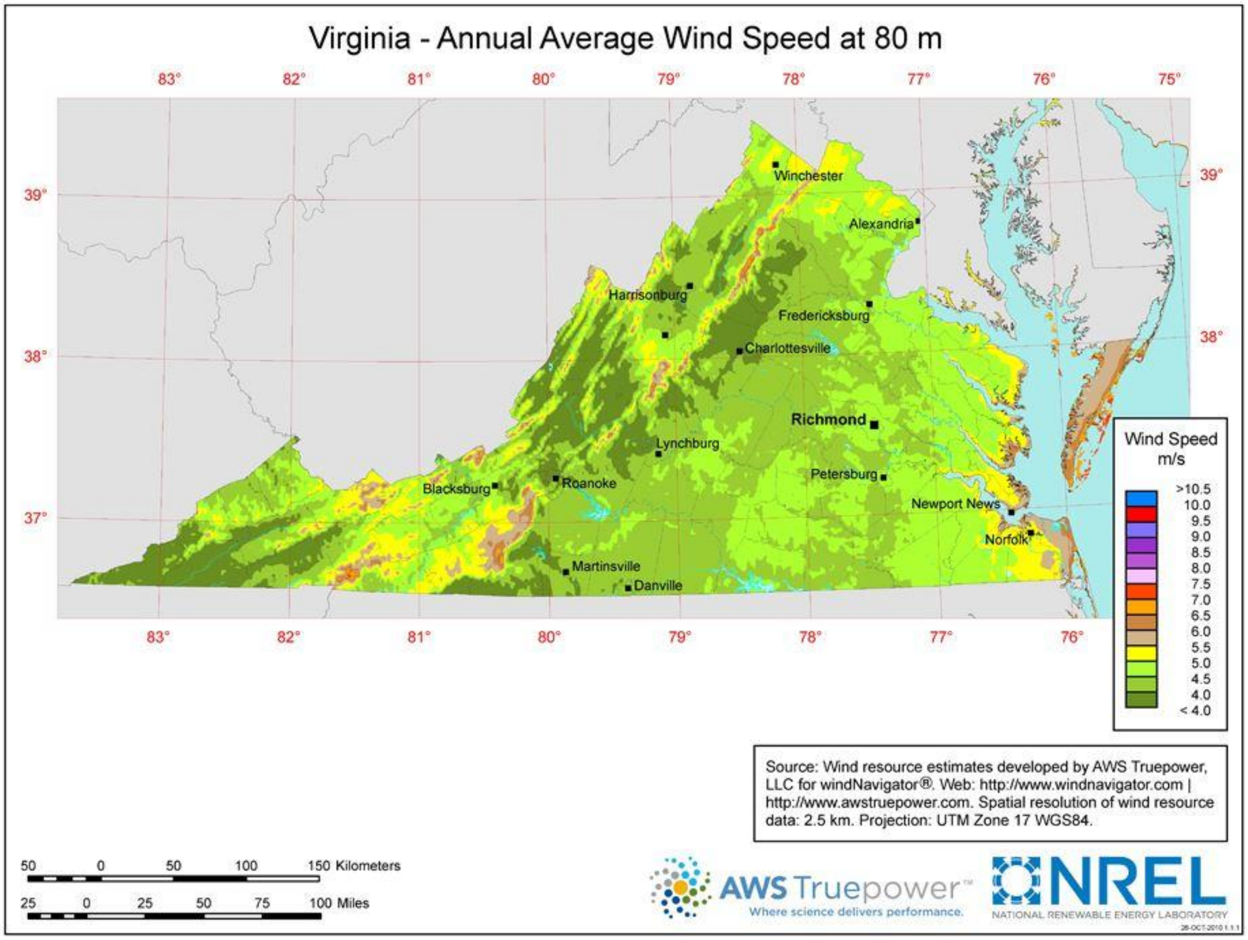
Onshore Wind Power in Virginia

Virginia has an onshore wind resource potential of 1,793 MW at an 80 meter "hub height"[7] Capable of providing clean renewable power to thousands of Virginia homes and businesses. The most promising onshore wind resources are in the Western part of the state along mountain ridges. The hub height is defined as the distance from the center axis of a wind turbine rotor to the ground. A hub height of 80 meters in not uncommon for modern utility-scale wind turbines, and the future looks towards hub heights of upwards of 100 meters.

In general, wind speed increases as the height above the ground increases and the amount of clearance of obstructions like trees and buildings increases. This is important because the power output of a wind generator is proportional to the cube of the wind speed. For example, if you double the wind speed, the power output from the wind turbine will increase by a factor of eight.

[7] American Wind Energy Association's Virginia Wind Energy Fact Sheet" http://www.awea.org/Resources/state.aspx?ItemNumber=5180

Figure 4-1: Virginia Wind Speeds – 80 meter height[8]



To date, the only onshore wind power project to receive regulatory approval is the 39 megawatt Highland New Wind project in Highland County, which received final approval to begin construction in 2008. A number of other developers, including Dominion have been exploring projects in several Virginia counties.

Dominion Virginia Power currently operates two wind power generation facilities that serve Virginia load. These Include 1) a fifty percent interest in the 264 megawatt NedPower Mount Storm facility in Grant County, West Virginia, and 2) a fifty percent interest in the 300 megawatt Fowler Ridge I facility located in Benton County, Indiana.[9]

[8] U.S. DOE WINDExchange: http://apps2.eere.energy.gov/wind/windexchange/wind_resource_maps.asp?stateab=va
[9] http://www.dom.com/about/environment/report/renewable-energy-and-green-power.jsp

Appalachian Power Company purchases 75 megawatts worth of renewable energy certificates from the Camp Grove wind facility in Illinois and 100 megawatts from the Fowler Ridge II project in Indiana.[10]

To support the development of wind power in Virginia, the Virginia Center for Wind Energy at James Madison University (JMU) has created several programs to assist in assessing the suitability of sites for land-based residential and utility-scale wind projects. This assistance to local governments, state agencies, landowners, academia, non-governmental organizations, and businessesincludes wind resource measurements, economic modeling, education & outreach, energy policy analysis, assessment of technical specifications, Geographic Information Systems analysis, and the strategic deployment of wind power within the Commonwealth and beyond.

More information on JMU's wind power activities is available at: http://wind.jmu.edu.

Onshore wind is a well-established technology and industry. In 2013, the U.S. had 61,091 MW of onshore wind capacity, second only to China.[11] Wind only generates electricity when wind speeds are sufficient to turn the turbine blades, and because wind is intermittent and unpredictable, sufficient other generation assets must be available to ensure capacity requirements are met. Typical capacity factors for onshore wind range between 30% and 45%, with a median of 39%.[12] The percent of time a wind turbine generates power is called its capacity factor

Wind projects have relatively high capital costs, but benefits from low operating costs and zero fuel costs for the life of the project. Because the fuel (wind) is free, electricity from wind is not subject to escalating fuel costs.

In 2012, the capacity-weighted average installed project cost stood at roughly $1,940/kW, down almost $200/kW from the reported average cost in 2011 and down almost $300/kW from the apparent peak in average reported costs in 2009 and 2010.[13]

After topping out at nearly $70/MWh for power purchase agreements (PPAs) executed in 2009, the average levelized price of wind PPAs signed in 2011/2012—many of which were for projects built in 2012—fell to around $40/MWh nationwide, which rivals previous lows set back in the 2000–2005 period.[14]

Offshore Wind Power

Offshore wind has the potential to provide the largest, scalable renewable energy resource for Virginia. The state currently does not have any utility-scale wind power in operation,

Virginia is unique with a shallow continental shelf that extends out 30 miles. With its proximity to load

[10] Commonwealth of Virginia State Corporation Commission, "Report to the Commission on Electric Utility Regulation of the Virginia General Assembly", http://www.scc.virginia.gov/comm/reports/2010_veur.pdf, June 24, 2011
[11] Global Wind Statistics 2013. Global Wind Energy Council. May 5, 2014. p. 3.
[12] Transparent Cost Database. OpenEI. Retrieved from http://en.openei.org/apps/TCDB/, May 27, 2014.
[13] http://www1.eere.energy.gov/library/asset_handler.aspx?src=http://wind.energy.gov/pdfs/2012_wind_technologies_market_report.pdf&id=6436
[14] Ibid.

centers, supply chain infrastructure, a trained work force and best in class ports, offshore wind can provide substantial benefits to the state.

In 2013, Dominion Virginia Power won a federal lease for 112,800 acres off the Virginia coast to develop offshore wind power with the potential to generate up to 2000 megawatts, or enough to electricity to power 500,000 homes.[15]

Offshore wind has the potential to provide the largest, scalable renewable energy resource for Virginia

The Chesapeake Bay and state waters within 3 nautical miles off the coast of Virginia are dominated by Class 4 winds (7 to 7.5 meters per second).

Federal waters on Virginia's Outer Continental Shelf (OCS) are dominated by Class 5 and Class 6 winds (7.5 to 8.8 meters per second).

The total potential wind power generation capacity in Class 5 and Class 6 winds on Virginia's OCS between 3 and 50 nautical miles offshore is 47,900 MW, having a maximum potential annual energy output of 176 million megawatt-hours per year.

It is estimated that there are more than 3,000 megawatts of offshore wind capacity in waters with depth less than 30 meters. This depth is important as it allows use of conventional, commercially available foundation technologies, improving the cost effectiveness of offshore installations.[16]

The Virginia Department of Mines, Minerals and Energy submitted 2 unsolicited applications for research leases.

Research Lease 1 was initially intended for siting of meteorological ocean and environmental monitoring platforms, however, final details on the specific research activities have not yet been determined.

Research Lease 2 was secured for the development of Dominion Virginia Power's *Virginia Offshore Wind Technology Advancement Project* (VOWTAP). The VOWTAP will culminate in the construction of two, 6 megawatt Alstom Haliade™ wind turbines. The primary objectives of the VOWTAP are:

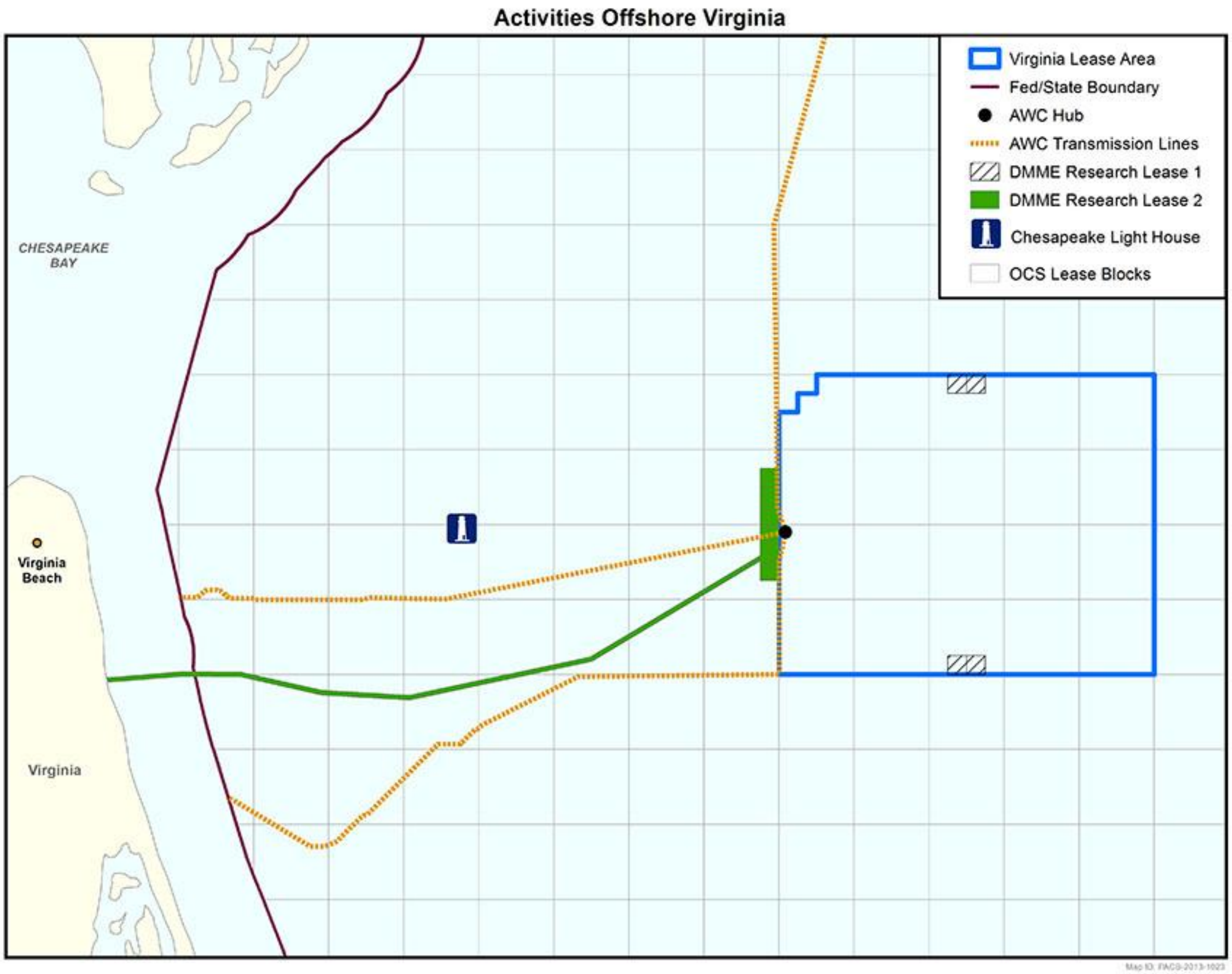
- To design, develop, and demonstrate a state-of-the art grid-connected 12 megawatt (MW) offshore wind research facility off the coast of Virginia.
- Employ technology innovations and research that will inform and benefit future commercial scale offshore wind developments in the United States.
- Develop technologies and process solutions that will contribute to establishing offshore wind as a cost-effective renewable energy solution for the United States.

[15] Dominion Virginia Power: https://www.dom.com/about/stations/renewable/offshore-wind-power.jsp
[16] VCERC Virginia Offshore Wind Studies, July 2007 to March 2010 Final Report
http://www.vcerc.org/VCERC_Final_Report_Offshore_Wind_Studies_Full_Report_newest.pdf

In May of 2014, Dominion's VOWTAP was one of three projects nationally selected by the U.S. Department of Energy to receive up to $47 million each over a four-year period for construction of offshore wind demonstration projects. To be eligible to receive funding, the projects must be operational by the end of 2017. The wind produced by the VOWTAP project will be tied to the grid and distributed to Virginia residents, subject to approval of the costs by the State Corporation Commission. Once approved, up to 3000 homes and businesses will benefit from this clean, renewable energy.

Additional information on the Virginia Wind Energy Area and the two Research Leases is available at http://www.boem.gov/State-Activities-Virginia.

Figure 4-2: Virginia Offshore Wind Energy Area and Two Research Leases



In 2010, the General Assembly adopted legislation to create the Virginia Offshore Wind Development Authority (VOWDA). The mission of the Authority is to facilitate, coordinate, and support development of Virginia's offshore wind energy industry, offshore wind energy projects, and supply chain vendors by:

- Collecting metocean and environmental data.
- Identifying regulatory and administrative barriers.
- Working with local, state, and federal government agencies to upgrade port and logistic facilities and sites.
- Ensuring that development is compatible with other ocean uses and avian/marine wildlife.
- Recommending ways to encourage and expedite offshore wind industry development through public-private partnerships with developers.

More information on VOWDA activities and reports is available at http://wind.jmu.edu/offshore/vowda/index.html.

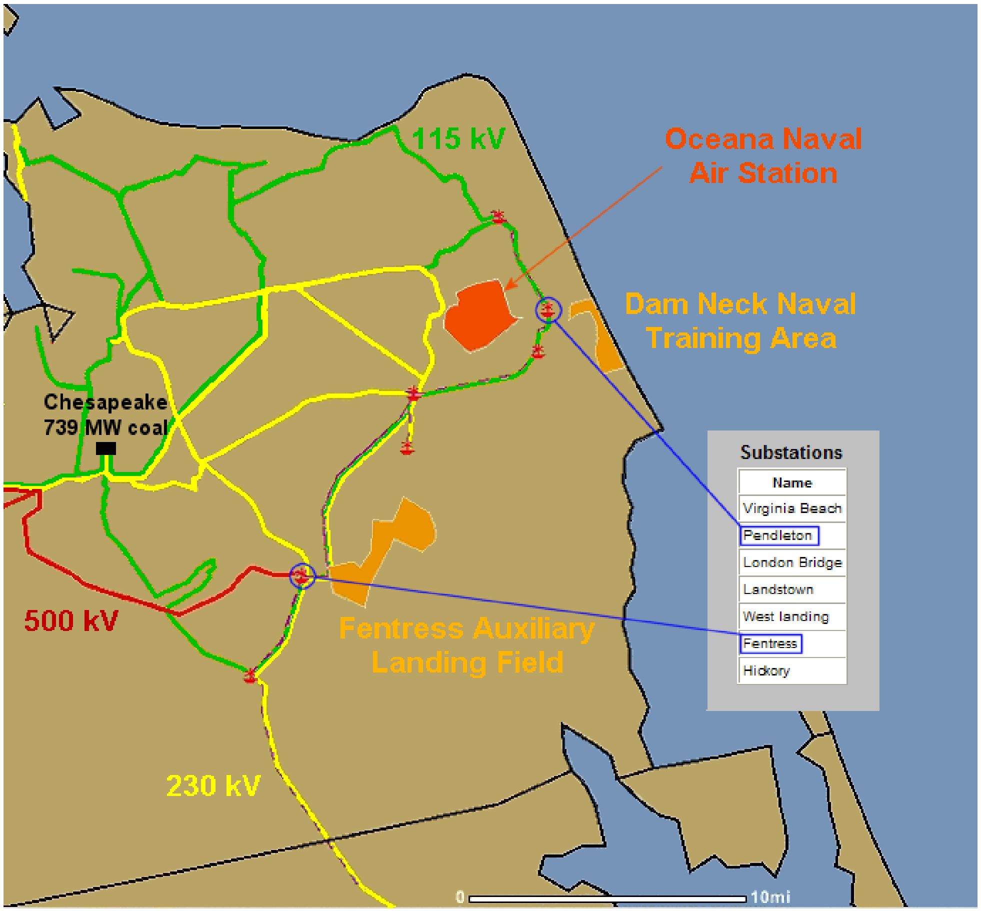
Dominion Virginia Power developed a report for VOWDA exploring the feasibility for offshore wind energy transmission in South Hampton Roads. The results indicate that it is technically possible to interconnect up to 4500 MW of offshore wind generation with the existing transmission system in the Virginia Beach area, but that above 2700 MW, transmission upgrades will be necessary to prevent wind power operators from having to curtail generation (and to lose revenue) during certain times. It is estimated that depending on the level of wind generation injected into the local grid, these transmission upgrades will cost between $30 million and $70 million.

The legislature also created the Virginia Coastal Energy Research Consortium (VCERC) to develop coastal energy technologies. VCERC provides the research and development required for the commercialization and implementation of new coastal energy resources – including offshore wind power - through multidisciplinary research collaborations between seven Virginia universities:

- Virginia Tech Advanced Research Institute
- James Madison University
- Norfolk State University
- Virginia Commonwealth University
- University of Virginia
- Hampton University
- George Mason University

VCERC has mapped Virginia's offshore wind resource and prepared other research and reports to help inform decision makers, and is assisting the Commonwealth with a plan for use of proposed research leases and other R&D opportunities.[17]

Figure 4-3: Offshore Wind Grid Access Points[18]



In October 2010, the independent transmission company Trans-Elect, in partnership with Good Energies Capital, Google and Marubeni Corporation, announced their proposed Atlantic Wind Connection (AWC) backbone transmission project – a high-voltage direct current transmission system that will allow the interconnection of offshore wind power installations from New Jersey to Virginia.

The AWC project is designed to link Offshore Wind Energy Areas identified by the Bureau of Ocean Energy Management (BOEM), and it is the first offshore backbone electric transmission system proposed in the United States.

[17] Ibid.
[18] Presentation at the Virginia Manufacturing Association, 2010 Energy Summit, VIRGINIA WIND POWER OPPORTUNITIES - JOBS FOR VIRGINIA, March 2010

Offshore Wind and Economic Development

Wind energy development off the coast of Virginia has the potential to become a $15 billion dollar industry over the next ten years and can support new jobs in project construction and operation, and in supply chain businesses. According to VCERC, "*within two decades, 9,700 to 11,600 career-length jobs can be created, solely associated with developing the 3,200 megawatts of offshore wind potential that VCERC has identified in shallow waters beyond the visual horizon off Virginia Beach*."[19]

> The Port of Hampton Roads offers highly suitable port, manufacturing, and project development sites to support offshore wind development, as well as wind turbine and supply chain manufacturing. Because of its central location in the mid-Atlantic, Virginia has the potential to play a major role in offshore wind development along the entire east coast.[1]

Challenges to Offshore Wind

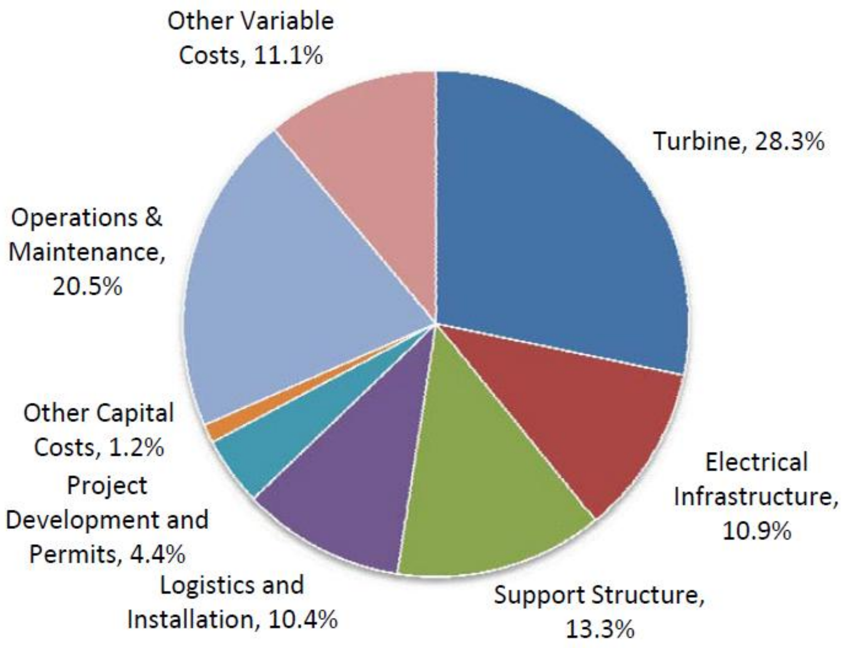
Offshore wind technology is estimated to cost between $125 and $225 per megawatt hour (12.5 to 22.5 cents per kilowatt hour). This would not be competitive with other power sources in today's market, although costs are likely to come down as construction begins and economies of scale allow for lower equipment and installation costs.

As shown in Table 4-4, capital costs for offshore projects are estimated to be more than double those for land-based wind projects. These higher costs accrue from specialized offshore turbine support structures, offshore electrical infrastructure construction, the high cost of building at sea, operations and maintenance (O&M) warranty risk adjustments, turbine cost premiums for marinization (designed and built to survive in a harsh marine environment), and a decommissioning contingency. These costs can be partially offset by increased energy production from higher wind speeds and capacity factors.[20]

[19] http://www.vcerc.org/VCERC_Final_Report_Offshore_Wind_Studies_Full_Report_newest.pdf

[20] W. Musial, R. Thresher, B. Ram. *Large-Scale Offshore Wind Energy for the United States: Assessment of Opportunities and Barriers.* CO, Golden: National Renewable Energy Laboratory, 2010

Figure 4-4: Estimated Life-Cycle Cost Breakdown for a Typical Offshore Wind Project[21]



In addition to cost challenges, offshore wind has numerous technical, infrastructure and permitting challenges associated with it. For example, the offshore wind resource is not yet well characterized, which can negatively affect financing costs. Current wind data is based on computer models, while lenders typically require physical measurement of wind speeds at the location wind installations will occur. Gathering this "bankable" data will require the installation of meteorological equipment, such as LIDAR (a system that uses lasers to detect wind speed and direction based on the time delay of the laser beam reflected by airborne aerosols) in the Wind Energy Area.

Offshore wind turbines also require specialized vessels which are not readily available in the U.S. While foreign-flagged turbine installation and maintenance vessels exist, for example in Europe, the Jones Act limits the ability of these vessels to operate in U.S. waters. On the other hand, shipyards in the Hampton Roads area are well positioned to build these specialized vessels for not only Virginia offshore wind projects, but for projects along the entire east coast.

On June 2, 2014, the United States Environmental Protection Agency (EPA) released the *Clean Power Plan Proposed Rule,* with the goal of reducing carbon dioxide (CO_2) emissions from existing fossil electric generating units. EPA created emissions intensity reduction targets for each state measured as a reduction in the pounds of carbon dioxide per megawatt hour (MWh) of electricity produced in the state. For Virginia, the proposed target will require a 38 percent reduction from the 2012 level of 810 pounds of carbon dioxide per megawatt hour by 2030. Increasing the use of renewables, especially solar and wind (both offshore and on land), can significantly help the state reach this goal.

[21] Ibid..

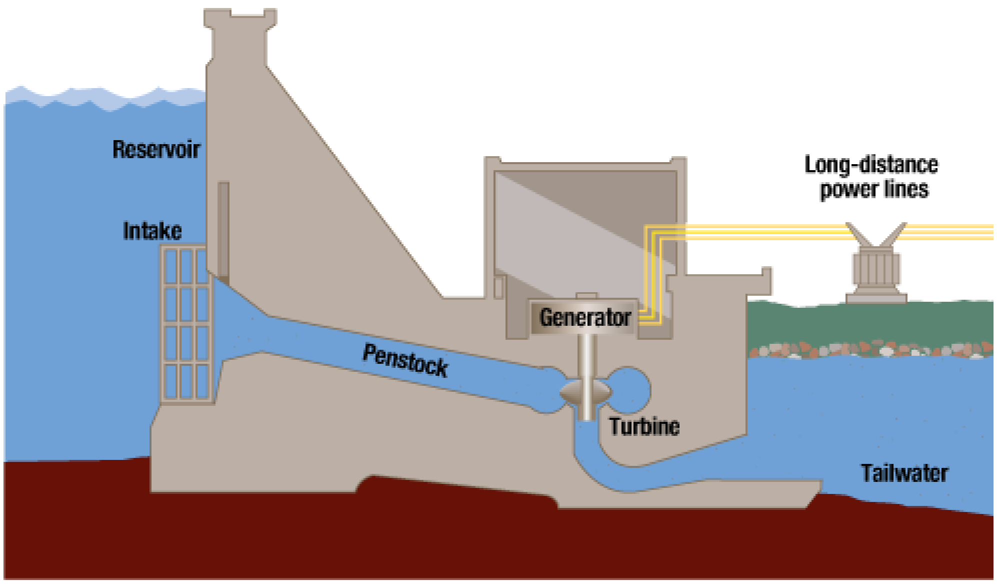
Hydroelectric Power

Hydro projects are long-lived assets with a few projects operating for 100+ years. Nationally, water is currently the leading renewable energy source used by electric utilities to generate electric power.

Like solar and wind they have no direct fuel costs so delivered energy costs depend on the capital equipment and water availability. Once installed these generators emit no greenhouse gas or other pollutants and do not generate solid or hazardous wastes. Dam operations do have implications for water consumption, which are usually detailed in their operating plans in terms of recreational, fish and wildlife, agricultural and potable water uses of their reservoirs and their priority assigned to power generation compared to competing uses.

There are several types of hydroelectric facilities currently used. The most common hydroelectric plant uses a dam across a river to create a reservoir at a higher elevation than that of the undammed river. This height differential allows water to flow at high pressure and velocity though the blades of a turbine connected by a shaft to an electric generator that creates electricity. The water then exits the facility at the lower elevation of the original river.

Figure 4-5: Hydroelectric Facility Diagram

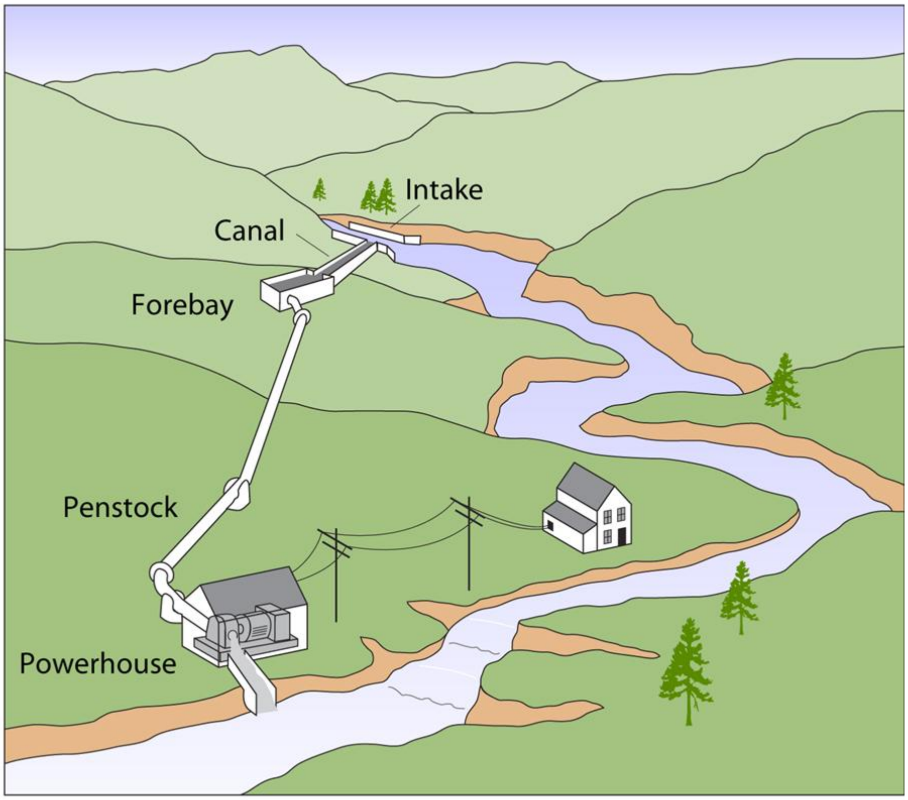


Source: Tennessee Valley Authority (Public Domain)

In a “pumped-storage” plant, two reservoirs at different elevations are used. To generate electricity, water flows through the turbine to turn a generator and exits into the lower reservoir. During periods of low electric demand, however, such as at nights, the turbines, using electricity from the grid, act as pumps to move water from the lower back up to the upper reservoir. Because power, typically from non-renewable sources, is used for pumping mode, only the net generation over and above what is used to pump the water can be considered renewable. Pumped storage is a way to smooth out the intermittent nature of other renewables like solar and wind.

A third type of hydroelectric plant is called “run-of-river”, in which a portion of a river is diverted to flow through a channel or a pressurized pipeline, or *penstock*, to turn a turbine. Because run-of-river plants typically do not involve large dams, they are considered more environmentally friendly because they don't require flooding valleys to create large reservoirs.

Figure 4-6: Run-of-River Power Plant



In this run-of-river microhydropower system, water is diverted into the penstock and exits down-river from the intake.

Generating electricity using water has several advantages. A major advantage is that water is a source of cheap power. Like solar and wind power, the "fuel" is free, and since there is no fuel combustion, there is no air pollution.

Like other energy sources, the use of water for generation has limitations, including environmental impacts caused by damming rivers and streams, which affects the habitats of the local plant, fish, and animal life.

Virginia is home to 24 conventional hydropower facilities with a combined capacity of 439 megawatts, and two pumped storage facilities with a combined capacity of 3659 megawatts. The Bath County pumped storage facility, jointly owned by Dominion and the operating companies of the Allegheny Power System, make up the bulk of Virginia's pumped storage, and is the second largest pumped storage facility in the world.

Figure 4-7: Conventional Hydroelectric Facilities

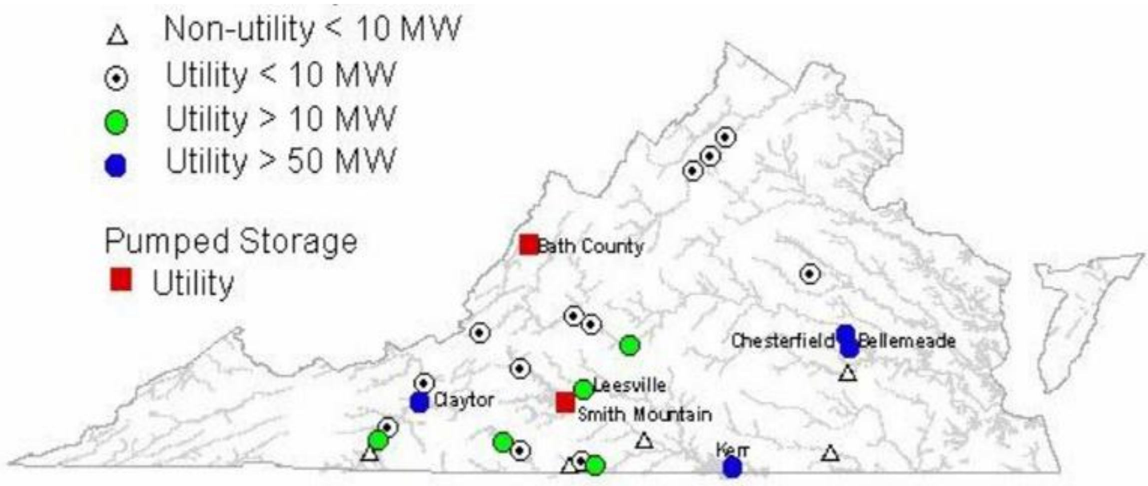


Table 4-4: Hydroelectric Facilities (Pumped Storage in Red)

Owner	Name	County	Summer Capacity (MW)
Allegheny Energy Supply Co LLC	Luray	Page	1.6
Allegheny Energy Supply Co LLC	Newport	Page	1.4
Appalachian Power Co	Buck	Carroll	8.4
Appalachian Power Co	Byllesby 2	Carroll	21.6
Appalachian Power Co	Claytor	Pulaski	74.8
Appalachian Power Co	Leesville	Campbell	40
Appalachian Power Co	Niagara	Roanoke	3.6
Appalachian Power Co	Reusens	Campbell	22.5
Appalachian Power Co	Smith Mountain Dam	Franklin	656
Appomattox River Associates LP	Brasfield	Appomattox	3
Aquenergy Systems Inc	Fries Hydroelectric Project	Grayson	5.4
Bedford City of	Snowden	Amherst	5
Danville City of	Pinnacles	Patrick	11.1
Dominion Virginia Power	Bath Pumped Storage	Bath	3003
Dominion Virginia Power	Cushaw	Amherst	7.5
Dominion Virginia Power	North Anna	Louisa	1
Georgia Pacific Corp-Big Island Mill	Georgia Pacific Big Island	Bedford	0.4
Holcomb Rock Company	Coleman Falls	Bedford	1.5
Holcomb Rock Company	Holcomb Rock	Bedford	1.8
Martinsville City of	Martinsville	Henry	1.3

Radford City of	Radford	Pulaski	1
Ridgewood Power Management LLC	Emporia	Greensville	2.4
Ridgewood Power Management LLC	Halifax	Halifax	1.6
STS HydroPower Ltd	Schoolfield Dam	Pittsylvania	4.5
USCE-Wilmington District	John H Kerr	Mecklenburg	204
USCE-Wilmington District	Philpott Lake	Henry	14

Upgrades at Existing Hydropower Facilities

The Federal Energy Regulatory Commission (FERC) compiles a list of hydropower projects that have been certified to receive the production tax credit (PTC).[22] Projects that add capacity or do efficiency improvements qualify. The most recent update we have is from the end of December 2013. There have been 128 projects certified with an average generation increase of about 9.5 percent, with individual increases have ranged from under 1 percent to over 60 percent. This list demonstrates the potential to further maximize the output of existing hydropower facilities through replacement of equipment with new technologies, as well as expansion opportunities.

The Bath County project is one Virginia project that has filed in recent years and was certified. There may be similar opportunities for other projects in the state.

Powering Non-Powered Dams

In April 2012, the DOE/Oak Ridge Laboratory released a report titled, "An Assessment of Energy Potential at Non-Powered Dams in the United States." See: http://energy.gov/sites/prod/files/2013/12/f5/npd_report_0.pdf.

Of the 80,000 dams in the U.S., only 3 percent have hydropower generating facilities on them. The remaining 97 percent were built for other purposes – flood control, navigation, irrigation, municipal water supply, etc. For Virginia, the report found 50 MW of potential on these facilities in the State.

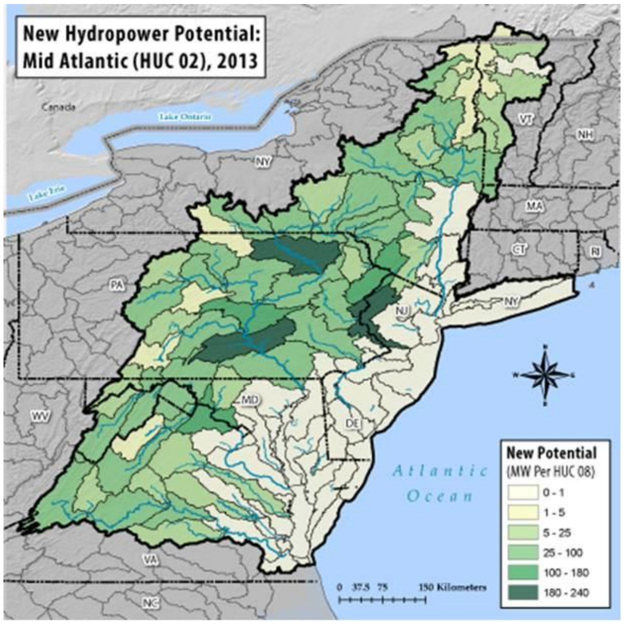
New Stream-Reach Development

In April 2014, the DOE/Oak Ridge Laboratory released another report titled, "New Stream-Reach Development: a Comprehensive Assessment of Energy Potential in the United States."[23]

This report provides the technical potential (and does not make recommendations for any individual project) for new hydropower development that involves new dam infrastructure. The report categorizes potential by regions, not by states. Virginia crosses four regions: Mid-Atlantic, South Atlantic-Gulf, Ohio Region, and Tennessee Region. An example is provided immediately below.

[22] See http://www.hydro.org/wp-content/uploads/2014/01/PTCs-Issued-as-of-December-2013.pdf
[23] See: http://nhaap.ornl.gov/sites/default/files/ORNL_NSD_FY14_Final_Report.pdf.
Also see the fact sheet at: http://nhaap.ornl.gov/sites/default/files/NSD_overall_fact_sheet.pdf

Figure 4-8: New Hydropower Potential



Projects That Have Filed For a Preliminary Permit at FERC

On FERC's website are listed those projects that have filed for preliminary permits to begin examining sites for development. Currently, Virginia has two such preliminary permit applications on file for small projects at the Commission, totaling 5 MW. Information on these projects can be found by going into the FERC e-Library and searching by project number (example: P-14425).

Table 4-5: Conventional Hydroelectric Facilities

Docket Number	Project Name	Expiration Date	Authorized Capacity (KW)	Licence	Waterway	ST	Description
P-14425	Scott's Mill	11/30/15	**4800**	Liberty University	James River	VA	Conventional Permit
P-14526	Danville Union Dam	2/28/17	**620**	KC Small Hdyro LLC	Dan River	VA	Conventional Permit

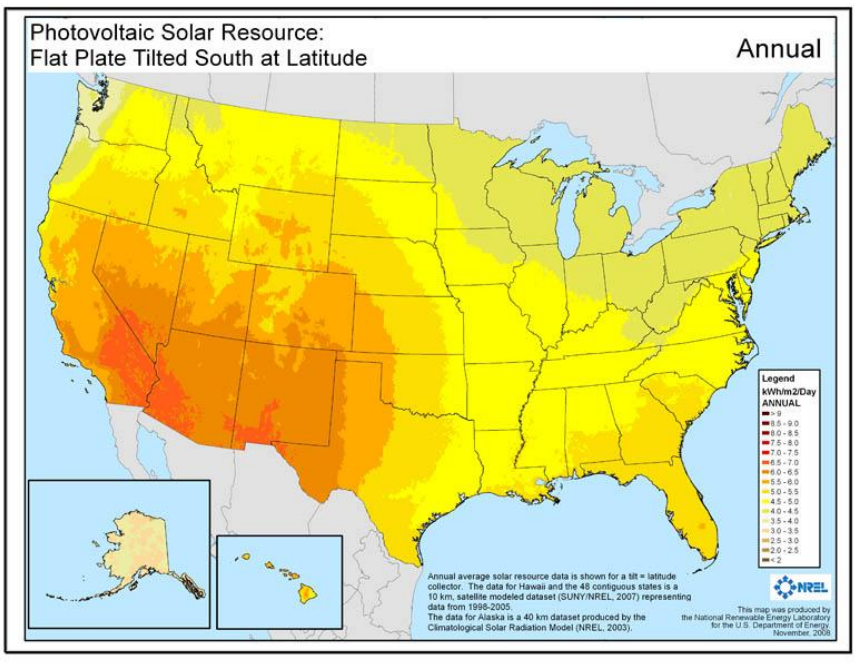
A total of **36 projects** are listed with a combined authorized capacity of about **3632 MW**. Project types include conventional hydropower (large and small), hydropower pumped storage, and conduit power projects. Conduit power projects tap water flows in man-made channels or pipes, for instance the flows from elevated potable water reservoirs.

Navigant Consulting conducted a study in 2009-2010 that looked at the job creation benefits that are derived from the hydropower industry.[24] The report estimated that the U.S. hydro industry employs overall up to 300,000 workers. The U.S. hydropower industry could install 23,000 MW to 60,000 MW of new capacity by 2025, representing only 6-15 percent of the total untapped hydropower resource potential in the U.S. The total jobs required to meet these targets would be in the range of 230,000 to 700,000 jobs.

Solar Power

Photovoltaics ("PV") are a well-established, commercial technology that converts sunlight into direct current (DC) electricity. PV devices generate electricity directly from sunlight via an electronic process that occurs naturally in certain types of material, called semiconductors. Thin-film PV is a fast-growing but small part of the commercial solar market. These are generally less efficient – but often cheaper – than c-Si modules. Solar heating & cooling (SHC) technologies collect the thermal energy from the sun and use this heat to provide hot water, space heating, cooling, and pool heating for residential, commercial, and industrial applications. The SHC technologies displace the need to use electricity or natural gas.

Figure 4-9: Solar Resources Map



[24] See http://www.hydro.org/why-hydro/job-creation/navigant-study/ for the full report, highlights, state-by-state breakdowns.

Sunlight can be used effectively to heat water or air using solar thermal collectors. A typical solar water heating system for a family of four delivers 4 kilowatts of electrical equivalent thermal power under full sun, and defers up to 0.5 kilowatts of peak demand.[25]

Large community swimming pools heated using oil or propane and institutional facilities such as prisons and health care facilities are ideal applications of solar thermal systems.

Photovoltaic (PV) energy is produced using semiconductor materials. Unlike solar thermal systems for heating air or water, PV does not use the sun's heat to make electricity. Instead, specially treated semiconductor materials interact with photons from the sun to free up electrons to flow in an electric current. There are numerous semiconductor technologies used to manufacture PV products. The most common is silicon, which is a primary component in sand, and the second most common element on earth.

PV is an evolving technology, with incremental efficiency gains each year. As technology and manufacturing methods improve, costs continue to come down.

PV industry jobs include work in cell and module manufacturing; assembly, installation: sales and distribution; and project development. In 2013, the U.S. solar industry directly employed over 142,000 people, with the largest concentration in installation (21 percent), sales and distribution (14.2 percent), manufacturing (8.6 percent), project development (3 percent) and the remainder in various supporting activities (16.1 percent).

Solar generating capacity grew significantly in the past several years Because of declining solar equipment costs. Between 2007 and 2012, it is estimated that solar manufacturing costs fell by between 70 and 80 percent[26].

When PV was first used commercially to power satellites in the 1950s a 1W cell cost $300. In 2013, residential system prices fell 8.8 percent from a year earlier to an average $4.59/W, non-residential prices fell 16.3 percent to an average $3.57/W, and utility systems declined to an average $1.96/W. The lowest levelized costs of electricity for PV in the NREL Transparent Cost Database are $0.10/kWh, with a median value of $0.32/kWh and a DOE program estimate of $0.20/kWh, although comparisons are highly dependent on whether the PV is competing against retail rates (residential and non-residential) or utility busbar rates and how net metering and other policies impact the valuation of PV. The U.S. DOE SunShot program is working toward reducing utility-scale PV costs to $0.11/kWh by 2015 (without subsidies) and to $0.06/kWh by 2020, where it will be cost-competitive with traditional electricity sources.

Solar module costs have dropped to the point where it is the non-hardware, balance of systems costs associated with solar energy systems keeping installed system costs as high as they currently are. These “soft costs” represent as much as 64 percent of the total installed system price[27] and include:

- Customer Acquisition
- Financing and Contracting
- Permitting, Interconnection, and Inspection
- Installation and Performance
- Operations and Maintenance

[25] Solar Rating and Certification Corporation Fact Sheet: http://www.solar-rating.org/facts/Energy_Production.pdf
[26] http://reneweconomy.com.au/2014/solar-pv-continues-shoot-cost-curve-42386
[27] http://energy.gov/eere/sunshot/reducing-non-hardware-costs

In 2011, the U.S. Department of Energy launched the "SunShot" initiative to reduce the total costs of photovoltaic solar energy systems by about 75 percent so that they are cost-competitive at large scale with other forms of energy without subsidies before the end of the decade. By reducing the cost for utility-scale installations by about 75 percent to roughly $1 a watt—which would correspond to roughly 6 cents per kilowatt-hour—solar energy systems could be broadly deployed across the country.[28]

As of June 2014, the total net metered capacity of solar photovoltaic systems in Virginia was just over 12 megawatts, with additional non-net metered solar totaling approximately four megawatts (mostly on military installations). This is far less than in neighboring Maryland, with 158 MW (MEA, 2014), District of Columbia with 14 MW at end of 2012 (Sherwood, 2013), and North Carolina with 592 MW (SEIA, 2014).

Legislation enacted in 2011 allows for the creation of utility distributed solar generation demonstration programs.

Pursuant to that legislation, Dominion plans to install up to 30 megawatts of company-owned distributed solar generation on leased commercial rooftops in strategically located areas of its service territory. This project will allow the utility to learn how to manage a larger scale intermittent resource and include such assets in its generation and reliability planning. Not only will this project increase the renewable power available to Virginia electricity customers, but it will provide an important research opportunity to support further expansion.

Currently, Virginia law does not allow a third party to install and own a renewable energy facility on a utility customer's property and sell the utility customer the renewable output of the renewable energy system.

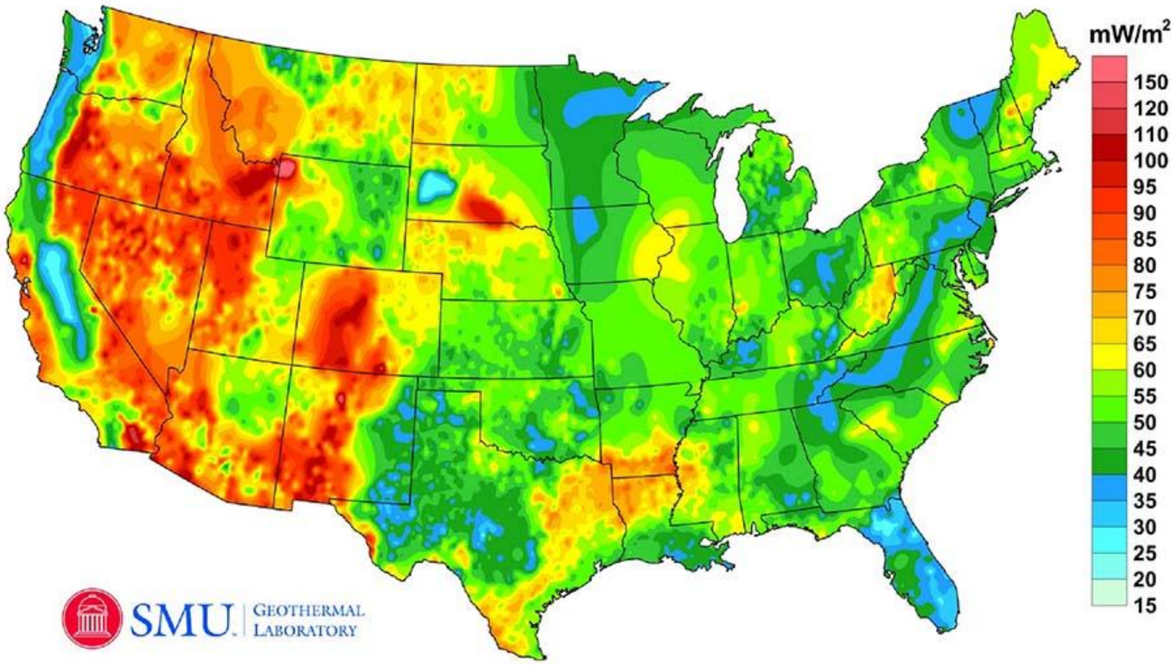
However, in 2013, the Legislature enacted legislation that would allow for a pilot program within Dominion Virginia Power's service territory to enable third party power purchase agreements for systems as large as one megawatt, up to an aggregate of 50 megawatts system wide.

Geothermal Energy

According to the VA Division of Geology and Mineral Resources, geothermal energy is the heat produced by and contained within the Earth. It can be used as a clean, reliable, and renewable energy resource. Geothermal energy is an efficient heating and cooling alternative for residential, commercial, and industrial applications, and is potentially a significant source for electrical power generation in some regions of the United States.

[28] http://www1.eere.energy.gov/solar/sunshot/news_detail.html?news_id=16701

Figure 4-10: Geothermal Resource Potential [30]



Heat from Earth's mantle and crust is stored and transferred to Earth's surface differently depending on geologic setting.

In the western United States, geothermal energy is commonly associated with hot springs and geysers where high-temperature geothermal reservoirs form in areas of relatively recent volcanic and earthquake activity. In these locations groundwater circulates deep into permeable bedrock picking up heat and bringing it close to the surface creating a high geothermal gradient. Several of these reservoirs have been developed for commercial applications including direct heating, food dehydration, aquaculture, and electrical power generation.

In the relatively stable geologic environment of the eastern United States, heat-generating rocks are much deeper and geothermal gradients tend to be lower. Yet opportunities exist for developing lower-temperature geothermal resources that may include direct use, geo-exchange systems, co-produced geothermal with oil and gas resources, and[29] enhanced geothermal systems (EGS).

[29] http://www.dmme.virginia.gov/dgmr/geothermal.shtml

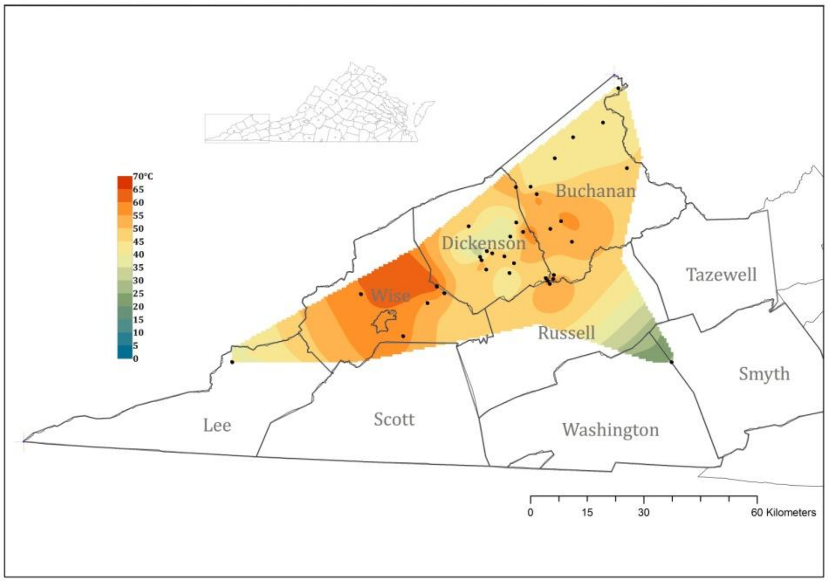
Thermal springs, such as the Jefferson Pools in the town of Warm Springs, Virginia, have been a source for health and relaxation for Virginians for hundreds of years.

In Virginia, thermal springs in Bath and Alleghany Counties have long been utilized as spas and resorts providing a direct use geothermal resource to the public since the 1760s. These hot springs originate from water that was heated deep within the Earth's crust and transported relatively quickly to the surface along geologic faults and fractures.

In Virginia's coal and gas producing regions, warm water is often a by-product of fossil fuel production and generally considered a waste product. New developments in binary geothermal power generation utilizing lower temperature resources may make it feasible in the near future to co-produce geothermal energy along with traditional fossil fuel resources. Generally, the amount of water produced with natural gas in the Southwest Virginia Coalfield region is very small, yet the possibility of geothermal co-production from wells with higher water volumes, depleted gas wells or underground mine sites remains untested.

The diverse geologic setting of Virginia provides possibilities for enhanced geothermal system (EGS) technologies. Heat-generating granitic rocks situated at depths beneath insulating layers of sedimentary rocks, such as may occur in the Coastal Plain, can provide the necessary natural heat for geothermal development if permeability and/or groundwater supply and circulation can be artificially enhanced.

Figure 4-11: Ground Temperature Gradient in Southwest Virginia[31]



Color contoured temperature in °C at elevation -1,200 m (-3,937 ft) below sea level datum. Preliminary results based on temperature logs from gas wells in the Southwest Virginia Coalfield.

Geothermal Heating and Cooling in Buildings

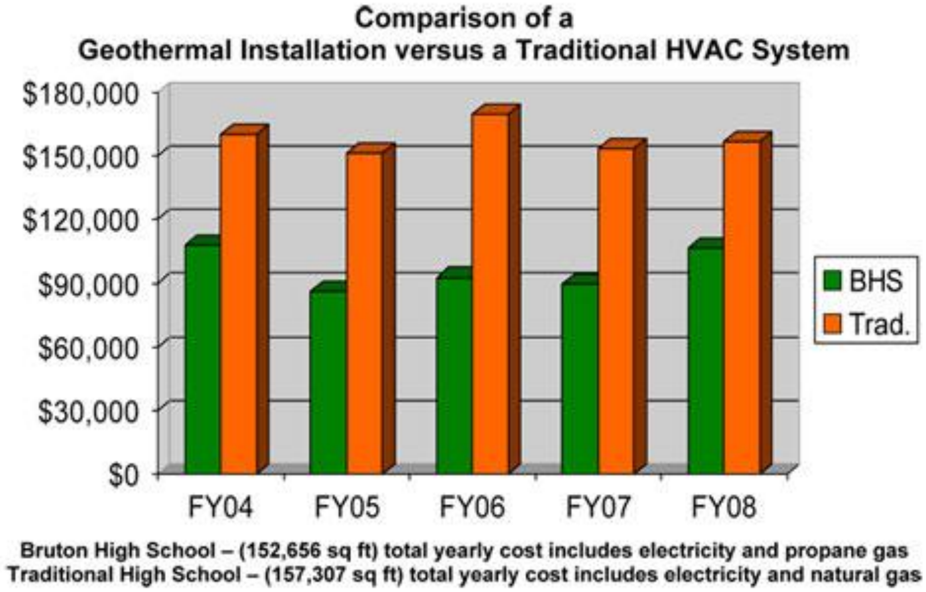
Geothermal energy can provide heating and cooling through use of geothermal heat pumps. geothermal heat pumps are not truly a renewable energy technology, but instead a much more efficient heat pump that takes advantage of the relatively stable year-round temperature of the earth to extract heat from in the winter and throw off heat to in the summer. There are limited low-temperature geothermal resources in Bath County that may be suitable for water and space heating. Hot-rock geothermal resources are found near the Virginia Atlantic coastline. Due to the depth of these rocks, systems to exploit this heat source are not economical with current technology.

According to the York County Schools website[32], the County uses geothermal systems operating wells in nine county school facilities. In September of 2000, the York County School Division completed its first geothermal renovation at Tabb Middle School. The subsequent energy savings achieved at that site prompted similar renovations throughout the school division. Today, more than one third of the school buildings in the division have been converted to geothermal heating and cooling systems. These renovations have reduced site energy consumption by up to 40%. Energy costs for a typical York County geothermal school were reduced by approximately $60,000 per year.

[31] http://www.dmme.virginia.gov/DGMR/geothermal.shtml

[32] York County Schools, Green YCSD Geothermal Heating and Cooling, http://yorkcountyschools.org/greenYCSD/geothermal.aspx

Figure 4-12: Geothermal Heat Pump and Traditional Heating and Cooling Energy Costs at Bruton High School in York County[30]



Biomass

Biomass is any organic material that can be used as a bioenergy feedstock. The *Code of Virginia*[31] defines biomass as agricultural and forest-related materials, animal wastes, mill residues, urban woody wastes, purpose grown energy crops, landfill and wastewater gas, biosolids, and municipal solid waste. The moisture content of the material typically determines the way it can best be used. The higher the moisture content, the lower the heating value when used in combustion processes, as a portion of the energy in the fuel is expended in driving off the water. High moisture content feedstocks are more suitable for anaerobic digestion to generate biogas.

Biomass Resources

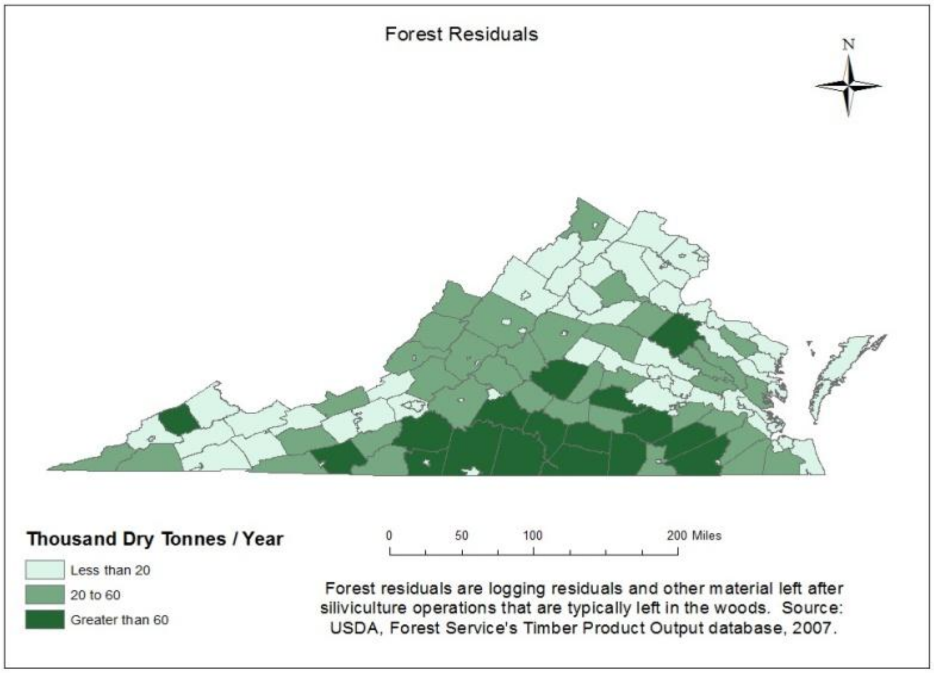
Forest Residuals

Low moisture content biomass is often referred to as solid fuels. The latest data from the National Renewable Energy Lab[32] estimates over seven million dry tonnes (1 tonne = metric ton = 1000 kg or ~ 2200 lbs) of forest residues, primary and secondary mill residues, urban wood wastes, and crop residues are available, annually, statewide. Forest residues, most plentiful in Southside Virginia and in the Coastal Plain (Figure 4-13), are the tops and branches of trees harvested for timber, along with dead,

[30] York County Schools, Green YCSD Geothermal Heating and Cooling, http://yorkcountyschools.org/greenYCSD/geothermal.aspx
[23] Biomass definition in the *Code of Virginia*: http://lis.virginia.gov/cgi-bin/legp604.exe?000+cod+10.1-1308.1.
[32] National Renewable Energy Laboratory Biomass Data: http://www.nrel.gov/gis/data_biomass.html.

diseased, poorly formed, and other non-merchantable trees that would otherwise be left in the woods.

Figure 4-13. Availability of Forest Residuals in Thousand Dry Tonnes by County in Virginia.[33]



Mill Residues

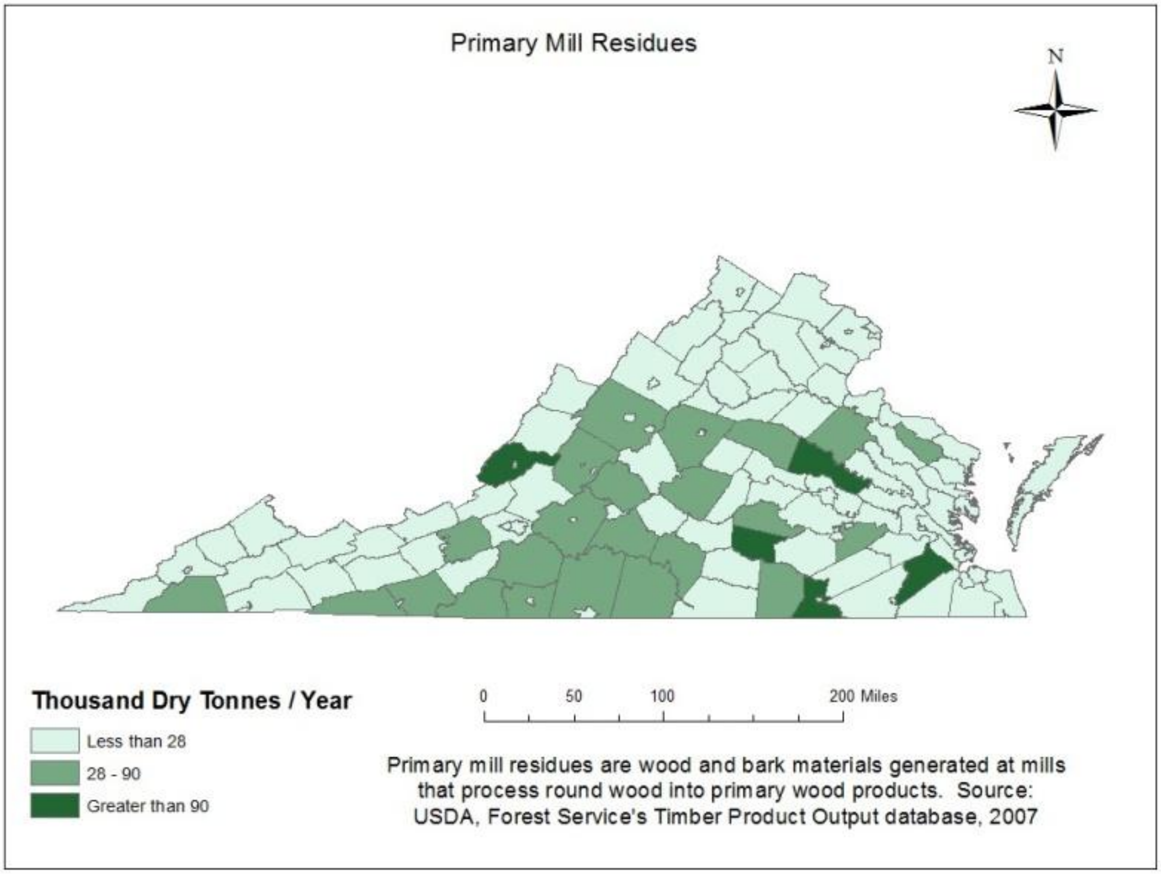
Primary mills take harvested logs, called roundwood, and process these into primary wood products such as pulp, lumber, plywood, posts, etc. Primary mill residues include the coarse and fine wood material (slabs, edgings, trimmings, and sawdust) and bark remaining after initial processing. The Primary Forest Products Network[34] lists over 175 primary mills distributed throughout Virginia. The greatest volume of residues production is concentrated in Alleghany, Amelia, Greensville, Hanover, and Isle of Wight Counties (Figure 4-14). Primary mills will either use their residues as fuel in their own boilers or have secondary markets for fuel or raw materials at other locations.

Recently harvested wood that is green has a relatively high moisture content, and consequently lower energy content. Secondary mill residues, when kiln-dried, have very low moisture content and accordingly are very desirable as a boiler fuel. Secondary mill residues include scraps and sawdust from furniture factories, millwork, wood container, pallet mills, and lumberyards. In addition to use as boiler fuel, sawdust is in demand by the wood pellet and animal bedding industries. Secondary mill residues are available in limited quantities throughout Virginia (Figure 4-15) and can be purchased from individual mills.

[33] Source: NREL Biomass Data, last updated 2008.

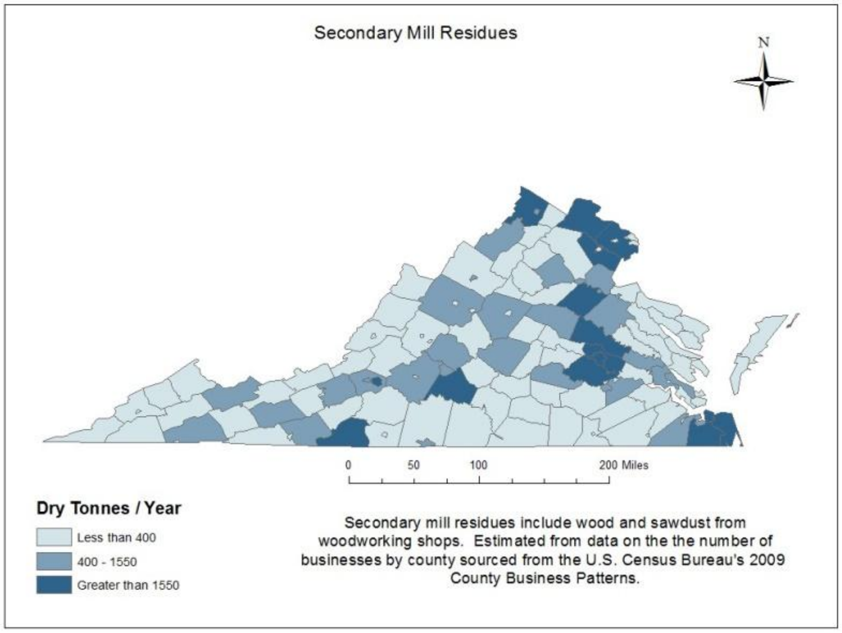
[34] Primary Forest Products Network Forest Products Locator: http://www.forestproductslocator.org/.

Figure 4-14. Primary Mill Residues in Thousand Dry Tonnes per County in Virginia.[35]



[35] Source: Compilation of Virginia Biomass Resources from NREL Biomass Data, last updated 2008

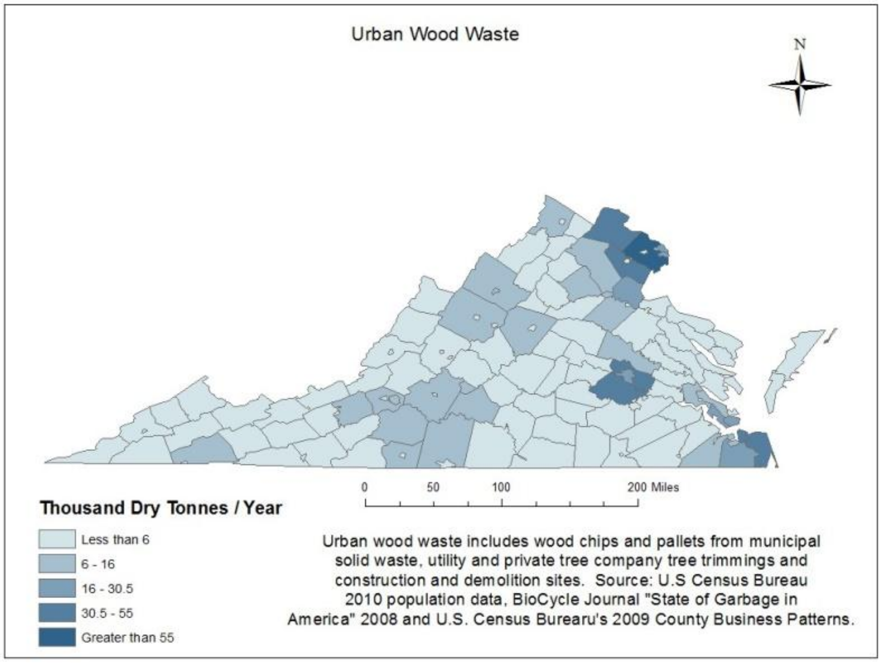
Figure 4-15. Secondary Mill Residues in Dry Tonnes per County in Virginia. Source: Compilation of Virginia Biomass Resources from NREL Biomass Data, last updated 2012.



Urban Wood Wastes

Urbanization and parcelization, (the subdivision of industrial forestland into smaller, privately held tracts), fragments forestland, thereby reducing the acreage available for timber production. Declining tract size increases the relative cost of harvest operations. Generally, lots of 20 acres or fewer are not profitable if commercially harvested; however, significant residuals are still generated from urban and suburban areas. Yard and other wood residues derived from municipal solid wastes (MSW), highway right-of-way and utility clearings, debris from private tree companies, and construction and demolition (C&D) sites generate over a million dry tonnes of urban wood wastes, annually (Figure 4-16). The primary challenge with utilizing urban wood wastes is aggregating the material so that it can be processed and delivered to end-users.

Figure 4-16. Urban Wood Waste in Dry Tonnes per County in Virginia.[36]

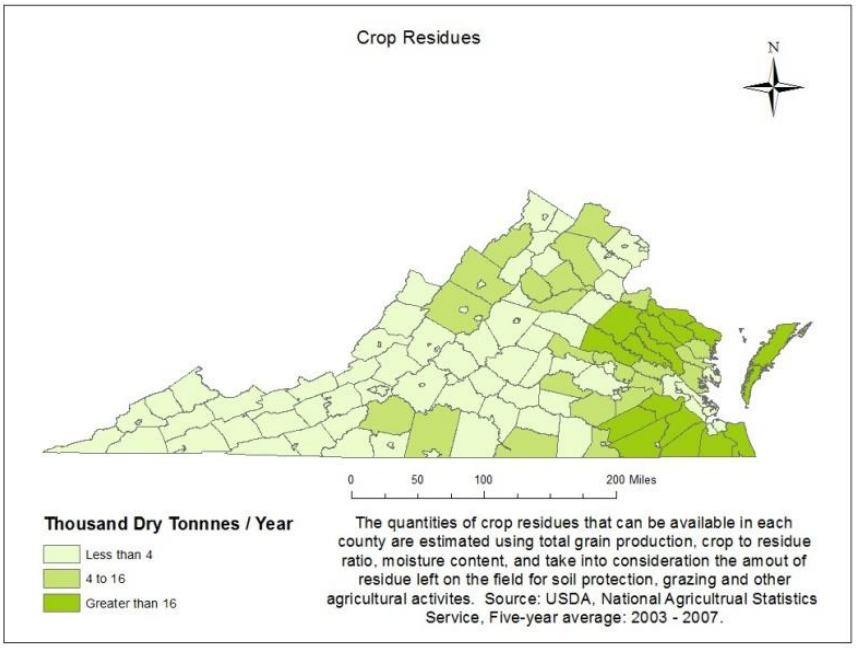


Agricultural Crop Residues

Crop residues comprise another sizable source of potential biomass fuels. Approximately 750 thousand dry tonnes of post-harvest residuals are generated annually from the production of barley, corn, oats, peanuts, sorghum, soybeans, and wheat (Figure 4-17). These residues include corn, peanut, sorghum, and soybean stover (leaves and stalks) and barley, oats, and wheat straw. Crop residues are typically used for grazing, animal bedding, and silage and, like forestry residuals, retention of crop residues on the land is important for soil health. Therefore, the NREL estimate assumes a 35% collection rate. In Virginia, the majority of these residuals would be available in the row crop agriculture regions of the Coastal Plain, Southern Piedmont, and the Shenandoah Valley.

[36] Source: Compilation of Virginia Biomass Resources from NREL Biomass Data, last updated 2012.

Figure 4-17. Crop Residues in Dry Tonnes per County in Virginia.[37]



Residual Biomass Inventory of the Commonwealth of Virginia

Researchers at Virginia Tech and the Virginia Cooperative Extension released an updated and expanded *Residual Biomass Inventory of the Commonwealth of Virginia,* in 2011. In addition the materials just discussed, their study also included animal manures, food residuals, biosolids and vegetative yard wastes with an estimated annual availability of over ten million bone dry tons of biomass residuals. The *Residual Biomass Inventory* [38] makes an important distinction between availability and recoverability. Not all the estimated biomass is economically or socially recoverable and these results should be seen as illustrative. Furthermore, materials that are readily recoverable may likely have an existing market. For example, there are at least 10 wood pellet mills operating in Virginia, producing over 1 million tons of wood pellets a year, mostly for the export market. Any project feasibility analysis should include both feedstock availability and an evaluation of competing market demand.

Energy Crops

In addition to the utilization of residuals, production of dedicated energy crops can increase the sustainable biomass energy supply and bring a revenue stream for landowners. The 2011 National Landcover Database[39] classified over four million acres of Virginia as hay and pasture-land, a million acres as croplands, six hundred-thousand acres as grasslands, and another seventy-thousand acres as barren land. Dedicated energy crops can also be grown on brownfields and minelands as part of remediation and

[37] Source: Compilation of Virginia Biomass Resources from NREL Biomass Data, last updated 2008.
[38] http://www.dmme.virginia.gov/DE/Biomass.shtml.
[39] Multi-Resolution Land Characteristics Consortium 2011 National Land Cover Database 2011. http://www.mrlc.gov/nlcd2011.php.

restoration efforts. Potential energy tree crops include hybrid willows and poplars that can be produced on rotations as short as four to six years. Other energy crops include the annual native warm season grasses, primarily switchgrass, and the exotic miscanthus.

In Southside Virginia, a nascent energy crop industry is developing in and around Nottoway County, led by the bioenergy pioneers at the Piedmont Geriatric Hospital (PGH). PGH, which has been heating with sawdust sourced from local mills for several decades, is switching to pelletized native warm season grasses, bringing considerable cost savings to the Commonwealth[40]. Grasses grown and harvested within 50 miles of Blackstone, Virginia are brought to a processing center located just outside of Fort Pickett where they are aggregated, ground, and pelletized for use as boiler fuel and animal bedding. New markets for energy crops, whether grasses or trees, can expand acres of perennial land cover. In areas of the Commonwealth within the Chesapeake Bay watershed, where local governments must develop strategies to meet total maximum daily load (TMDL)[41] targets, bioenergy production could synergize with their compliance efforts (through establishment of riparian buffers and conversion of row crops to permanent land cover as the most effective practices for improving water quality).

Wet Biomass

Since wetter material has a lower heating value when combusting, high moisture content biomass feedstocks are more appropriately suited for anaerobic digestion. Animal manures, the wet portion of municipal solid waste, and waste water treatment plant effluent can be anaerobically digested to produce a biogas that can be burned directly to generate heat or run through an internal combustion engine to generate electricity. Landfill gas projects are essentially large anaerobic digesters of municipal solid waste. In addition to generating energy from these underutilized waste streams, the physical containment and enclosures required to capture the biogas serve as an effective mechanism for odor control and can facilitate enhanced nutrient management and recovery.

Animal Manures

The United States Department of Agriculture's *2012 Census of Agriculture for Virginia*[42] lists 574 farms with over 50 head of dairy cows, four of them with over 1000 animals. The *Census* also lists 47 farms with more than 200 hogs or pigs, five of them with between 1000 and 2000 animals, 18 with between two and five thousand animals, and six with over five thousand. Anaerobic digestion technologies can convert carbon in liquid manures (such as manure from daily and hog production) into bio-gas. Digested manures have a reduced volume and odor, compared to raw manures, potentially expanding end-user markets; however, considering the capital costs associated with an anaerobic digestion installation, these projects tend to occur only on larger farms. To date, only one anaerobic digester has been installed on a dairy farm in Virginia.

Feedstocks for Liquid Fuels

Biofuels, a term which typically denotes liquid fuels, can be produced from many of the same biomass feedstocks, as discussed above. First-generation biofuels are produced with easily obtainable sugars and vegetable oils such as corn, sugar beets, sweet sorghum, and soybean. The use of food crops for biofuels production has been a source of contention highlighted by the "food vs fuel" debate. Advanced or second-generation biofuels are made from woody biomass, non-edible agriculture residues, or other waste biomass, avoiding the "food vs fuel" debate. While production of ethanol from cellulosic material is still in the

[40] A Cooperative Native Warm Season Grass Biofuel to Steam at Piedmont Geriatric Hospital. http://www.youtube.com/watch?v=AVMt9B6nz00.
[41] US Environmental Projection Agency, Total Maximum Daily Load Program. http://water.epa.gov/lawsregs/lawsguidance/cwa/tmdl/.
[42] USDA Census of Agriculture, 2014: 2012 Census Volume 1, Chapter 1: State Level Data (Virginia): http://www.agcensus.usda.gov/Publications/2012/Full_Report/Volume_1,_Chapter_1_State_Level/Virginia/.

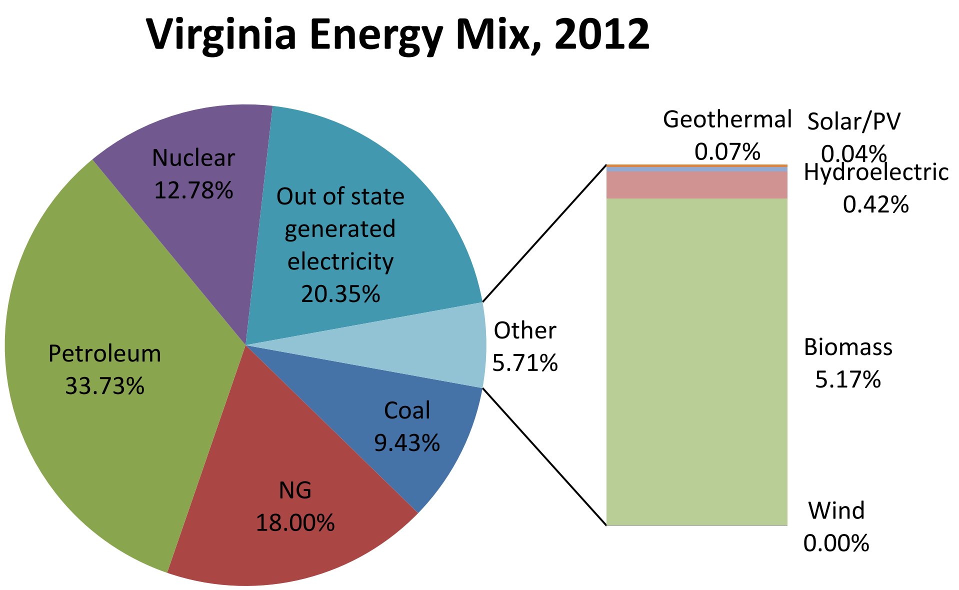
demonstration phase in Virginia, there are two commercial biodiesel producers in the Richmond area that collect and process used restaurant grease (yellow grease) for making biodiesel.

Biomass Utilization in Virginia

In 2012, the last year complete data was available, renewable energy supplied 5.7% of Virginia's overall energy mix (Figure 4-18). Biomass supplied 90% of the renewable component, contributing just over 5% to the Commonwealth's total energy supply. The biomass contribution to Virginia's renewable energy mix has remained relatively constant for over 20 years, supplying on average 89% of the renewable mix (Figure 4-19).

The 2012 figure for bioenergy consumption was 29%, in the form of liquid fuels for transportation, and 71% solid biomass was used for heat and/or power generation. By sector, as defined by the U.S. Energy Information Administration (EIA), 16% was consumed in the residential, 8% in the commercial, and 58% in the industrial sectors, while 18% was used in electric power generation. EIA's residential sector is principally private households, and the commercial sector includes institutional living quarters and public sector facilities such as government buildings and wastewater treatment plants. Energy consumption in the industrial sector is primarily used for process heating, cooling, and powering machinery. The electric power sector includes combined heat and power (CHP-- the generation and use of both thermal energy and power), where the thermal energy and/or electricity is sold to another party, in addition to stand alone generation.

Figure 4-18. Virginia Energy Mix, 2012.[43]



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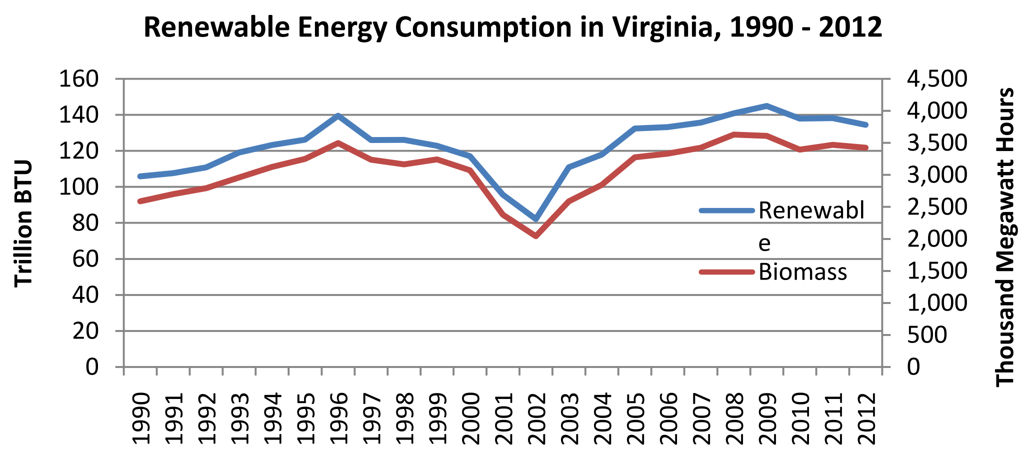
[43] **Source: EIA SEDS Virginia 1960 - 2012 Primary Energy Consumption Estimates: http://www.eia.gov/state/seds/seds-data-complete.cfm?sid=VA**

Applications of biomass energy include combustion of solid fuel (wood, waste wood, and other waste materials) for stand-alone electricity generation or combined heat and power; anaerobic digestion of animal manures and the organic component of industrial and municipal solid wastes; collection of landfill gas; and the production of liquid fuels. While electricity generation from woody biomass has seen large gains in recent years and utilization of municipal wastes (waste-to-energy, landfill gas, and waste water treatment plants) increased, installed generation is only about 16% of potential capacity.[44] Volatility in the prices of fuel oil and propane has renewed interest in the use of biomass as a heating fuel at the institutional and residential levels, as well. Fuel costs savings from conversion of these older systems to modern biomass heating systems suggest that growth in institutional solid fuel biomass thermal energy projects can now be expected in Virginia.

Figure 4-19. Renewable Energy Consumption in Virginia, 1990 – 2012.[45]



Utility-Scale Biomass Energy

At the utility-scale, stand-alone power generation with woody biomass can meet base load demand, providing constant, steady power to the grid. Dominion has been generating electricity with woody biomass at their 83-megawatt Pittsylvania Power Station in Hurt, Virginia since 1994. The Company has also received approval from the Virginia State Corporation Commission to convert three 63-megawatt coal-fired power stations at Altavista, Hopewell and Southampton to 51-megawatt woody biomass plants, one of which, Altavista, went online in 2013. Additionally, Dominion began co-firing woody biomass with coal at their new 600-megawatt Virginia City Hybrid Energy Center in 2012. The Hybrid Energy Center is designed to burn up to 20% woody biomass, generating 117 megawatts of biomass energy. Co-firing with woody biomass diversifies their fuel supply and reduces sulfur and nitrogen oxide emissions. The Northern Virginia

[44] EIA assumes that other than biofuels, all renewable energy is consumed at the time of production; production data is presented as the aggregate of renewable energy consumption. While EIA breaks out biofuels from other forms of biomass energy, at this time biofuels is strictly ethanol, and they do not provide separate estimates for biodiesel or wood pellets. The raw materials for the approximately one million tons of wood pellets exported annually from Virginia originate in Virginia forests. If used domestically, the exported wood pellets could displace between 200 and 700 MW of power and thermal energy currently generated with fossil fuels.
[45] Source: EIA SEDS Virginia 1960 - 2011 Primary Energy Consumption Estimates. http://www.eia.gov/state/seds/seds-data-complete.cfm?sid=VA.

Electric Cooperative's 49.9-megawatt Halifax County Biomass Plant also began commercial operations in 2013, utilizing forest residues harvested within 75 miles of their South Boston location.
The use of biomass for stand-alone power generation has become a source of contention, however. Overall efficiencies of stand-alone power generation are around 30% and the waste heat is by definition not utilized. Concerns have been raised about the "carbon debt" of biomass power generation and the recent release of the EPA's proposed Clean Power Plan to regulate carbon dioxide under section 111(d) of the Clean Air Act requires clarification on how biogenic (biomass) carbon emissions will be handled.

Combined Heat and Power

Combined heat and power (CHP) addresses some of these issues by utilizing the heat generated during combustion for other purposes, such as process or space heat. CHP facilities can achieve total systems efficiencies of 60 to 80 percent when producing both electricity and thermal energy. In 2012, there were five operational industrial-scale CHP facilities associated with pulp and paper mills, generating process heat for the plant and a combined 330-megawatts. In addition to solid wood waste, these mills utilize black liquor, (the by-product of the kraft pulping process), which contains more than half the energy content of the original wood. A promising new application in Combined Heat and Power is the incorporation of an Organic Rankine Cycle (ORC) which uses an organic, high molecular fluid with a lower boiling point than water to drive a turbine. One advantage of an ORC is that it permits work, (in this case, the turning of a turbine for electricity production), to take place at a lower temperature than in a classic steam-driven turbine system, and allows for generation using much smaller systems. Another advantage of an ORC is that a non-corrosive organic fluid can be used, extending the operational life of the machinery and reducing operation and maintenance costs for the facility.

Waste-to-Energy

Virginia also hosts several Waste-to-Energy (WTE) facilities. Combustion of municipal solid waste (MSW) at plants in Alexandria, Fairfax, and Portsmouth generates over 200-megawatts of electricity. The Wheelabrator plant in Portsmouth is also a co-generation facility, providing steam to the Norfolk Naval Shipyard, in addition to electricity.

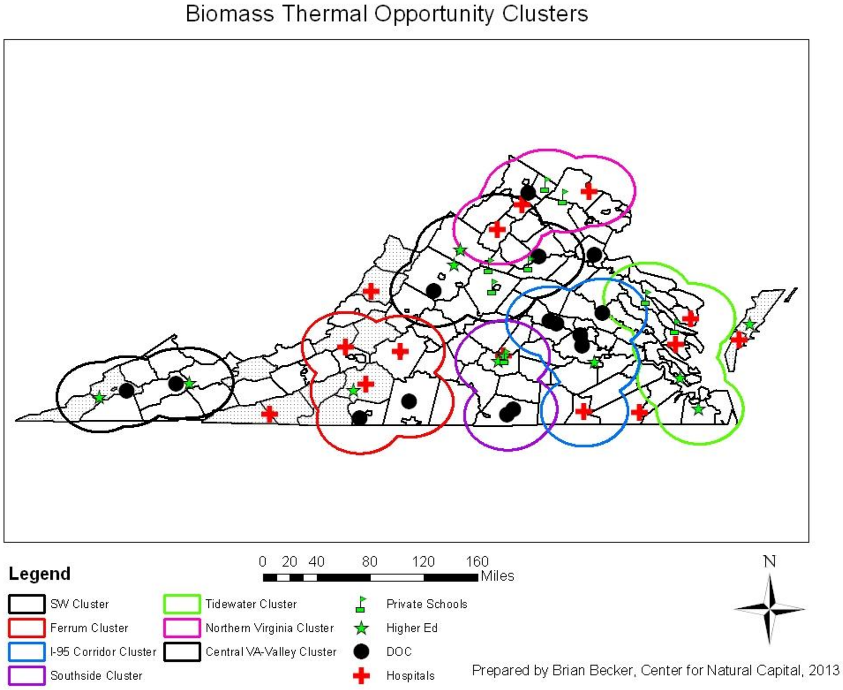
Thermal Biomass Energy

Direct thermal energy generation for hot water, hot air, and steam for space or process heat is still the most efficient application when combusting biomass. Longwood University and Piedmont Geriatric Hospital (PGH) have been producing heat and hot water with sawdust from local mills for decades. Recently, PGH embarked on switching over to locally-grown and processed warm season grasses, diversifying their fuel supply and catalyzing a nascent bioeconomy in Southside Virginia. In 2013, Ferrum College, located in Southwest Virginia, installed a biomass CHP system to produce hot water and to meet about a quarter of the electricity demand of the campus. Over 90 other locations throughout the Commonwealth have boilers fueled by wood, wood chips, or sawdust. Significant growth potential exists for expansion of intuitional-scaled thermal energy. A recent study of public institutions with active fuel oil or propane boilers in areas of Virginia without access to natural gas identified over 450 locations that include institutions of higher education, private schools, hospitals, correctional facilities and K-12 public schools (Figure 4-20).

Figure 4-20. Biomass Thermal Opportunity Clusters in the Commonwealth of Virginia.[46]

[46] Biomass Thermal Opportunity Clusters in the Commonwealth of Virginia. Center for Natural Capital, 2013. http://naturalcapital.us/2014/01/10/local-bioenergy-opportunities-phase-i-project-completed/.

Figure 4-20. Biomass Thermal Opportunity Clusters in the Commonwealth of Virginia.[47]



Anaerobic Digestion

Anaerobic digestion, the biological decomposition of organic materials in the absence of oxygen, finds applications across sectors, primarily as a waste management technology. To date, Virginia has seen few anaerobic digestion projects for the production, capture, and utilization of methane for energy. At the industrial level, the MillerCoors Shenandoah Brewery hosts an anaerobic digester, generating a little over a megawatt of electricity from brewing by-products, and in the agricultural sector there is only one dairy farm currently with an operational anaerobic digester. While low retail electricity prices make small projects economically challenging, throughout the Commonwealth there are close to 100 farms with 200 or more dairy cows and over 40 with 500 or more swine that potentially could be suitable for anaerobic digesters[48]. Benefits include odor, fly, and pathogen control and can be coupled with a nutrient management program for additional environmental benefits and financing opportunities.

Methane is also produced by organic matter decomposing under the anaerobic conditions found within landfills. Capturing and flaring the methane avoids the emission of a powerful greenhouse gas. The methane can also be run through an internal combustion engine to generate electricity. The EPA's Landfill Methane Outreach Program (LMOP) database [49] contains 20 active landfill projects in Virginia, generating over 100 megawatts of electricity, with 3 more projects under construction and another 42 candidate or potential locations identified. Another waste stream that can be anaerobically digested is sewage at wastewater treatment plants. The enclosures for creating the anaerobic condition and for capturing the methane are effective at odor control, and the collected gas can be used to offset plant operations or injected into natural gas (NG) pipelines after cleanup. The Water Resource Recovery Facility database of

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[47] Biomass Thermal Opportunity Clusters in the Commonwealth of Virginia. Center for Natural Capital, 2013. http://naturalcapital.us/2014/01/10/local-bioenergy-opportunities-phase-i-project-completed/.

[48] USDA Census of Agriculture 2012 Census, Virginia Livestock. http://www.agcensus.usda.gov/Publications/2012/. Last accessed June 30th, 2014.

[49] EPA's Landfill Methane Outreach Program (LMOP) Database: http://www.epa.gov/lmop/.

waste water treatment plants[50] contains seventeen Virginia entries where anaerobic digestion is incorporated into the water treatment regime.

Biofuels

Liquid fuels production from biomass feedstocks lags well behind total capacity. In 2013, 4.3 million gallons of biofuels (biodiesel and ethanol) were produced out of total production capacity of 17.5 million gallons[51]. There are two biodiesel producers collecting and processing restaurant (yellow) grease located in the Richmond area, an operation in Southside that produces biodiesel from locally-grown canola oil, and the Shenandoah Agricultural Products Farmer's Cooperative in the Shenandoah Valley that produces for their users[52].

On the ethanol side, the only commercial operation is the recent reopening of the former Appomattox Bio Energy plant by Vireol Bio-Energy, located in Hopewell, Virginia, which is expected to produce over 60 million gallons a year.[53] There are also currently two cellulosic demonstration projects operational in Virginia, 1) Fiberright has a MSW cellulosic demonstration plant in Lawrenceville, with 0.5 million gallon capacity,[54] and 2) a new effort under development in Callaway, in Southside Virginia, by BCLF (Biomass Cellulosic Liquid Fuels) Corporation to produce 0.37 million gallons of cellulosic ethanol a year from agriculture and wood residues.[55]

[50] Water Resource Recovery Facility, Biogas Data, 2013. http://www.wrrfdata.org/biogas/biogasdata.php.
[51] Virginia Alternate Fuels Report, 2014. http://www.vacleancities.org/wp-content/uploads/Alt-Fuels-Report-Q4-2013-Final.pdf.
[52] Virginia Biodiesel Plant Listings. http://www.biodiesel.org/production/plants.
[53] Vireol Bio Energy Joins Growth Energy, http://www.growthenergy.org/news-media/press-releases/vireol-bio-energy-joins-growth-energy/.
[54] U.S. Ethanol Plants, 2014. http://www.ethanolproducer.com/plants/listplants/US/All/All/page:1/sort:state/direction:asc.
[55] Personal Communications, Charles Bowman, BCLF Corporation, June 30th, 2014.

SECTION 5 - NUCLEAR POWER

Nuclear Generation in Virginia

- These two nuclear plants provided 38 percent of the net electricity generated in Virginia during 2013. [1]
- Two units are located at the North Anna Power Station in Louisa County and two are There are four nuclear units in operation in Virginia. All four unites are operated by located at the Surry Power Station in Surry County.
  - Dominion owns an 88.4 percent share of the North Anna station. The Old Dominion Electric Cooperative (ODEC) owns the remaining 11.6 percent share.
  - Dominion owns 100 percent of the Surry Station.
  - Generally, the Nuclear Regulatory Commission (NRC) issues licenses for reactors to operate for up to 40 years. The NRC extended both Surry's and North Anna's operating licenses in 2003 for an additional 20 years (60 years total).[2] Both plants have the potential for extending their operating license another 20 years for a total of 80 years.
  - North Anna generates 1,892 megawatts from its two units — enough electricity to power 450,000 homes[3]. Surry Power Station generates 1,676 megawatts of electric power from its two nuclear reactors — enough electricity to power 420,000 homes[4].
- North Anna employs 960 employees and Surry currently employs 965 employees at an average salary (exclusive of benefits Dominion at its two Virginia nuclear power plants of more than $80,000 per year.

Table 5-1: Virginia Nuclear Generating Units – Startup Date[5]

Unit Name	Year	End of Operating License Term
Surry Unit 1	1972	2032
Surry Unit 2	1973	2033
North Anna Unit 1	1978	2038
North Anna Unit 2	1980	2040

  - Dominion has made operating and capital improvements to the plants that have reduced down time for refueling and repairs increased plant efficiency, and improved uprates that have increased their generating capacity, in excess of 150

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[1] Energy Information Administration, Virginia State Profile and Energy Estimates: Quick Facts.
[2] National Regulatory Commission, Nuclear Reactors, License Renewal, Overview.
[3] Dominion North Anna Power Station, https://www.dom.com/about/stations/nuclear/north-anna/
[4] Dominion Surry Power Station, https://www.dom.com/about/stations/nuclear/surry/
[5] http://www.eia.doe.gov

megawatts[6]. Operating capacity for the four units in Virginia in 2013 ranged from 77.7 to 96.9 percent with an average of 90.1 percent[7]. Nuclear power is considered baseload power, meaning it is designed to run around the clock.

- In addition to its nuclear generation plants at Surry and North Anna, Virginia hosts a number of nuclear powered naval vessels, including aircraft carriers, other surface vessels, and attack and ballistic missile submarines.
- Electricity Production costs of nuclear power plants are the lowest of any baseload power source with nuclear at 2.40 cents/kW-hr, coal at 3.27 cents/kW-hr, natural gas at 3.40 cents/kW-hr, and petroleum at 22.48 cents/kW-hr.[8]
- Nuclear power has no carbon emissions and no other air emissions.

Used Nuclear Fuel Management

- According to the Nuclear Waste Policy Act of 1982, amended in 1987, the U.S. Department of Energy (US DOE) is obligated to take used nuclear fuel from the North Anna and Surry sites.
- The Nuclear Waste Fund, created by fees paid by US nuclear power plants since 1983 and with more than $35 billion to date, is the mechanism that was used to finance the design, licensing, construction and management of a suitable repository at the Yucca Mountain site in Nevada.
- On June 2008, the US DOE completed the Yucca Mountain repository license application, and submitted it to the NRC for their review. On March 2010, the US DOE withdrew the license application and created the Blue Ribbon Commission for America's Nuclear Future (BRC) to evaluate potential paths forward for the long term management of used nuclear fuel. On September 2011 the NRC stopped the review of the Yucca Mountain license application[9], a decision that was reversed in August 2013 by the US Court of Appeals for the DC Circuit[10]. The BRC issued its final report on January 2012[11]. The US DOE review of the BRC recommendations resulted in a January 2013 report[12] that details the steps of a new program that will be implemented over the next 10 years. This plan culminates with the availability of a geologic repository for the long-term storage of used nuclear fuel by 2048.
- A US Court of Appeals has ruled that the US DOE must stop collecting nuclear waste fees from utilities until it decides how used nuclear fuel is to be managed**[13]**.
    - Used nuclear fuel is currently stored at the North Anna and Surry sites in the spent fuel pools and in dry storage casks and will continue to be stored at North Anna and Surry until the U.S. Government is able to fulfill its obligation to the U.S. nuclear industry.

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[6] 150 megawatts is reflective of summer net performance
[7] http://www.eia.doe.gov
[8] http://www.nei.org/Knowledge-Center/Nuclear-Statistics/Costs-Fuel,-Operation,-Waste-Disposal-Life-Cycle/US-Electricity-Production-Costs
[9] http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/fs-yucca-license-review.html
[10] http://www.world-nuclear-news.org/WR-US_court_rules_on_Yucca_Mountain-1408137.html
[11] http://cybercemetery.unt.edu/archive/brc/20120620211605/http:/brc.gov//
[12] http://energy.gov/sites/prod/files/Strategy%20for%20the%20Management%20and%20Disposal%20of%20Used%20Nuclear%20Fuel%20and%20High%20Level%20Radioactive%20Waste.pdf
[13] http://www.world-nuclear-news.org/WR-Court-orders-halt-to-nuclear-waste-fees-2011134.html

Nuclear Plant Siting and Construction

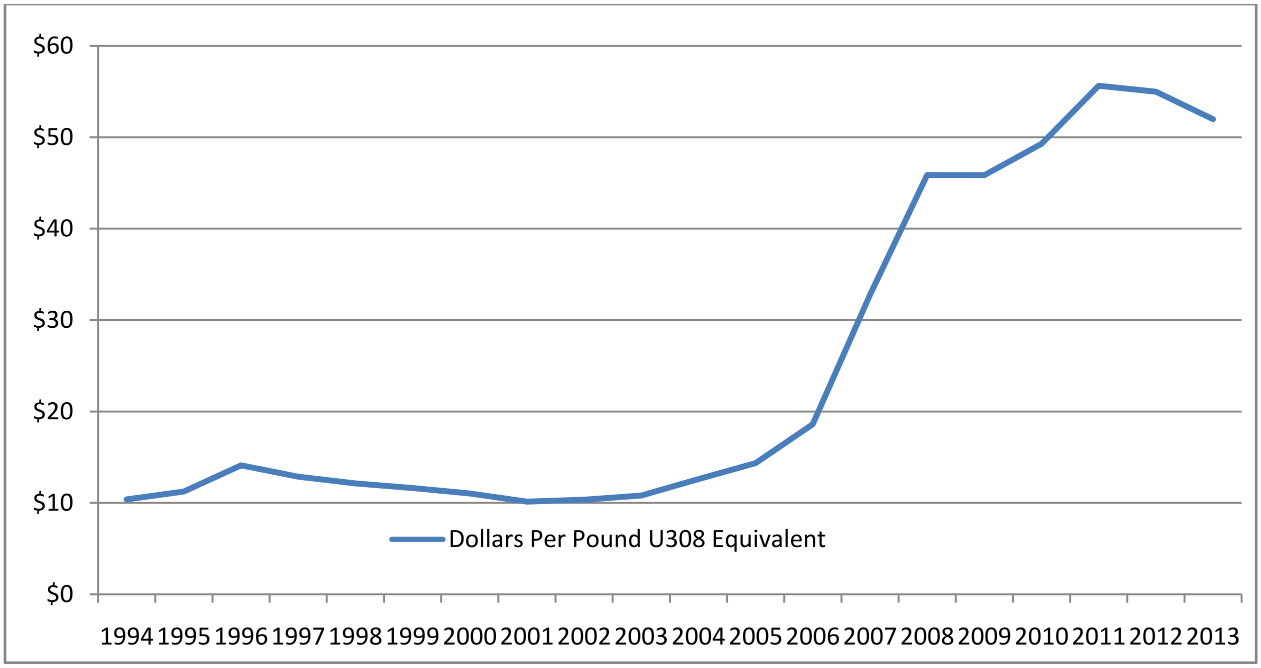
- Nuclear power plant siting is largely regulated through the licensing process of the Nuclear Regulatory Commission (NRC). Licensing requirements have been streamlined since plants were licensed in the 1960s and 1970s. Nuclear utilities now can receive an early site permit followed by a combined construction-operating permit.
- Dominion has received its early site permit for the proposed third North Anna unit.
- Dominion's combined construction-operating permit application is pending before the NRC.
- Nuclear plant permitting and construction can take up to 8-10 years.
- Time and budget experience with new plant construction overseas has been mixed.
- Shared risk between utilities and project design and construction firms supports financing new nuclear projects.
- State and federal incentives, including providing a higher rate of return under Virginia law for utility investments in new nuclear power plants and federal loan guarantees, may help mitigate the financial risk.
- U.S. nuclear reactor manufacturing capability is growing to meet national and international demand. New facilities include the Westinghouse-Chicago Bridge and Iron plant in Lake Charles, Louisiana.
- Nuclear plants are major construction projects, involving thousands of construction workers. North Anna 3 would be one of the largest construction projects in Virginia history.

Nuclear Fuel Costs

- The average purchase price of uranium oxide was consistently below $20/pound until the mid 2000s. Since then the average purchase price has increased to just above $50/pound but is expected to return to a lower price level, as shown in Figure 5-1. The current spot market for uranium oxide is at $29/pound.

Figure 5-1: Weighted-average price of uranium purchased by owners and operators of U.S. civilian nuclear power reactors, 1994-2013 dollars per pound U308 equivalent[14]

[14] http://www.eia.doe.gov



- The current market for nuclear fuel (i.e. prices for new contracts) is under downward price pressure and is expected to stay this way for the near-term.
  - Changes in spot nuclear fuel cost have a limited impact on the cost of nuclear generated electricity. Nuclear fuel is generally purchased through long-term contracts and amortized over multiple years. In addition, fuel costs are a smaller percentage of total nuclear power cost than with other technologies (approximately 30 percent versus 78 percent and 89 percent for coal and gas, respectively).[15]

Uranium Mining

- Currently, over 90 percent of uranium used in commercial nuclear reactors in the United States is imported.[16]

A uranium oxide resource has been identified in Pittsylvania County in the southern region of Virginia. The resource is estimated to contain 119 million pounds of uranium oxide (at a 0.025 percent uranium oxide cutoff).

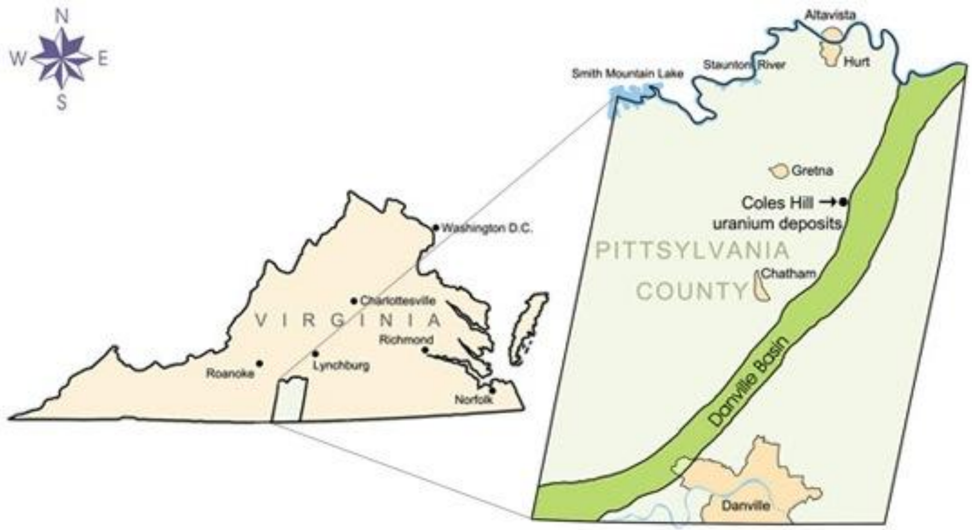
Since 1983, Virginia has had a moratorium on uranium mining in place. It is expected that the moratorium will remain in place for the foreseeable future.

A number of studies have been conducted and published related to uranium mining in Virginia. These include:

[15] http://www.world-nuclear.org/info/Economic-Aspects/Economics-of-Nuclear-Power/
[16] http://www.eia.doe.gov

- The National Academy of Sciences study, commissioned by the Virginia Coal and Energy Commission
- Chmura Economics and Analytics Socioeconomic Study, commissioned by the Virginia Coal and Energy Commission
- RTI Socioeconomic Study, commissioned by the Danville Regional Foundation
- Michael Baker Corporation Study, commissioned by the City of Virginia Beach
- Michael-Moran Associates, LLC study, commissioned by the Roanoke River Basin Association
- Hazen and Sawyer/Tetra Tech study, commissioned by Fairfax Water.

Figure 5-2: Map of Coles Hill Uranium Deposit

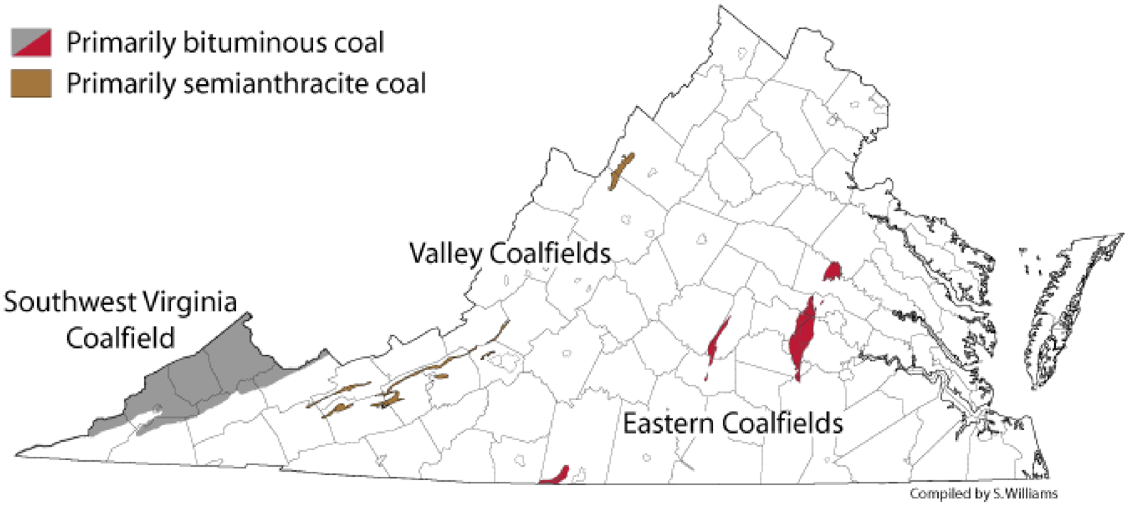


SECTION 6 - COAL

Coal Mining in Virginia

- The first commercial production of coal in the United States occurred in 1748 from the Richmond coalfield located in the Richmond Basin of Virginia (Fig.6-1). The last major mines in this area closed in 1927.
- Coal was also commercially produced off and on from the Valley Coalfield from the 1850's until 1954.
- Today, coal is mined in the Southwest Virginia Coalfield which began shipping coal commercially in 1882. Since the 1950's, virtually all of Virginia's coal production has come from the Southwest Virginia Coalfield. This coalfield is part of the extensive Appalachian Coal Basin, which extends from Pennsylvania to Alabama.

Figure 6-1: Virginia's Coalfields[1]



- Fifty-one Virginia mining companies produced 17 million tons of coal in 2013, ranking the state 14th in production nationwide. Two companies produced nearly eight million tons, accounting for 45 percent of 2013 production, as noted in the table below.

[1] DMME, http://www.dmme.virginia.gov/dgmr/coal.shtml

Table 6-1: Virginia's Two Largest Coal Producing Companies

CONSOL Energy	4,800,000 tons
Paramont Coal Company Virginia, LLC	3,258,138 tons

- Production decreased in Virginia from 30 million tons in 2002 to 19 million tons in 2012. Virginia coal production peaked at 46.6 million tons in 1990. The gradual decline is the result of the depletion of the more productive (thick) and easily mined coal seams that have lower mining costs[2].

Figure 6-2: Virginia Coal Production, 1960–2012[3]

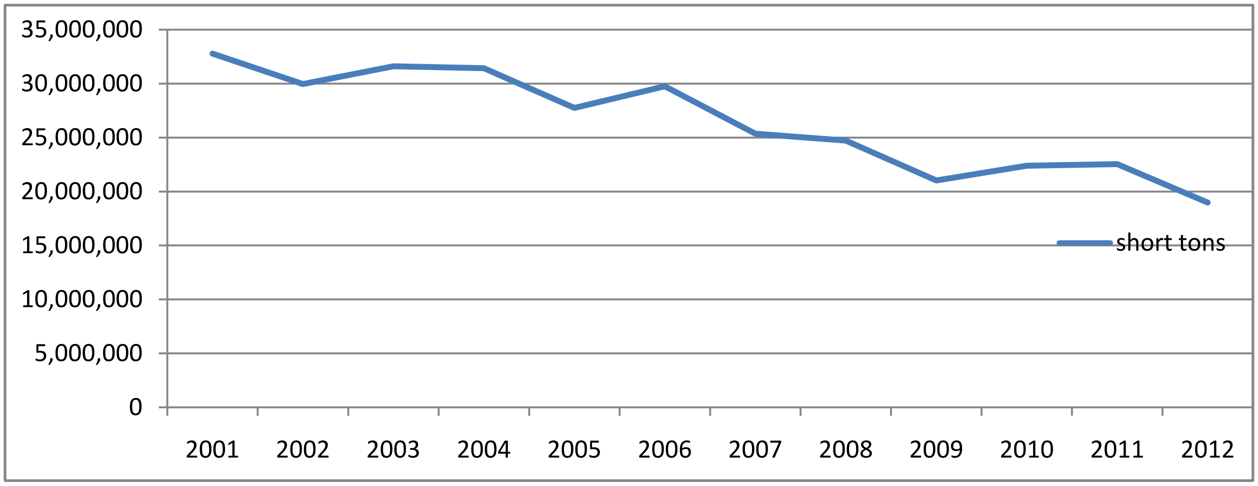


Table 6-2: Virginia Coal Mining Employment[4]

Year	Number of Producing Mines	Number of Coal Miners At Producing Mines
2003	156	4,411
2008	143	4,394
2012	112	4,641
2013	89	4,864

2 http://www.energy.vt.edu/vept/coal/
3 Virginia Department of Mines, Minerals and Energy
4 Virginia Department of Mines, Minerals and Energy

- Virginia's coal industry directly employed 4,864 people in 2013, up from 4,411 in 2003.
- While the number of producing mines has decreased as more productive and easily obtained coal reserves have been depleted, the number of miners has increased by approximately 10 percent.

- Virginia produces the majority of its coal from underground mines.[5]
  - In 2012, 61 percent of coal mined in Virginia came from underground mines.
  - The percentage of surface mined coal has increased in recent years, from 16 percent in 1990, to 25 percent in 1998, and to 39 percent in 2012.[6]
  - The percentage of coal mined from surface sites is expected to decrease over the next 10 years as the larger areas of surface reserves are mined out.
  - Virginia accounted for 4.5 percent of U.S. coal production east of the Mississippi River in 2012.[7]
- There has been a trend towards consolidation of coal ownership.
  - The top five companies produce more than 50 percent of the coal mined in the United States in 2010. Of those companies, listed in Table 6-3, Arch Coal Inc., Alpha Natural Resources LLC, and CONSOL Energy Inc. operate coal mines in Virginia.

Table 6-3: Top 5 Coal Producers in the United States, 2012[8]

Rank	Controlling Company Name	Production (thousand short tons)	Percent of Total Production
1	Peabody Energy Corporation	192,563	18.9
2	Arch Coal Inc.	136,992	13.5
3	Alpha Natural Resources LLC	104,306	10.3
4	Cloud Peak Energy	90,721	8.9
5	CONSOL Energy Inc.	35,406	5.5

- In Virginia, production is predominately (70 percent of mining operations) from small operations (36 employees on average) mining remnant or finite reserves using the room and pillar mining method. Most of these smaller operators contract for larger companies.
- Coal mining companies pay severance taxes of 2 percent of the value of the coal extracted to the county where the mine is located, as well as personal property and other local taxes.

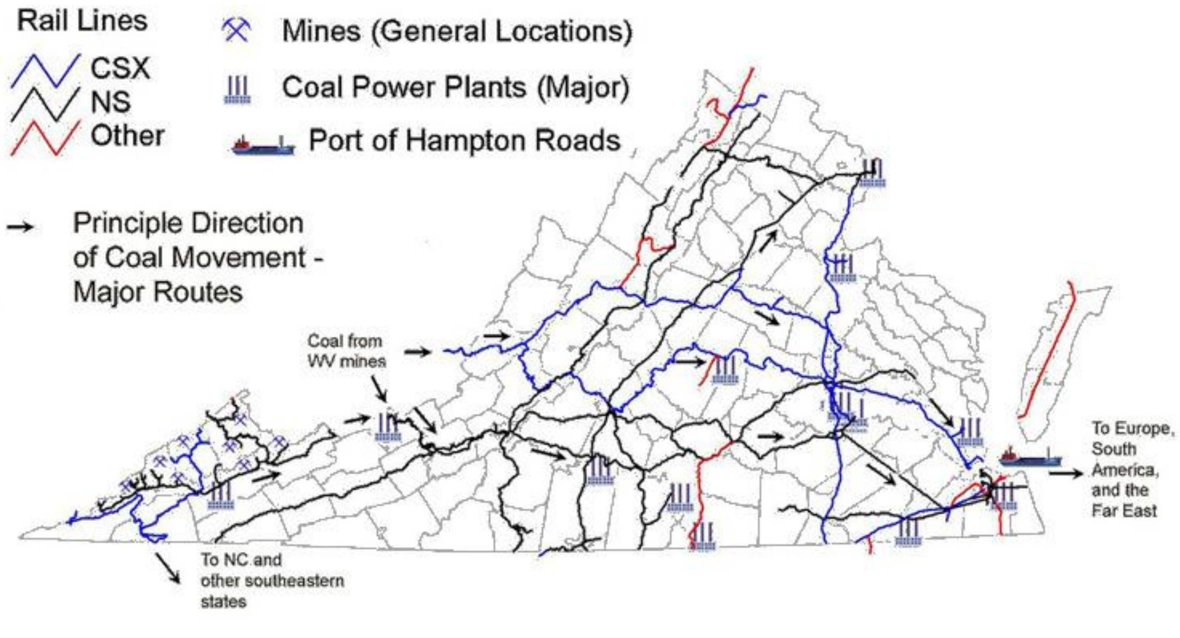
[5] http://www.eia.doe.gov
[6] EIA Annual Coal Report – November 2014: http://www.eia.gov/coal/annual/
[7] http://www.eia.gov/state/?sid=VA
[8] http://www.eia.doe.gov

- Percentage of local government revenue derived from mineral taxes in the coal producing counties: [9]
  - Buchanan: 52%
  - Dickenson: 41%
  - Lee: 2%
  - Russell: 13%
  - Tazewell: 62%
  - Wise: 21%*

Infrastructure

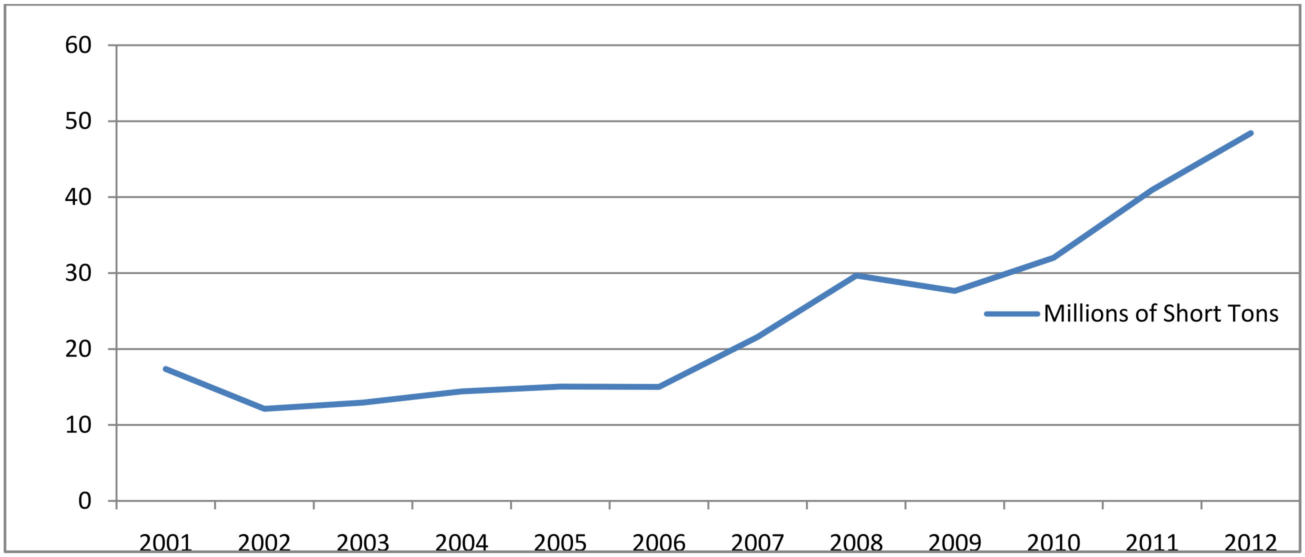
- Most Virginia coal is shipped from mines to preparation plants and rail load outs by truck, then to market and ports by rail.
- On a tonnage basis, coal accounts for more than two-thirds of all Virginia rail freight traffic. Coal is shipped from the Southwest Virginia coalfield via Norfolk-Southern and CSX railroads via each company's primary coal corridor lines.
- Virginia coal is exported from terminals in the Port of Hampton Roads to Europe, South America, and the Far East.
  - The port, America's largest coal export facility, serves as an export point for Virginia coal and processed over 38 percent of U.S. coal exports in 2012.
  - The markets for this coal include electric generators located close to East Coast shipping lanes and overseas electric utilities and steel manufacturers.

Figure 6-3: Map of Coal Transportation Network[10]



[9] Virginia Auditor of Public Accounts, Comparative Report of Local Revenue, June 30, 2011 *Wise County reflects June 30, 2010 report as most recent available.
[10] Virginia Energy Patterns and Trends (VEPT), Virginia Coal Transportation, http://www.energy.vt.edu/vept/coal/virginiacoal.asp, June 28, 2010

Figure 6-4: Coal Shipments from Norfolk, 2001–2012[11]

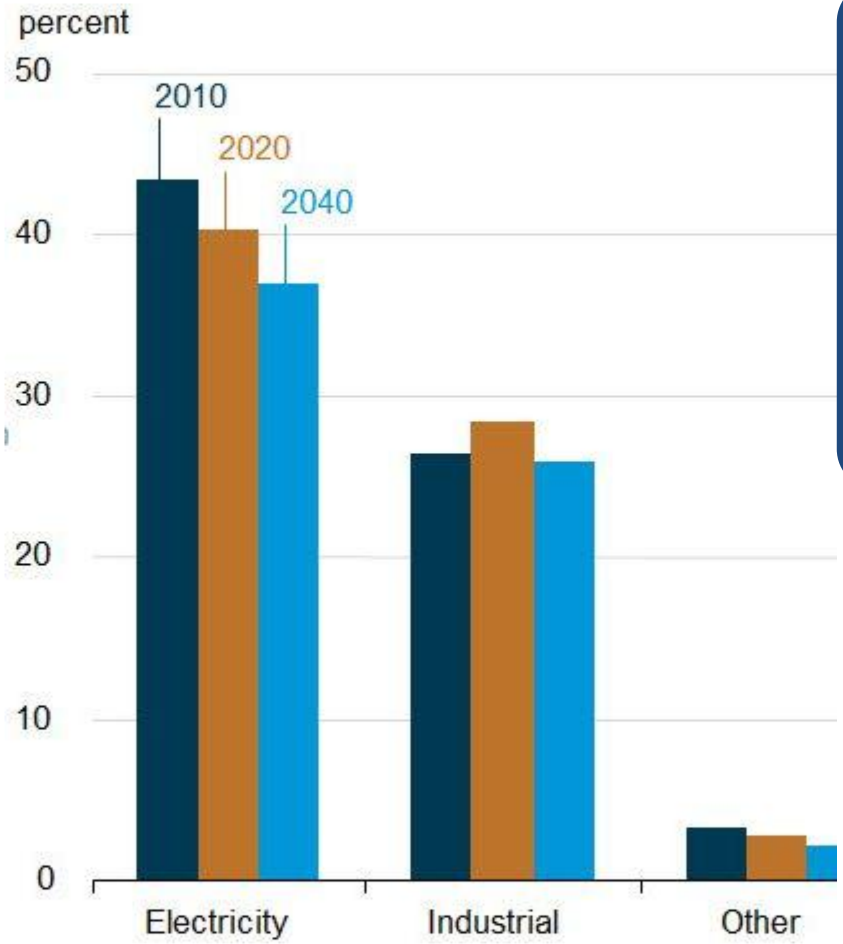


Global Coal Market

- In 2010, 7.5 percent of coal produced in the US was exported and 2 percent of the coal consumed in the U.S. was imported. [12]
- In 2007, coal accounted for 27 percent of world energy consumption.
- Of the coal produced worldwide in 2007, 64 percent was shipped to electricity producers.[13]

[11] Virginia Energy Patterns and Trends: Coal Shipments from the Port of Hampton Roads, www.energy.vt.edu/vept/coal/basins.asp
[12] http://www.eia.doe.gov
[13] http://www.eia.doe.gov

Figure 6-5: Coal share of world energy consumption by sector, 2010, 2020, and 2040



In a typical year, 25-30 percent of Virginia coal is sold domestically in Virginia and to other states for manufacturing steel or making industrial steam.

- Given the noticeable decline in estimated reserves, the large reserves-to-production ratio for world coal indicates there is sufficient coal to meet demands well into the future. Additionally, those estimates could increase substantially as coal mining technology improves and as additional geological assessments of the coal resource are completed.[14]
- World coal reserves, although historically stable, have declined gradually from 1,145 billion tons in 1991 to 1,083 billion tons in 2000 and 909 billion tons in 2008.
- World coal reserves are estimated at 909 billion tons, which equates to a reserves-to-production ratio of 129 years.
- In 2007, China accounted for nearly 42 percent of world coal production, compared to the United States at 18 percent. Other major leading coal producing countries include Australia, India, Africa, and Russia, which combined to produce 22 percent of the world's coal.[15]

[14] International Energy Outlook 2010, http://www.eia.gov/oiaf/ieo/coal.html, June 27, 2011.
[15] http://www.eia.doe.gov

Coal Markets – Other Uses

- In a typical year, 25-30 percent of Virginia coal is sold domestically in Virginia and to other states for manufacturing steel or making industrial steam.
- A small amount is sold domestically for institutional, commercial, and residential heating.

- Virginia coal operators also sell coal in the European and Asian markets for steel manufacturing or electric generation.
  - Overseas tonnage varies greatly from year to year, depending on the competitiveness of Virginia coal as compared to Australian, Chinese, South African, Polish, and South American coal.

Coal Prices

- Coal is priced separately in the steam and metallurgical coal markets.[16] Steam coal is generally lower in cost.
- Coal prices fluctuate over a considerable range as the international and domestic coal markets fluctuate due to changes in economic activity and demand for electricity and steel. The average sales price for coal Virginia coal in 2010 was $98.46 per short ton compared to a U.S. average price of $35.61. The average reflects steam and metallurgical coal prices.

Table 6-4: Steam Coal Prices – Average Delivered Price ($/short ton)[17]

Year	Electric Utility Plants	Other Industrial Plants
2000	$24.28	$31.46
2001	$24.68	$32.26
2002	$24.24	$35.49
2003	$25.82	$34.70
2004	$27.36	$39.30
2005	$31.22	$47.63
2006	$34.26	$51.67
2007	$36.06	$54.42
2008	$41.32	$63.44
2009	$44.47	$64.87
2010	$45.09	$64.24

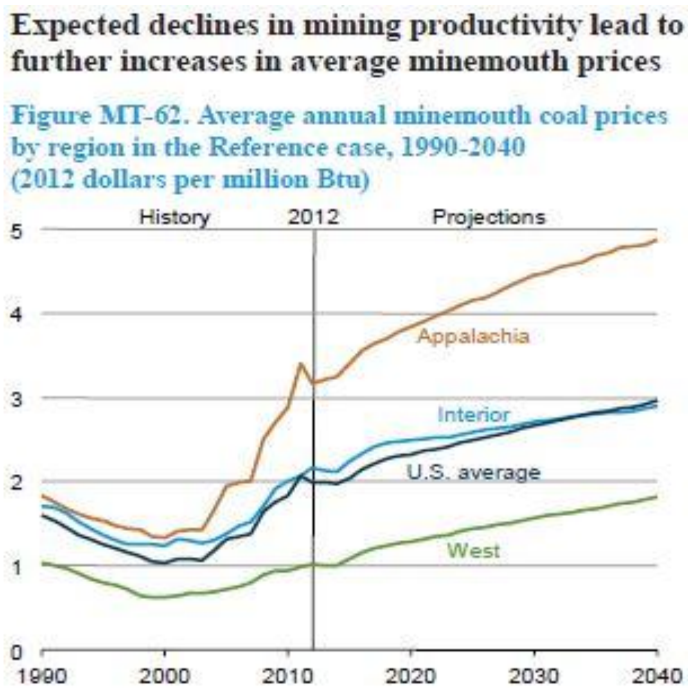
- The federal Energy Information Administration (EIA) estimates that average mine mouth prices[18] for Appalachian steam coal, after peaking in 2009, will decline by 0.5 percent

[16] Metallurgical coal is used for making steel and generally has a higher energy value, lower ash, and higher volatility than steam coal.
[17] http://www.eia.doe.gov
[18] Minemouth price is the price paid by a purchaser at the mine, without added transportation costs.

per year through 2035. The decline will be a result of falling demand for the region's coal and a shift to lower cost production in the northern part of the Appalachian basin.

- Metallurgical coal prices are projected to remain volatile based on international demand for steel.

Figure 6-6: EIA Coal Price Forecast.[19]

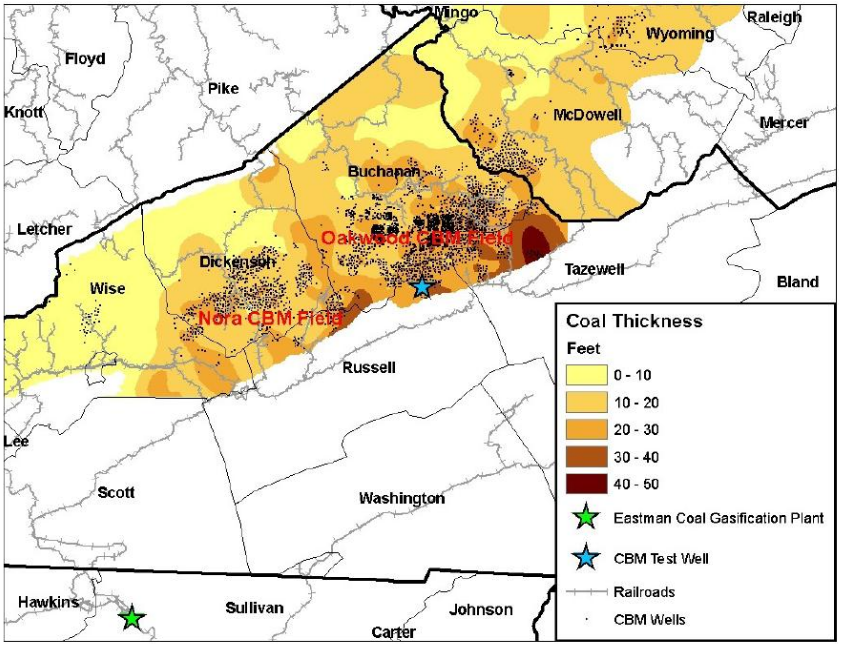


Future Use of Coal

The Virginia Center for Coal and Energy Research led a team under the Southeastern Carbon Sequestration Partnership (SECARB) that tested key concepts of carbon capture and storage, including characterization of unmineable coal seams for carbon sequestration and testing sequestration technology in Russell County.

[19] http://www.eia.doe.gov

Figure 6-7: Location of Carbon Sequestration Test Well in Russell County, Virginia[20]



[20] Southeast Carbon Sequestration Partnership, Central Appalachian Coal Seam Project Fact Sheet, http://www.energy.vt.edu/secarb/index.asp, June 23, 2010

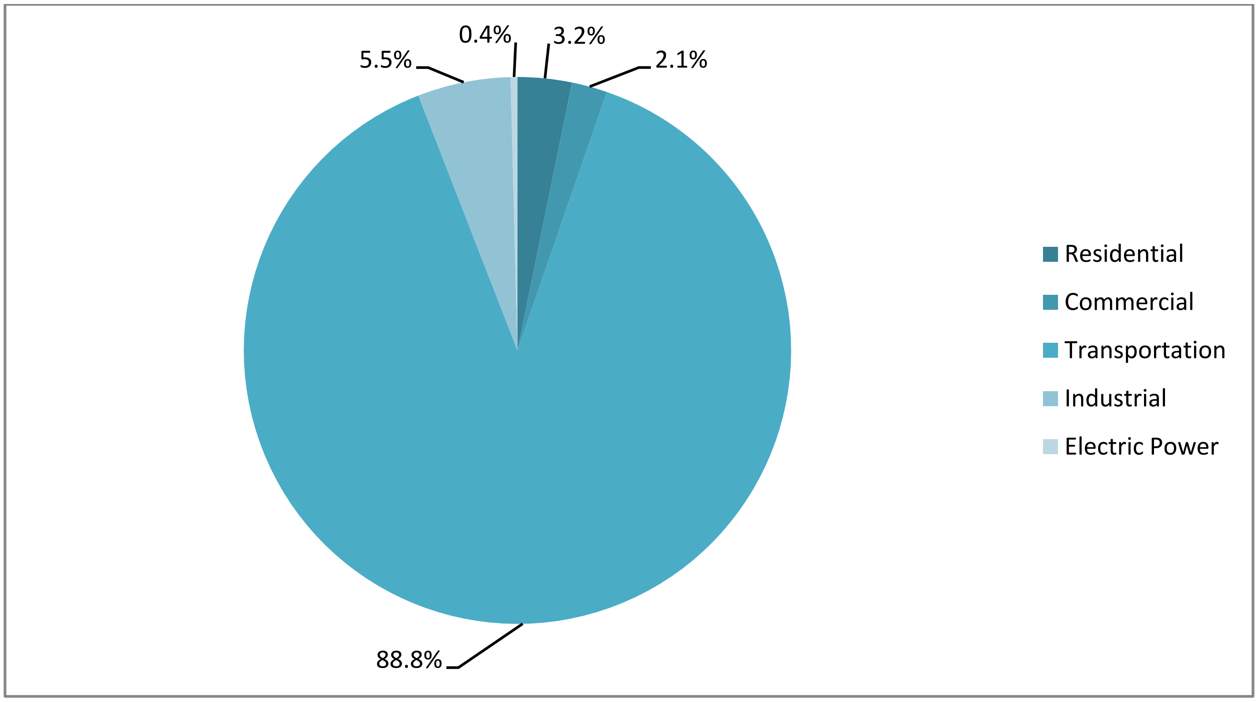
SECTION 7 - PETROLEUM

Petroleum is a broadly defined class of liquid hydrocarbon mixtures which includes crude oil, lease condensate, unfinished oils, refined products from the processing of crude oil, and natural gas plant liquids.

Petroleum Consumption

- Approximately 92.9 million barrels of motor gasoline, including ethanol blends, were used in 2012, which comprised 60.9 percent of the total petroleum usage for the year. Heating oil was the second largest use - approximately 34.3 million barrels or 21 percent of the total. Smaller amounts were used for aviation (16.9 million barrels or 11 percent) and residual fuel oil (1.9 million barrels or 1.3 percent), while propane accounted for the remainder of just over 3 percent or 4.8 million barrels

Figure 7-1: Petroleum Consumption in Virginia, 2012[1]



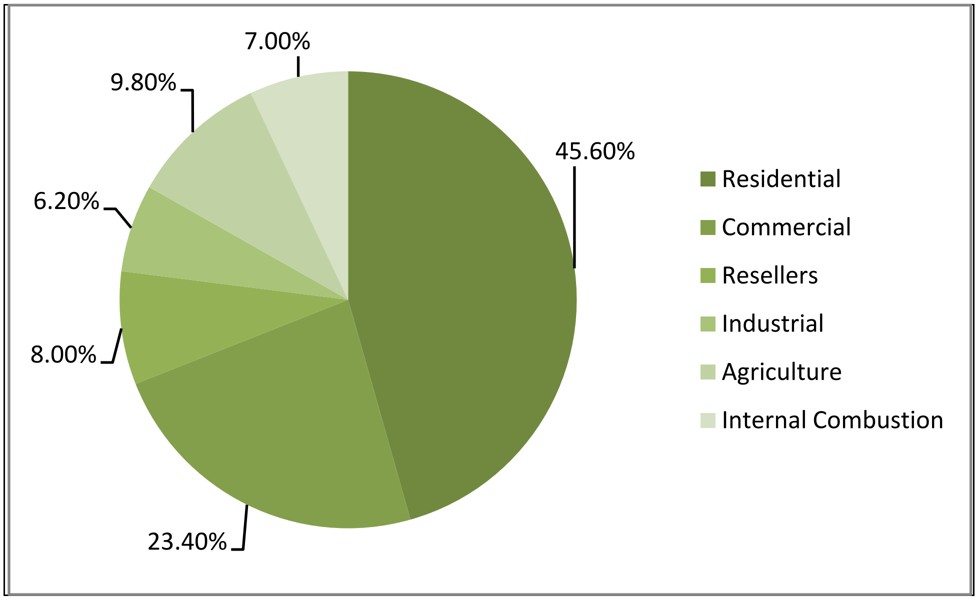
- Petroleum use in Virginia grew on average one percent per year from 1989 through 1998. Use has been stable since 1999 as vehicle miles traveled stabilized and the oldest, less fuel efficient vehicles were replaced by consumers

Petroleum is a broadly defined class of liquid hydrocarbon mixtures which includes crude oil, lease condensate, unfinished oils, refined products from the

[1] EIA, SEDS, www.eia.gov/state/seds/hf.jsp?incfile=sep_sum/plain_html/sum_use_tot.html, July 27, 2011.

- Propane is a normally gaseous straight-chain hydrocarbon and is a colorless gas that is extracted from natural gas or refinery gas streams

Figure 7-2: Propane Consumption Virginia, 2012[2]

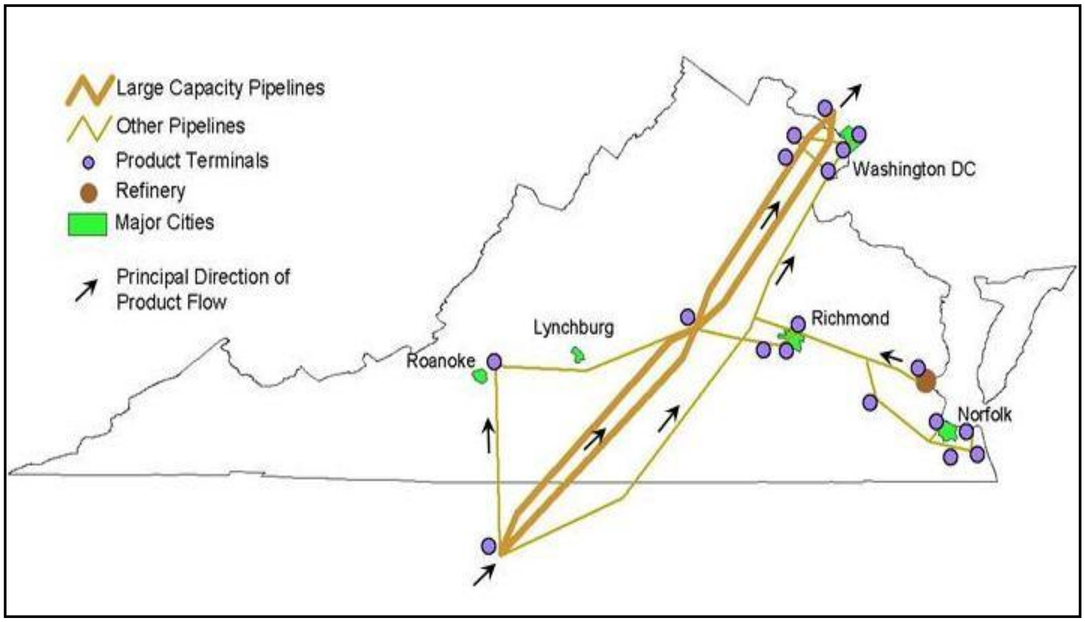


Petroleum Product Infrastructure

- Petroleum is supplied to Virginia through a network of refineries, pipelines, port facilities, terminals, and retail outlets
  - Finished petroleum products are shipped to petroleum terminals across Virginia in various ways:
    - The Colonial and Plantation underground pipelines deliver product from refineries in the Gulf of Mexico region to distribution terminals in Fairfax, Richmond, Montvale/Roanoke, and Chesapeake
    - Tankers and barges deliver product to coastal petroleum distribution terminals in Chesapeake and Richmond
  - Virginia consumers are also regularly supplied from out-of-state petroleum terminals in Baltimore, MD; Greensboro, NC; and Knoxville, TN.

[2] Propane Council, Propane Database and Forecasting Model, v.7.2

Figure 7-3: Major Petroleum Pipelines and Terminals in Virginia[3]

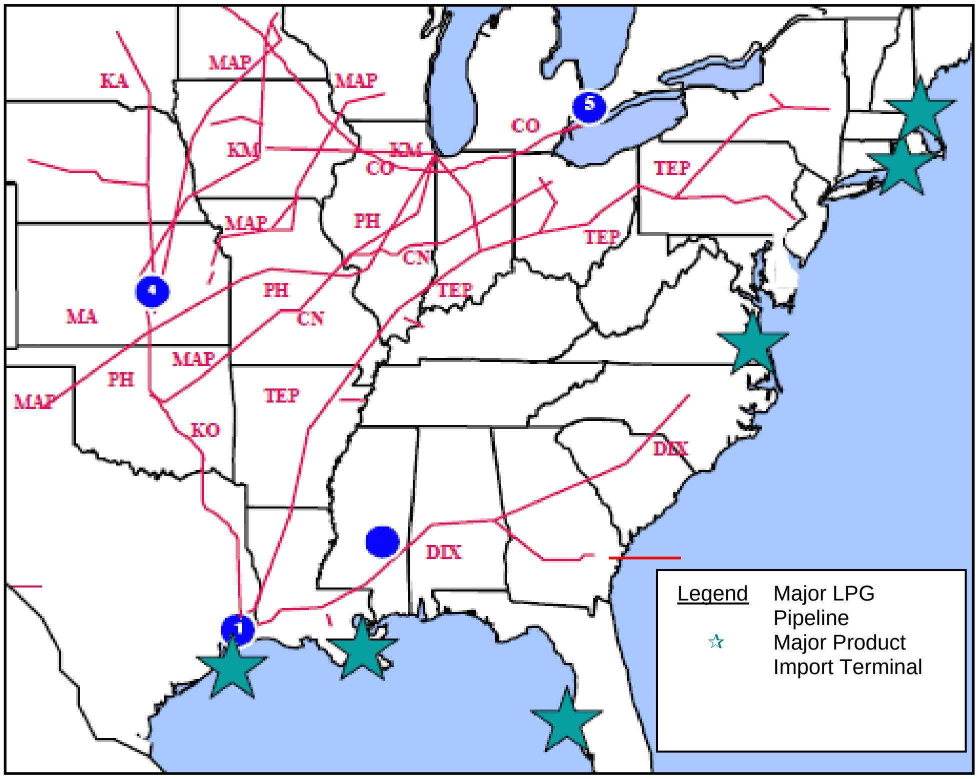


- Petroleum distributors, also called jobbers, purchase gasoline, diesel, heating oil, and other products from central terminals and truck them directly to large users, gas stations, and other retailers. Most jobbers also store gasoline, diesel, fuel oil, kerosene, lubricants, and other petroleum products in smaller storage facilities located in nearly every locality across Virginia

- The petroleum product supply chain has limited ability to respond to delivery disruptions such as from storms, pipeline problems, or panic buying runs. On average, there is a larger volume of empty capacity in vehicle gas tanks than there is in the entire fuel delivery system which results in shortages when motorist try to top off gas tanks in a perceived emergency
- The majority of Virginia's propane gas is supplied by the interstate propane pipeline terminating in Apex, North Carolina, and the water-based terminal in Chesapeake
- Propane is trucked from the North Carolina and Chesapeake terminals to bulk plants, and then distributed to end users

[3]Virginia Energy Patterns and Trends: Major Petroleum Product Pipelines, www.energy.vt.edu/vept/petroleum/oil_pipeline.asp The Yorktown refinery featured on this map is currently not operational.

Figure 7-4: Propane Pipelines and Major Terminals[4]



Petroleum Prices

- Petroleum price and availability are affected more by national and international policies and events than from in-state factors. These include
    - Political instability in oil producing countries
    - Drops in productivity in some oil producing regions
    - Effects of weather such as Gulf of Mexico hurricanes
    - Growth in demand in international markets such as China, India, Central America, and the Middle East
- Gasoline prices have been volatile over time, increasing to $4.04 in June 2008 and dropping to $2.51/gallon 15 months later in September 2009[5]
- Gasoline prices trended higher from year to year until 2009 when they declined. In 2010 and 2011, prices averaged $2.86 and $3.83/gallon, respectively. Seasonal adjustments combined with unplanned hikes due to severe weather events and unrest in the Middle East combine to create a volatile market with often sharp spikes in pricing

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[4] Harry Hunter Hanger, Jr., Atlantic Energy Import Terminal, Presentation to the Pennsylvania Public Utility Commission Winter Meeting, November 9, 2006

[5] EIA, Petroleum Navigator, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mg_tt_1c&f=m, June 29, 2010

Table 7-1: Gasoline Prices, 1993-2011[6]

Year	Average Retail Gasoline – Price per Gallon (Including Federal and State Gasoline Taxes)
2000	$1.52
2001	$1.46
2002	$1.39
2003	$1.60
2004	$1.90
2005	$2.31
2006	$2.62
2007	$2.84
2008	$3.30
2009	$2.41
2010	$2.84
2011	$3.58
2012	$3.68
2013	$3.58

- The Energy Information Administration (EIA) predicts that petroleum prices will rise over the next ten years,[7] with annual refined petroleum prices paid for a product or service at the time of the transaction to increase from $2.69/gallon (including taxes) in 2010 to $4.12/gallon by 2020

- Petroleum product prices are also affected by changes in delivered input costs
  - Crude oil prices were about $68/barrel in 2007, accounting for 58 percent of the $2.80/gallon regular grade gasoline price; $100/barrel in 2008, accounting for 69 percent of the $3.25/gallon price; $62/barrel in 2009, accounting for 61 percent of the $2.34/gallon price; $79.40/ barrel in 2010 and $101.91/barrel in 2011 accounting for a 28.8 percent increase in consumer price over the previous years[8]

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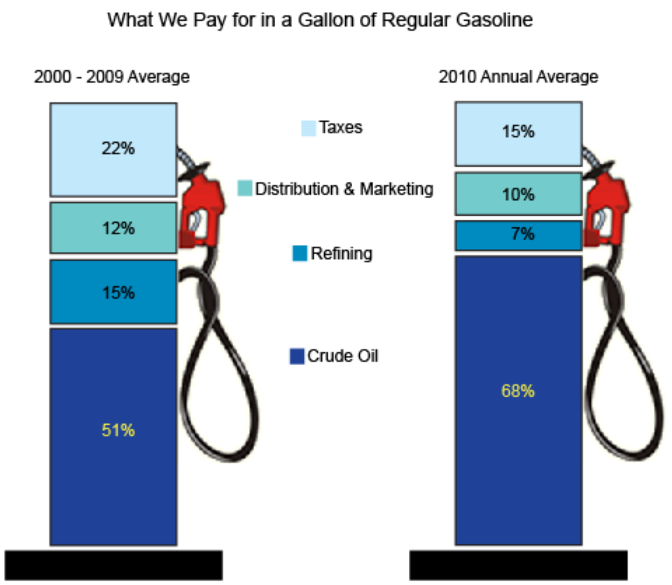
[6] EIA, Petroleum Navigator http://www.eia.gov/forecasts/steo/,
[7] EIA, Gasoline Prices by Formulation, Virginia, Sales to End Users, Average Through Retail Outlets, http://www.eia.doe.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=d100613512&f=m, June 1, 2010
[8] EIA, A Primer on Gasoline Prices, http://www.eia.doe.gov/bookshelf/brochures/gasolinepricesprimer/index.html, July 18, 2014

Figure 7-5



Source: U.S. Energy Information Administration

- Propane prices (residential) have been less prone to dramatic increases than petroleum prices, ranging from $3.09/gallon in October 2008, $2.27 in October 2009, and $2.12/gallon in 2010. Annual prices are projected to increase to $3.17 in 2020

Table 7-2: US Residential Propane Price[9]

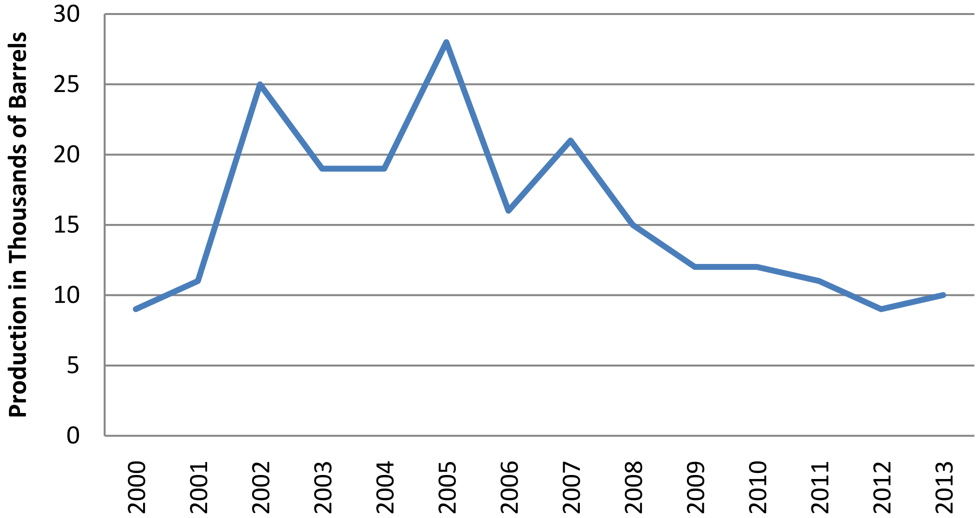
Year	Residential Price
2009	$2.22
2010	$2.48
2011	$2.68
2012	$2.47
2013	$2.41

Petroleum Production

- Virginia's oil and gas operators produced 11,508 barrels of oil in 2010 from wells located in Lee, Wise, and Russell Counties, equivalent to less than one percent of the state's annual consumption. This production is typically shipped to refineries in Kentucky for processing.

[9] EIA, East Coast (PADD1) Propane Residential Price, http://tonto.eia.doe.gov/dnav/pet/hist_xls/MPRREP14m.xls, June 23, 2010

Figure 7-6: Petroleum Production in Virginia, 1980–2010[10]



Offshore Oil

- There is an estimated 4.72 billion barrels of technically recoverable oil and 37.51 trillion cubic feet of technically recoverable natural gas in federal waters in the Atlantic Outer Continental Shelf[11]
    - The ultimate value of these reserves will depend on the actual amount of recoverable resources and the cost of oil
- Offshore oil production would support infrastructure expansion in Hampton Roads, attracting new business and creating jobs in the supply chain and for exploration and production
- Developing offshore oil resources is dependent on an extensive federal lease sale and permitting process

[10] Data from the Department of Mines, Minerals and Energy's Division of Gas and Oil
[11] http://www.boem.gov/Assessment-of-Oil-and-Gas-Resources-2014-Update/

SECTION 8 – ENERGY INFRASTRUCTURE

EXISTING AND IMPROVING ENERGY INFRASTRUCTURE

Introduction

As illustrated in previous Sections of the Energy Plan, a dynamic and diverse infrastructure is needed to provide Virginia's businesses and residents with the energy they need. The existing infrastructure includes:

- Electricity generation, transmission and distribution
- Coal mining, transportation and export
- Nuclear power, spent fuel storage and training
- Natural gas production, transmission and storage
- Renewables, including wood/biomass production and transportation, solar, geothermal, hydroelectric, landfill gas capture and wind
- Petroleum and propane production, refining, transportation and distribution
- Alternative Fuels and Advanced Vehicle Technology

Other sections of the Energy Plan have detailed individual energy sources and their production, generation, distribution, demand and future trends. Some of that information is summarized here to reiterate the importance of maintaining and growing the infrastructure in order to continue to provide affordable energy to Virginians.

Electricity

With the numerous energy sources and vast infrastructure in Virginia, the utilities do not own in-state generation capacity sufficient to meet their territories' peak loads plus the reserves required by the Federal Energy Regulatory Commission.

- In 2010, 35.9 percent of the electricity consumed was purchased on the wholesale market pursuant to existing contracts[1].

- Up to 45 percent of Virginia's electric supply comes from power generated out of state. Most imports come from coal-fired plants located west and north of Virginia. A small amount of imports come from renewable projects such as wind projects in West Virginia, Illinois, and Indiana. According to the State Corporation Commission (SCC), however, between 85 and 90 percent of the total supply of electricity to Virginia's Investor Owned Utilities is produced from facilities owned by the utilities that serve Virginia and are under SCC rate setting jurisdiction.

- All three of Virginia's investor-owned utilities own out-of-state generation facilities dedicated to serving their Virginia customers.

[1] EIA. State Electric Profiles, Virginia, http://www.eia.doe.gov/cneaf/electricity/st_profiles/virginia.html

Transmission and Distribution of Electricity

Within the electric system, transmission lines carry bulk power from power stations to substations. Dominion Virginia Power, Appalachian Power, Delmarva Power, and Allegheny Power own and maintain transmission and distribution facilities in Virginia. The Virginia State Corporation Commission (SCC) must certify the need for and approve the location of proposed new electric transmission lines. Substations "step-down" voltages from the very high voltages used in the bulk power system to lower voltages needed to serve retail customers. Distribution lines carry power from substations to individual homes and businesses. These lines include main lines and smaller "tap" lines. Since the early 1990s most neighborhood tap lines have been placed underground as a matter of course to improve reliability. In 2014, the Virginia General Assembly approved legislation that allows utilities to place up to 20 percent of the worst performing neighborhood lines underground, in order to reduce the frequency and duration of electricity outages in neighborhoods served by overhead distribution lines.

Transmission is regulated by the Federal Energy Regulatory Commission, pursuant to federal law. FERC, together with the Regional Transmission Organizations, in Virginia the RTO is PJM, review and approve proposed new transmission projects and set rates of recovery for those projected developments.

PJM Interconnection

PJM is an independent service operator (ISO); as such it has been designated by the FERC as a regional transmission organization that manages the interstate high voltage electric delivery system, as well as coordinating and creating a forward pricing market for electric power within its region.

PJM works closely with other ISOs, such as the Midwest, New York, and New England ISOs to provide enhanced reliability for the electricity transmission system in the entire Mid-Atlantic and northeastern United States. PJM also sets market rules related to the purchase of wholesale power, and has emergency management protocols and capacity retention tools.

PJM is charged with the responsibility of assuring the reliability of the transmission grid in its territory. PJM publishes annually a Regional Transmission Expansion Plan (RTEP) to identify the need for new transmission resources.[2] The RTEP process involves a 15 year planning window to address transmission investments to ensure grid reliability and improve economic efficiency. PJM continues to assess the ongoing reliability of transmission facilities throughout the Commonwealth.

Virginia Electric Utility Companies

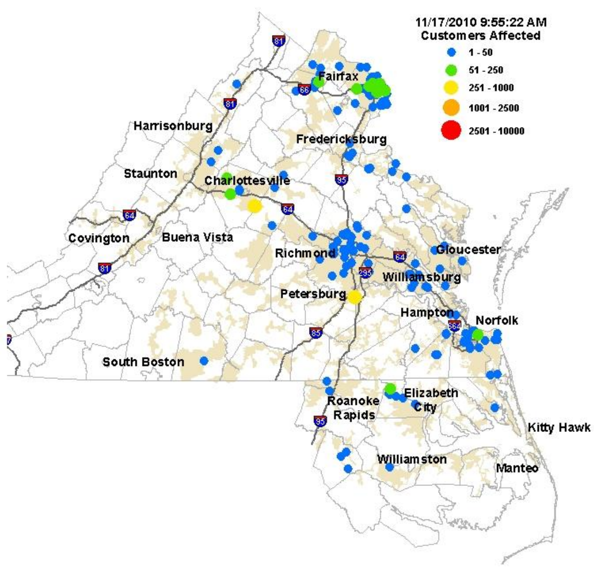
Three regulated investor-owned electric power companies serve Virginia: Dominion Virginia Power, Appalachian Power, and Kentucky Utilities/Old Dominion Power.

[2] PJM Fact Sheet, http://www.pjm.com/documents/~/media/about-pjm/newsroom/fact-sheets/rtep-fact-sheet.ashx.

Dominion Virginia Power
Dominion Virginia Power is the largest electricity provider in the Commonwealth. The parent company operates in several states where it sells both electricity and natural gas, and owns extensive critical energy assets. System-wide, these assets include 5,000 miles of electricity transmission lines; 12,000 miles of natural gas transmission, storage, and gathering pipelines; and 925 Billion cubic feet (Bcf) of natural gas storage capacity. Within Virginia, the company serves 2.4 million electricity customers, principally in the eastern half of the State: 42 percent residential, 34 percent commercial, 11 percent governmental, and 8 percent industrial. Figure 8-1 shows a typical weather-related outage map that encompasses Dominion's service territory in the Commonwealth.

The map also includes the company's service area in North Carolina.

Figure 8-1. Dominion Virginia Power Service Territory

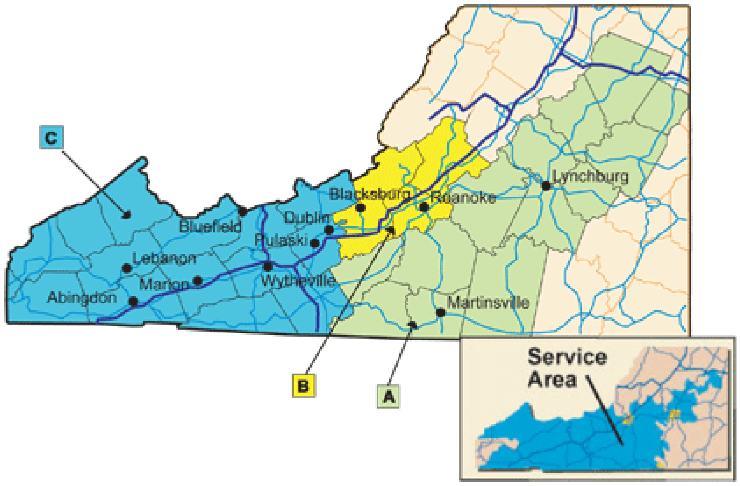


Source: Dominion, https://www.dom.com/storm-center/dominion-electric-outage-map.jsp.

Dominion Virginia Power has 29 electric power generating plants representing 61 percent of total generation capacity within Virginia. Two of the generating plants are nuclear plants, eleven burn coal, ten burn natural gas, five burn oil, and one is pumped storage hydroelectric.

American Electric Power
AEP is a large, multi-State electric power generator that owns the nation's largest electricity transmission system. Appalachian Power, a subsidiary of AEP, serves about one million customers in its three-state operating area that includes Virginia, West Virginia, and Tennessee. The utility owns nearly seven percent of Virginia's total generation capacity and over 2,000 miles of electric transmission lines. The company serves Virginia customers west of a line that runs approximately from Lynchburg to Martinsville. Figure 8-2 depicts the service territory and the location of external affairs offices in Virginia.

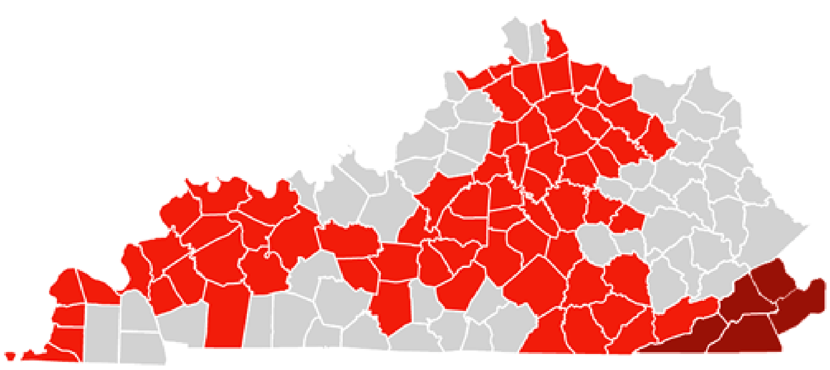
Figure 8-2. Appalachian Power Territory and External Affairs Offices



Source: Appalachian Power, External Affairs, https://www.appalachianpower.com/account/bills/rates/RatesAndTariffs.aspx.

Kentucky Utilities
Kentucky Utilities, headquartered in Lexington, Kentucky, is known in Virginia as Old Dominion Power. In 2010, Kentucky Utilities was acquired by PPL Corporation of Allentown, Pennsylvania. It has a total generation capacity of 4,570 MW. All four of its generating plants are located in Kentucky: Ghent in Carroll County, Tyrone in Woodford County, E.W. Brown in Mercer County, and Green River in Muhlenberg County. Kentucky Utilities serves five counties and 29,000 customers in the southwestern tip of Virginia. Figure 8-3 depicts the utility's entire service area, which is mostly in Kentucky; the darker-shaded region on the lower right side of the map includes the southwestern tip of Virginia served by Old Dominion Power.

Figure 8-3. Kentucky/Old Dominion Service Territory



Source: LGE/KU Service Territories, http:// www.lge-ku.com/service_territory.asp.

Cooperative Utilities
The SCC regulates 13 distribution electric cooperatives; all are members of the Virginia/Maryland/District Association of Electric Cooperatives (VMDAEC), an association of 16 member cooperatives in Virginia, Maryland and Delaware. The Virginia cooperatives serve over 600,000 retail customers. The Virginia cooperatives are listed here with URL linkage:

A&N Electric Cooperative
B-A-R-C Electric Cooperative
Central Virginia Electric Cooperative
Community Electric Cooperative
Craig-Botetourt Electric Cooperative
Mecklenburg Electric Cooperative
Northern Neck Electric Cooperative
Northern Virginia Electric Cooperative
Prince George Electric Cooperative
Rappahannock Electric Cooperative
Shenandoah Valley Electric Cooperative
Southside Electric Cooperative
Powell Valley Electric Cooperative

The VMDAEC assists the Commonwealth and member cooperatives with mitigation of electricity problems and restoration of service. In addition to monitoring federal and State policy issues, the Association has training programs that help workers at member cooperatives maintain and upgrade their professional skills and the members ensure compliance with applicable federal and state safety regulations.

Old Dominion Electric Cooperative
Old Dominion Electric Cooperative (ODEC), headquartered in Glen Allen, Virginia, is a generation and transmission cooperative that serves wholesale and retail electricity customers in Virginia, Delaware, Maryland and North Carolina. The nine Virginia member cooperatives are A&N, BARC, Community, Mecklenburg, Northern Neck, Prince George, Rappahannock, Shenandoah, and Southside.

ODEC generates power from five power plants in Virginia and Maryland. ODEC has purchased undivided shares in:

- North Anna Nuclear Plant, Louisa County – 11.6 percent of 1,800 MW
- Clover Power Station (coal-fired), Halifax County – 50 percent of 850 MW
- Three combustion turbine peaking plants:
  - Marsh Run Station, near Remington in Fauquier County
  - Louisa Power Station, near Gordonsville, Virginia
  - Rock Springs in Cecil County, Maryland

In 2010, ODEC acquired interests in hydro, landfill gas and wind power facilities. In addition, ODEC owns transmission lines and delivers electricity via power lines that Dominion Virginia Power, Appalachian Power and Delmarva Power operate in Delaware, and Allegheny Power Company operates in Maryland, respectively. Four other Virginia cooperatives purchase power via bilateral contracts with various providers, such as IOUs or non-utility generators.

Municipal Utilities
There are 16 municipal electric utilities serving approximately 161,000 retail customers Virginia customers. The Municipal Electric Power Association of Virginia (MEPAV) represents them. MEPAV's president, vice president, and three other individuals constitute an executive committee. MEPAV does not have a separate office or executive director; however, MEPAV retains a legislative consultant who monitors electricity policy matters on behalf of the membership. When the need arises, MEPAV can be contacted through the Virginia Municipal League or by contacting any of the member municipalities for the contact information.

The members of MEPAV are:

- City of Bedford
- Town of Blackstone
- City of Bristol
- Town of Culpeper
- City of Danville
- Town of Elkton
- City of Franklin
- Town of Front Royal
- Harrisonburg Electric Commission
- City of Manassas
- City of Martinsville
- City of Radford
- Town of Richlands
- City of Salem
- Virginia Polytechnic Institute & State University
- Town of Wakefield

Coal Mining, Transportation, and Exports
Coal is one of the top three sources used to generate electricity, along with nuclear and natural gas, and accounts for about 20 percent of Virginia's total energy generation. Virginia supplied 25 percent of the coal while the rest came from Kentucky and West Virginia based on availability and cost.

Virginia’s mining companies produce nearly 4.5 percent of U.S. coal east of the Mississippi River from underground and surface mines in Southwest Virginia. It is mined in the Southwest Virginia Coalfield, part of the Appalachian Coal Basin which extends from Pennsylvania to Alabama, where to this day almost all of Virginia’s coal is produced. In 2013 there were 51 Virginia mining companies which produced 17 million tons of coal. Of the 51 companies, 2 produced 8 million tons (45 percent of the 2013 production).

While Virginia is 14th in the nation in terms of coal production, over the past 10 years production has begun to decrease. The easily mined coal seams have been depleted and the number of producing mines has decreased by 10 percent making it more challenging to continue to produce at the same level. The majority of the coal comes from underground mines.

Coal is transported by rail throughout Virginia and beyond. On a tonnage basis, coal accounts for more than two-thirds of all Virginia rail freight traffic. Coal is shipped from the Southwest Virginia Coalfield via Norfolk-Southern and CSX railroads via each company’s primary coal corridor lines.

Not all of the coal produced in Virginia is used to produce energy in the state. Much of the coal that is produced in the state is sold in the European and Asian markets for steel and manufacturing or electric generation. In a typical year, 25-30 percent of the coal is sold domestically for manufacturing steel or making industrial steam. Only a small amount is sold for institutional, commercial and residential heating.

Nuclear Power

Dominion operates four nuclear units at its two Virginia nuclear power plants. In 2012, these plants provided 36.4 percent of the electricity generated in Virginia. All of the plants were started in the 1970s and 1980s and currently have operating licenses which extend to 2030-2040. Operating capacity for the four reactors in Virginia in 2013 ranged from 77.7 to 96.9 percent with an average of 90.1 percent[3].

Two units are located at the North Anna Power Station in Louisa County and two are located at the Surry Power Station in Surry County.

- Dominion owns an 88.4 percent share of the North Anna station. The Old Dominion Electric Cooperative owns the remaining 11.6 percent share.
- Dominion owns 100 percent of the Surry Station.
- The Nuclear Regulatory Commission (NRC) extended both Surry’s and North Anna’s operating licenses in 2003. Generally, the NRC issues licenses for reactors to operate for up to 40 years. These licenses can be renewed for up to an additional 20 years, which is the case for both North Anna and Surry.[4]
- Surry currently employs 965 employees and North Anna employs 960 employees at an average salary (exclusive of benefits) of more than $80,000 per year.

[3] Energy Information Administration, Sources & Uses, Total Energy, Monthly Energy Review, Nuclear Energy, Table 8.1 Nuclear Energy Overview.

[4] National Regulatory Commission, Nuclear Reactors, License Renewal, Overview.

In addition to its nuclear generation plants at Surry and North Anna, Virginia hosts a number of nuclear powered naval vessels, including aircraft carriers, other surface vessels, and attack and ballistic missile submarines.

Dominion has made operating and capital improvements to the plants that have reduced down time for refueling and repairs and increased plant efficiency as well as upgrades that have increased their generating capacity.

Spent Fuel Management
Nuclear fuel is currently stored on the North Anna and Surry sites in spent fuel pools and dry storage casks. Dominion customers have been paying a fee of one-tenth of one cent/kilowatt hour ($.001/kWh) generated by nuclear power plants into the federal Nuclear Waste Fund to finance a permanent spent nuclear fuel storage facility.

Nuclear Plant Siting and Construction
Nuclear power plant siting is largely regulated through the licensing process of the Nuclear Regulatory Commission (NRC). Licensing requirements have been streamlined since plants were licensed in the 1960s and 1970s. Nuclear utilities now can receive an early site permit followed by a combined construction-operating permit.

Dominion has received its early site permit for the proposed third North Anna unit and the combined construction-operating permit application is pending before the NRC. Nuclear plant permitting and construction can take up to 8-10 years. Nuclear plants are major construction projects, involving thousands of construction workers. North Anna 3 would be one of the largest construction projects in Virginia history.

Uranium Mining
Currently, more than 90 percent of uranium used in commercial nuclear reactors in the United States is imported.[5] Virginia has a uranium oxide resource in Pittsylvania County, estimated at 119 million pounds (at 0.025 percent uranium oxide cutoff). There is currently a moratorium on uranium mining in Virginia, with no change expected.

Nuclear Industry Workforce Development
Construction of the North Anna 3 plant would provide thousands of construction jobs in addition to the growing reactor manufacturing in Newport News. US customer needs are met by Mitsubishi Nuclear Energy Systems (MNES) headquarters based in Arlington, VA, which supports existing power plants, as well as new facilities, through the introduction of the US Advanced Pressurized Water Reactor technology.

Virginia is a leader in design, construction, and maintenance of nuclear power plants through AREVA, B&W, Dominion, and Northrop Grumman.

- AREVA, B&W, and Northrop Grumman have an ongoing need for nuclear and other engineers and service technicians
- Northrop Grumman employs thousands of workers at its Newport News shipyard constructing nuclear powered ships

[5] EIA, http://www.eia.gov/todayinenergy/detail.cfm?id=2150, July 11, 2011

- Dominion's current nuclear workforce is nearing retirement age and trained technicians and engineers are needed to replace those leaving
- Dominion will also need additional nuclear plant operation, engineering, maintenance, and other workers if it adds the third unit to the North Anna power station

Furthermore, both Virginia Tech and Virginia Commonwealth University have nuclear-related teaching and research capacity to serve the industry.

Natural Gas Production, Transmission, and Storage

Most of Virginia's natural gas production comes from coal bed methane fields, two of which (Nora and Oakwood fields) are among the 100 largest natural gas fields in the United States. Virginia ranked 4th among the states in coal bed methane proved reserves at the end of 2011. Virginia produces the equivalent of approximately 50 percent of the natural gas the state consumes. According to the U.S. Energy Information Administration (EIA), Virginia ranked 16th in the nation among all States that produced natural gas in 2012. Coal bed methane accounted for roughly 82 percent of the total production (about 121 bcf) and conventional gas accounted for about 18 percent (about 26 bcf).

> Virginia ranked 16th in the nation among all States that produced natural gas in 2012.

Natural gas is produced in Southwest Virginia, in Buchanan, Dickenson, Russell, Lee, Scott, Tazewell and Wise counties. Coal bed methane (CBM) is also produced in Buchanan, Dickenson, Russell, Tazewell and Wise counties. Virginia natural gas and coal-bed methane wells have produced 1.63 trillion cubic feet of gas since 1950.

In 2012, Virginia consumers used 392.2 billion cubic feet (BCF) of natural gas. An additional 17.8 billion cubic feet was consumed in the operation of pipelines, primarily in compressors, and in well, field, and lease operations, such as drilling operations, heaters, dehydrators, and field compressors.[6] The total amount of natural gas consumed in Virginia in 2012 by all sectors was 410.1 billion cubic feet. Natural gas use increased by 58 percent over the last decade primarily attributable to new customer growth and use of natural gas for electric generation requiring additional infrastructure to distribute the gas to consumers.

Local Distribution Companies

Natural gas transmission companies move natural gas from production areas to population centers through transmission pipelines. Local Distribution Companies (LDCs), which are utilities regulated by the SCC, then distribute the gas to end users. LDCs primarily sell gas to the residential and commercial markets. A total of 10 natural gas LDCs serve Virginia customers in assigned territories; seven are investor owned LDCs, and the remaining three are municipal LDCs. Virginia's investor-owned LDCs are:

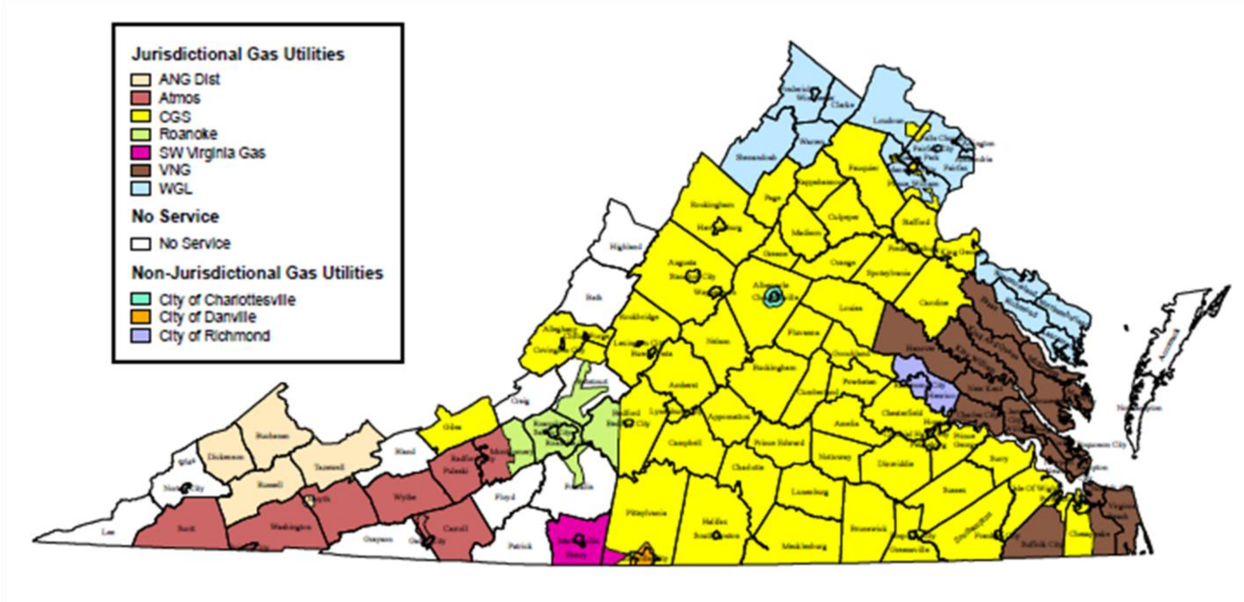
- Columbia Gas of Virginia
- Washington Gas
- Virginia Natural Gas
- Roanoke Gas

[6] EIA. Natural Gas Navigator. http://www.eia.doe.gov/dnav/ng/ng http://www.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SVA_a.htm.sum_lsum_dcu_SVA, July 31, 2014

- Atmos Energy
- Appalachian Natural Gas Distribution Company
- Southwestern Virginia Gas Company

The municipal LDCs are in the Cities of Richmond, Charlottesville, and Danville. Figure 8-4 shows the territory of each LDC in Virginia.

Figure 8-4: Service Areas of Virginia Natural Gas Distribution Companies[7]



Appalachian Natural Gas Distribution Company
Headquartered in Abingdon, Virginia, Appalachian Natural Gas serves customers in southwest Virginia with natural gas that includes gas produced within the Commonwealth. Virginia counties served include Buchanan, Dickenson, Russell, and Tazewell.

Atmos Energy
Atmos Energy Corporation, headquartered in Dallas, Texas, is a natural gas distributor, serving customers in 12 states. The company serves consumers in western Virginia, (to the south of the West Virginia border) with its 650 miles of distribution pipelines. Atmos also has extensive non-utility operations related to natural gas.

Columbia Gas of Virginia
Columbia Gas of Virginia is a NiSource company. NiSource, headquartered in Merrillville, Indiana, is multistate gas transmission and distribution company, with operations stretching from New England to Texas, and west to Oklahoma, Missouri, Illinois, and Michigan. CGV, headquartered in Chester, Virginia, serves 240,000 customers in the Commonwealth, with nearly 5,000 miles of distribution and 61 miles of transmission pipelines. The LDC provides natural gas to 81 communities in Chesapeake, Chesterfield County, Fairfax County, Fredericksburg, Harrisonburg, Lexington, Lynchburg, Petersburg, Portsmouth, Prince William County, and Staunton. Figure 8-5 shows CGV's service area.

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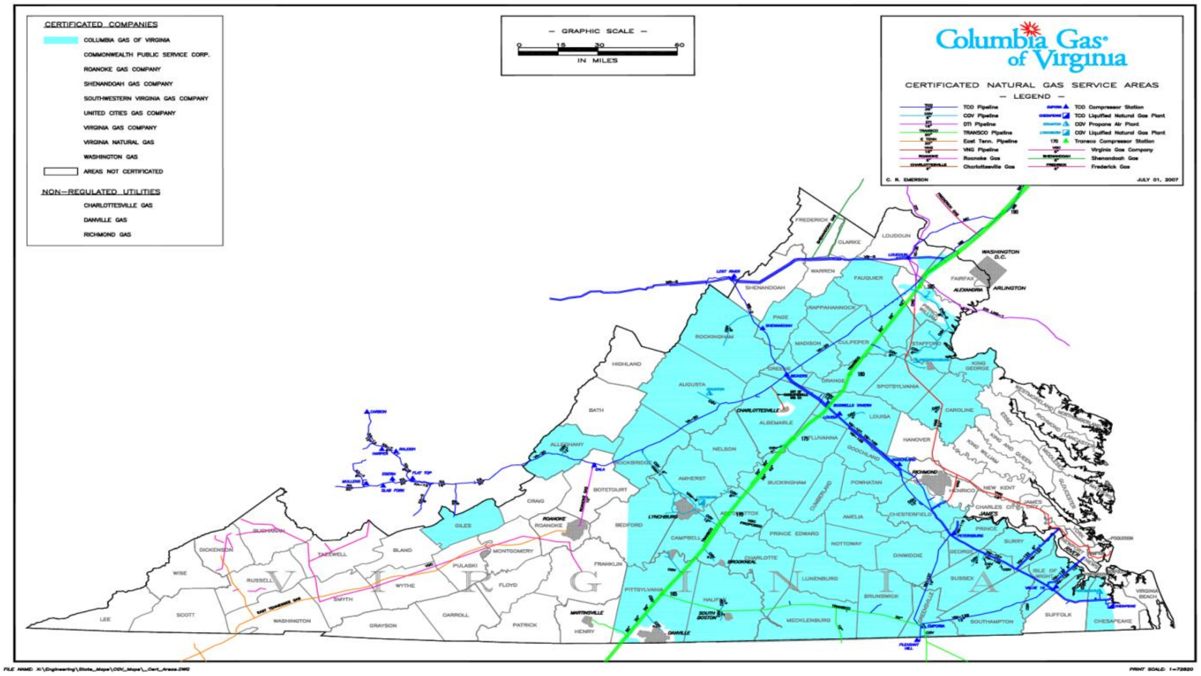
[7] State Corporation Commission, http://www.scc.virginia.gov/pue/gas/map.aspx. June 23, 2010.

Figure 8-5. CGS Service Area

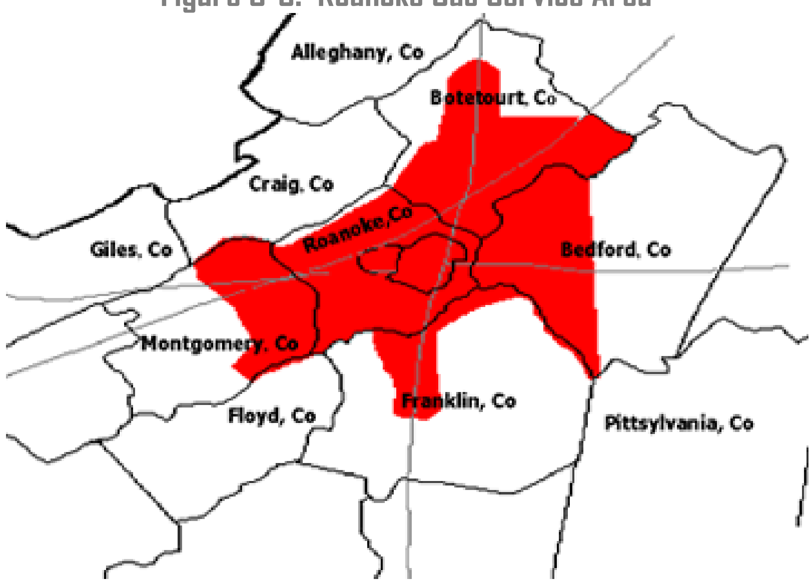


Source: Columbia Gas of Virginia, <http://www.columbiagasva.com/about-us>.

Roanoke Gas Company

A holding company, RGC Resources, owns Roanoke Gas. The company services over 51,000 accounts in its five county metropolitan service area with over 1,000 miles of distribution and 66 miles of transmission pipelines. Figure 8-6 depicts this company's service area.

Figure 8-6. Roanoke Gas Service Area

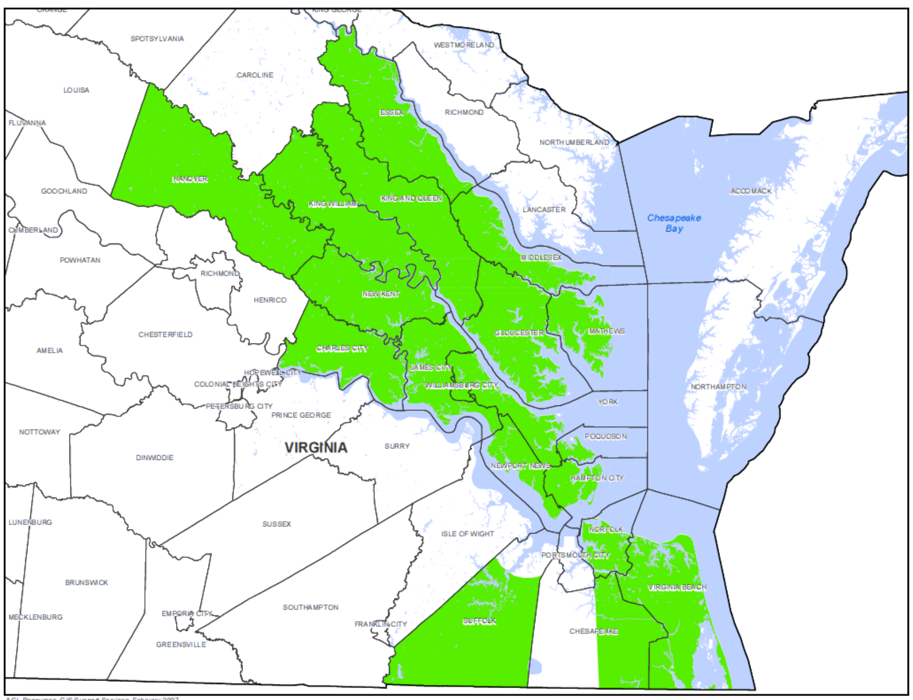


Source: RGC Resources, http://www.roanokegas.com/aboutus/servicearea.html

Southwestern Virginia Gas Company
Southwestern Virginia Gas Company is located in Martinsville, Virginia, and serves 4,600 accounts. The company's customers reside in Henry County and parts of Pittsylvania County.

Virginia Natural Gas
Virginia Natural Gas (VNG) is located in Norfolk, Virginia. VNG is a subsidiary of AGL Resources, headquartered in Atlanta, Georgia. AGL covers nine southeastern States. VNG serves over 264,000 customers in southeastern Virginia with over 5,000 miles of distribution and 156 miles of transmission pipelines. Figure 8-7 shows the company's service territory in detail.

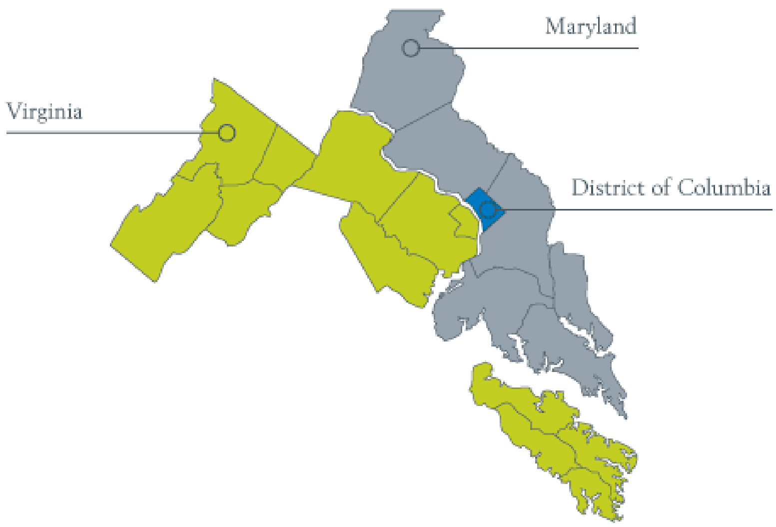
Figure 8-7. VNG Service Territory



Source: Virginia Natural Gas, About Us, Areas We Serve, http://www.virginianaturalgas.com/Universal/AboutUs.aspx.

Washington Gas Light (Including Shenandoah Division)
Washington Gas Light or Washington Gas headquartered in Washington, DC serves customers in the Washington Metropolitan Council of Governments (WMCOG) area. The service territory includes southern areas of Maryland, DC, Northern Virginia, and the Shenandoah area. The Shenandoah division is located in Winchester, Virginia, and the Washington Gas & Light division is located in Herndon, Virginia. Utilizing its 5,500 miles of distribution and 81 miles of transmission pipeline, the company serves over one million customers throughout its service territory with approximately 480,000 end-users in Virginia. Figure 8-8 illustrates the company's service areas.

Figure 8-8. WGL Service Territory



Source: WGL Holdings, About WGL Holdings, Service Territory, http://www.wglholdings.com/territory.cfm.

Municipal Natural Gas Utilities
In Virginia, three municipal natural gas utilities are governed by their local jurisdictions as authorized by Virginia Code. The three utilities are Charlottesville Gas, Danville Utilities, and Richmond City Gas.

Charlottesville Gas
The City of Charlottesville operates its municipal gas distribution as Charlottesville Gas, within the city's Department of Public Works, Public Utilities Division. The city serves 18,300 gas customers, purchasing and reselling wholesale natural gas through a variety of rate schedules, including firm and interruptible tariffs. The service area for Charlottesville Gas includes the City of Charlottesville and parts of Albemarle County.

Danville Utilities
Danville provides electricity and natural gas to its city residents, serving some 16,500 customers. The city purchases gas on a firm contract from the Transcontinental Gas Pipeline Corporation (TRANSCO) as well as other major producers.

Richmond City Gas Utility
The City of Richmond Department of Public Utilities (DPU) operates five utilities including natural gas. The DPU serves more than 500,000 residential and commercial customers in Richmond and the surrounding metropolitan region including Chesterfield and Henrico counties.

Natural Gas Pipelines
Natural gas produced in Virginia is collected in gathering pipeline systems. These systems include low pressure pipelines from wells to compression facilities where the gas is cleaned and

compressed. After being compressed, the gas is fed into the interstate pipeline network where it is delivered to customers.

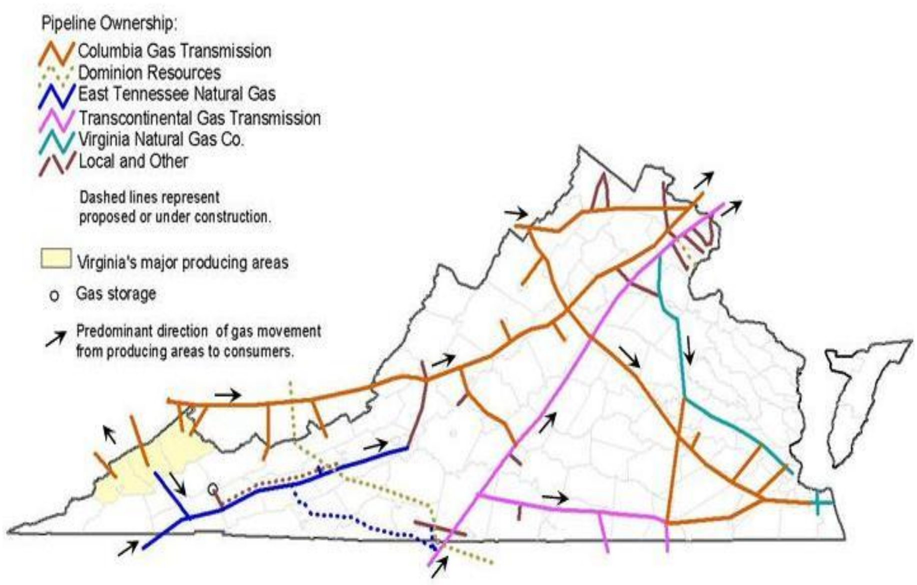
Natural gas produced in Virginia is sold in Tennessee, Southwestern Virginia, and in Northeastern states because there is limited pipeline capacity to deliver gas from Southwestern Virginia to the Central and Eastern Virginia markets. However, the capacity to deliver Virginia produced natural gas to the Northern, Central, and Hampton Roads regions of Virginia increased with the connection of the Spectra Patriot Pipeline to the Transco interstate pipeline.

Natural gas consumed in Virginia comes from three main sources:

- The Gulf of Mexico and other southern supply sources through the Transco natural gas transmission pipeline
- Virginia and other Appalachian natural gas production through the Spectra pipeline system in Southwest Virginia and the Columbia Gas Transmission pipeline system through West Virginia to Northern Virginia
- The Cove Point Liquefied Natural Gas (LNG) import facility in Maryland through the Dominion/Virginia Natural Gas pipeline serving Eastern Virginia. Dominion Cove Point received authorization on October 7, 2011, from the Department of Energy to enter into contracts to export liquefied natural gas to countries that have free trade agreements with the United States. Dominion is permitted to enter into multi-year contracts up to 25 years long with companies wishing to export natural gas to countries with free trade agreements. The authorization is for up to 1 billion cubic feet per day

There are approximately 2,950 miles of natural gas transmission pipelines in Virginia as shown in Figure 8-9 below.

Figure 8-9: Major Natural Gas Transmission Pipelines in Virginia[8]



[8] Modified from VEPT. Major Natural Gas Pipelines. http://www.energy.vt.edu/vept/naturalgas/NG_pipelines.asp. June 28, 2011

Table 8-1: Principal Natural Gas Pipeline Companies Serving Virginia[9]

Pipeline Name	Principal Supply Source(s)
Interstate & Importing Pipelines	
Columbia Gas Transmission Co	Southwest, Appalachia
Dominion Cove Point LNG LP	Northeast
Dominion Transmission Corp	Southwest, Appalachia
East Tennessee Natural Gas Co	Interstate System
NORA Gas Transmission Co	Southeast
Transcontinental Gas Pipeline Co	Southwest
*Intrastate Pipelines***	
Virginia Natural Gas Co	Interstate System

Natural gas companies have added new pipeline capacity across the state in recent years, including:

- Virginia Natural Gas' HRX pipeline that provides a third pipeline water crossing in Hampton Roads[10]
- Spectra's East Tennessee Line to Southside Virginia and North Carolina[11]
- Spectra's Jewell Ridge Pipeline to deliver natural gas from Southwest Virginia's gas production areas to the East Tennessee line and Saltville natural gas storage facility[12]

Storage facilities

Virginia is home to two underground natural gas storage facilities, the Spectra salt cavern storage facility in Saltville and the Early Grove underground storage field in Scott and Washington Counties.[13] Other underground natural gas storage services available to Virginia utilities and consumers are located in West Virginia, Pennsylvania, and Ohio. Dominion is one of the largest operators of these underground natural gas storage facilities. The locations of the facilities are illustrated in figure 8-10 below.

[9] The pipeline table data is taken from http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/MajorInterstatesTable.html, from http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/interstate.html "Interstate Pipeline Capacity on a State-to-State Level, and http://www.eia.gov/state/state-energy-profiles-data.cfm?sid=VA#Distribution. The pipeline figure is taken from EIA., "About US Natural Gas Pipelines" http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/northeast.html. June 28, 2011

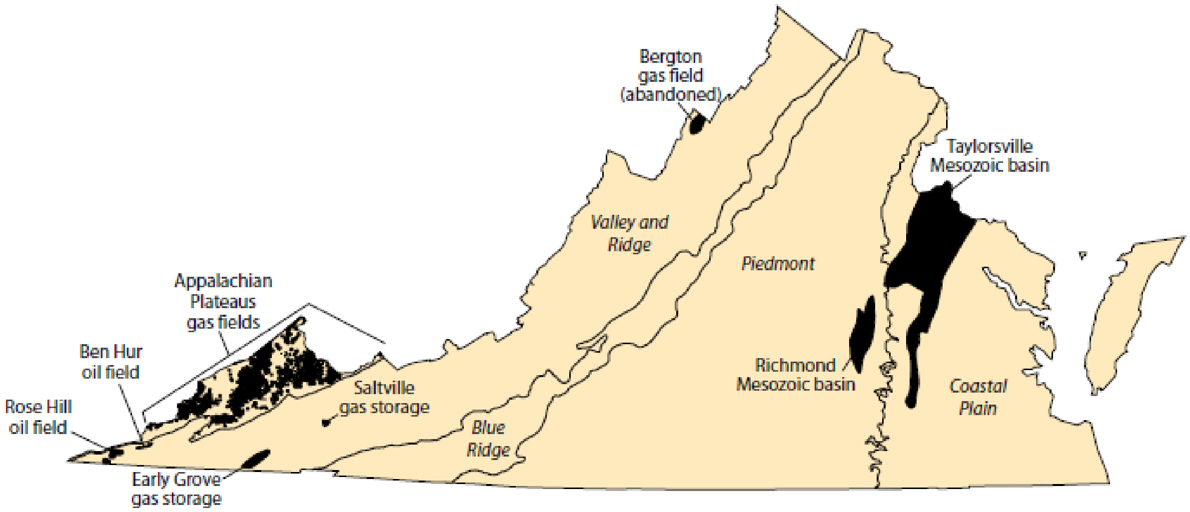
[10] Virginia Natural Gas, "Hampton Roads Crossing Pipeline",",http://www.virginianaturalgas.com/Universal/AboutUs/InOurCommunity/HamptonRoadsCrossingPipeline.aspx, June 29, 2011

[11] http://www.spectraenergy.com/Operations/US- Natural-Gas-Pipelines/East-Tennessee-Natural-Gas/

[12] Ibid.

[13] Storage/Saltville-Gas-Storage/

Figure 8-10: Underground Natural Gas Storage Facilities



Virginia LDCs operate peaking natural gas storage facilities near their local distribution networks. These facilities include compressed natural gas tanks, liquefied natural gas tanks, and one underground propane storage cavern. Companies store gas in these facilities when demand is low and inject gas into the pipeline system during times of peak demand.

Renewables:
Virginia's viable renewable resources include:

- Biomass
- Waste to energy and landfill gas
- Wind, both offshore and on-shore
- Hydroelectric, not including pumped storage
- Low temperature geothermal
- Solar

In 2013 these resources provided about 6 percent of the electricity capacity in Virginia and about 5 percent of the electricity generated.[14] Virginia is ranked number 26 in the nation for renewable capacity, with just under 1.5 gigawatts of net summer renewable generating capacity.[15]

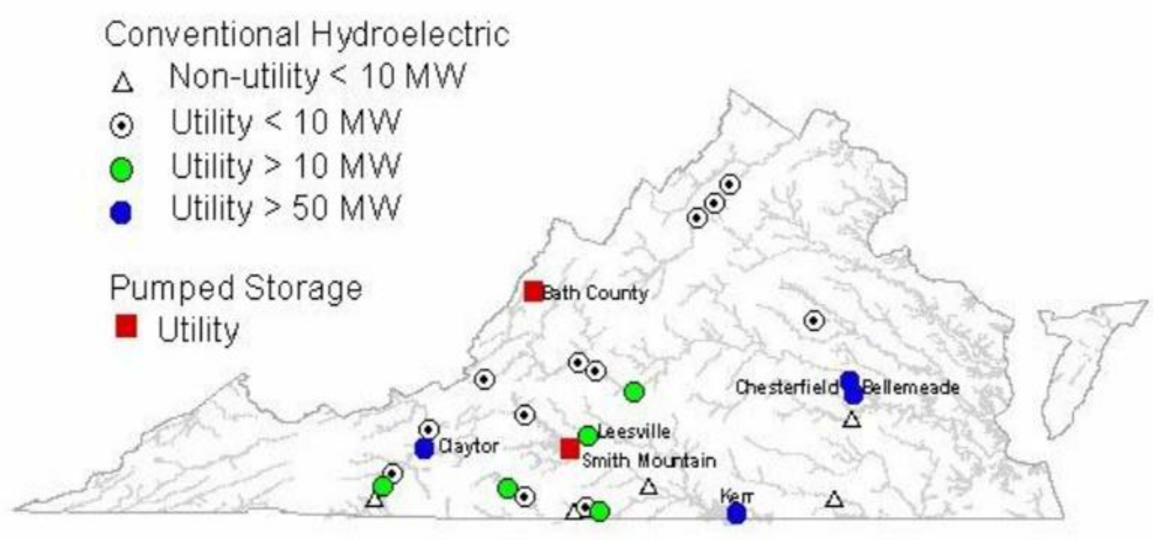
[14] Energy Information Administration Virginia Renewable Energy Profile 2010 http://www.eia.gov/renewable/state/virginia
[15] Energy Information Administration, State Renewable Electricity Profiles: http://www.eia.gov/renewable/state

Electricity generated from renewables in Virginia is used in several ways.

- The primary use of renewable electricity has been on-site distributed generation using primarily grid connected solar photovoltaic or small wind systems. While exact counts are not available, a small number of off-grid homes use solar and/or small wind systems coupled with battery storage. Typically, however, even systems with battery storage are grid connected and the batteries add a measure of energy security in the event of power outages.
- Virginia's electric utilities own renewable generation assets and operate them to meet their service obligation and renewable energy portfolio goals.
- Independent renewable generation projects contract to provide their power to investor-owned or cooperative utilities, or sell their power on the wholesale market.

Hydroelectric Power
Virginia is home to 24 conventional hydropower facilities with a combined capacity of 439 megawatts, and two pumped storage facilities with a combined capacity of 3659 megawatts. The Bath County pumped storage facility, jointly owned by Dominion and the operating companies of the Allegheny Power System, make up the bulk of Virginia's pumped storage, and is the second largest pumped storage facility in the world.

Figure 8-11.



Solar Power
Sunlight can be used to generate electricity or to directly heat water or air for homes and businesses. Solar generating capacity grew significantly in the past several years because of declining solar equipment costs, which fell between 70 and 80 percent between 2007 and 2010[16].

As of March 2014, the total net metered capacity of solar photovoltaic systems in Virginia was just under 12 megawatts, with additional non-net metered solar totaling approximately four megawatts (mostly on military installations).

[16] http://reneweconomy.com.au/2014/solar-pv-continues-shoot-cost-curve-42386

Legislation enacted in 2011 allows for the creation of utility distributed solar generation demonstration programs.

Pursuant to that legislation, Dominion plans to install up to 30 megawatts of company-owned distributed solar generation on leased commercial rooftops in strategically located areas of its service territory. This project will allow the utility to learn how to manage a larger scale intermittent resource and include such assets in its generation and reliability planning.

Because Virginia is a regulated monopoly utility state, Virginia law does not allow a third party to install and own a renewable energy facility on a utility customer's property and sell the utility customer the renewable output of the renewable energy system. In 2013 the Legislature enacted legislation that would allow for a pilot program within Dominion Virginia Power service territory to enable third party power purchase agreements (PPAs) for systems as large as one megawatt, up to an aggregate of 50 megawatts system wide.

Geothermal

Geothermal energy can provide heating and cooling through use of geothermal heat pumps. These can be found on both residential homes and commercial businesses. Geothermal technology has been available for more than 30 years. There has been an increase in systems installed due to state and federal tax incentives.

York County Schools have geothermal systems operating wells in nine school facilities. Energy costs for a typical York County geothermal school were reduced by approximately $60,000 per year. There are limited low-temperature geothermal resources in Bath County that are suitable for water and space heating.

Onshore Wind Power in Virginia

To date, the only onshore wind power project to receive regulatory approval is the 39 megawatt Highland New Wind project in Highland County. It received final approval to begin construction in 2008, but has not constructed the project. A number of developers, including Dominion, have been exploring projects in several Virginia counties.

Dominion Virginia Power currently operates two wind power generation facilities that serve Virginia load, including a 50 percent interest in the 264 megawatt Ned Power Mount Storm facility in Grant County, West Virginia, and a 50 percent interest in the 300 megawatt Fowler Ridge I facility located in Benton County, Indiana.[17]

Appalachian Power Company purchases 75 megawatts worth of renewable energy certificates from the Camp Grove wind facility in Illinois and 100 megawatts from the Fowler Ridge II project in Indiana.[18]

To support the development of wind power in Virginia, James Madison University (JMU) operates several programs to assist landowners and local officials in assessing the suitability of sites for land-based residential and utility-scale wind projects.

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[17] http://www.dom.com/about/environment/report/renewable-energy-and-green-power.jsp

[18] Commonwealth of Virginia State Corporation Commission, "Report to the Commission on Electric Utility Regulation of the Virginia General Assembly", http://www.scc.virginia.gov/comm/reports/2010_veur.pdf, September 1, 2010

The Virginia Center for Wind Energy at JMU provides wind related services to local governments, state agencies, landowners, academia, non-governmental organizations, and businesses. These services include wind resource measurements, economic modeling, education and outreach, energy policy analysis, assessment of technical specifications, Geographic Information Systems analysis, and the strategic deployment of wind power within the Commonwealth and beyond.

Offshore Wind Power
Offshore wind has the potential to provide the largest, scalable renewable energy resource for Virginia. The state currently does not have any utility-scale wind power in operation.
Virginia is unique with a shallow continental shelf that extends out 30 miles. With its proximity to load centers, supply chain infrastructure, a trained work force and best in class ports, offshore wind can provide substantial benefits to the state.
In 2013, Dominion Virginia Power won a federal lease for 112,800 acres off the Virginia coast to develop offshore wind power with the potential to generate up to 2000 megawatts, or enough to electricity to power 500,000 homes.

Waste-to-Energy and Landfill Gas
Virginia currently has 33 landfills that are capturing, converting and using landfill gas (LFG) as an energy source. Twenty-five of these landfills are generating electricity and have a combined capacity of 94.5 megawatts. Three LFG projects are under construction and 38 landfills are either candidates or potential sites for projects. LFG projects are operational, under construction or planned in 54 counties from Eastern Shore to Southwest Virginia.

Wood/Biomass Production and Transportation
Biomass is a broad term used to describe organic materials of a biological origin that can be used as a source of energy. These may include agricultural and forestry residues, the organic component of municipal solid wastes, and terrestrial and aquatic crops, such as switch grass or algae, grown solely for energy purposes. Biomass can be used to generate electricity by burning it in place of fossil fuels in steam turbines. It can also be converted to methane through anaerobic digestion, or to liquid fuels, also called biofuels, such as ethanol or biodiesel, primarily for transportation.

Virginia has multiple waste-to-energy projects listed below which are part of the overall energy infrastructure of the state.

Table 8-2: Biomass and Waste-to-Energy Projects[19]

Project	Energy Produced
Fairfax County Covanta WTE plant	124 MW of electricity
Alexandria/Arlington Covanta WTE plant	29 MW of electricity
SPSA WTE plant	60 MW plus steam
Harrisonburg WTE plant	2.5 MW plus steam
Dominion Multitrade (sawdust and wood chips)	80 MW of electricity and steam

[19] Virginia Cooperative Extension, "Preliminary Residual Biomass Inventory for the Commonwealth of Virginia: Geographic Information System Based Multi-Feedstock Bioresidue Assessment"

Dominion Altivista (wood chips co-fired with coal)	2 MW electricity
21 Landfill Gas generating plants	20.6 MW electricity
Sussex County Landfill	Process gas for Honeywell in Hopewell
Wood pellet manufacturing plants	Wood pellets for domestic/export markets
Six industrial CHP (wood, wood waste, black liquor)	182 MW electricity and steam
Institutional boilers such as Piedmont Geriatric Hospital and Longwood University	Steam
Piedmont Bioproducts	Green diesel
Five in-state biodiesel producers	Biodiesel
Five commercial biodiesel plants (soy, canola, waste greases)	Biodiesel
Farm and coop biodiesel operations (unknown number)	Biodiesel; filtered vegetable oil
Louisa County pellet plant	Wood pellets

Virginia has substantial biomass resources. Below are some individual biomass resource assessments which have been completed.

Table 8-3: Biomass Waste Inventories

Type of Biomass	**Amount of Resource**
Forest slash	2,253,244 dry tons
Sawdust and sawmill waste	2,538,140 dry tons
Crop residues	750,137 dry tons
Animal wastes	1,045,946 dry tons
Municipal solid waste	2,016,587 tons
Landfill gas	66 landfills; 21 operational projects; 11 candidate landfills
Construction debris	593,211 tons
Food processing waste	763,022 tons

Stand-alone power generation with woody biomass can meet base load demand, providing constant, steady power to the grid. Dominion has been generating electricity with woody biomass at their 83-megawatt Pittsylvania Power Station in Hurt, Virginia since 1994. Dominion received approval from the Virginia State Corporation Commission to convert three 63-megawatt coal-fired power stations at Altavista, Hopewell and Southampton to 51-megawatt woody biomass plants, one of which, Altavista, went online in 2013. Dominion also began co-firing woody biomass with coal at their new 600-megawatt Virginia City Hybrid Energy Center in 2012. The Hybrid Energy Center is designed to burn up to 20 percent woody biomass, generating 117 megawatts of biomass energy. Co-firing with woody biomass diversifies their fuel supply and reduces sulfur and nitrogen oxide emissions. The Northern Virginia Electric Cooperative's 49.9-megawatt Halifax County Biomass Plant also began commercial operations in 2013, utilizing forest residues harvested within 75 miles of their South Boston location.

The use of biomass for stand-alone power generation has become a source of contention, however. Overall efficiencies of stand-alone power generation are around 30 percent and the waste heat is by definition not utilized. Concerns have been raised about the "carbon debt" of biomass power generation and the recent release of the EPA's proposed Clean Power Plan to regulate carbon dioxide under section 111(d) of the Clean Air Act requires clarification on how biogenic (biomass) carbon emissions will be handled.

Petroleum Production, Refining, Transportation and Distribution

Petroleum is used mainly for transportation but also heating oil, and propane. Heating oil was the second largest use, with smaller amounts used for aviation, residual fuel oil, and propane. Use in Virginia grew through 1998 but has stabilized since 1999 as vehicle miles traveled stabilized and the oldest, less fuel-efficient vehicles were replaced by more efficient models. The majority of Virginia's propane gas is supplied by the interstate propane pipeline terminating in Apex, North Carolina, and the water-based terminal in Chesapeake, Virginia. Some propane is produced in the Lee, Wise and Russell Counties' wells. It is equivalent to less than one percent of the state's annual consumption. The propane produced is typically shipped to refineries in Kentucky for processing.

Petroleum is supplied to Virginia through a network of refineries, pipelines, port facilities, terminals, and retail outlets. All of the petroleum production in Virginia occurs in Lee and Wise Counties. The volumes are small so collection tanks are placed at each wellhead. Collection trucks transport the collected crude to a central location periodically for shipping.

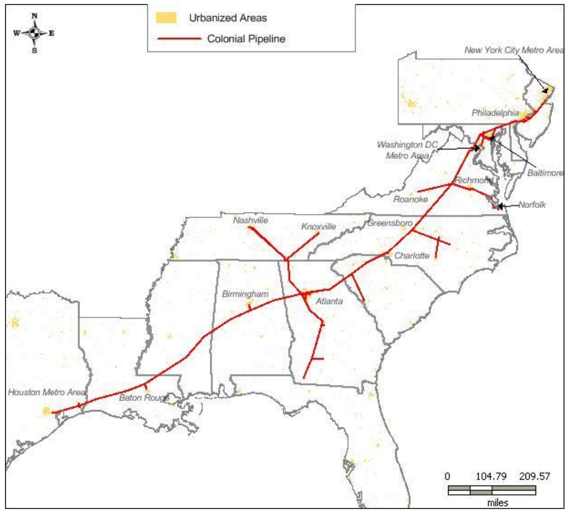
Pipelines and Ports

Because more of the petroleum is supplied from other states, the pipelines and their companies and the ports are critical for the Commonwealth's petroleum product supply. The different pipelines that serve Virginia are outlined below:

The Colonial Pipeline

The Colonial Pipeline (Colonial) headquartered in Avenel, New Jersey, operates an office in Fairfax, Virginia. Colonial is a major supplier for the Commonwealth and surrounding states delivering refined petroleum products from the Gulf Coast, as far north as New Jersey. The liquid products Colonial carries vary seasonally and according to demand, but included among the most important are: distillates such as diesel, home heating oil, and jet fuel and motor gasoline. Colonial ships product in batches and then offloads the product at terminals for sale to end-users. The Colonial Pipeline system is shown in Figure 8-12.

Figure 8-12. The Colonial Pipeline system.



Source: www.colpipe.com/home/about-colonial/system-map

Plantation Pipeline
Kinder Morgan, a major natural gas and petroleum pipeline and energy storage company in the U.S., owns the Plantation Pipeline. Like the Colonial Pipeline, the Plantation Pipeline delivers petroleum products from the Gulf Coast area along the Eastern Seaboard. The pipeline terminates in Washington, DC. Industry sources informally estimate that a batch of product requires approximately 20 days to reach the DC and Virginia area. The Plantation Pipeline is shown in Figure 8-13.

Figure 8-13. Plantation Pipeline Owned by Kinder Morgan

Source: Kinder Morgan, http://www.kindermorgan.com/asset_map/

Dixie Pipeline and Chesapeake Port/Terminal
The Dixie Pipeline does not enter Virginia. However, it is a major source of propane for the Commonwealth. Dixie is a subsidiary of Enterprise Products Partners, L.P. of Houston, Texas. LPG is trucked from the Apex Terminal near the intersection of U.S. Route 1 and Route 55 in Apex, North Carolina, to bulk distributing retailers in Virginia. Enterprise also offloads LPG from vessels to a terminal at the Port of Norfolk, located in Chesapeake, Virginia.

Port of Norfolk
The Port of Norfolk both receives and ships petroleum products. The port classifies petroleum products as "mineral fuel, oil, etc." This classification constituted the largest cargo shipments in 2012, with 65,050,050 short tons exported and 9,160,010 short tons imported.[20] The percentage of fuel and oil comprising these volumes (versus minerals and coal) is unclear

Terminals

Terminals are the major infrastructure elements between supply from pipeline or port and distribution to service stations and end-use customers. Distribution terminals in Fairfax, Richmond, Montvale/ Roanoke, and Chesapeake receive petroleum from the Colonial and Plantation underground pipelines which receive product from refineries in the Gulf of Mexico region. Additionally tankers and barges deliver product to coastal petroleum distribution terminals in Chesapeake and Richmond. Virginia consumers are also regularly supplied from out-of-state petroleum terminals in Baltimore, MD; Greensboro, NC; and Knoxville, TN.

Refined products received at Virginia terminals are offloaded to large (8,000 or 16,000 gallon) tanker trucks owned and operated by local distribution companies or wholesale marketers (jobbers) for delivery to local retail locations. Motor gasoline and diesel fuel are delivered to service stations in this way. Heating oil and propane are picked up by local wholesaler/retailers and transferred to smaller trucks for delivery to the tanks of individual customers (usually 250 to 500 gallon). As of September 2010, there were 45 petroleum terminals in Virginia. These 45 terminals are operated by 23 companies. The companies with multiple terminals are:

- Kinder Morgan: 7
- TransMontaigne: 7
- Motiva: 4
- BP: 3
- CITGO: 2
- Magellan: 2
- NuStar: 2
- Quarles: 2
- Richmond: 2

Refining
The only oil refinery in Virginia was closed in 2010 and is in the process of being converted into a storage hub and transportation hub as a link in the East Coast Chain. Petroleum products will pass through the former refinery by water and rail. (http://hamptonroads.com/2012/12/virginias-only-oil-refinery-becoming-storage-facility)

[20] Virginia Port Authority, *Comprehensive Annual Financial Report*, June 30, 20132009, pp 91.

Industry Organizations

There are several umbrella or industry organizations that represent the interests of the petroleum industry in the state.

1. ***The Virginia Petroleum, Convenience, and Grocery Association (VPCGA)*****:** The VPCGA has 650 member retail dealers who operate over 4,500 locations throughout the Commonwealth. These retail dealers sell motor gasoline, diesel, and/or heating oil. VPCGA provides liaison with governmental policy makers and offers training on safety and business practices for its members. The VPCGA headquarters is located in Richmond, Virginia.
2. ***The Virginia Petroleum Council*****:** The Virginia Petroleum Council represents the interests of the major petroleum suppliers that do business in the Commonwealth. The Council is a division of the American Petroleum Institute (API), and is located in Richmond.
3. ***The Virginia Propane Gas Association (VAPGA):*** VAPGA represents the business interests of member companies in the Commonwealth. Its basic operations are similar to VPCGA, representing member interests before governmental bodies and offering training for member employees. VAPGA is headquartered in Charlottesville, Virginia.

Alternative Fuels and Advanced Vehicle Technology

Virginia produces very little petroleum and therefore currently must rely almost entirely for oil and motor fuel on imports from other states and countries. There is a push by the state to move towards alternative fuels, at least for state-owned vehicles, to reduce emissions and the dependence on foreign oil. Alternative fuels include ethanol, propane, biodiesel, hydrogen and others.

Natural gas, propane, biodiesel and ethanol are the most produced alternative fuels in the state. In 2013, mines in Southwest Virginia produced 146.4 trillion cubic feet of natural gas. Biodiesel is produced at 2 active refineries and in 2013, 3.3 million gallons were produced. Around 1 million gallons of ethanol was produced at one active refinery. Virginia biofuel producers report the existing potential to produce 17.5 million gallons of biofuel annually which means currently the state is only producing 25 percent of its current capacity with the existing infrastructure.

Natural gas, propane, biodiesel and ethanol are the most produced alternative fuels in the state

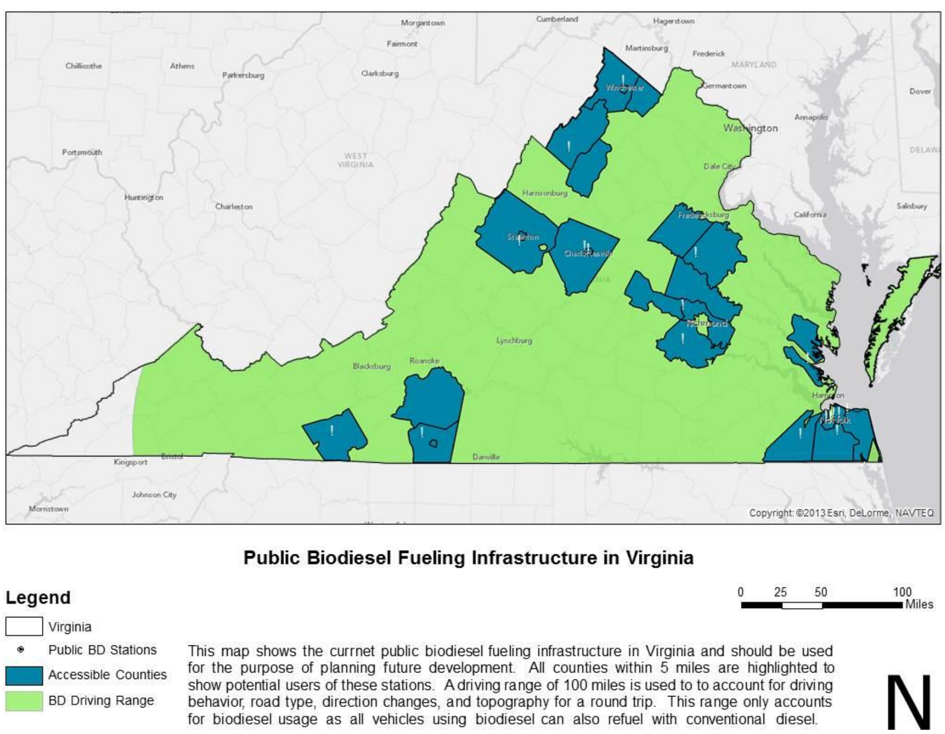
The alternative fuel infrastructure is growing, supported by public-private partnerships to increase the use of alternative fuels. By the end of 2013, Virginia had 364 public and private alternative fuel stations throughout the Commonwealth. In 2013 alone, 78 electric fueling stations were added making electric, biodiesel and propane stations the most readily available in the state.

Most of the alternative fuel is utilized by government and private fleet vehicles with the largest consumption of fuel being E85 and biodiesel. In 2013, Virginia fleets reported using E85 in over 8,500 vehicles and biodiesel in over 4,300 vehicles. The heavy duty vehicles primarily use natural gas and in 2013 Virginia consumed 217 million cubic feet for fuel. Although currently a very small portion of existing fleets, electric vehicle use is growing. 78 additional electric fueling stations built in 2013.

Biodiesel

Biodiesel in Virginia is produced at several facilities that collect waste grease and vegetable oils to process into biodiesel. The map below shows the existing biodiesel infrastructure.

Figure 8-14. Biodiesel in Virginia



In Virginia 3.5 million gallons of biodiesel is produced a year.   There are two large producers: Reco Biodiesel in Richmond and Virginia Biodiesel in West Point. However, there are many small producers including farmers exploring production as well. The biodiesel is currently distributed from these sites via truck, train and barge. It is distributed directly to retail fueling stations and directly to large scale end users with vehicle fleets. It is dispensed through equipment similar to regular diesel dispensers making existing infrastructure easily adaptable for biodiesel distribution. Therefore numerous existing vehicle fleets utilize biodiesel, such as but not limited to the following:

- Williamsburg-James City County Schools
- Virginia Beach Public Schools
- Arlington County and Arlington Schools
- US Army
- US Navy
- US Air Force
- Gloucester County Schools
- Woodfin Oil
- Newport News
- SuperValu
- Staunton
- Waynesboro
- The University of Virginia
- Chesterfield County
- WestmorelandCounty
- Northumberland County
- Roanoke and Roanoke Schools
- Virginia Tech
- Blacksburg

Ethanol

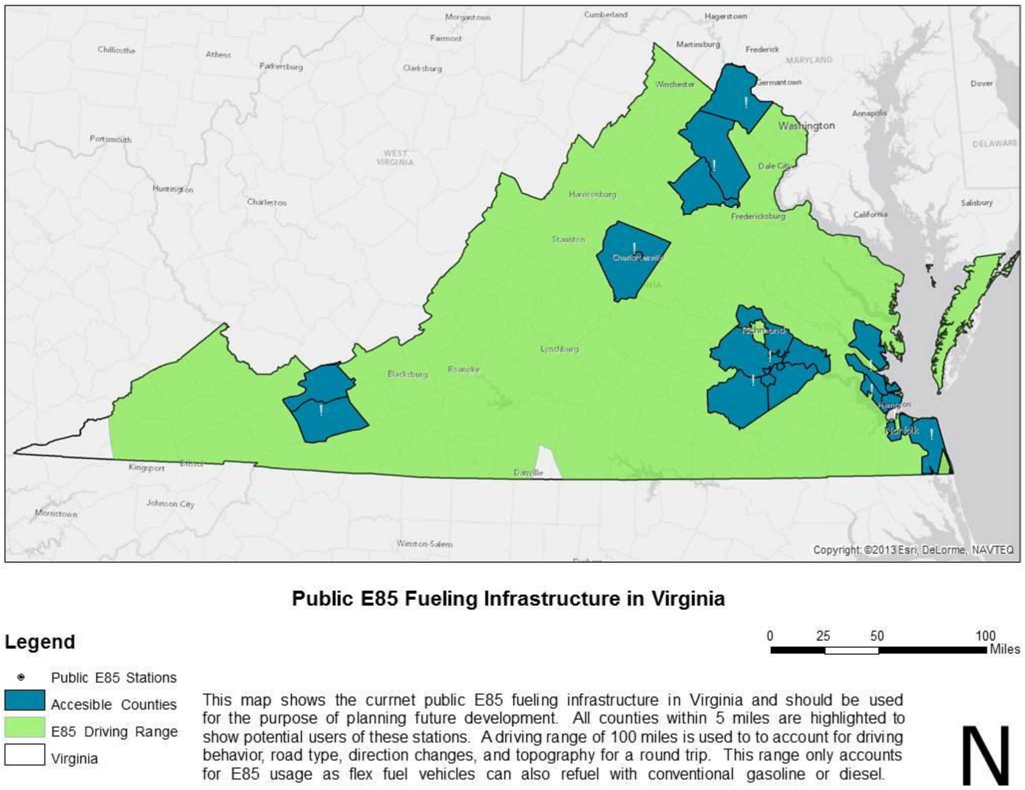
Ethanol is a renewable fuel made from various plant materials and is blended with gasoline. The blends are from 10 percent ethanol up to 85 percent ethanol and can be dispensed at existing fueling stations as long as the stations have blender pump infrastructure. The mid-level blends utilizing 85 percent ethanol with 15 percent gasoline (E85) are used in flex-fuel vehicles of which there are 300,000 in Virginia today.   Currently there are over 90 vehicle models with flex fuel options based on 2014 models making the technology readily available to the average consumer. The E85 fueling equipment is slightly different than the petroleum fueling equipment, but the costs are similar and it is possible to convert the equipment with little cost.

Virginia currently has several ethanol producers in the state.

- Vireol Ltd opened an ethanol plant in Hopewell in 2014 and has the capacity to produce 62 million gallons of bioethanol a year. The ethanol is produced from corn, barley and other small grains. The byproduct, dried distiller grains, is used in poultry and livestock industries. MXI Environment Services, LLC recycles the grains and has a facility in Abingdon, VA.
- Fiberight LLC has a pilot plant in Southern Virginia that turns garbage, corn stalks and wheat straw into biofuel ethanol.

There are several other companies with plans to build ethanol plants in the near future. The map below shows the existing E85 fueling infrastructure in the state.

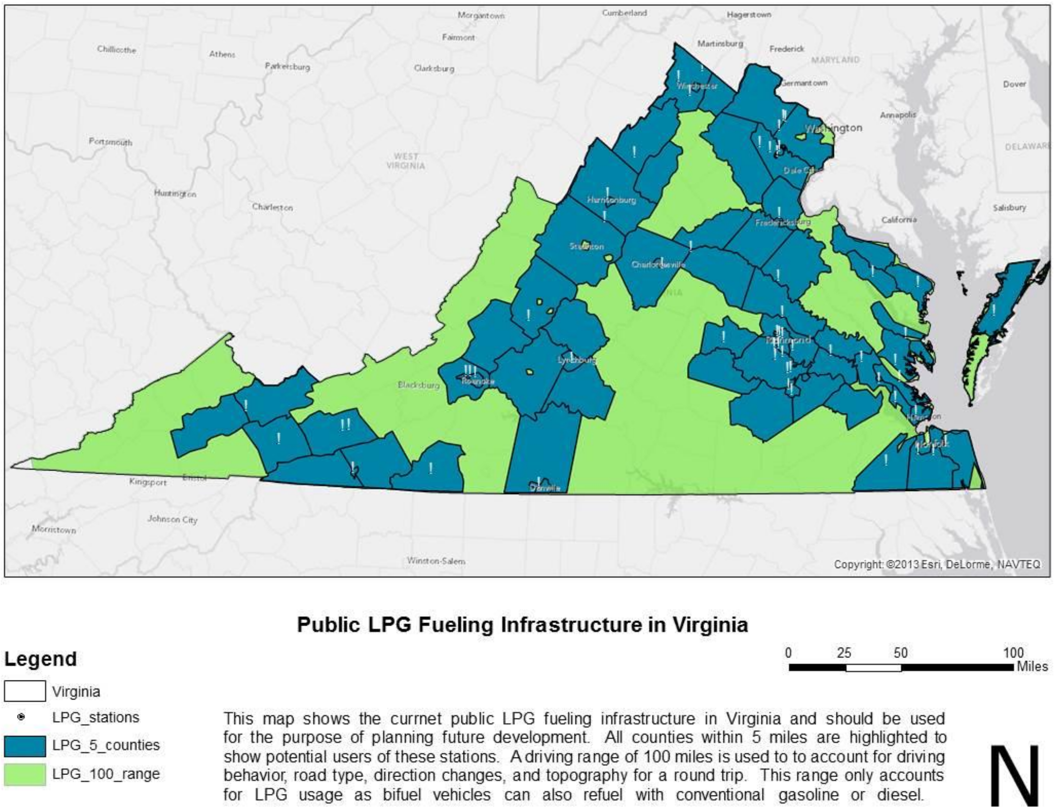
Figure 8-15. E85 Fueling Infrastructure



Propane

There is significant interest in propane as a domestic vehicle fuel because of high energy density, clean-burning qualities, and low costs at the volumes utilized. It is the most commonly alternative transportation fuel and the third most used vehicle fuel, behind gasoline and diesel. Propane engines are largely used in medium and heavy duty vehicles such as street sweepers and school buses. Currently 500 vehicles are operating on this fuel in Virginia. Conversions to propane fuel are complicated and require EPA certification. However,,; the upfront cost can be offset by the lower fuel cost, operating and maintenance expenses over time. Below is a map of the current LPG fueling infrastructure in the state.

Figure 8-16. LPG Fueling Infrastructure

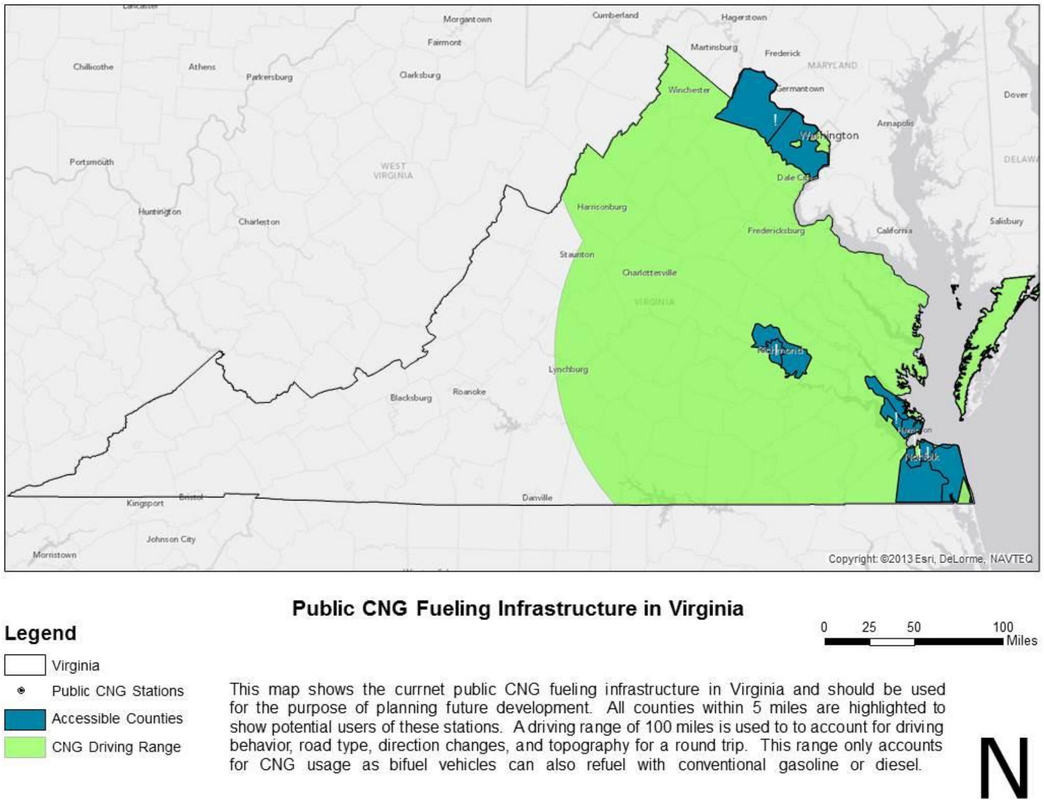


Natural Gas

Natural Gas is one of the cleanest burning alternative fuels available and Virginia has significant production, making it an attractive option. Because of the gaseous nature, it must be stored on the vehicle either at 3600 psi as compressed natural gas (CNG) or in a liquefied state (LNG). The primary applications for CNG are heavy haulers, public transit bus fleets, and waste hauling trucks, but small passenger vehicles are becoming more popular.

The vehicles may be fueled at public stations or private filling stations. Station development is expensive and time-consuming due to local permitting processes and locating near existing natural gas pipelines, in addition to finding adequate customers for the fuel to justify the effort. Below is a map of the current natural gas fueling infrastructure.

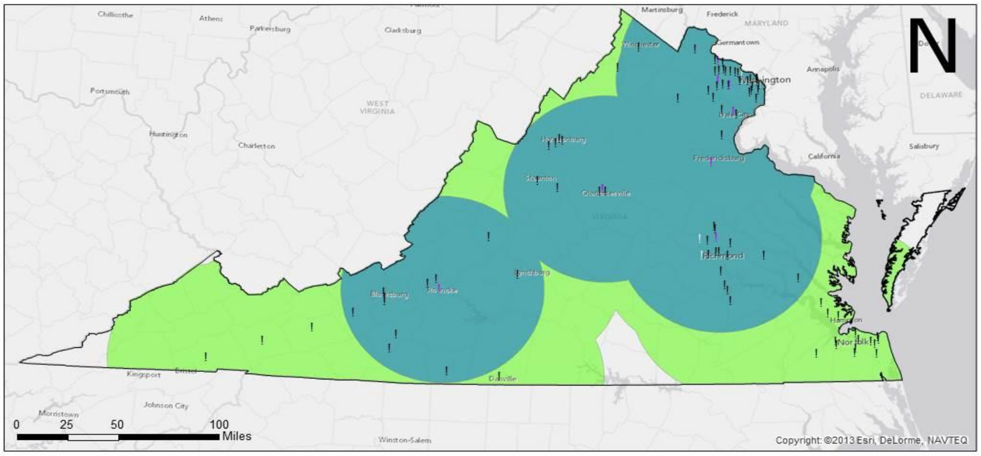
Figure 8-17. Natural Gas Fueling Infrastructure



Electric Vehicles

An Electric Vehicle (EV) stores electricity from the grid on-board to power the motor. Some have on-board chargers while others plug into a charger located outside of the vehicle. There are several models of EVs offered and on the road today. Some are 100 percent electric and some have small combustion engines on board and operate as traditional hybrid cars once the battery power is exhausted, allowing for greater flexibility in travel. As of October 2013, based on information from the Virginia Department of Motor Vehicles, there were 2,521 electric vehicles on the road in Virginia, an increase of over 1000 percent since 2012. According to Virginia Clean Cities there are currently 249 electric charging stations across Virginia to support the growing number of EVs on the road today. The maps below show both the existing electric vehicle charging stations and the plan for additional stations along highways in the future.

Figure 8-18. Existing and Future Electric Vehicle Charging Stations



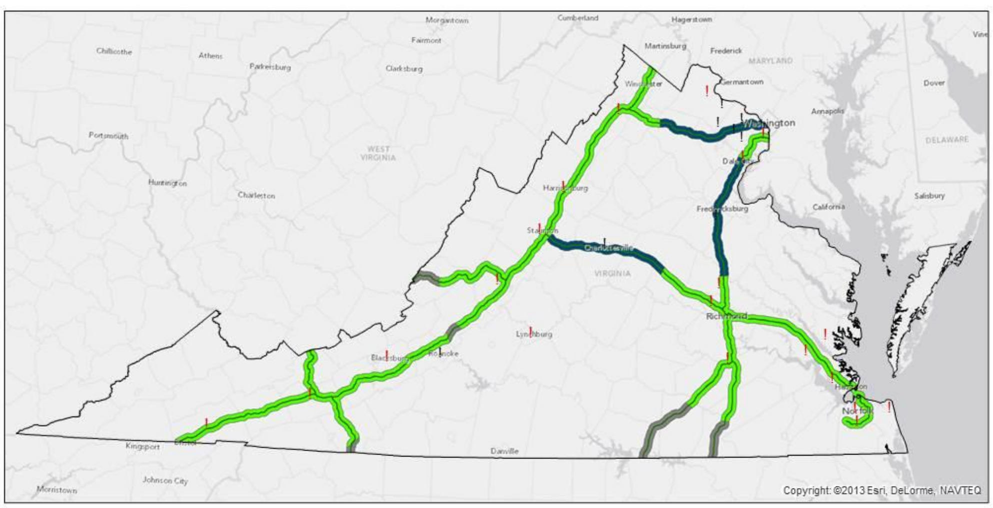
Electric Vehicle Charger Infrastructure in Virginia

Legend

- Virginia
- L3 Chargers
- L1 & L2 Chargers
- L3 Electric Range
- L1 & L2 Electric Range

The purpose of this map is to show the extent and limitations of Virginia's current electric vehicle charging infrastructure. Virginia's electric vehicle charging infrastructure is currently most concentrated in the high population centers of Hampton Roads, Richmond, and Northern Virginia. Through Virginia Clean Cities' initiatives, DC fast chargers (Level 3) have been added in Roanoke and Charlottesville as well. Despite its relatively high level of EV adoption, the Hampton Roads region has no Level 3 chargers. To give an estimate of electric vehicle access in Virginia, 50 mile buffers were placed around all charging infrastructure. Fifty miles was chosen as a conservative estimate to account for direction changes, road type, topography, and driving style. The LEAF is Virginia's most popular electric vehicle, however other vehicles may have different ranges.

Figure 8-19. Existing and Proposed Level 3 Highway Charging Range



Existing and Proposed Level 3 Highway Charging Range

Legend

- Virginia
- Proposed L3 Chargers
- Existing L3 Chargers
- Existing L3 Charger Range
- Proposed L3 Hwy Range

The purpose of this map is to show the interstate access of electric vehicles based on current level 3 chargers located within 3 miles of Virginia's interstates. With current highway accessible DC fast chargers, EV drivers have access to approximately 180 miles (18%) of Virginia's interstate system. If all Virginia Clean Cities target L3 chargers are realized the highway accessability will increase by 690 miles to approximately 870 miles (87%) of accessible interstate. For this map 30 mile buffers were placed around both existing and proposed chargers to account for direction changes, road type, topography, and driver behavior. These distances assume a round trip on the interstate.

0 25 50 100 Miles

N

SECTION 9 – ENERGY CONSERVATION: IMPROVING EFFICIENCY, REDUCING DEMAND

This section provides information for government agencies and institutions, public and private organizations, businesses, and residents about energy conservation programs, infrastructure -- such as educational resources, policies and regulations -- and incentives to encourage energy conservation.

Energy Conservation

Energy conservation refers to efforts made to reduce energy consumption. It can be achieved through increased efficient use of energy, in conjunction with decreased consumption of depletable energy sources. The results of energy conservation can include increased financial capital, national and personal security, environmental quality, human comfort and health benefits, reduced energy costs, and maximized profits. Energy conservation is broader than energy efficiency. It includes active efforts to reduce energy consumption through behavior change, technological developments and policies that encourage such efforts.

Other examples of the Commonwealth's focus on energy conservation and efficiency include the state energy policy framework established by the General Assembly in Chapter 1 of Title 67 of the Code of Virginia which directed the Department of Mines, Minerals and Energy to draft the Virginia Energy Plan (VEP). The Code set several energy policy objectives, including one that provides that Virginia should "use resources efficiently and facilitate energy conservation."[1]

Energy conservation refers to efforts made to reduce energy consumption.

Energy Efficiency

Energy efficiency to a Virginia consumer could include taking steps to reduce consumption of energy, which will save both energy and money. But it can be more complicated. The U.S. Department of Energy's (DOE) Energy Information Administration (EIA) defines Energy Efficiency as "a ratio of service provided to energy input (e.g., lumens to watts in the case of light bulbs). Services provided can include buildings-sector end uses such as lighting, refrigeration, and heating; industrial processes; or vehicle transportation. Unlike conservation, which involves some reduction of service, energy efficiency provides energy reductions without sacrifice of service."[2] "Efficiency" is defined by The Merriam-Webster Thesaurus as "the capacity to produce desired results with a minimum expenditure of energy, time or resources."[3] Energy efficiency tips and ideas can be found on the DMME website, including the Virginia's Energy Savers Handbook[4], and the U.S. Department of Energy's *Energy Savers Handbook on Tips on Savings Money and Energy at Home* [5].

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[1] VEP, Section 1, General Energy information, page 1-2, http://www.dmme.virginia.gov/DE/VEP_TitlePage.html
[2] EIA, www.eia.gov/tools/glossary/index.cfm?id=E
[3] The Merriam-Webster Thesaurus, New York, 1978 edition, page 186.
[4] http://www.dmme.virginia.gov
[5] http://www.energysavers.gov/pdfs/energy_savers.pdf

Market Trends

According to the U.S. Energy Information Administration in its Annual Energy Outlook 2011[6], growth in energy use is linked to population growth through increases in housing, commercial floor space, transportation, and goods and services. The following energy efficiency market trends have been identified to occur between 2014 and 2040:

- Annual electricity demand for the average household declines by 4%, from 12.1 megawatt hours (MHz) in 2012 to 11.6 MWH in 20140. In 2012, the largest uses of electricity at the household level are space cooling, small devices and other minor electric uses, and lighting. In 2040, electricity consumed for lighting per household is 65% lower, and electricity use for minor electric end uses and for space cooling rises by 33% and 17%, respectively. Regulations implementing lighting efficiency standards established by the Energy Independence and Security Act of 2007 (EISA2007) are a major factor in the replacement of incandescent bulbs with more efficient compact fluorescent lighting (CFL) and light-emitting diode (LED) lamps.

- The second-largest increase in total primary energy use, 3.3 quadrillion Btu from 2012 to 2040, is in the commercial sector. Even as standards for building shells and energy efficiency are tightened and commercial energy intensity (energy use per square foot) decreases by 0.4%/year from 2012 through 2040, energy use grows by 0.6%/year as annual growth in commercial floor space averages 1.0%.

Barriers to Achieving Conservation and Efficiency

Electric efficiency actions can be used to reduce future growth in electrical demand. Substantial cost-effective investments in energy efficiency remain unmade as there are factors that undercut market forces. These include:

- Principal-agent barriers – the party responsible for the building improvements may not pay electric bills for rented space;

- Information barriers – consumers don't have sufficient information they can trust in order to act;

- Transaction cost barriers – consumers cannot budget or borrow the upfront investment needed for energy efficiency projects

- Externality cost barriers – benefits of energy efficiency, such as lower utility costs from reduced peak demand, accrue to people other than those making the investments.

[6] http://www.eia.gov/forecasts/aeo/topic_efficiency.cfm

- Traditional systems of utility regulation in which utilities use revenues from electricity and gas sales to recover the costs of production and administration. They earn a rate of return for investments in their rate base – typically capital investments like power plants and transmission lines. This creates two major disincentives for utilities to promote energy efficiency.
    - Utilities are not compensated for the direct cost of implementing efficiency programs.
    - Efficiency reduces revenues and profits through decreased energy consumption.

State government has taken a number of actions to overcome these market barriers, including:

- Adoption by the General Assembly of voluntary goals to reduce electric use by 2022, through conservation and efficiency, by an amount equal to 10 percent of 2006 use
- Creation of Virginia Energy Sense, an information source where consumers can learn how to save energy and lower their energy bills
- An Energy Star appliance sales tax holiday over Columbus Day weekend in October
- An income tax exemption for sales tax paid on certain energy efficiency improvements
- $600 million in energy efficiency improvements made to state government facilities
- Authorization for local governments to provide property tax and other incentives for Energy Star buildings (at least 20 percent more efficient than minimum building code requirements); Buildings with green roofs and solar energy systems
- Property Assessed Clean Energy (PACE) or support for Home Performance with Energy Star programs.
- The passing of S. 1416, in 2007 which allows utilities to recover the projected and actual costs of designing, implementing and operating efficiency programs, subject to SCC approval. However, to garner approval, the SCC must determine that “the program is in the public interest.”
- The decoupling of sales volume and revenue for natural gas utilities.

Virginia consumers also benefit from federal incentives and programs that encourage efficiency, such as:

- Competitive State Energy Program awards made to Virginia’s energy office that help create and support residential, commercial, and energy performance contracting programs

- Federal energy efficiency income tax credits; [7]

- Strengthened minimum equipment efficiency requirements; and

- Expansion of the Energy Star program.

Virginia's Regional Energy Alliance Network (REAs)

There are now three REAs operating programs in 4 areas of Virginia. These REAs are non-profit Virginia corporations that were established in the last 3 years to undertake residential and commercial energy efficiency retrofits in their self–designated service areas. Each REA has a Board of Directors that oversees the operation of the non-profit organization. Each REA has its own operating budget which combines DOE grants, local government funds, utility contracts and program participation fees, and private sources. The overriding economic development goal of this project is to develop, train and sustain numerous partners in the new and emerging energy efficiency retrofit and renewable energy market. This project is a comprehensive undertaking that combines workforce training and development, building auditor and contractor training and quality assurance and training of realtors and appraisers in incorporating the value of energy efficiency retrofit work when pricing a structure. The REA act as catalysts for market transformation and through leveraging the power of market forces, they seek to underwrite program costs via fees for services tied to their mission.

Virginia Energy Efficiency Council (VAEEC)

The DMME supports the efforts by the Virginia REAs and other energy efficiency stakeholders in the development of the Virginia Energy Efficiency Council – a statewide association whose goals are to assess and support programs, innovation, best practices and policies that grow Virginia's energy efficiency industry and to provide a forum for stakeholder interaction. The VAEEC received a foundation grant to create the first Virginia Energy Efficiency Industry Census in 2013, and is part of a multistate consortium working under a DOE grant to complete a census update in 2014.

Accelerating the Commercial Building Retrofit Market

The DMME was grant funded by the DOE to undertake a project with the goal of accelerating the commercial building retrofit market. Through the development and deployment of initiatives/deliverables in each of three areas of policy, best practices/protocols and pilot program implementation, the DMME proposes to significantly increase the infrastructure and uptake of commercial building retrofits in Virginia and Maryland. This project proposes to increase the depth and breadth of ongoing commercial retrofits by incrementally facilitating improvements to both contractor capacity and customer demand. DMME also proposes to accelerate the policy and programmatic changes necessary to build and sustain a robust market-based industry for this sector five years from now.

This effort will simultaneously confront the major barriers to a successful private sector commercial building retrofit market: split incentives, lack of knowledge, shortage of capital, perception of poor value add, absence of documented successes, and economies of scale among them.

Energy Efficiency in Manufacturing

[7] http://www.virginiaenergysource.org

The Genedge Alliance of Martinsville (formerly the A. L. Philpot Manufacturing Extension Partnership), participates as the Commonwealth's representative in the federal Manufacturing Extension Partnership (MEP) program. Supported by the National Institute of Standards and Technology, the MEP works with small and mid-sized U.S. manufacturers to help them create and retain jobs, increase profits, and save time and money.

The Genedge Alliance provides a variety of services, from innovation strategies to process improvements to green manufacturing to training. It works with partners at on programs that put manufacturers in position to develop new customers, expand into new markets, and create new products. Training and education is offered in the areas of Lean Six Sigma, Lean Enterprise, Innovation & Business Growth, Quality Management Systems, Lean Supply Chain, and engineering and technical services. Visit the Genedge Alliance's website at: http://www.vpmep.org/index.php.

State Corporation Commission (SCC) 10% Savings on Electricity

Based on its goals of effecting a 10% reduction in electricity use by 2022, based on 2006 usage, the 2008 Virginia General Assembly directed the State Corporation Commission to develop an energy consumer education program to encourage electric energy efficiency and conservation in Virginia households, businesses, and institutions. ***Virginia Energy Sense*** is intended to offer a one-stop information source to guide consumers through specific steps to increase energy efficiency and reduce energy usage. According to its website, "reaching this goal would postpone the need to build four to five power generation stations. It will also save Virginians a net $200 million to $700 million".

Beginning in February 2011, ***Virginia Energy Sense*** invited businesses and organizations across the Commonwealth to become partners. As of January 1, 2012, more than 38 corporations, institutions and nonprofit groups agreed to share tips and best practices on being energy efficient with their employees or members. ***Virginia Energy Sense*** provides the informational resources for partners to distribute to their employees or members through periodic emails, newsletters, or other preferred forms of communication and encourages partners to share what steps they are currently taking to save energy. Through the expanding partnership program, ***Virginia Energy Sense*** has reached over 430,000 Virginians.
For more information on ***Virginia Energy Sense***, visit the website at: http://www.virginiaenergysense.org/cue/about.html.

Utility Programs and Incentives

Demand-Side Management promotes initiatives and programs to shift the timing of electricity use from peak to nonpeak demand periods. Electric utility customers are encouraged to reduce their electricity usage during peak hours to manage load congestion over the course of the day.

Several utilities that provide energy services in Virginia currently offer, or plan to offer, their customers programs and incentives to encourage energy efficiency through such efforts as residential energy load control, on-line usage audits, installation of high efficiency technologies such as lighting and HVAC systems, and home retrofits for lower income residential customers. These programs are approved by the State Corporation Commission and change over time. Links to utilities providing electric, natural gas, and water service to Virginia are provided below:

Dominion Virginia Power
www.dom.com

Appalachian Power Company (APCO)
www.appalachianpower.com

Tennessee Valley Authority (TVA)
http://www.tva.com/power/index.htm, http://www.energyright.com/

Old Dominion Power (ODP)
http://lge-ku.com/ku/about_odp.asp

Electric Cooperatives
http://www.odec.com

Municipal Power Producers - Municipal Electric Power Association of Virginia (MEPAV)
http://www.vml.org

James City Service Authority
http://www.jccegov.com

Virginia Natural Gas
http://www.virginianaturalgas.com

Columbia Gas of Virginia
http://www.columbiagasva.com

Washington Gas
http://www.washgas.com

Municipal Gas Utilities
http://www.charlottesville.org/index.aspx

Utilities often partner with dedicated efficiency firms to achieve these goals. An example of one such firm is O-power, a behavioral energy efficiency firm. Behavioral energy efficiency firms operate by using statistical software to analyze client energy consumption patterns and then inform energy users of their use patterns and best methods of energy reduction. Incorporating behavioral science techniques helps these firms achieve better results. By allowing energy consumers to see how their energy consumption compares with that of other similar consumers in their region, consumers are further incentivized to compete in reducing their consumption, especially during peak times.

By partnering with firms like O-power, utilities are able to help their customers meet their energy needs at much lower cost than that derived from the generation of additional energy. To put this in perspective, an O-power like program costs utilities an average of $0.025 per kilowatt hour saved while generating new, low-emission electricity costs approximately $0.05 to $0.15 per kilowatt-hour produced. Under proper regulatory conditions, these cost savings can increase value for both consumers and utility shareholders when compared against new generation.

Federal Incentives

Federal Tax Credits for Consumer Energy Efficiency

Homeowners can claim a federal tax credit of 30% of the cost with no upper limit for the installation of geothermal heat pumps, small wind turbines, and solar energy systems, through December 31, 2016. Existing homes and new construction qualify. Both principal residences and second homes qualify; rentals do not qualify for the tax credit. Another tax credit is available for residential fuel cell and microturbine systems of 30% of the cost, up to $500 per 0.5 kW of power capacity, through December 31, 2016. Existing homes and new construction qualify, but it must be the homeowner's principal residence. Rentals and second homes do not qualify for the fuel cells tax credit. Go to www.energystar.gov for further details about federal energy efficiency tax credits.

Commercial Buildings Tax Deduction

The federal Energy Policy Act of 2005 established a tax deduction for energy-efficient commercial buildings applicable to qualifying systems and buildings placed in service from January 1, 2006, through December 31, 2007. This deduction was subsequently extended through 2008, and then again through 2013 by Section 303 of the federal Energy Improvement and Extension Act of 2008 (H.R. 1424, Division B), enacted in October 2008.

A tax deduction of $1.80 per square foot is available to owners of new or existing buildings who install (1) interior lighting; (2) building envelope; or (3) heating, cooling, ventilation, or hot water systems that reduce the building's total energy and power cost by 50% or more in comparison to a building meeting minimum requirements set by ASHRAE Standard 90.1-2001. Energy savings must be calculated using qualified computer software approved by the IRS.

Deductions of $0.60 per square foot are available to owners of buildings in which individual lighting, building envelope, or heating and cooling systems meet target levels that would reasonably contribute to an overall building savings of 50% if additional systems were installed.

The deductions are available primarily to building owners, although tenants may be eligible if they make construction expenditures. In the case of energy efficient systems installed on or in government property, tax deductions will be awarded to the person primarily responsible for the system's design. Deductions are taken in the year when construction is completed.

Additional information is available from the *Commercial Building Tax Deduction Coalition* at www.efficientbuildings.org/.

FHA Energy Efficient Mortgages

The FHA allows lenders to add up to 100% of energy efficiency improvements to an existing mortgage loan with certain restrictions. FHA mortgage limits vary by county, state and the number of units in a dwelling. These mortgages were previously limited to $8,000. In June 2009, HUD announced the removal of the dollar cap. The maximum amount of the portion of an energy efficient mortgage allowed for energy improvements is now the lesser of 5% of:

- The value of the property
- 115% of the median area price of a single-family dwelling
- 150% of the Freddie Mac conforming loan limit

Department of Veterans Affairs (VA) Energy Efficient Mortgages

The VA insures EEMs to be used in conjunction with VA loans either for the purchase of existing homes or for refinancing loans secured by the dwelling. Homebuyers may borrow up to $3,000 if only documentation of improvement costs or contractor bids is submitted, or up to $6,000 if the projected energy savings are greater than the increase in mortgage payments. Loans may exceed this amount at the discretion of the VA. Applicants may not include the cost of their own labor in the total amount. No additional home appraisal is needed, but applicants must submit a Home Energy Rating (HER), contractor bids and certain other documentation. The VA insures 50% of the loan if taken by itself, but it may insure less if the total value of the mortgage exceeds a certain amount.

This mortgage is available to qualified military personnel, reservists and veterans. (See http://www.benefits.va.gov/benefits/ for more details). Applicants should secure a certificate of eligibility from their local lending office and submit it to a VA-approved private lender. If the loan is approved, the VA guarantees the loan when it is closed.

State Incentives

Energy Star Sales Tax Holiday

Virginia funds an annual Energy Star Sales Tax Holiday over the Columbus Day weekend in October that exempts both state and local sales taxes on Energy Star qualified products purchased by homeowners, for certain appliances and items that cost $2,500 or less and are made for non-commercial and personal use. Qualifying products include compact fluorescent bulbs (CFLs), ceiling fans, dehumidifiers, programmable thermostats, WaterSense labeled toilets, urinals, showerheads and high efficiency bathroom sink faucets. Eligible appliances include clothes washers, dishwashers, refrigerators and room air conditioners. In 2012, the General Assembly extended the sales tax holiday law through July 1, 2017. For more information about Energy Star and EPA's WaterSense programs, go to www.energystar.gov and www.epa.gov/watersense. Details about the state sales tax holiday guidelines are available through the Virginia Department of Taxation at: http://www.tax.virginia.gov/site.cfm?alias=EnergyStarQualifiedProductsHoliday.

Revolving Loan Funds

Through the ARRA stimulus law passed in 2009, the DMME funded a number of financial incentive programs throughout the State to provide 6 Revolving Loan Funds (RLFs) as well as 3 Loan Loss Reserve Funds (LLRFs) to assist homeowners with undertaking energy efficiency retrofit projects on their homes.

The RLFs funds were established by local governments and other governmental entities with ARRA Grant Funds to provide homeowners with loans to undertake energy efficiency improvements to their homes. These local government projects provided home energy audits to assist homeowners to decide which retrofit projects to undertake on their homes.

The RLFs are being established with financial institutions in the Richmond, Roanoke/ Blacksburg and Arlington County areas of the state. Homeowners can apply for market rate loans at these financial institutions to undertake comprehensive energy retrofit projects on their homes that will reduce energy consumption by 20% with the LLRF providing loan loss coverage in case a homeowner defaults on their loan.

In the Charlottesville and surrounding area, local housing foundations identified homeowners that were in need of a new heat pump for their homes. Once again, an ARRA funded RLF was established to fund the new heat pumps. Funds from the loan repayments will be made available as loans to other homeowners in the future to replace their heat pumps.

In the Bristol area, the Bristol Virginia Utilities Authority operates a RLF that provides loan assistance for home retrofit projects. Their loan program works with BVUA customers who are having difficulty paying their utility bills and where energy efficiency improvements could help to lessen their energy usage.

There are several state incentives for alternative fuel use. They are described in the section of the Virginia Energy Plan on Alternative Fuel and Advanced Technology Vehicles and available on the website of the Alternative Fuels Data Center at www.afdc.energy.gov/afdc/laws/.

Virginia's Residential Sector

SECTOR DEFINITION AND BACKGROUND INFORMATION

The residential sector can be loosely defined as the sector of the economy that consists of private households and living quarters.[8] For energy planning, the United States Department of Energy defines the residential sector as single- and multi-family housing units and mobile homes. Typical energy consumption in the residential sector is driven largely (about ½) by heating and cooling needs with the remainder of consumption coming from lighting, electronics, and household appliances.[9]

In 2011, 26.5% of total energy consumption in Virginia was attributed to the residential sector.[10] This is approximately 5% greater than the 21.05% of total energy consumption attributed to the residential sector at the national level in the same year. "Virginia homes are typically newer and larger than homes in other parts of the country."[11] Virginia's demographic characteristics are summarized in the table below.

Table 1. Residential Population and Housing Characteristics 2010

	Virginia	US
Population 2013	8,260,40	316,128,83

[8]EIA: *Definitions, Sources and Explanatory Notes.* 2014

[9] EIA: *Household Energy Use in Virginia*. 2009

[10] EIA: *Virginia State Profile and Energy Estimates.* 2014

[11] EIA: *Residential Energy Consumption Survey (RECS.)* 2014

	5	9
Housing Units 2012	3,398,286	132,452,405
Households, 2008-2012	3,006,219	115,226,802
Persons per household, 2008-2012	2.59	2.61
Homeownership rate, 2008-2012	67.8%	65.5%
Housing units in multi-unit structures 2008-2012	67.8%	65.5%

Source: 2010 census data[12] [13] [14]

METRICS OF CURRENT CONSUMPTION

Energy Use

Virginia residential customers consumed 632 trillion Btus of energy in 2011 – 3% of US total residential consumption – on which they spent $6761 million – 2.7% of US residential sector expenditures.[15] "Virginia households consume an average of 86 million Btu per year, about 4% less than the U.S. average."[16]

A breakdown of the sources utilized to provide this energy is shown below in table 2. The table outlines direct energy sources and does not include indirect sources such as the coal used to provide retail electricity to residential customers.

Table 2: 2011 Residential Sector Energy Consumption by Fuel Type (Trillion Btus)

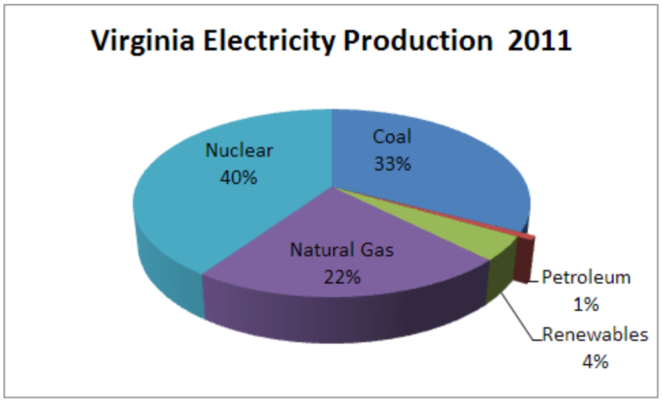
Coal	Natural Gas	Fuel Oil	Kerosene	Propane	Wood
0.0	81.4	16.4	0.9	13.0	14.4
Geothermal	Solar	Retail Electricity Sales	Net Energy	System Energy Losses	Total
0.8	1.3	156.2	284.3	347.8	632.0

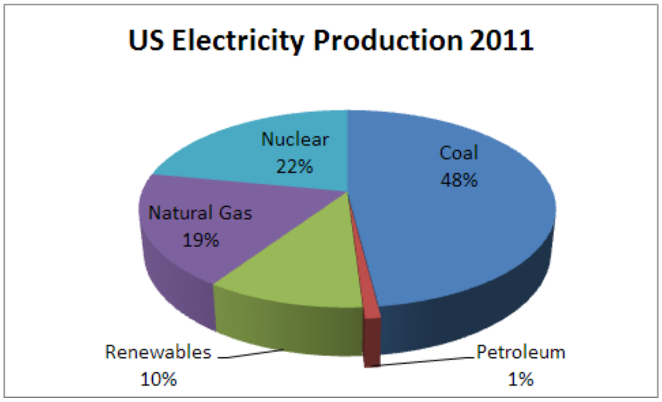
Source: EIA Table C5.[17]

[12] US Department of Commerce: *Virginia: 2010 Summary Population and Housing Characteristics*. 2010
[13] US Department of Commerce: *Virginia: 2010 Summary Population and Housing Unit Counts*. 2010
[14] US Census Bureau: *State and County QuickFacts Virginia.* 2014
[15] EIA: *Virginia State Profiles and Energy Estimates: Virginia Profile Data-Prices.* 2014
[16] EIA: *Household Energy Use in Virginia*. 2009
[17] EIA: *Table C5. Residential Sector Energy Consumption Estimates.* 2011

To get a more detailed picture of energy use in the residential sector we must look at Virginia's overall electricity mix. Figures 1 and 2 illustrate that when these are accounted for, the residential sector consumes more coal, natural gas and nuclear power than the table above illustrates.

Figures 1 and 2: Fuel Sources for Electric Power Generation in Virginia and the US in 2011 (% Total of Btus)





Source: EIA Table C5.[18]

An important note, Virginians use electricity to heat their homes at a rate greater than the national average, as shown below.

Table 3: Virginia Fuel Use For Home Heating, 2012.

	Virginia	US Average
Natural Gas	34.1%	49.4%
Fuel Oil	7.0%	6.5%
Electricity	50.9%	35.5%
Propane	4.5%	5.0%
Other/None	3.4%	3.6%

Source: EIA Virginia Profile Analysis[19]

In Virginia, one in three residential units uses natural gas for home heating. This accounts for approximately one-fourth of all natural gas delivered to end users in the state.[20]

Energy Costs and Prices

18 Ebit.

19 EIA: *Virginia State Profiles and Energy Estimates: Virginia Profile Data-Prices.* 2014

20 EIA: *Virginia State Profiles and Energy Estimates: Profile Analysis.* 2014

Current energy prices for residential consumers can be found in the table below.

Table 4: Residential Energy Prices 2014

	Electricity (¢/kWh)	Natural Gas ($/thousand sf)
Virginia Average	10.60	12.60
National Average	13.13	12.96

Source: Virginia Profile Data-Prices [21]

“Average electricity consumption and costs are higher for Virginia households than the national average, but similar to those in neighboring states where electricity is the most common heating fuel.”[22]

PROJECTIONS

1. **Key drivers of ongoing changes in consumption** - There are 2 main drivers changing energy consumption trends in Virginia that push consumption in opposite directions. Increasing energy efficiency, especially in newer homes tends to reduce the amount of energy needed per household unit. These newer homes, however, are also significantly larger than older homes have typically been. This has the effect of increasing energy use per housing unit.[23]

2. **Historical consumption patterns** - Figure 3 below shows that total residential energy consumption in Virginia has increased from 192 Trillion Btus in 1960 to over 632 Trillion in 2011. This represents an average increase of 9.49 Trillion Btus per year. [24]

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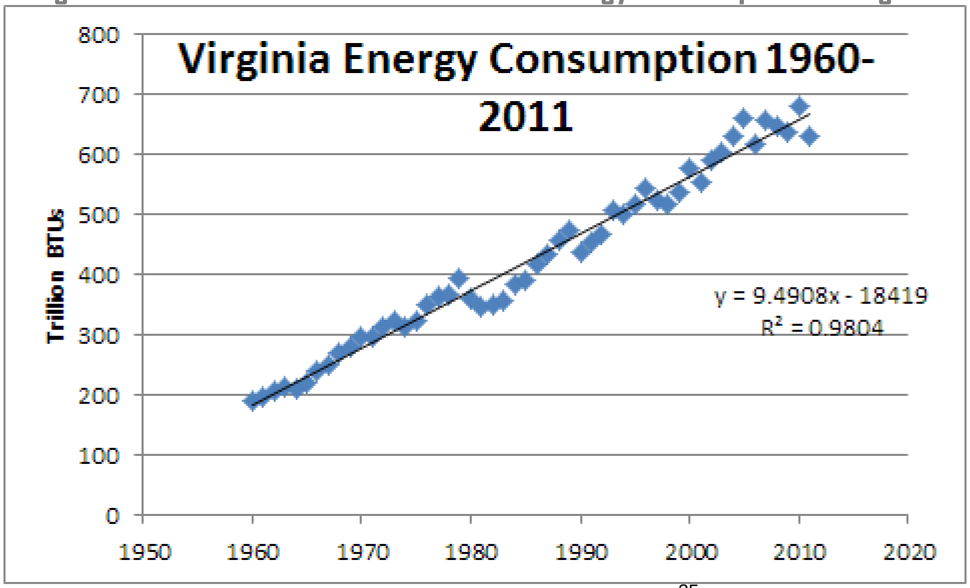
[21] EIA: *Rankings: Average Retail Price of Electricity*. 2014

[22] EIA: *Household Energy Use in Virginia*. 2009

[23] Ebit.

[24] EIA: *Table CT4. Residential Sector Energy Consumption1960-2011, Virginia*. 2014

Figure 3: Historical Data on Residential Energy Consumption in Virginia



Source: EIA Table CT4 Virginia[25]

1. **Projections for 5, 10, and 20 years** Based on the historical trend, should energy consumption continue to grow at its historical rate the following rough estimates of future energy use can be derived.

- Consumption in 2019: 742.92 Billion Btus
- Consumption in 2024: 790.37 Billion Btus
- Consumption in 2034: 885.29 Billion Btus

Virginia's Commercial Sector

SECTOR DEFINITION AND BACKGROUND INFORMATION

The EIA defines the commercial sector as all energy consuming, non-transportation activities other than whose principal activities are neither residential nor industrial. Thus the commercial sector is incredibly varied and diverse, including all private sector operations outside housing, manufacturing, and resource extraction.[26] It is important to note that under this definition much of the energy consumption in the MUSH sector (municipalities, universities, schools and hospitals) is likely to be included in EIA commercial sector data. According to the EIA, "the vast majority of energy use in this sector occurs in buildings, to maintain the building environment and provide building based services."[27]

In 2012 the Virginia commercial sector consumed 25.1% of all the energy consumed in the commonwealth. This amounted to 590.8 Trillion Btus of energy that year and made the commercial sector the second largest consumer of energy in the state behind the transportation sector.[28] Over time this sector has become increasingly energy efficient as measured by the

[25] Ebit.
[26] EIA. *Commercial Building Sector*. 1999
[27] Ebit.
[28] EIA: *Virginia State Profile and Energy Estimates: Profile Overview*. 2012

gross product produced in this sector per kWh of electricity input adjusted for inflation. Despite these increases in efficiency in Virginia's commercial sector, growth has outpaced efficiency gains leading to a net increase in sector energy consumption over the last several decades.[29]

CURRENT CONSUMPTION AND EXPENDITURE

In 2011 Virginia's commercial sector consumed 607.7 Btus of energy, 16.9 more Btu's of energy than in 2012. The sources of this energy are shown in Table 5 below.

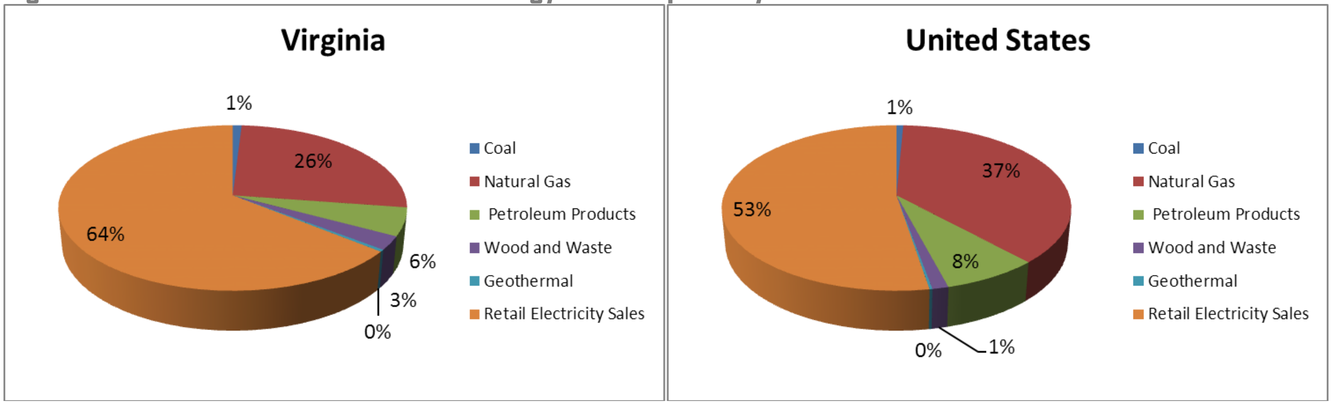
Table 5: Commercial Sector Energy Consumption by Source- Virginia, 2011 (Billion Btus)

	Coal	Natural Gas	Petroleum Products	Wood and Waste	Geothermal	Retail Electricity Sales	Net Energy	Electrical System Energy Losses	Total
Virginia	2.4	66	13.7	6.6	1	160.5	250.2	357.5	607.7
United States	61.7	3,224.70	666.1	111.7	19.7	4,531.30	8,604.30	9,347.60	17,951.90

Source: *EIA Table C6. Commercial Sector Energy Consumption Estimates, 2011*[30]

As can clearly be seen, the majority of the total energy used by the sector was through electricity consumption. On average for every Btu of retail electricity consumed by this sector 2.23 Btus of energy were lost through electrical system energy losses. As a result of this, electrical system energy losses accounted for over 58.8% of all energy consumption in the commercial sector. By comparison, at the national level, the commercial sector consumes less electricity as a proportion of its overall energy consumption as show in Figures 4 and 5 below and more natural gas.

Figures 4 and 5: Commercial Sector Energy Consumption by Source, 2011.



Source: *EIA Table C6. Commercial Sector Energy Consumption Estimates, 2011*[31]

As a result of these patterns of consumption, the US on aggregate loses only 52% commercial sector energy through electrical system losses, 8% less than Virginia.

In order to pay for this energy, Virginia's commercial sector spent $4.73 Billion dollars in 2011 alone. Table 6 below shows that once again most of this expenditure came from the purchase

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[29] USDOE: Clean Energy in My State. 2014
[30] EIA *Table C6. Commercial Sector Energy Consumption Estimates, 2011*. 2014
[31] Ebit.

of retail electricity.[32]

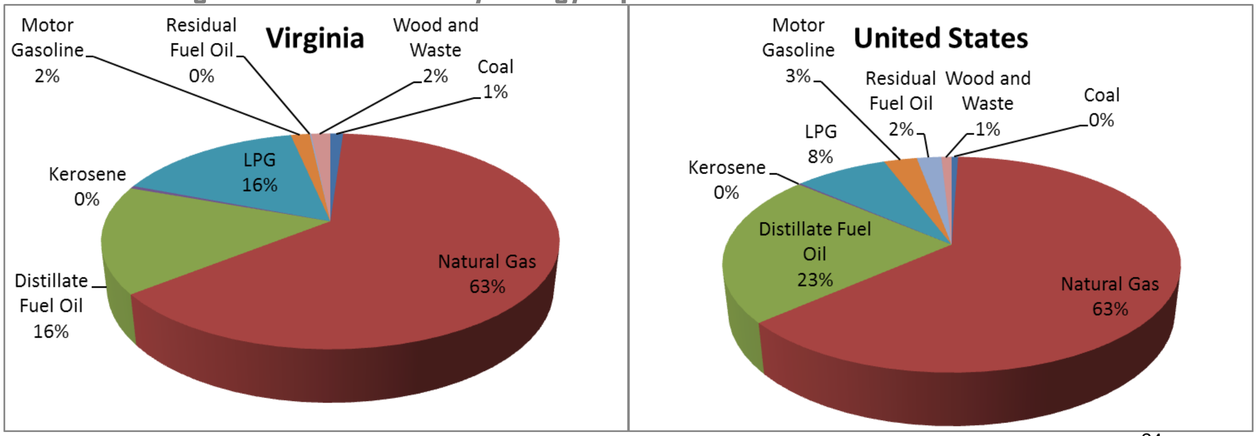
Table 6: Commercial Sector Energy Expenditure, Virginia 2011. (Millions of Dollars)

	Total Primary Energy	Retail Electricity Sales	Total Energy
Virginia	984.9	3,742.90	4,727.80
% of Total	20.8%	79.2%	100.0%
United States	45,044.50	135,926.50	180,970.90
% of Total	24.9%	75.1%	100.0%

Source: EIA Table E11.[33]

This illustrates two main points: first, Virginia's commercial sector pays more as a percentage of its energy expenditures for retail electricity than the US commercial sector does. Second, because retail electricity expenditures are, on a percentage basis, higher than electricity consumption, electricity is a relatively expensive form of energy use in this sector compared to current alternatives. These alternatives which constitute 36% of Virginia commercial sector energy consumption and only 21% of total expenditures are shown below in Figure 6. Figure 7 shows a comparison of these against, primary energy use in the US commercial sector.

Figures 6 and 7: Primary Energy Expenditure: Commercial Sectors 2011.



Source: EIA Table E11. Commercial Sector Energy Expenditure Estimates, 2011[34]

This table shows that while Virginia uses, as a percentage, less primary energy in its commercial sector than the US, the energy mix of this primary energy is similar with the exception that Virginia uses less distillate fuel oil and more liquefied petroleum gas.

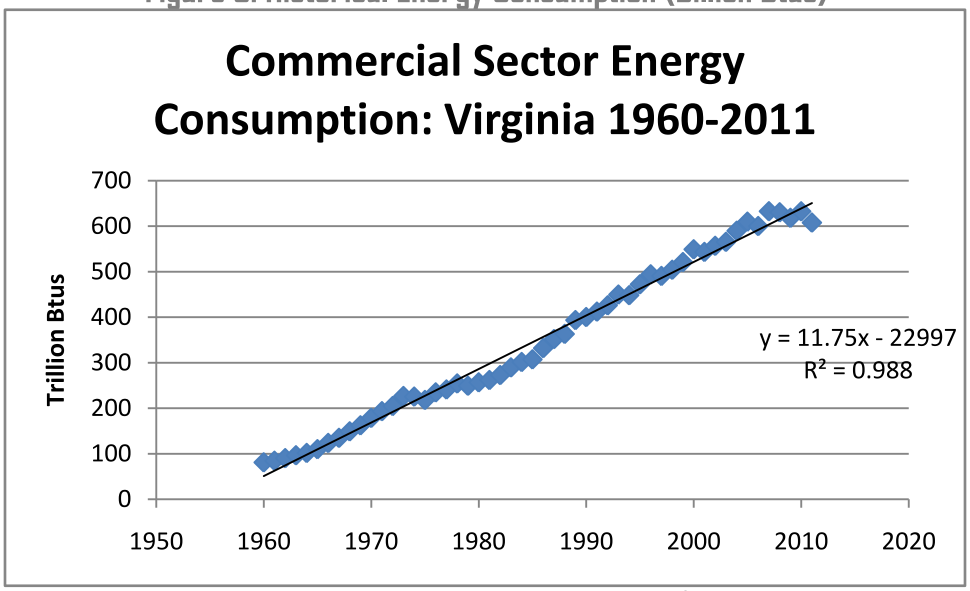
HISTORICAL CONSUMPTION AND PROJECTIONS

Energy consumption in Virginia's commercial sector has steadily risen over the past 50 years at approximately 11.759 Billion Btus a year.[35] This growth has occurred despite increases in

[32] EIA: *Table E11. Commercial Sector Energy Expenditure Estimates.* 2011
[33] Ebit
[34] EIA *Table E11. Commercial Sector Energy Expenditure Estimates.* 2011.
[35] EIA *Table CT5. Commercial Sector Energy Consumption Estimates, Selected Years, 1960-2011 Virginia*

energy efficiency measured in gross output per Btu as mentioned in the introduction of this section. This trend of growing commercial sector energy consumption matches that of the US overall.[36] In the US, the main drivers of this growth have been increases in the absolute number of commercial buildings and an even greater increase in the total amount of commercial floorspace which has outpaced efficiency gains. Despite this, both Virginia and the US have seen some leveling off of energy consumption in this sector in recent years. Figure 8 below shows the historical trend of energy consumption in Virginia's commercial sector from 1960 to 2011.

Figure 8: Historical Energy Consumption (Billion Btus)



Source: EIA Table CT5 Virginia[37]

Based on this historical data, and assuming that historical trends continue into the near future, Virginia's commercial sector can be expected to roughly consume the following amounts of energy in the following years.

- 2019: 744.421 Billion Btus
- 2024: 803.216 Billion Btus
- 2034: 920.806 Billion Btus

Virginia's Industrial Sector

SECTOR DEFINITION AND BACKGROUND INFORMATION

The EIA defines the industrial sector as "An energy-consuming sector that consists of all facilities and equipment used for producing, processing, or assembling goods The industrial sector encompasses the following types of activity: manufacturing (NAICS codes 31-33); agriculture, forestry, fishing and hunting (NAICS code 11); mining, including oil and gas extraction (NAICS code 21); natural gas distribution (NAICS code 2212); and construction

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[36] EIA *Table CT5. Commercial Sector Energy Consumption Estimates, Selected Years, 1960-201United States*
[37] EIA *Table CT5. Commercial Sector Energy Consumption Estimates, Selected Years, 1960-2011 Virginia*

(NAICS code 23).”[38] Unlike the commercial and residential sectors, the main driver of energy consumption in the industrial sector is process heat and cooling and powering machinery. To a lesser extent, facility heating, air conditioning and appliances also drive energy consumption. Of addition and important note, fossil fuel inputs for manufactured products, such as those needed in plastic or pesticide manufacture are also counted in industrial sector energy consumption.[39]

Virginia’s industrial sector is incredibly diverse with multiple different industries contributing to its vibrancy. Sectors of Virginia’s economy that contributed $5 Billion dollars or more to the annual payroll in the state are listed in Table 7 below.

Table 7. Major Sectors of Virginia’s Economy by Laborforce

Selected 2012 Labor Statistics		
Sector	**Paid Employees**	**Annual Payroll ($1000)**
Construction	168,289	8,128,619
Manufacturing	232,037	12,003,730
Wholesale Trade	103,377	6,085,181
Retail Trade	415,037	10,235,129
Information	95,292	7,869,285
Finance and Insurance	158,126	11,935,932
Professional, Scientific, and Technical Services	421,502	36,700,334
Management of Companies and Enterprises	63,693	6,458,223
Management and Remediation Services	245,675	9,847,709
Health Care and Social Assistance	407,055	18,338,902
Accommodation and Food Services	318,037	5,122,916

Source: *2012 County Business Patterns*[40]

There is a fine line between what in this table constitutes the commercial and what constitutes the industrial sector. Of the sectors shown here manufacturing and construction are squarely part of the industrial sector while other sectors such as the professional, scientific and technical services sector are a mix of both commercial and industrial sectors.

CURRENT CONSUMPTION AND EXPENDITURE

In 2011 Virginia’s industrial sector consumed an estimated 436.5 Trillion Btus of energy according to the United States Energy information administration.[41] Table 8 shows this energy consumption by source.

Table 8: Virginia Industrial Sector Energy Consumption by Source, 2011.

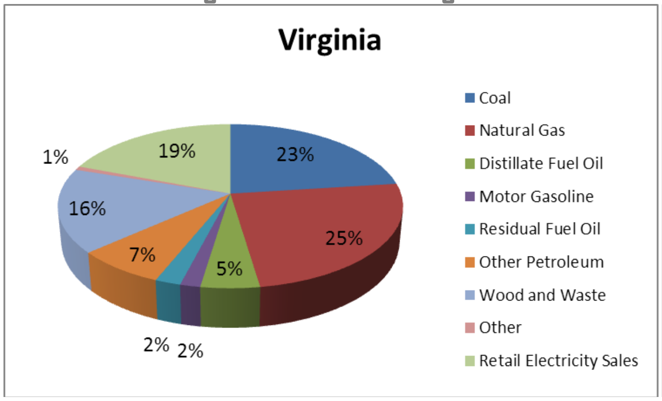
[38] EIA. *Petroleum and Other Liquids: Definitions Sources and Explanatory Notes.* 2014
[39] Ebit.
[40] United States Census Bureau. *2012 County Business Patterns.* 2012
[41] EIA *Table C7. Industrial Sector Energy Consumption Estimates.* 2011

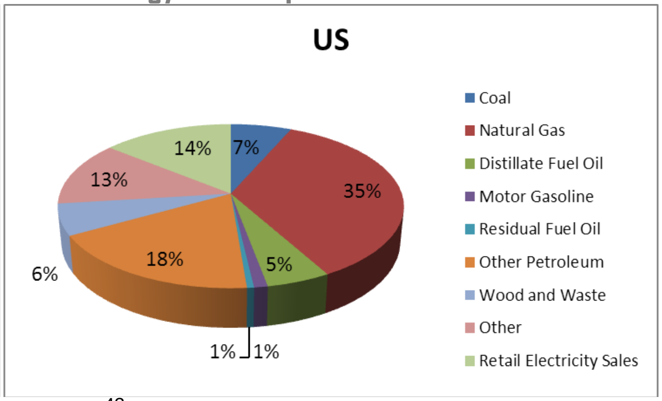
Trillion Btus	Coal	Natural Gas	Distillate Fuel Oil	Motor Gasoline	Residual Fuel Oil	Other Petroleum	Wood and Waste	Other	Retail Electricity Sales	Net Energy	Electrical System Energy Losses	Total
Virginia	70.3	75.3	14.6	5	6.4	22.4	50.7	2.3	58.7	305.6	130.8	436.5
US	1,566.70	8,410.80	1,242.50	261.7	134.9	4,329.30	1,473.60	3040.3	3,382.40	23,825.30	7,098.50	30,923.80

Source: EIA Table C7.[42]

Figures 9 and 10 below show how this consumption compared against consumption trends in the US industrial sector in the same year.

Figures 9 and 10: Virginia and U.S. Industrial Energy Consumption 2011.





Source: EIA Table C7.[43]

As can be seen here, in percentage terms, Virginia's industrial sector consumes more coal, wood and waste, and retail electricity and less natural gas and petroleum products than the Nation overall. Of additional note, Virginia consumes vastly less liquefied petroleum gas than the US on a percentage basis, which makes up the vast majority of the "other" category for both Virginia and the US in figures 9 and 10.

Virginia's industrial sector spent an estimated $3.08 Billion dollars for this energy in 2011.[44] Table 9 below shows these expenditures by source both for Virginia and for the US and their percentage of overall energy expenditure.

Table. 9: Industrial Sector Energy Expenditure by Source. 2011

Millions of Dollars	Coking Coal	Steam Coal	Natural Gas	Distillate Fuel Oil	LPG	Motor Gasoline	Residual Fuel Oil	Other Petroleum	Wood and Waste	Retail Electricity	Total Energy
Virginia	207.7	144.1	426	349.8	57.5	142	107.1	411.2	120.3	1,118.00	3,083.60
% of Total	6.74%	4.67%	13.82%	11.34%	1.86%	4.61%	3.47%	13.34%	3.90%	36.26%	100.00%
United States	3,885.40	3,452.60	37,511.40	30,483.90	48,840.20	7,337.10	2,086.10	47,436.20	3,272.80	64,566.10	249,213.60
% of Total	1.56%	1.39%	15.05%	12.23%	19.60%	2.94%	0.84%	19.03%	1.31%	25.91%	100.00%

Source: EIA. *Table E12.*[45]

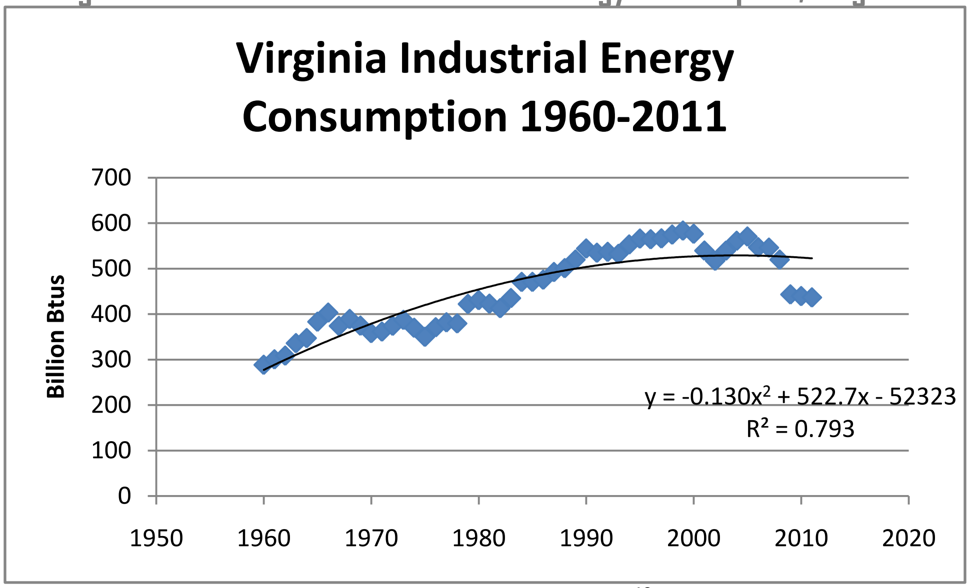
[42] Ebit.
[43] Ebit.
[44] EIA. *Table E12. Industrial Sector Energy Expenditure Estimates*. 2011
[45] Ebit.

As the table demonstrates, Virginia's industrial sector spends a great deal more on coal and retail electricity, in percentage terms, than the nation does as a whole. It can also be seen, when comparing Tables 2 and 3 that the use of electricity in this sector is relatively expensive as retail electricity costs are disproportionately greater than electricity consumption when both are expressed as percentages of total cost and consumption respectively. However, this may be an oversimplification since other fuel inputs are often used in industry to generate electricity on site. When the additional costs of turning other energy inputs into electricity onsite are factored into non-retail electricity costs, retail electricity expenditures may appear more competitive than they seem at first glance.

HISTORICAL CONSUMPTION AND PROJECTIONS

Figure11 below shows the total amount of energy consumed by the industrial sector from 1960-2011.

Figure 11. Industrial Sector Historical Energy Consumption, Virginia.



Source: EIA Table CT6.[46]

This sector is incredibly sensitive to economic booms and recessions and thus historical energy consumption in this sector can fluctuate substantially from year to year. This as well as a general trend in OECD countries towards a leveling off of energy consumption in this sector makes forecasting consumption in this sector incredibly difficult. As can be seen above, a simple linear trend does not do a good job of capturing the historical trend of energy consumption in this sector. A polynomial trend while achieving a higher coefficient of determination also is of limited use. While there is a recent trend in the last 2 decades of industrial sector energy consumption leveling off in Virginia, the drastic reduction in energy use observed from 2009 to 2011 are likely largely driven by the 2007 recession and subsequent slow economic recovery.

Assuming historical trends continue, it is likely that energy consumption in this sector is will continue leveling off or even decline in the near to medium future. Extrapolating on the current

[46] EIA. *Table CT6. Industrial Sector Energy Consumption Estimates, Selected Years, 1960-2011*. 2014

trend line we would expect to see the following levels of energy consumption by Virginia's industrial sector in the following years.

2019: 604.4 Billion Btus.
2024: 582.0 Billion Btus
2034: 517.7 Billion Btus

Municipal, University, State and Hospital (MUSH) Energy Use in Virginia

SECTOR DEFINITION AND BACKGROUND INFORMATION

The MUSH market in Virginia covers a wide range of building types and owners. There are government owned and privately owned buildings that range in operation from typical office space to biosafety laboratories and acute care hospitals.

The Municipal sector is made up of 95 counties, 38 towns and 39 cities.[47] Each municipality provides services to citizens and maintains a building stock.

The University sector is made up of over 80 universities and colleges.[48] Almost half of the facilities are state owned institutions. The state universities, colleges and community colleges serve over 70% of the student population.[49]

The State sector is comprised of over 50 state agencies[50] and departments with over 100,000 employees[51] that serve the citizens of the Commonwealth.

The Hospital sector has over 100 hospitals[52] with over 19,000 patient beds.[53] These hospitals include multi-site healthcare systems, independent community hospitals, state owned hospitals and behavioral health facilities.

CURRENT CONSUMPTION AND EXPENDITURE

The MUSH sector consumes approximately 43.43 Trillion BTUs per year at an annual cost of $758 million.[54] This includes electricity, natural gas, petroleum products, coal, wood and other fuels.

Fuel Type	BTU (Trillion)	% of Total Consumption	Annual Cost (Million)
Electricity	21.46	49.4%	$540.4
Natural Gas	15.42	35.5%	$162.0
Petroleum Products	1.48	3.4%	$36.0
Coal	4.99	11.5%	$18.4
Wood and Other Fuels	0.09	0.2%	$1.2

[47] Commonwealth of Virginia: Commonwealth Data Point: Transparency at Work in Virginia. 2014
[48] State Council of Higher Education for Virginia: Virginia Colleges and Universities. 2014
[49] IES: IPEDS Data Center. 2014
[50] Commonwealth of Virginia: Agency Website Directory. 2014
[51] USCB: Government Employment and Payroll 2014
[52] VHHA: Map of VHHA Hospital and Health System Members 2014
[53] AHD: Individual Hospital Statistics for Virginia. 2014
[54] Commonwealth of Virginia: Commonwealth Data Point: Transparency at Work in Virginia. 2014

Total	43.43	100%	$758

EIA data on energy pricing[55] was used to determine energy consumption based on cost data collected from Commonwealth Data Point.[56]

HISTORICAL CONSUMPTION AND PROJECTIONS

Over the last few years the electricity and natural gas consumption has been increasing in this sector. Coal consumption has been declining and petroleum products have been stable. The reduction in coal consumption and the increase in natural gas consumption are related; the environmental impacts of coal and the low price of natural gas are encouraging the market to convert to natural gas.

These trends are expected to continue. Electricity and natural gas consumption will increase slowly as the sector constructs new buildings and maintains the existing stock. Coal will continue to decrease as natural gas increasingly becomes the preferred fuel. Petroleum products should remain stable since the areas and equipment that rely on these fuels often have limited fuel choices.

Virginia's Transportation Sector

SECTOR DEFINITION AND BACKGROUND INFORMATION:

The Virginian transportation sector is defined as the sector of the economy devoted to the movement of people and goods within the state. Energy use in this sector thus includes all the energy used to transport these people and goods by road, rail, air, water or pipeline. The main drivers of transportation energy demand are economic activity and trade with additional drivers such as urbanization, fuel market prices, land use patterns and travel behavior contributing to demand to a lesser degree.[57]

The transportation sector uses more energy than any other sector of Virginia's economy having accounted for approximately 747.3 Billion Btus, 31.7% of the state's total energy use, in 2012. By comparison the commercial sector, the second most energy intensive sector after transportation, accounted for only 25.1% of the state's energy consumption in the same year.[58] For further comparison the transportation sector accounted for 31.3%, 27.5% and 24.7% of energy consumption in the neighboring states of Maryland, North Carolina and West Virginia respectively.[59,60,61]

The single largest driver of this energy consumption came from motor vehicles. The registered motor vehicle fleet consisted of 6,222,928 vehicles in 2010. Of these, 3,510417 were automobiles, 15,823 were Buses, 2,622,554 were trucks and 74,134 were motorcycles.

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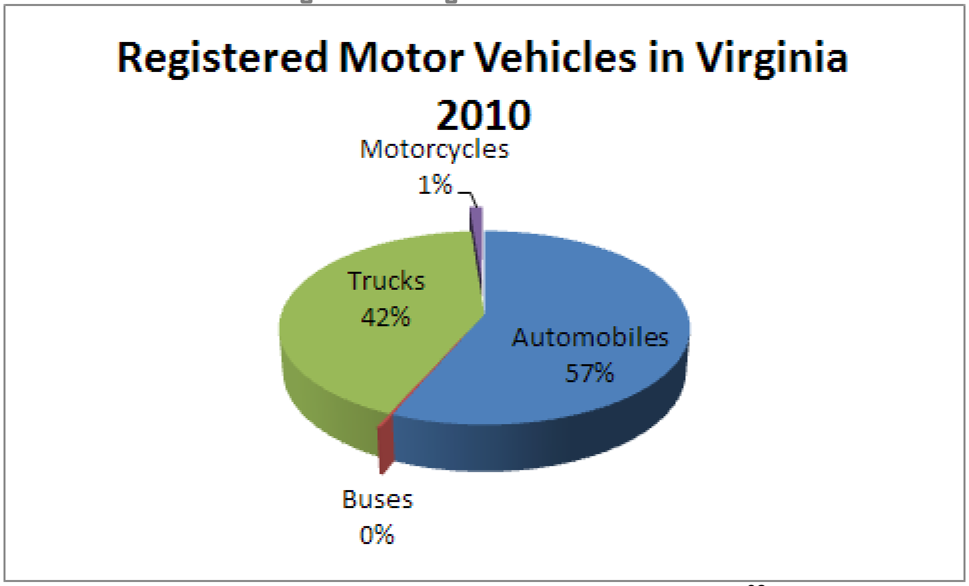
[55] EIA: Virginia State Profile and Energy Estimates: Profile Data 2014
[56] Commonwealth of Virginia: Commonwealth Data Point: Transparency at Work in Virginia. 2014
[57] EIA: *International Energy Outlook* 2013
[58] EIA: *Virginia State Profile and Energy Estimates:* 2014
[59] EIA: *Maryland State Profile and Energy Estimates:* 2014
[60] EIA: *North Carolina State Profile and Energy Estimates:* 2014
[61] EIA: *West Virginia State Profile and Energy Estimates:* 2014

Figure 12: Virginia's Vehicle Fleet



Source: US Department of Transportation[62]

CURRENT CONSUMPTION AND EXPENDITURE

In 2011 the Virginia Transportation sector consumed an estimated 712.3 Billion Btus of energy. Motor gasoline consumption was the main driver of energy use in this sector. The table below shows a breakdown of energy consumption in Virginia in 2011 by fuel type.

Table 9: Virginia Transportation Energy Consumption by Fuel Type 2011 (Billion Btus)

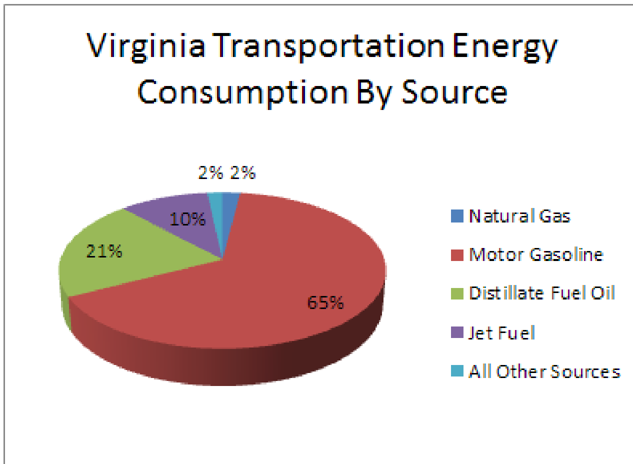
Natural Gas	14.4
Motor Gasoline	465.5
Distillate Fuel Oil	147.7
Jet Fuel	72.4
All Other Sources	12.2

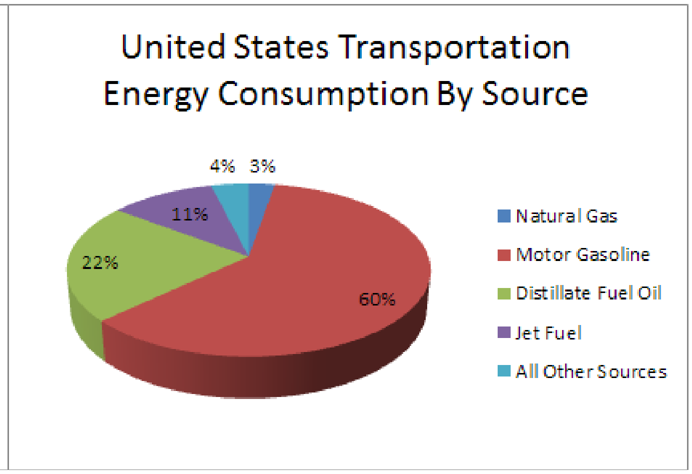
Source: EIA Table C8[63]

[62] US DOT *State Motor-Vehicle Registrations* – 2010

Figures 13 and 14 demonstrate that Virginia used more motor gasoline and significantly less natural gas as a proportion of its transportation energy mix than the United States overall.

Figs 13 and 14: Virginia and US Transportation Energy Consumption 2011





Source: EIA Table C8[64]

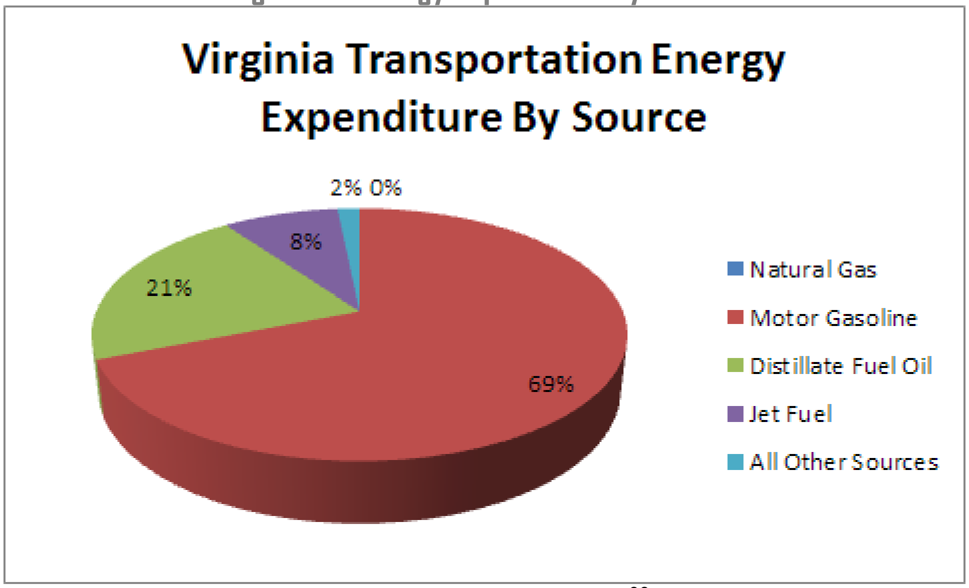
In 2011 this energy used to fuel Virginia's transportation sector cost the commonwealth an estimated 19.342 billion dollars.[65] This expenditure largely reflected overall consumption but was also affected by market prices at the time. This is illustrated in Table 10 and Figure 15 below.

Table 10: Energy expenditure by Source: Virginia 2011

Virginia Transportation Energy Expenditure By Source	Millions of Dollars
Natural Gas	0.7
Motor Gasoline	13342.9
Distillate Fuel Oil	4075.3
Jet Fuel	1617.2
All Other Sources	305.8

[63] EIA: *Table C8. Transportation Sector Energy Consumption Estimates* 2010
[64] Ebit.
[65] EIA: *Table E13. Transportation Sector Energy Expenditure Estimates, 2011*

Figure 15: Energy Expenditure by Source



Source: EIA Table E13.[66]

HISTORICAL CONSUMPTION AND PROJECTIONS

Virginia's energy consumption in the transportation sector has grown steadily over the past several decades, increasing at an average rate of 932.7[67] million Btus per year since 1960. This growth has not been smooth, however, with high levels of growth during economic booms and stagnant or even negative growth during recessionary periods. Recent years have seen marked decreases in transportation energy use in Virginia. This is likely primarily driven by the great recession of 2007-08 and subsequent slow economic recovery. Other factors that may have affected some reduction in transportation energy use in Virginia include the federal cash for clunkers program, increasing federal vehicle efficiency standards, and several years of continuing high oil prices.[68]

Considering the various factors that affect energy consumption in the transportation sector, it is difficult to predict future consumption. Based on the historical trend however and assuming business as usual continues for the next 10 years. We would expect Virginia to consume approximately 792.275 billion Btus of energy by 2019 and 838.4 billion Btus of energy by 2024. The current trend in transportation energy consumption can be found in Figure 16 below.

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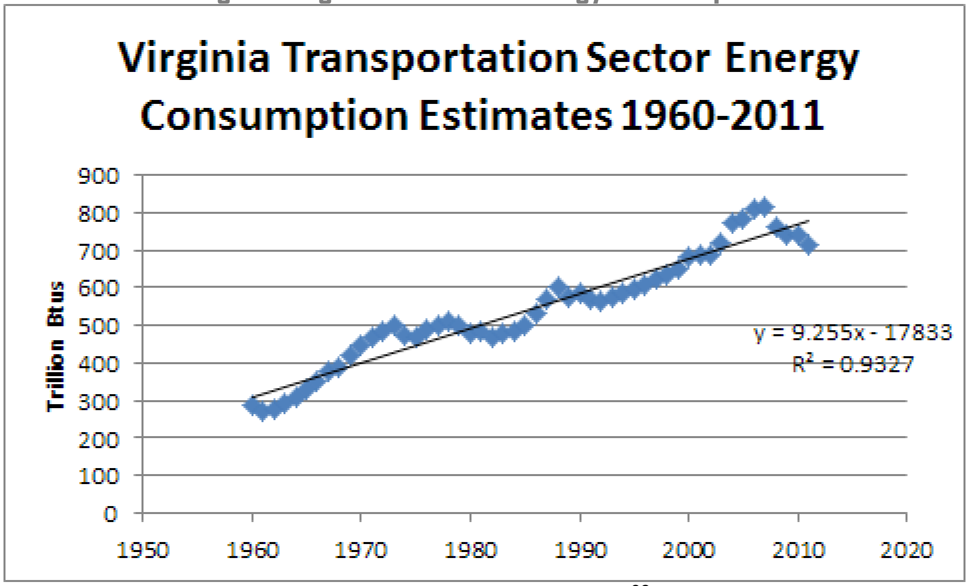
[66] Ebit.
[67] EIA *Table CT7 1960-2011, Virginia* 2011
[68] EIA: *Virginia State Energy Profile,* 2011

Fig 16: Virginia Historical Energy Consumption



Source: EIA Table CT 7[69]

- Consumption in 2019: 792.275 Billion Btus
- Consumption in 2024: 838.4 Billion Btus
- Consumption in 2034: 930.65 Billion Btus

Conclusion

Virginia's growing economy will need increasing amounts of energy over the next ten years as more computers, electric appliances, and equipment are placed in use. Virginia will need a broad mix of energy sources to accommodate for this growth. At the same time, Virginia will also need to reduce the energy growth rate through conservation and efficiency measures.

Energy efficiency and conservation offer Virginians the most cost-effective and most readily deployable method to manage the Commonwealth's energy future. As Virginia's population, business community, and energy needs continue to grow, energy efficiency and conservation can defer the need for new energy-supply facilities and the associated environmental burdens they place on land, water and air resources. Energy efficiency is a true "pollution prevention" technique, because at its core is source reduction and improved production efficiency. Improvements to process efficiency result in the decreased use of materials, labor, and wastes. The efficient use of energy results in decreased use of resources, less air pollution, and therefore, cost savings. [70]

[69] EIA *Table CT7 1960-2011, Virginia* 2011
[70] http://www.dmme.virginia.gov/DE/ConsumerInfo/consumerinfo.shtml

SECTION 10 – RESEARCH AND EDUCATION

Research and development (R&D) will continue to drive innovation and growth in Virginia's advanced energy industry. To maximize the value and impact of R&D, Virginia can build on its strong base of existing research institutions and innovative companies to create and attract new businesses, build Virginia's workforce, and solve environmental and energy challenges. Pursuing federal research dollars can multiply the impact of Virginia's own expenditures and investments. Virginia is already 3rd in the nation in terms of overall federal R&D funding, based on the latest data available.

State-of-the-art technology and systems are required for the Commonwealth to effectively compete on a national and global scale. But there cannot be successful adoption of advanced energy technology and processes without this key demand driver in place: a formidable Virginia workforce that is appropriately skilled, experienced, innovative, and highly adaptable.

The U.S. Bureau of Labor Statistics' Virginia Green Workforce Estimates are skewed heavily to U.S. military and federal government employment. With these jobs removed, the Commonwealth's green jobs concentration drops to an unremarkable 2.6 percent share of workforce. As is the case with workforces in other states, the number of Virginians employed in green jobs remains relatively small, at 2.6 percent of workforce, perhaps an estimated 100,000 Virginians--from within a population of 8.3 million people.

Virginia can reduce barriers to innovation, and make more of the opportunities and substantial scientific and technical resources it has already developed. One of the most important recurring elements is finding new ways to secure existing federal R&D funds and if possible expand Virginia's share to counter shrinking federal investment. In addition, Virginia should demonstrate Energy Incubators and expand on initial results by providing state support and funds to emerging energy technology incubators, such as the spin-off smart grid companies attracted to Virginia Tech and Blacksburg.

Current Environment in Research

There is a State role in bringing together research and businesses based on new technology and services with Virginia's major energy businesses to develop applications and markets that will serve Virginia's changing energy and environmental needs. Research, Development and Demonstration (RD&D) is essential to growth and productivity in the energy industry just as it is for the information technology, biotechnology, communications, medical and other sectors. Clean energy integration into the existing energy system is an important target of opportunity for research and demonstration. There is also fruitful RD&D for specific energy technologies, Virginia interests align very well with national research programs in solar energy, wind, bioenergy, hydropower, building efficiency technologies, smart grid, advanced vehicles and advanced manufacturing. The Department of Defense (DoD) is investing heavily in developing and deploying new energy technologies to reduce the agency's environmental impact and become more resilient.

Virginia is already one of the largest recipients of Federal R&D expenditures, 14th in terms of funds from the Department of Energy, 2nd in terms of DoD funding, and 3rd in overall Federal R&D funding in 2010.[1] Virginia has a concentration of high-technology companies involved in Federal contracting and world-class universities that are already engaged in clean energy development including the Center for Smart Power Grids at George Mason University, the Virginia Coastal Energy Research Consortium at Old Dominion University, the Center for Catalytic Hydrocarbon Functionalization at the University of Virginia, and the Institute for Energy and Environmental Research at James Madison University.[2] Virginia Tech has several leading research centers.[3] The Center for Energy Systems Research, The Macromolecules and Interfaces Institute and the Future Energy Policy Center all work on hydrogen fuel cells. The Center for Intelligent Materials Science and Structures, The Center for Photonics Technology (detection and diagnostics for electrical equipment), The Center for Power Electronics Systems (advanced electronic power conversion and power electronics) and the Consortium on Energy Restructuring are all broadly involved in energy infrastructure research. In energy efficiency and conservation Virginia Tech includes The Center for Turbo Machinery and Propulsion Research and the Multidisciplinary Analysis and Design Center. The Center for Energy and the Global Environment and the Conservation Management Institute encompass work on wind, solar, hydroelectric and biomass energy.

Virginia Tech also hosts the Virginia Center for Coal and Energy Research which is one of the institutions leading carbon sequestration research in Virginia including the Southeast Regional Carbon Sequestration Partnership (SECARB). SECARB is one of seven DOE-funded regional partnerships developing carbon sequestration. This is important clean energy research that has the potential to solve at least part of the largest barrier to Virginia's continued reliance on coal, climate change.

Dominion Virginia Power recently received a $47 million grant from DOE to demonstrate innovative technologies to reduce off-shore wind costs.[4] Dominion is one of 22 firms selected under a $7 billion multiple award task order contract (MATOC) for the Army to obtain solar energy through private sector financing,[5] and was also selected for a parallel $7 billion wind MATOC, which together will create opportunities for Dominion to apply solar and wind technologies on a large scale for one of the largest energy customers in Virginia, the DoD.[6]

[1] TABLE 85. Federal obligations for research and development, by state and other locations and selected agency: FY 2010, Federal Funds for Research and Development: Fiscal Years 2010–12. July 2013. National Science Foundation National Center for Research Statistics. NSF 13-26.
[2] Weigman, Leo; Preefer, Alexandra; Santana, Jose Miguel; & Vosmeir, Liz. National Guide to State Research Centers, 2011-2012. 2013. Association of State Energy Research and Technology Transfer Institutions.
[3] Centers and Groups Doing Energy Research. May 7, 2014. Retrieved from www.research.vt.edu/energy/energycenters.html. Virginia Tech.
[4] Coy, Brian. "Governor McAuliffe Statement on U.S. Department of Energy Grant Award to Dominion Virginia Power for Wind Energy Demonstration Program." May 7, 2014. Press release from Office of Governor Terry McAuliffe.
[5] Army Selects 22 Solar Contractors under $7B MATOC. September 2, 2013. Association of Defense Communities website. Retrieved from www.defensecommunities.org/headlines/army-selects-22-solar-contractors-under-7b-matoc/#
[6] Army awards third technology, wind, under $7 billion renewable energy MATOC. September 10, 2013. www.army.mil, the official webpage of the U.S. Army. Retrieved from
www.army.mil/article/111010/Army_awards_third_technology__wind__under__7_billion_renewable_energy_MATOC/

Potential

Clean energy integration into the existing energy system is an important target of opportunity for research and demonstration. There are plenty of clean energy generation, efficiency and conservation technologies that are cost-effective or near cost-effective but their full potential is limited by the difficulty of integrating them into current regulated and competitive energy markets. Alternative transportation fuels, including electric vehicles, are limited by the need to invest in refueling infrastructure in competition with the mature refueling network for gasoline and diesel. Renewable electric generation is dependent on local resources, and for intermittent resources like wind and Photovoltaic (PV) solar the ability to integrate with the grid to act as storage and backup when the resource is not available.

A major focus of smart grid research is adapting to high penetration of intermittent renewables by leveraging micro-grids, storage, and most important the 2-way communications and control and intelligence that makes coordination between generation and demand management resources possible. Virginia Tech and the Blacksburg smart grid demonstration are internationally recognized contributors to this field that could be a model for expanded research, development and demonstration in Virginia and a starting point for using research to incubate new clean energy businesses to design and supply the smart grid. New areas of development could include improved short-term forecasting for grid management (see the Northwest Transactive Control activities in their Smart Grid Demonstration as an example, www.pnwsmartgrid.org/), 2-way integration of Electric Vehicles (EV) and Plug-In Hybrid Electric Vehicles (PHEV) to provide electric storage (see DOE Clean Cities demonstrations and work at Argonne National Laboratory). Non-electric energy applications including thermal energy and alternative transportation fuels also need work on integration and competition with existing systems. Virginia has a start in the use of compressed natural gas for fleets and bus transport, and modest use and development of biofuels.

Current Environment in Education

Despite all of the quality instruction, training, and certification/accreditation available in Virginia, these resources are not tied together, properly integrated, nor, are they led by the clean energy industry to ensure that we build the workforce that they need, ready when needed.

Our higher education research and instructional advantages extend far. Over 20 of our colleges and universities provide excellent Bachelor and advanced degree programs in Engineering and Business Administration with course concentrations in Environmental Science. Further, our institutions may extend their specialized instruction and training through clean energy research, development, and demonstration (RD&D) projects.

Energy Research and Development

New energy sources and technologies are crucial to achieving energy independence and security and to providing affordable and reliable sources of energy with limited environmental impact. Targeted energy research and development (R&D) and its effective deployment are critical to meeting Virginia's future energy needs and those of the nation. By enabling energy innovation and commercialization, the Commonwealth has the opportunity to deliver manifold environmental and economic benefits.

Virginia boasts a vibrant, diverse energy research community. Leading energy R&D is underway in academia, industry, and federal laboratories in Virginia, in a broad range of technologies and applications important to the Commonwealth and globally. Virginia's energy assets include nationally and internationally recognized researchers, centers, and laboratories, including those with unique or distinctive equipment required in energy R&D.

The National Science Foundation (NSF)'s 2011 Science and Engineering State Profiles ranked Virginia #12 among states in federal Department of Energy (DOE) R&D obligations. Virginia colleges and universities' 2011 DOE R&D obligations of $17.98 million were approximately 1.8 percent of the total received by U.S. colleges and universities, $1.01 billion[7]. Virginia's federally-funded energy R&D is in fact larger, as many federal agencies and organizations, other than DOE, also support energy R&D. These other agencies include the Department of Defense (DOD), the Department of Transportation (DOT), and NSF. Energy R&D also is supported by such other sources as universities themselves, foundations, the private sector, and the Commonwealth, including through the Department of Mines, Minerals and Energy (DMME) and the Commonwealth Research Commercialization Fund (CRCF) administered by the Center for Innovative Technology (CIT).

Energy R&D in academia, industry, and federal laboratories in Virginia overlaps in many sectors, particularly in clean and renewable energy. Specific areas include next generation biofuels; smart grid; offshore wind; efficiency and conservation; solar; energy storage, including fuel cells; and nuclear technologies. Substantial research in coal and energy policy continues in Virginia.

Virginia's federal laboratories have a long-standing interest in energy and perform research that supports their missions. Interests of the Thomas Jefferson National Accelerator Facility (Jefferson Lab), the Naval Surface Warfare Center Dahlgren Division (NSWCDD), and the NASA Langley Research Center (NASA LaRC) include nuclear, fuel cells, alternative fuels, and energy efficiency.

Significant energy research also is being performed by Virginia industry. Dominion Virginia Power was awarded $47 million in continued funding in May 2014 by DOE to continue a 12-megawatt offshore wind turbine generator demonstration project off the coast of Virginia[8]. AREVA and Babcock & Wilcox are leaders in nuclear. Newport News Shipbuilding and Opower are other large companies investing in R&D. Small early-stage companies are advancing a number of new technologies, supported in part by federal Small Business Innovation Research (SBIR) and Small Business Technology Transfer Research (STTR) funding as well as public and private investment.

Finally, there is a new and growing source of energy R&D within the Commonwealth originating from entrepreneurs with start-ups aiming to capitalize "garage" technologies or, in other instances, those spun out from a research institution via a licensing mechanism. The

[7] National Science Foundation, *State Agency Expenditures for R&D, Fiscal Year 2011,* Detailed Statistical Table 19 (2014).
[8] Dominion Virginia Power. (2014). *Dominion Awarded $47 Million by DOE for Offshore Wind Turbine Demonstration Project* [press release]. Retrieved from http://dom.mediaroom.com/2014-05-07-Dominion-Awarded-47-Million-by-DOE-for-Offshore-Wind-Turbine-Demonstration-Project.

emergence of the Commonwealth Energy Fund (CEF) in 2011 sponsored by DMME and the DOE as well as the precursor Technology Acceleration Program (TAP) Fund signal both the availability of high impact, R&D stage technologies combined with targeted equity designed to drive start-ups toward broader commercial uses.

Energy R&D at Virginia Colleges and Universities

Table 10-1 highlights the energy-related R&D performed by Virginia institutions of higher education, and demonstrates the breadth of research and potential synergies among the organizations.

Table 10-1: Sampling of Energy R&D at Virginia Colleges and Universities

Sampling of Energy R&D at Virginia Colleges and Universities														
INSTITUTION	**Energy Generation / Sources & Technologies**									**Energy Trans-mission & Technol-ogies**	**Energy Use / Impact & Technologies**			**Energy Policy**
	Fossil Fuels	Nuclear	Fuel Cells / Hydrogen	Biofuels	Waste-to-Energy	Geothermal	Water / Hydroelectric	Solar / Photovoltaics	Wind	Electric Grid	Energy Storage	Energy Efficiency / Conservation / Environment	Buildings / Construction	Energy Policy
College of William & Mary (W&M)		•		•			•	•	•		•	•		•
George Mason University (Mason)	•	•	•					•		•	•	•		•
George Washington University (Virginia campus) (GWU)	•	•						•		•	•	•		•
Hampton University (HU)	•			•		•		•		•	•	•		•
Institute of Advanced Learning and Research (IALR)				•	•						•	•		•
James Madison University (JMU)			•	•	•		•	•	•			•	•	•
Norfolk State University (NSU)				•	•			•						•
Old Dominion Univerisity (ODU)			•	•	•		•	•	•	•		•		•
University of Virginia (UVA)	•	•	•	•				•	•		•	•	•	•
Virginia Commonwealth University (VCU)		•	•	•	•			•		•	•	•		•
Virginia Military Institute (VMI)				•	•			•						
Virginia Tech (VT)	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Virginia State University (VCU)				•									•	

Research areas with current or potential national prominence include:

- Carbon sequestration
- Advanced separation technologies
- Nuclear power
- Fuel cells and hydrogen
- Biofuels
- Electric grid
- High-power electronics
- Wind
- Energy storage
- Energy efficiency, environment, and conservation
- "Green" building design
- Solar / photovoltaics
- Energy policy

Virginia Tech. The most comprehensive portfolio of energy-related research is found at VT, which supports research activities in every energy area defined in this chapter. Since 2006, VT has identified energy and sustainability research as one of four strategic focus areas within its long range plan, in recognition of the strength and breadth of faculty research in related areas. In that year, the university deans and the Office of the Vice President for Research, created the Virginia Tech Deans' Task Force for Energy Security and Sustainability in an effort to coordinate, promote, and position VT's educational, research, and outreach efforts to achieve sustainable and secure energy systems. Tracking of energy-related research growth began university-wide in 2007. In FY2013, Virginia Tech's energy-related research expenditures, excluding energy-related transportation research, totaled more than $55 million, an increase of more than 62 percent since FY2007. As of 2014, five VT faculty performing energy-related research have been inducted into the prestigious National Academy of Engineering[9].

University of Virginia. At UVa, the Energy Systems Prototyping, Research, Innovation and Translation (ESPRIT) program is a priority initiative within the Office of the Vice President for Research. UVa is coordinating its ESPRIT initiative through a faculty steering committee comprised of representatives from its Schools of Architecture, Business, Education, Engineering, Law, and Arts and Sciences. In the broader view, UVa considers the areas of energy, conservation, and environmental sustainability as closely coupled and is striving for a balanced program of research and education.

College of William & Mary. Energy is also prominent at W&M. For example, the Commonwealth Center for Energy and Environment (CCEE) was formed by mandate of the Board of Visitors and is an integral part of the current strategic plan. The CCEE supports initiation grants for the development of strong interdisciplinary approaches to the scientific, social, economic, and political challenges of new and emerging energy-related technologies and environmental challenges. One target of the development group of the College is to promote endowment-funding for centers, to ensure consistent, ongoing support required for success in long-term endeavors like alternative energy.

George Mason University. At Mason, nearly 40 scientists are involved in climate change research and see direct spillover effects on energy. Climate change research has been a strong

[9] Virginia Tech. (2014). *2014 Virginia Energy Plan: Virginia Tech Inputs*.

component of Mason's College of Science for ten years, with work that has yielded climate change studies for a number of nation states around the world.

Virginia Commonwealth University. VCU is engaged in a comprehensive portfolio of energy research and education activities. With nearly 30 researchers engaged in interdisciplinary projects, VCU's areas of strength include energy generation (renewable energy sources, nuclear energy), energy distribution and storage, energy conservation (green technologies, energy efficiency), environmental impact, and energy policy and education. VCU's portfolio includes more than $10.7 million in sponsored awards to the university to support energy research and education, with funding from the DOE accounting for over $5 million.

Old Dominion University. ODU's energy R&D expertise has focused on biomass / algae, photovoltaics, and coastal and environmental research, including wind and wave energy. The Commonwealth assigned ODU the leadership role in the Virginia Coastal Energy Research Consortium (VCERC), with the mission to seek out and develop new alternative energy research directions and evaluate renewable energy sources including algal biomass, wind, and wave resources available in Virginia. VCERC is composed of ODU, HU, JMU, W&M, NSU, VCU, UVa, and VT, as well as government and industry partners.

According to the DOE, wave energy has the potential to power over 100 million homes annually. To realize this potential, **Columbia Power Technologies** (Charlottesville) is delivering a floating, offshore wave energy solution that is scalable in a range of wave conditions.

Although energy R&D is pervasive and among several institution's priorities, academia's energy-related R&D expenditures and obligations cannot be verified and tracked with current data sources. NSF, the source of data for R&D expenditures at colleges and universities does not include "energy" among the fields it tracks in its annual survey of higher education research and development (HERD). Instead, energy R&D is captured under other disciplines, including computer sciences, environmental sciences, life sciences, physical sciences, and social sciences. Since universities track data that aligns with NSF and other requirements, they typically do not measure energy R&D expenditures or obligations.

Key energy-related research activities and expertise at Virginia colleges and universities are discussed in the following sections, organized by research category.

Energy Generation and Sources

Fossil Fuels

Among its fossil fuel research, Virginia has two nationally-recognized research centers in the area of coal and energy research, as well as advanced separation technologies.

Virginia Tech. Two VT centers are nationally prominent in coal-related research: the Virginia Center for Coal and Energy Research (VCCER) and the Center for Advanced Separation Technologies (CAST). VCCER was created by the Virginia General Assembly in 1977 as an interdisciplinary study, research, information, and resource facility for the Commonwealth and has become one of the nation's leading interdisciplinary energy and environmental research centers. It has a array of high profile R&D programs in areas such as carbon sequestration, coal-bed methane and shale gas production, uranium fuel resource development, international energy development, mining and reclamation environmental science, sustainable power generation, and energy information management.

VCCER has developed a strong reputation in the field of carbon capture and storage (CCS). Competencies include technical, financial, legal, and planning disciplines of CCS and unconventional natural gas development. A particular area of expertise is monitoring, verification, and accounting (MVA). Other areas include modeling, reservoir characterization, environmental testing, and methane storage mechanisms. As a part of the Southeast Regional Carbon Sequestration Partnership (SECARB) and, under funding via DOE's National Energy Technology Laboratory (NETL), VCCER coordinates all coal seam-related sequestration activities for the SECARB partnership.

VT received $11.5 million from DOE to implement a pilot project in Central Appalachia. This four-year project is part of a portfolio of projects aimed to better understand the effect of CO_2 on geologic formations. The objective of this project is to design and implement characterization, injection, and monitoring activities of approximately 20,000 metric tons of CO_2 into unconventional (coal or organic shale) geologic formations in Central Appalachia. VCCER also is managing a project to test the injectivity of CO_2 into unmineable coal seams and the potential for enhanced coal bed methane (ECBM) recovery by stressing the coals under injection into three legacy coal bed methane (CBM) wells for an approximate one-year period. In addition, VCCER has conducted a “huff-n-puff” test on a horizontal shale well. The organic shale research will provide much needed information on organic shale sequestration and enhanced gas recovery (EGR).

Led by VT, CAST is a consortium of five universities, which represent the major coal mining schools in Central Appalachia. The consortium was established in 2001 to develop advanced separation technologies that can be used to produce clean-burning solid fuels in an environmentally acceptable manner. CAST has developed advanced separation technologies now widely used in industry, including the Microcel flotation column, hyperbaric centrifuge, and dewatering aids. Its facilities at VT can test new separation processes developed at the Center at proof-of-concept and pilot-scale.

CAST Director, Dr. Roe-Hoan Yoon, has commercialized a number of technologies including techniques to recover coal from slurry ponds as well as a hydrophobic-hydrophilic separation (HHS) process that can produce super-clean coal, recover critical materials from unconventional resources, and clean up the environment.

VT's R&D in fossil fuels extends to mine de-gasification design, groundwater monitoring and modeling, and seismic monitoring and interpretation.

VT departments also are active in energy minerals, including the environmental impacts of the production and use of energy minerals and minerals exploration, extraction, and processing. VT's Department of Mining and Minerals Engineering is the largest such program in North America and has a strong international reputation for its academic, research, and public service programs.

University of Virginia. UVa's DOE-funded Energy Frontiers Research Center (EFRC), the Center for Catalytic Hydrocarbon Functionalization (CCHF), is led by Director Brent Gunnoe. The mission of this Center, which includes leading institutes from across the U.S., is to develop homogeneous catalysts and highly efficient catalytic processes for natural gas, methane, and other fuels, as well as feedstock chemicals. This effort is a key element of the current initiative to create the joint Max Planck Society-UVa laboratory on new chemical energy processes.

Additionally, other Virginia colleges and universities, including Mason, GWU, HU, ODU, VMI, and W&M are performing R&D to advance fossil fuels technology and policy.

Nuclear

Virginia continues to have a strong nuclear R&D foundation as evidenced by the scale of research investigations identified and educational programs offered.

The Virginia Nuclear Energy Consortium Authority (VNECA) was established to position Virginia as a national and global leader in nuclear energy and to serve as an interdisciplinary study, research, and information resource for the Commonwealth on nuclear energy issues. Established in the 2013 Session of the General Assembly, VNECA members include educational institutions, Virginia-based federal research laboratories, nuclear-related nonprofit organizations, and business entities.

Virginia Commonwealth University. As a founding member of the VNECA, VCU's sponsored programming activities contribute to "making the Commonwealth a national and global leader in nuclear energy and serving as an interdisciplinary study, research, and information resource for the Commonwealth on nuclear energy issues."[10] Major efforts are currently funded by a number of agencies, including the Nuclear Regulatory Commission (NRC), NSF, and DOE.

Several noteworthy research projects are underway at VCU's Department of Mechanical and Nuclear Engineering, including applied research for nuclear power plant safety, such as thermal-hydraulics modeling and simulation of event scenarios and nuclear systems for existing and advanced nuclear reactor designs conducted by Dr. Sama Bilbao y León.

Dr. Supathorn Phongikaroon is advancing and developing materials accountability and detection techniques for used nuclear fuel in reprocessing technologies and developing advanced fuel cladding materials for existing light water nuclear reactors for safer, accident-resistant nuclear fuels. Additionally, Dr. James Miller is designing and constructing a small electrostatic inertial confinement fusion reactor to be used for fundamental nuclear fusion research, a gamma radiation and neutron flux source for teaching and research applications, and designing and implementing a full-scale nuclear plant simulator that may be used for education and outreach. The latter project opens new applications for nuclear safety and design.

University of Virginia. UVa maintains faculty expertise – Drs. John Scully, Rob Kelly, and Glenn Stoner – in nuclear containment systems based on amorphous materials resistant to corrosion, although the two nuclear reactors at the university were decommissioned (in 1988 and 1998) and the program ceased in 1999[11]. The university's Center for Safety-Critical Systems includes a virtual nuclear reactor control room located at the Center for Advanced Engineering Research (CAER) in Lynchburg. The Lynchburg control room, established in conjunction with AREVA and Babcock & Wilcox, is utilized for education and training of nuclear reactor control room personnel into safe operations of nuclear reactors.

[10] Va. Code Ann. § 67-1400 (2013).
[11] P. Parrish, personal communication, September 22, 2006.

UVa's Dr. Hornberger was named to the U.S. Nuclear Waste Technical Review Board by President Bush in 2004. The board provides independent scientific and technical oversight of the U.S. program for management and disposal of spent nuclear fuel from civilian nuclear power plants[12].

College of William & Mary. W&M is active in R&D for nuclear energy, including in the areas of high heat flux and corrosion resistant materials. W&M has a particular interest in materials for small modular reactors (SMRs) and is developing proposals for R&D related to these materials in SMR shipboard use.

George Mason University. Mason's Dr. Roger Stough had a significant role in designing the KEPCO International Nuclear Graduate School (KINGS), Korea's leading nuclear power training program for export markets. The program was launched with a focus on education and training; the R&D program is under development, with a Korean R&D expert planning to stay at Mason's campus for the next year to participate in the design of the research program[13].

Virginia Tech. VT also is engaged in nuclear energy-related R&D. Its Nuclear Engineering Program (NEP) in the Department of Mechanical Engineering has expanded over the past six years via new and affiliate faculty bringing expertise in the areas of: (1) particle transport methods and their applications (reactor physics and shielding, nuclear safeguards and security, radiation diagnostics); (2) reactor operations and instrumentations; (3) nuclear materials; (4) plasma physics and fusion; and (5) reactor thermal hydraulics and safety. In support of their research activities new laboratories include: (1) Radiation Measurement, Simulation and Visualization (RMSV); (2) Multiphase Flow and Reactor Thermal Hydraulics (MURETH); and (3) Ionized Species for Innovative Science (IS2). The Nuclear Science and Engineering Lab (NSEL) extends the NEP to the National Capital Region.

VT's Experimental Nuclear and Particle Physics group is involved in experiments that explore the nature of the fundamental building blocks of the universe and seek to measure their properties as precisely and accurately as possible. Additionally, the Microwave Processing Research Facility in the Department of Materials Science and Engineering VT is examining new ways to expand the use of nuclear energy while minimizing the risks to the public. In addition to the efficiency of the processing method being studied, the approach would use stockpiles of what is now considered radioactive waste in an energy-producing application.

Nuclear seismic safety is another area of research at VT, with expertise in such topics as performance-based design of nuclear facilities; wave and tsunami modeling, coastal erosion, and associated probability and risk assessment; seismic hazard analysis, soil structure interaction, and analysis of soil-related hazards such as liquefaction and slope stability; novel materials, such as ultra-high performance concrete, steel, glass and carbon fiber composites; seismic engineering; and structural health monitoring and diagnosis.

Fuel Cells / Hydrogen

There is a diverse array of research in fuel cells and hydrogen-related technologies with manifold applications such as transportation, buildings, and storage.

Virginia universities have significant research strength in the area of fuel cells and hydrogen.

[12] University of Virginia. (2014). *Assessment of Energy-Related Research and Development in Virginia*.
[13] "Energy". *George Mason University: Center for Infrastructure Protection & Homeland Security*. 2014. Retrieved from: http://cip.gmu.edu/programs/energy/.

Virginia Commonwealth University. Professor Puru Jena leads research aimed at finding materials that are light, cost-effective, safe, and can store a large amount of hydrogen so that a car can have a driving range of 300 miles. The VCU team is among the world leaders in providing the fundamental understanding of these hydrogen storage materials and designing novel nanomaterials and catalysts to improve performance. Their theory of trapping hydrogen in molecular form is guiding world-wide research; several laboratories around the world are trying to synthesize novel storage materials designed at VCU. Additionally, the research team of Drs. Hani El-Kaderi and Samy El-Shall is working on developing metallic and bimetallic nanostructures encapsulated within highly porous coordination polymers (nanopores) for efficient storage of hydrogen.

Virginia Tech. At the Advanced Research Institute (ARI), Dr. Saifur Rahman and Mr. George Hagerman conducted a survey of technologies for producing, transporting, storing, and using hydrogen and compiled the findings into short overviews and fact sheets for use by the general public.

VT has a cluster of researchers focused on improving fuel cell performance, including fuel cell durability / sealants, composite systems, durability modeling, the integration and performance analysis of fuel cells in systems such as buildings and automobiles as well as for stationary (residential) power plan applications. A number of centers are engaged in the research, including the Center for Automotive Fuel Cell Systems, Center for Energy Systems Research (CESR), and the Future Energy Electronics Center (FEEC), and the Institute for Critical Technology and Applied Science (ICTAS). ICTAS has a strong focus on electrochemical energy and storage within its larger thrust area of sustainable energy.

A research team led by Dr. Percival Zhang has developed a battery that runs on sugar and has an unmatched energy density, a development that could replace conventional batteries with ones that are cheaper, refillable, and biodegradable. While other sugar batteries have been developed, Dr. Zhang said his has an energy density an order of magnitude higher than others, allowing it to run longer before needing to be refueled[14].

University of Virginia. Several researchers are focused in the non-hydrogen fuel cell arena. Dr. Elizabeth Opila is working to develop high-performance anode materials for versatile high-temperature solid oxide fuel cells that can use a variety of combustible fuels including gasoline and biodiesel to produce both heat and electricity while minimizing carbon release. On a more fundamental level, research is underway to optimize catalytic materials for yield, selectivity, or minimized energy use. A specific focus is on the reactivity of methane, which, with the right catalysts and conditions, could potentially be harnessed at the well-head as a reliable source of easily transportable methanol for powering fuel cells.

James Madison University. Drs. Samuel Morton III and Bradley Striebig are working on the development of microbial fuel-cells (MFC) designed to produce low-level power from carbohydrate rich waste streams. The potential to produce power directly from aqueous waste streams is significant, and the work at JMU has focused on developing low-cost, feedstock agnostic MFC systems for use at smaller scale facilities, where other waste stream conversion systems are not economically viable.

[14] Virginia Tech. (2014). *2014 Virginia Energy Plan: Virginia Tech Inputs*.

George Mason University. As part of Mason's global climate change research, fuel cell technology is viewed as a scalable way to help offset the impact of the build-up of CO_2. Mason's multi-faceted fuel cell research includes that in microbial fuel cells and that based on nano porous materials.

Biofuels

There is demonstrable institutional expertise and critical mass with feedstock R&D across the State.

Virginia Commonwealth University. Professor Stephen Fong is leading research aimed at developing efficient processes that can produce large quantities of biofuel. Specific projects underway in 2014 include turning biomass into usable sugar, for which a patent is being filed; using novel microorganisms to convert cellulose into butanol; and computational modeling of organisms to predict genetic engineering designs.

Other research at VCU deals with the development of biofuels from algae, including determining the oil content of naturally occurring algae in water bodies of the Commonwealth of Virginia to assess their utility for biofuel production. In collaboration with ODU, VCU is developing technology related to biomass production and oil extraction.

> The potential upside for the biomass industry in Virginia is enormous. **Piedmont Bioproducts** (Gretna) is one of many firms offering unique renewable energy solutions. Piedmont's process involves generating bio-crude from feedstock utilizing a thermal-chemical refining process.

Institute for Advanced Learning and Research. At the IALR, biomass to cellulosic ethanol and biodiesel energy generation are important areas of research. From development of mutagenic processes to improve yields, cold or heat tolerance, or other trait enhancements for various bioenergy feedstocks to commercial processing options using various chemistries, IALR's researchers, along with its commercial and academic partners, are driving toward identifying an optimal directed-energy feedstock for the mid-Atlantic region while examining the environmental and economic impacts, positive and negative, on all research endeavors.

Dr. Yinghui Dan is researching and developing trait improvements and a high-throughput micropropagation system around a promising bioenergy crop, *Arundo donax L*., due to its perennial nature and high levels of biomass production. Drs. Barry Flinn, Chuanshang Mei, Scott Lowman, and others have published results from studies around a promising bioenergy crop candidate, switchgrass. Through the use of microbial endophytes, IALR has helped improve switchgrass performance by developing a low input, sustainable production system. The endophyte-inoculated, tissue-cultured switchgrass plants grow bigger and are designed to require less water and fertilizer than control plants. Critical to the success of these two crops is the work on a third, *Miscanthus x giganteus*; Drs. Kedong Da and Song Zhang provide world-class tissue culture expertise in IALR's study of these bioenergy generation sources, as high-volume breeding will be necessary to launch the production of such crops.

Old Dominion University. Dr. Sandeep Kumar's laboratory is collaborating with Tyton BioSciences of Danville, VA to develop sugar extraction technology from tobacco feedstock for biofuels production. Their research aims to prove the feasibility of an integrative approach of applying subcritical water extraction methods to enhanced tobacco varieties for the economic production of sugars and oils for bioethanol and biodiesel manufacturing.

Virginia Tech. VT's efforts include issues ranging from biomass production, to deconstruction and conversion technologies, along with significant expertise in environmental impacts, community viability, and numerous enabling technologies ranging from computational support and genomics to engineering process technology, business development, and land use policies. Additionally, VT is collaborating with bioenergy crop developers and many other universities in a large project that aims to deliver highly productive crops with minimal risk of escaping cultivation and becoming harmful invasive pests.

Scientists in the laboratory of Dr. Bingyu Zhao are working on improving the characteristics of the feedstock switchgrass, which is considered a prime candidate for large-scale biomass production for ligno-cellulose derived bioenergy. VT researchers Dr. Eric Beers and Dr. Amy Brunner are looking at poplar as a feedstock source, while researchers in the laboratory of Dr. Ryan Senger are looking for ways to overcome the recalcitrance of cellulosic materials through biological conversion. Dr. Jactone Ogejo and others are investigating biogas options for dairies in Virginia, specifically the use of anaerobic digestion to produce biogas from manure.

Dr. Percival Zhang has developed a gentle and cost-effective pretreatment process for biomass. The weakened biomass can be fractionated into four products: lignin, acetic acid, hemicellulose sugars, and amorphous cellulose. This technology has been licensed by Biomethodes. Dr. Zhang has also developed another energy product from biomass sugars – hydrogen to power a fuel cell. His aim is to have the conversion occur in a car's fuel tank or at a fuel cell site.

Virginia Military Institute. At VMI, research is underway to develop a soybean cultivar for use as an alternative fuel source and test the cultivars for their energy and emissions potential. Additional research is in biochar production for use in water treatment and to test various blends of biodiesel fuels for their performance in diesel combustion engines.

College of William & Mary. W&M has programs underway to develop large-scale algae biomass for non-ethanol transportation fuels, or for environmental remediation of water contamination associated with fossil fuel and natural gas production.

James Madison University. A primary focus of JMU's Alternative Fuel Vehicle Laboratory is R&D of a novel algae-oil harvesting strategy developed by Dr. Chris Bachmann for the production of biofuels. This harvesting strategy is the result of algae-based biofuels research that began at JMU in 2005.

Nearly all of the algae harvesting strategies developed to-date involve dewatering and drying the algae prior to extracting valuable components. These drying steps are both energy intensive and expensive. In August 2012, researchers applied a commercially available device to successfully extract oil from salt-water algae without removing them from the seawater culture media. Test results indicated that the strategy was, in fact, capable of isolating lipids including high-value co-products and pharmaceuticals from algae without removing them from sea-water. A provisional patent application has been filed by James Madison Innovations, Inc.

Other areas of research include biodiesel production on the development of a small-scale, portable continuous flow system for producing biodiesel from waste oil at the point of generation and a multi-pronged approach to generation of biofuels and bioproducts from the lignin-fraction of lignocellulosic biomass.

University of Virginia. UVa has a number of research efforts to convert biomass into fuels, chemicals, and feedstocks for pharmaceuticals. These efforts are led by Dr. Robert Davis. Research includes deriving butanol from biomass-based ethanol, as butanol has higher energy content as a fuel than does ethanol and is a feedstock to produce a number of chemicals and pharmaceutical products, and transforming biomass from farm crops to advanced fuels and chemicals. The latter research is performed through the NSF Engineering Research Center, Center for Biorenewable Chemicals (CBiRC), led by Iowa State.

Norfolk State University. NSU is developing a research effort in renewable energy solutions and applications; many of the renewable energy sources are currently disposed of as waste. Each of the effort's four major thrusts constitutes a portion of an interconnected bio-energy manufacturing process: (1) bio-diesel from grains resulting in glycerol production; (2) production of bio-jet fuel; (3) waste oil to bio-diesel and glycerol; and (4) other marketable manufacturing process by-products.

Waste-to-Energy

James Madison University. Dr. Adebayo Ogundipe is developing an assessment tool to be used in comparative analyses to determine the sustainability potential of various alternatives for poultry litter disposal, particularly poultry litter to energy technologies. This research is important to the Commonwealth, as poultry production results in massive amounts of litter that are applied to pastures and hay meadows and can lead to an excessive accumulation of nitrogen and phosphorus in soil and bodies of water. Dr. Ogundipe's Sustainability Assessment Matrix (SAM) allows for the comparison of overall systems and guides decision-making within subsystems. Additionally, research is being performed on biochar, a soil amendment / energy source that was first utilized more than 3,000 years ago. In this regard, Dr. Wayne Teel oversees projects involving the construction of biochar chambers, which are installed on Shenandoah Valley farms to produce heat for greenhouses as well as a fertilizer that reduces loss of nutrients in the field, promotes local nutrient cycles, and sequesters carbon.

Old Dominion University. Dr. Sandeep Kumar's laboratory at ODU is working with Fiberight, LLC in Lawrenceville, VA to develop innovative solutions to convert trash, otherwise destined for disposal, into a renewable fuel and energy. The process is aimed at converting municipal solid waste (MSW) into cellulosic biofuel and marketable electricity in a cost-effective and efficient manner.

Faculty in the Colleges of Sciences and Engineering are researching novel methods of producing biochar from waste biomass. The technology is directed at different biochar chemical compositions containing partially oxygenated materials with higher cation exchange capacity for soil amendment, water cleaning, and carbon sequestration. The goal of the project is to develop advanced biochars as a strategy to retain soil water and enhance environmental water quality.

Geothermal

Virginia Tech. VT Geological Sciences performs geothermal energy research. It developed the southeastern United States Geothermal Database website, hosting data on terrestrial heat flow, practical applications of low temperature geothermal energy, and a temperature vs. depth database for those wanting to do their own calculations to evaluate hypotheses of global warming using a geothermal approach to climate reconstruction. This site is frequently updated to include temperature data, rock thermal conductivity, and heat flow values from New Jersey to Georgia[15].

Water / Hydroelectric Power

Virginia Tech. Dr. Donald Orth (College of Natural Resources and Environment) noted that faculty members in the College have expertise in river and reservoir water quality, fish protection, and screening at hydropower plants, population viability analysis, and environmental analysis of the costs and benefits of alternative operation regimes. These skills are essential to the process of licensing new hydropower facilities as well as the rehabilitation and upgrade of existing facilities[16].

Solar / Photovoltaics

Old Dominion University. ODU established the Virginia Institute of PhotoVoltaics (VIPV) in 2013 under the direction of Dr. Sylvain Marsillac. Research interests include fabricating the next generation of highly efficient and cost-effective thin film solar cells, developing innovative tools for in-situ and real-time analysis, and engineering new systems for large area photovoltaic installations. The university's research focus on photovoltaic energy expanded to include partnering with Dominion Power to install more than 600 solar panels in 2013 and 2014 on the roof of the Student Recreation and Wellness Center in the heart of the campus. The panels will generate kilowatt power for the electric grid with enough energy to power about 31 homes and tie in to the photovoltaic research laboratory.

Norfolk State University. Dr. Sam-Shajing Sun is a recognized leader in polymer materials research for solar cell applications. Dr. Sun's research expertise includes the design, synthesis, processing, characterization, and modeling of novel organic and polymeric solid state supra-molecular and nanostructured materials and thin films devices for electronic, photonic, magnetic, and energy conversion applications. Current research projects funded by the DOE and the Army Research Office (ARO) include development of photovoltaic polymers and thermoelectric polymers.

George Mason University. Dr. Jessica Lin is applying computer science and data mining techniques to advance efficiencies in solar power technology.

Virginia Commonwealth University. Professors Hadis Morkoc and Umit Ozur are developing a new class of solar cells beyond the silicon technology (~20 percent efficiency for single crystal Si) through multiple electron hole generation for >50 percent efficiency using stacked InAs quantum dots. Their pioneering research involves high brightness and longevity (>10 years) LEDs to replace the current incandescent (efficiency improvement of 10x) and fluorescent light (efficiency improvement of 3x) bulbs while avoiding the harmful mercury endemic to fluorescent light bulbs and reducing carbon emission[17].

A research team led by Dr. James McLeskey, Jr. is working on polymers for solar photovoltaic power that can be manufactured at very low cost. The polymer-based solar cells investigated involve nanomaterials such as carbon nanotubes that can be aligned through an electric field for improved efficiency. These researchers were the first to report the fabrication of polymer

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[15] "NGDS: National Geothermal Data System". *Virginia Tech.* http://www.geothermal.geos.vt.edu/.
[16] Virginia Tech. (2014). *2014 Virginia Energy Plan: Virginia Tech Inputs*.
[17] Virginia Commonwealth University. (2014). *VCU Energy Research_June 2014_FINAL*.

photovoltaics using a water-soluble polythiophine polymer known as PTEBS[18]. While most polymers will dissolve only in highly toxic solvents, water solubility offers the advantage of environmentally friendly processing – an important consideration for "green" technology.

Professor M. Samy El-Shall is collaborating on research to develop efficient photovoltaic cells based on chemically modified titanium dioxide and highly ordered CdSe quantum dots. Utilizing both CdSe quantum dots and nanorods with mesoporous titanium dioxide, the project is developing nanomaterial photovoltaic devices and evaluating their performance in ambient air conditions at room temperature. Dr. El-Shall also is developing nanomaterials that can serve as catalysts in petrochemical and environmental applications.

Virginia Tech. Dr. Ranga Pitchumani is a leading expert in the field of concentrating solar power. He and his research group at VT have developed novel thermal energy storage technologies for concentrating solar power applications that are widely published. For example, Dr. Pitchumani was invited to direct his Concentrating Solar Power (CSP) program for the 2011 DOE SunShot Initiative, a program to reduce the installed cost of solar energy systems by about 75 percent in order to allow widespread, large-scale adoption of this renewable clean energy technology. Under his leadership, the CSP has launched over $130 million in new funding initiatives since October 2011 dedicated to applied scientific research, development and demonstration to advance cutting-edge concentrating solar power technologies for the near-, mid- and long-terms.

Professor Karen Brewer and her group have been developing molecular devices for the photoinitiated collection of electrons and the production of hydrogen from sunlight. Professor Brewer's most recent research involves a system for the light-driven production of hydrogen from water.

Additional research includes that of the Amanda Morris Group of Inorganic and Energy Chemistry, which focuses on two aspects of solar energy conversion: artificial photosynthetic assemblies, assemblies that can oxidize water and reduce CO_2 efficiently to a solar fuel cell, and next-generation solar cells, where the focus is on two types of cell architecture – hybrid bulk heterojunction and quantum dot synthesized. The latter proves its importance as the 2010 cost of a residential photovoltaic system was more than four times the 2020 DOE goal; the dramatic and quick cost reduction required to reach this goal necessitates the development and demonstration of revolutionary photovoltaic technology.

VT models the integration of renewable sources such as solar photovoltaic generators with probability models of solar irradiance at various geographic locations in Southern California and Nevada. These models were used to improve the reliability of unit commitment of solar energy by a group of solar installations that are geographically distributed.

James Madison University. JMU Engineering faculty Dr. Jacquelyn Nagel, is exploring the technical challenge of sustainability as it relates to solar energy production, storage, and consumption. The two-phase energy system project aims to reduce chemical battery waste by providing electrical energy during both day and night without the use of chemical batteries and correlates to a reduction in pollutants at three points in the system's lifecycle: (1) less fossil fuel burned at a power plant; (2) less chemical waste created due to battery manufacturing, consumption and recycling; and (3) greater recycling potential.

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[18] Q. Qiao and J.T. McLeskey, Jr., "Water-soluble polythiophene / nanocrystalline TiO2 solar cells", Applied Physics Letters, Vol. 86, p. 153501, 2005.

Other Virginia universities are also focused on this area of energy-related research. Several UVa faculty, including Drs. Mool Gupta, Petra Reinke, and Joe Campbell are involved with photovoltaic materials and / or solar energy. At VMI, Drs. Daren Timmons, Daniela Topasna, and Gregory Topasna are among faculty involved in research that includes developing photovoltaic cells and thin films to improve their performance and to produce chemical coatings for more efficient solar panels.

Wind

Virginia Tech. Wind energy expertise and activities cover a broad range of technical areas and policy. On the technical side this includes programs in computational and experimental aerodynamics, aeroacoustics, acoustics, structures, materials, and ocean systems, centered at the Blacksburg campus. On the policy side, work is centered at the ARI in Arlington, Virginia.

Anchoring a substantial portion of the technical activities is the VT Stability Wind Tunnel. This internationally recognized facility is a major asset to the university and to the Commonwealth in many areas of aerodynamic and aeroacoustic testing, but particularly in wind energy. It produces an extremely high quality air-flow for testing at speeds of up to 190 mph and is one of the largest university-owned wind tunnels in the U.S. The key technical advance that has given this facility international visibility and placed it at the forefront of aeroacoustic and aerodynamic wind energy research is the invention at VT in 2005 of the hybrid anechoic test section (HATS)[19], a technology in which tensioned Kevlar cloth is used to guide the air flow over models, while allowing the sound produced to pass out of the flow and be accurately measured. The tunnel is the only accessible facility worldwide where wind turbine blade aeroacoustics and aerodynamics can be measured at, or near, full scale conditions. Additionally, under development are systems for infrared transition detection, global optical boundary layer measurement, and stereoscopic camera system for boundary condition definition.

A new area of aerodynamic and acoustic research is understanding what is required to fabricate wind turbine blades using fabric stretched across a frame, in place of the conventional fiberglass construction. This promises a substantial reduction in wind energy cost. A companion to VT's wind energy efforts is research in the science of aerodynamic testing itself, including efforts in instrumentation development, wind tunnel corrections, and in relating wind tunnel tests to computational simulations.

Accompanying the experimental wind turbine aerodynamics are programs and capabilities in aerodynamic simulation and modeling. VT Aerospace and Ocean Engineering (AOE) faculty and students are collaborators on a DOE-funded research project to develop a cyber wind facility, which is a wind turbine-level (vs. farm-level) simulation suite of tools for generating highly-resolved 4D cyber data. This data can be used to perform virtual full-scale experimental campaigns, support design of systems and experiments, improve actuator-line models and other design-level tools, and evaluate control systems. The long-term vision is the creation of a cyber facility for wind turbines to advance wind farm siting and design, and wind turbine / farm controls to simultaneously maximize production and increase turbine reliability.

VT faculty have diverse expertise in the modeling, analysis, and testing of structures and materials. This broad area of expertise includes the (a) analysis, optimization, and fabrication of composite airfoils; (b) multi-scale, multi-disciplinary analysis and design of wind turbine blades

[19] "Center for Energy and the Global Environment". Virginia Tech. Retrieved from: http://www.ceage.vt.edu/home.

with focus on aeromechanics and aeroelasticity of rotating systems; (c) damage detection, diagnostics, and failure prediction in composite structures; (d) multi-scale modeling and characterization of multi-functional nanomaterials; (e) dynamic analysis and testing of bladed structures; and (f) analysis and optimization of morphing structures for airfoils and related control surfaces.

VT has a cluster of faculty members in the AOE and Civil and Environmental Engineering (CEE) departments with research expertise in coastal systems. Research focuses on wave-seabed interactions, sediment transport, and on the impact and risk assessment of coastal hazards and climate change. Experience and capabilities include large-scale experimental investigations and advanced numerical model development for the failure potential and mechanism of foundations under extreme coastal loadings during tsunamis and storm surges. Understanding the failure potential of the turbine components, their supporting structures, and the seabed foundations is critical for assessing the uncertainty in the feasibility study phase and in selecting appropriate plans in the preliminary design phase.

In May 2014, **Dominion Virginia Power** (Richmond) and partners were awarded $47 million in continued funding from DOE to fund the construction of a 12-megawatt offshore wind demonstration project. The demonstration is intended to showcase the ability of two 6-megawatt wind turbines to power 3,000 homes by 2017.

The ARI is also engaged in policy and planning work to support offshore wind. The work includes support to DMME for lease applications to the U.S. Bureau of Ocean Energy Management (BOEM), DMME responses to BOEM sale notice for the commercial wind energy area, and a DMME-BOEM offshore regional geological study and ocean survey. This work also includes support for Virginia engagement with the DOE Chesapeake Light Tower initiative, Virginia offshore wind supply chain acceleration white papers, and Virginia Offshore Wind Development Authority briefings. In addition VT-ARI is supporting the Virginia Offshore Wind Technology Advancement Project (VOWTAP) five-year demonstration project.

James Madison University. Efforts began in 1999 at JMU to characterize the wind resource on land throughout the Commonwealth, and to promote stakeholder engagement within various sectors. JMU joined with ODU and other academic and business interests in 2006 to form the Virginia Coastal Energy Research Consortium (VCERC), and in 2009 the VCERC board recognized the JMU wind research team as the Virginia Center for Wind Energy (CWE) at JMU. Led by Professor Jonathan Miles, the CWE performs research and provides educational and technical opportunities, support, and resources to foster the advancement of sustainable energy in Virginia particularly to advance wind energy deployment.

The CWE conducts research pertaining to wind resource and siting assessment, primarily in support of small- and community-scale project development. Activities include wind data collection and analysis using conventional meteorological towers as well as SoDAR instruments, and analyses that involve the development and / or manipulation of Geographical Information Systems (GIS) data and assessments of policy, regulatory, and financial considerations. Since 2002, the Center has acquired wind data from several dozen locations throughout Virginia in support of project development by residents and businesses.

In 2011-12, CWE conducted a major study to determine the viability of deploying large offshore wind turbines in state waters. In 2012-13, under contract with the National Renewable Energy Laboratory (NREL), the Center completed two modeling studies that utilized NREL’s Jobs and

Economic Development Impact (JEDI) model for offshore wind to project jobs and economic benefits to the Southeastern and Mid-Atlantic regions of the U.S. as offshore wind is deployed through 2030. These studies underscored how Virginia is uniquely positioned, because of its exceptional resources and supply chain opportunities, to capitalize as this industry advances[20]. The Center expects to engage in further studies to support offshore wind development in Virginia, by addressing remote health monitoring of wind turbine blades and the development of a data repository and viewer to support public access to wind data offshore.

University of Virginia. Dr. Eric Loth is leading a large, multi-institutional research effort on bio-inspired morphing wind turbine blades for offshore wind applications and nanoparticle-containing coatings for the blade. This effort also includes AREVA-sponsored research on nacelles, which are oleophobic and shed water very efficiently. The research led to two patent applications and has the potential to reduce the size and cost of offshore wind turbine systems by 25 percent[21].

Energy Transmission and Technologies

Energy Grid

Virginia Tech. VT has been a leader in the field of power engineering, with its faculty and students receiving both teaching and research awards. The goal of its Center for Power and Energy is to shape the smart grid into a dependable, sustainable, and robust system. Projects focus on wide area monitoring, adaptive relaying for protection, communication and cyber security as related to power systems, economics of microgrids, and integration of renewables.

The Renewable Energy and Nanogrids (REN) mini-consortium, part of the Center for Power Electronics Systems (CPES) at VT, is developing electronic energy processing technologies for sustainable living environments that satisfy energy, functional, comfort, and zero-CO_2 emission goals. CPES is building a living lab testbed based on AC and DC electric power systems using photovoltaic solar cells, wind generators, micro-turbines, fuel cells, and lithium-ion storage. The testbed will help address many of the nanogrid issues, such as DC bus architecture, energy / power management, and various forms of utility interface converters and inverters.

VT received a $1.25 million five-year contract in 2009 from DOE to develop, manage, and maintain a public Smart Grid Information Clearinghouse (SGIC) web portal that encourages use of electricity in an environmentally responsible way. Project partners assist with content, which includes demonstration projects, use cases, standards, legislation, policy and regulation, lessons learned and best practices, and advanced topics dealing with R&D. The Smart Grid Clearing House site was launched in September 2010[22]. Furthermore, as part of a three-year DOE demonstration led by VT, a phasor only – three-phase state estimator – is being installed on the Dominion Virginia Power 500kV system. This technology will advance Dominion's ability to identify potentially damaging conditions and implement corrective and preventative strategies[23].

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[20] James Madison University. *James Madison University: Energy R&D Info – June 2014*.
[21] Loth, Eric. "Off-Shore Wind Energy Technologies". University of Virginia, Mechanical and Aerospace Engineering. 7 December 2010. Retrieved from: http://www.vaallies.org/assets/files/allymeeting/OffshoreWind/10.RichmondWindMeetingLoth.pdf.
[22] Virginia Tech. (2010). *Virginia Tech Officially Launches Smart Grid Information Clearinghouse Web Portal*. [press release]. Retrieved from: http://www.vtnews.vt.edu/articles/2010/09/093010-_ncr-_finalsmartgridportallaunch.html.
[23] Virginia Tech. (2014). *2014 Virginia Energy Plan: Virginia Tech Inputs*.

Virginia Commonwealth University. Professor Zhifang Wang performs research on energy distribution including smart grids, voltage stability and energy system modeling and optimization.

George Mason University. Mason's Center for Smart Power Grids performs research to move the centralized, producer-controlled electric network to one that is much more distributed and consumer interactive. The Center's twenty-five scientists, many of whom are world authorities in their areas of expertise, concentrate on Smart Grid technology research, development and demonstration, among other areas. Foci include recovery from energy supply disruptions to minimize negative economic impact, optimal enhancement of electric grid infrastructure to make it robust against natural and man-induced disasters, and smart grid interoperability.

Energy Use / Impact and Technologies

Energy Storage

College of William & Mary. Faculty are working on experimental and computational solid state physics and science of such materials, with an interest in solid state energy conversion devices, to include thermoelectrics and pyroelectrics on the one hand, and piezoelectrics and ferroelectrics on the other. Such devices, capturing waste heat from various sources, or capitalizing on motion associated with walking, gesturing, vehicle braking, or other motive power can be useful, including for the military, to supply power for field-portable devices, long-duration surveillance, autonomous underwater vehicles, or other applications.

Virginia Commonwealth University. Professors Puru Jena and Hani El-Kaderi and their research teams are collaborating to develop the next generation of Li-ion batteries that are halogen-free and less sensitive to moisture. Safe and efficient electrostatic storage of energy are keys to address challenges in solar and wind energy which need to be stored for later use.

Professors Max Bertino and Khaled Saoud (VCU, Qatar) are collaborating on a project to explore synthetic methods for aerogels. Aerogels are lightweight porous materials with the lowest known thermal conductivity which provide thermal insulation. They have been underutilized because of their mechanical fragility; by reinforcing aerogels with a polymer using a nanofabrication approach, the team has achieved mechanically stable, strongly insulating composites. Working with the Department of Sculpture at VCU, the Bertino group fabricated molds which will be used to create composites with custom shapes. Investors will be sought to take these to market.

Professor Karla Mossi is developing a hybrid piezoelectric / pyroelectric system to harvest wasted mechanical and thermal energy and convert the wasted energy into a useful energy source.

Other faculty are studying the effect of defects, surfaces, interfaces, and crystal orientation on the electrical and optical properties of GaN and ZnO materials of today's LEDs for low-cost, efficient, and reliable solid state lighting. This research also involves the development of methods for evaluation of absolute optical efficiency of semiconductors and semiconductor.

Additionally, research is underway on reducing defects in LED. The identification of point defects in GaN has immediate relevance to longer life time LEDs.

Researchers in the Quantum Device Laboratory (QDL) are working on replacing the transistor with more energy efficient spin-based devices that can reduce energy dissipation dramatically and lead to energy efficient electronics. Professor Supriyo Bandyopadhay showed that this device can reduce energy dissipation in electronics by at least 1000-fold, and the QDL has demonstrated extremely stable spin states in an organic molecule, a major step towards the realization of energy efficient green electronics.

With funding from DOE, the research group of Dr. Everett Carpenter is developing energy efficient electric motors. Dr. Carpenter is particularly interested in creating permanent magnets that can match the performance of the best commercial magnets and are less expensive than what is available on the market – without relying on rare earth elements. The goal of this project is to use the magnetic carbide-based composite to develop a magnet for use in a prototype electric motor. According to Dr. Carpenter, the program, if successful, would result in the first commercially viable, rare-earth-free magnet in nearly 50 years.

George Mason University. Mason's Center for Smart Power Grids performs research to move the centralized, producer-controlled electric network to one that is much more distributed and consumer interactive. The Center's 25 scientists, many of whom are world authorities in their areas of expertise, concentrate on smart grid technology research, development, and demonstration, among other areas. Foci include recovery from energy supply disruptions to minimize negative economic impact, optimal enhancement of electric grid infrastructure to make it robust against natural and man-induced disasters, and smart grid interoperability.

University of Virginia. UVa has major strengths and research activities in energy efficiency and conservation. Research is ongoing in the use of microheatpipe technology by Dr. Hossein Haj-Hariri to extract heat from computer chips, a major cause of energy use by air conditioning in data centers across Virginia and the U.S. In Virginia, it is estimated that the total energy usage in data centers costs $540 million, and that it will grow to $1 billion in five years, a growth rate of 20 percent. Nationally, this is equivalent to ten new power plants over a five-year timeframe. Extraction of this very high-value heat from data centers to power other systems will greatly diminish the need for air conditioning, which is over 50 percent of the energy cost in data centers today[24].

Dr. Kamin Whitehouse has developed a smart control technology for residential and industrial buildings which employs smart sensors and a control system which predicts the occupancy of buildings based upon an algorithm that is developed through tracking of individual occupancy in the building. This is projected to save 30 percent of building energy use[25].

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[24] J.B. Marcinichen, J.A. Olivier, J.R. Thome, "On-chip two-phase cooling of datacenters: cooling system and energy recovery evaluation," Applied Thermal Engineering, 41, 36, (2012).
[25] "Heating and Cooling Control". University of Virginia. Retrieved from: http://www.cs.virginia.edu/~whitehouse/research/thermostats/.

Virginia Tech. CPES is a $4 million / year research center dedicated to improving electrical power processing and distribution that impact systems of all sizes – from battery-operated electronics to vehicles to regional and national electrical distribution systems. CPES has a worldwide reputation for its research advances, its work with industry to improve the entire field, and its many talented graduates. From 1998-2008, CPES was a NSF ERC. During the ERC period, CPES developed the Integrated Power Electronics Modules (IPEM), a standardized off-the-shelf module that has revolutionized power electronics. Today, CPES is building on that foundation so that power electronics can fulfill its promise and reduce energy use while helping electronics-based systems grow in capability.

CPES expertise encompasses five technology areas: power conversion technologies and architectures; power electronics components; modeling and control; EMI and power quality; and high density integration, while the Center's targeted applications include: power management for information and communications technology; point-of-load conversion for power supplies; vehicular power conversion systems; and renewable energy systems. The Center is charged with inventing the technology and manufacturing processes for power electronics devices based on wide bandgap semiconductors. CPES will lead the power electronics research and applications thrust.

CPES is also a university partner in the Clean Energy Manufacturing Innovation Institute and will lead the Institute's power electronics research and applications thrust. Led by North Carolina State University, the $140 million advanced manufacturing institute will receive $70 million from DOE in the next five years, an amount that will be matched through a combination of funds from the businesses and schools involved, along with at least $10 million from the state of North Carolina[26].

The Power Management Consortium (PMC) aims to develop pre-competitive technologies in power management at the board level. PMC is developing technology for distributed power system architectures, power management, EMI / EMC, power quality, AC-DC converters, DC-DC converters, and POL converters. CPES expects PMC advances to lead to improved microprocessors, netbook, notebook, tablet, desktop, server and networking products, telecom equipment, solid state lighting, and more.

The Center for Energy Harvesting Materials and Systems (CEHMS) under director Dr. Shashank Priya is a consortium of major research universities, industry partners, and commercial and government organizations. It is sponsored through the NSF Industry / University Cooperative Research Centers (I/UCRC) program with the aim of developing integrated solutions for challenging energy efficiency, storage, and distribution problems. At CEHMS, research advances are being made in the fields of materials, structural dynamics, electronics, and storage media to develop self-powered systems, open pathway for distributed power sources and grid integration. CEHMS test beds include energy harvesting solutions for sensors in: extreme environments, intelligent packaging, wearable systems, and implantable systems.

> The **Center for Power Electronics Systems (CPES)** at **Virginia Tech** is dedicated to improving electrical power processing and distribution that impact systems of all sizes – from battery-operated electronics to vehicles to regional and national electrical distribution systems. Results are solutions that are more efficient, faster, and use fewer resources.

[26] Virginia Tech. (2014). *2014 Virginia Energy Plan: Virginia Tech Inputs*.

Efficiency / Conservation / Environment

College of William & Mary. Approximately 50 people self-identified with environmental research are based on W&M's main campus; a comparable number are based at VIMS. Research includes large-scale database collection on energy operations and other commercial development on habitat, impacts of offshore drilling and wind turbines on migratory birds, and environmental impacts of toxins from hydrocarbon energy on food webs. W&M's well-known experts include Dr. Robert Diaz, the world's foremost authority on marine "dead zones," and Dr. Deborah Bronk, a leading authority on deep-cycle interchange between organic and inorganic oceanic carbon, governing carbon oxide exchanges between the atmosphere and coastal and deep oceanic waters, geologic and biomineral sinks, and active marine life of all types. These areas of interest are directly connected to fossil energy production and refining within the coastal zone, and the generation of petroleum based fertilizers, pesticides and herbicides. In addition, and directly related to climate effects of greenhouse gas production from fossil fuels burning, W&M / VIMS is a world leader in predictive computational modeling of inundation in coastal zones.

Sustainability is a major issue at W&M, including for its undergraduate students. A several year-old program, funded as a Green Fee by students, supports undergraduate and graduate student research projects, larger facilities energy management grants, and education programs and conference opportunities. It also supports joint internship programs with Dining Services in areas such as composting and recycling. In 2011, W&M's undergraduate business program was ranked the best in the country for sustainability, according to the *Bloomberg BusinessWeek* rankings of 14 specialty areas[27]. In 2014, W&M appointed its first director of sustainability.

George Mason University. Drs. Hakan Aydin and Robert (Bob) Simon of Mason's Computer Science Dept. and the Center for Smart Power Grids are involved in energy-aware computing and networking. This research, which is interdisciplinary, particularly examines energy management and optimization of small, portable consumer-level devices.

Virginia Tech. Since its founding in 1987, researchers at VT's Interdisciplinary Center for Applied Mathematics (ICAM) have worked on the design, optimization, and control of energy efficient buildings, among numerous other challenges. ICAM is a partner in the DOE's Hub on Energy Efficient Buildings (EEB), now known as the Consortium for Building Energy Innovation (CBEI). CBEI develops and demonstrates systems solutions in a real-world regional context for future national deployment. ICAM also is involved in a collaborative project whose goal is to create new computational science tools to enable the design and control of buildings that consume 50 percent less energy while maintaining comfort.

The Virginia Water Research Center, housed at VT, was authorized by the Virginia General Assembly as a state agency in 1982. The Center has been recognized as one of the nation's outstanding water resources programs. Current projects include the effects of cellulosic biofuel production on regional hydrology and assessing the effectiveness of restoration efforts in Central Appalachian coalfield streams. Additional research in water issues related to coal mining is performed by the Appalachian Research Initiative for Environmental Science (ARIES), a program directed by VCCER.

James Madison University. Led by Dr. Christie-Joy Brodrick Hartman, JMU established the Office of Environmental Stewardship and Sustainability (OESS) to coordinate environmental

[27] College of William & Mary. *Virginia Energy Plan – R&D Chapter: William & Mary*.

stewardship efforts across campus, advocate for priorities, and challenge all members of the JMU community to think critically about their role in achieving the long-term stewardship of earth. Through the OESS, a diverse group of leaders across the university developed an environmental stewardship action plan for 2011-2015, with three primary goals: (1) minimize materials impact, emissions, toxins, solid waste, and consumption; (2) conserve, steward, and restore natural systems; and, (3) advance environmental literacy and engagement through research, education, and community programs.

Buildings / Construction

James Madison University. Dr. Maria Papadakis conducts research on energy management strategies for conserving energy and mitigating greenhouse gases in university residence halls. She also researches trends in building energy codes and the cost-effectiveness of "beyond code" building energy rating systems such as HERS, Energy Star, zero-energy homes, and passivhaus.

University of Virginia. As noted in Section 2.0, UVa's energy R&D is part of its ESPRIT initiative. UVa's view is that it is important from the outset to include and coordinate research on efficient use, conservation, sustainability issues, and environmental impacts with the development of alternate energy generation technologies.

> 80 percent of today's building stock will be in use by 2050. Reducing energy use in residential and commercial building will lower GHG emissions. The **University of Virginia**'s John Quale is leading an initiative to increase building efficiency, which includes sustainable design, and reduce the environmental impact of construction.

UVa designed and built the first passive standard, affordable house in South Boston, Virginia, with support from the Virginia Tobacco Commission. This effort was led by John Quale, a nationally recognized expert in sustainable building design, as well as experts in landscape and remediation technology and environmental planning and sustainable communities.

Virginia Tech. Areas of expertise in the Department of Building Construction include sustainability and green building, building performance, safety, and 3D and 4D modeling. Students have opportunities to gain industry experience while analyzing various construction elements by utilizing methods of virtual construction to compare the utility of virtual construction management to traditional methods.

In the Computational Research for Energy Systems and Transport (CREST) Laboratory, primary research areas during the last ten years include building energy and efficient energy utilization, alternative energy production, turbulent and reacting multiphase flows, and combustion. The primary applications of research include: building energy, such as for analyses of building codes to ensure construction of energy efficient residential homes; installation of ground-coupled heat pumps; and conditioning air for gasification processes.

Energy Policy

George Mason University. Mason's Center for Energy Science and Policy (CESP) in the School of Policy, Government and International Affairs includes a focus on affordable, reliable, and clean energy from a variety of sources that reflects both market-based decisions and technological innovation. Particular interests include advancing and coupling clean coal technology with new export markets for Virginia, power grid issues including grid security, and transportation policy as it intersects energy efficiency and conservation. The Center brings together the College of Science and School of Public Policy; funded projects are anticipated beginning in late 2014 or early 2015.

Dr. Alex Brodsky develops decision support, guidance, and optimization models; among others, he supports the energy, power and sustainability sectors. His research includes operational optimization for microgrids and large-scale power generation, transmission and distribution, and planning and investment decision-making for municipalities and companies. Additionally, Ambassador (ret.) Richard Kauzlarich is a member of the National Capital Area Chapter for the U.S. Association for Energy Economics and will supervise research regarding the intersection of the economics of science innovation with energy policy.

Mason researchers performing economic analyses in fuel cells show that fuel cells not only provide renewable energy but also make electric vehicles more affordable.

Virginia Tech. The Center for Energy and the Global Environment (CEAGE), based at ARI, is a research and educational center charged with determining reliable and secure methods of electricity generation and utilization that are compatible with the environment.

Virginia Commonwealth University. VCU's policy work includes interdisciplinary initiatives. For example, Drs. Sama Bilbao y León, Caley Cantrell, and Ken Kahn collaborate on a large, multi-disciplinary, DOE-funded project to select the optimum path for the long-term management of used nuclear fuel. The team takes into account technical, environmental, and economic considerations, as well as the public perception for the chosen solution.

Professor Bilbao y León also conducts studies in energy and environmental policy, with a focus on the optimum use of nuclear power to address climate change concerns and long-term sustainability. Her valuations of the economic, technical, and licensing feasibility of advanced nuclear technologies such as small modular reactors, assessments of long-term energy source availability, reliability and price stability, and valuation of energy resources have often been funded by stakeholders in the nuclear industry.

James Madison University. Through a partnership with JMU, Virginia Clean Cities (VCC) assists stakeholders, legislators, and agencies in the Commonwealth with various state, local, and national legislative efforts leading to the adoption of alternative fuel vehicles. At the federal level, VCC meets annually with congressional leadership on the success of programs and the value of coalition impact on energy, economic, and environmental security in the Commonwealth and U.S. In support of infrastructure development and vehicle conversion efforts, VCC led the Propane Corridor Development Program, which converted 1200 vehicles across 36 fleets to propane. Following a public-private partnership model, JMU, VCC, and Luck Stone worked with the U.S. Environmental Protection Agency (EPA) on the first comprehensive repower program for construction vehicles in the Commonwealth, by taking 11 old vehicles and modifying them with new engines or replacing them with vehicles that met modern emissions standards.

Dr. Rob Alexander is engaged in policy research regarding the extent to which a range of policy tools incentivizing development of biodiesel capacities at the state level incur the desired outcomes. The present study specifically examines political and capacity variables in North Carolina and Virginia to explain why North Carolina demonstrates greater capacity for biodiesel distribution when compared with Virginia. Preliminary results of this comparative case study indicate that centralized state government support and guaranteed fuel qualities are important variables to add to future explanatory models.

Dr. Maria Papadakis conducts research on the effects of land use planning, law, and regulation on the development of wind energy systems. She also conducts research and outreach on the cost-effectiveness of renewable energy systems for on-farm net metering applications in partnership with Virginia Cooperative Extension, the USDA's Natural Resources and Conservation Service, and Old Dominion Electric Cooperative. She and Dr. Mike Deaton have facilitated industry partnerships on the design and effectiveness of energy appliance rebate programs.

College of William & Mary. W&M's Public Policy Program and Law School address policy matters for a broad range of energy sectors. The public policy program addresses questions related to adopting new energy technologies, such as structuring incentives for contractors to use photovoltaics and LEED (Leadership in Energy and Environmental Design – a program of the U.S. Green Building Council) standards in their buildings. Other policy research covers environmental and social impacts of Virginia offshore energy development. The Law School is engaged in comparative studies of renewable energy policies (wind, solar) in China and the European Union.

The Institute for the Theory and Practice of International Relations comprises several projects, including a $25 million United States Agency for International Development (USAID) program. The program includes projects to assess developing world energy, environmental problems, food and military security, all of which have an integral relationship to energy economics.

Old Dominion University. Dr. Adrian Gheorghe works on issues related to comparative risk and vulnerability assessment of various energy systems and the impact of such evaluations on energy policy formation, critical energy infrastructures, and their interdependency with other critical systems such as transportation, information and communications, and pipelines. Recent energy policy modeling efforts include those related to resilience analysis and energy security in national and international scenarios. These scenarios have looked at risk analysis for energy systems and operation performance of computer-assisted infrastructures (e.g., SCADA systems) exposed to cyber attacks.

Other Energy Research Projects

College of William & Mary. W&M is active in multiple energy storage projects, including as a subcontractor to the University of Nevada, Las Vegas on a federally-sponsored R&D program for the development of molten salt storage for use on concentrated solar power units. Several groups at W&M have funded research associated with graphene for advanced battery and capacitor electrical storage, materials strengthening and corrosion resistance for hydrocarbon pipelines, and other energy applications.

James Madison University. Research includes range modeling of electric vehicles, particularly developing energy usage models of specific electric vehicles based on typical road load modeling techniques. Comparison of energy usage predictions along a particular route with actual energy usage as monitored along the route provides feedback on model efficacy. To date, electric vehicle projects with a range modeling component include: low-speed electric utility vehicle on and about campus; touring motorcycle prototype; and a cross-country endurance racer / coast-to-coast record-setting motorcycle.

JMU's VCC managed the Richmond Electric Vehicle Initiative. The main objective of this project was to advance the Richmond region as an attractive and sustainable market for electric vehicle technology and develop an electric vehicle readiness plan.

University of Virginia. In the area of conservation related to transportation energy use, the Smart Travel Lab is a joint effort between the Department of Civil Engineering and the Virginia Transportation Research Council. Part of the UVa Center for Transportation Studies, the Lab is connected to traffic management systems operated by the Virginia Department of Transportation (VDOT), providing researchers with direct access to current Intelligent Transportation System (ITS) data. This allows the Lab to help VDOT's Smart Travel Program reduce traffic congestion in the heavily populated areas of Northern Virginia and Hampton Roads.

Virginia Tech. To determine the effects of plug-in electric vehicles (PEVs) and solar generation on the grid using a networked micro-simulator, VT studied the capacity contribution of solar installations in New York City using four years of actual weather data and load curves. This study extrapolated out this information to identify an optimal installed capacity of solar generation based on the PEV penetration. Additionally, the studies conducted evaluated the introduction of wind and solar in the presence of PEVs. VT developed and successfully applied a model for computing optimal mixes of wind and solar generation to achieve a given overall renewable penetration target in a geographical region based on the historical weather and load patterns and conventional generation capacity in the area. VT also developed the ability to simulate the impact of PEVs on a grid while taking into account the stochastic nature of individual vehicle movements and charging / discharging along with the specific commute characteristics of a region.

> The intersection of transportation and energy provides opportunities to reduce energy consumption and GHG and enhance energy independence. Virginia universities are engaged in multiple areas of research, including fuel cell membranes and materials (Virginia Tech), electric vehicles (James Madison University), and policy work (George Mason University).

Energy R&D at Federal Laboratories in Virginia

Virginia is home to three major federal research laboratories that are conducting energy research, all of which are engaged in energy-related research and development. The laboratories surveyed for this report are:

- Thomas Jefferson National Accelerator Facility (Jefferson Lab)
- NASA Langley Research Center (NASA LaRC)
- Naval Surface Warfare Center – Dahlgren Division (NSWCDD)

Table 10-1: Sampling of Energy R&D at Federal Labs in Virginia

Sampling of Energy R&D at Federal Labs in Virginia														
FEDERAL LAB	Energy Generation / Sources & Technology									Energy Trans-mission & Technol-ogies	Energy Use / Impact & Technology			Energy Policy
	Fossil Fuels	Nuclear	Fuel Cells / Hydrogen	Biofuels	Waste-to-Energy	Geothermal	Water / Hydroelectric	Solar / Photovoltaics	Wind	Electric Grid	Energy Storage	Energy Efficiency / Conservation / Environment	Buildings / Construction	Energy Policy
Jefferson Lab		•						•	•			•		•
NASA LaRC		•	•	•					•		•	•	•	
NSWCDD												•		

Thomas Jefferson National Accelerator Facility

The Jefferson Lab is a DOE-funded facility whose primary mission is to conduct basic science research on sub-atomic particles (quarks and gluons). The Lab is a world leader in accelerator technology, and its Continuous Electron Beam Accelerator Facility (CEBEF) is the world's most advanced particle accelerator for investigating the quark structure of the atom's nucleus. Jefferson Lab conducts basic and applied research with industry and university partners utilizing CEBAF. As it relates to energy research, the Lab has an interest in Accelerator Driven Systems, when an electron beam is used to drive a nuclear reactor. Research applications also include advanced energy efficiency for multiple high tech areas including cryogenic systems, utilization of high power radio frequency (RF), and integrated complex system operations. Additionally, the Jefferson Lab is a leader in the Hampton Roads Energy Corridor, a loose federation of mostly federal facilities advancing opportunities for enhanced energy security, surety, and sustainability.

NASA Langley Research Center

NASA LaRC is a research, science, and technology development center that maintains expertise in systems concepts, climate research, and vehicle technologies. Its energy-related research crosses a variety of areas, including efficiency, waste mitigation, conversion, and storage.

NASA Langley leads NASA's Environmentally Responsible Aviation project, exploring and developing tools, technologies, and concepts to improve energy efficiency and environmental compatibility, and developing concepts and technologies for improvements in the noise, emissions, and performance of transport aircraft. The Center was recently selected to lead NASA's Advanced Composites Project – a project focused on reducing the time for development, verification, and regulatory acceptance of new composite materials and design methods for aircraft.

Energy-related earth science research is principally focused on searching for and creating better ways of gathering, measuring, and analyzing atmospheric data. Atmospheric scientists conduct research from the land, sea, air, and space to understand the atmospheric effects caused by volcanic eruptions, industrial pollution, changes in the planet's energy balance and other events. The Center is working toward improving the systems that take ozone measurements close to the earth's surface, better understanding impacts to the air we breathe, and is researching ways to improve earth observations from space – the characterization of near-surface pollution. In 2015, NASA LaRC will be delivering SAGE III, an instrument to study ozone and aerosols, to the International Space Station; the Center is operating five on-orbit instruments, all focused on monitoring air pollution and improving climate models to better understand and predict earth's climate change.

Naval Surface Warfare Center – Dahlgren Division

NSWCDD's main focus is on weapons / combat systems. Its energy-related research is on high-energy lasers and improved power efficiencies.

Tobacco Commission Centers

The Tobacco Indemnification and Community Revitalization Commission is a 31-member body created by the 1999 General Assembly. Its mission is the promotion of economic growth and development in tobacco-dependent communities, using proceeds of the national tobacco settlement. Supporting that revitalization mission, the Commission established six research and development centers in the Southside and Southwest regions of Virginia. The centers include:

1. R&D Center for Advanced Manufacturing and Energy Efficiency
2. Southern Virginia Product Advancement Center (formerly Riverstone Energy Centre)
3. Center for Advanced Engineering and Research (CAER)
4. Sustainable Energy Technology Center
5. Foundation Growth Ventures (formerly Southwest Virginia Clean Energy R&D Center)
6. Appalachia America Energy Research Center

Each Center operates independently and serves the research needs of its designated area. A summary of notable work performed follows.

- Foundation Growth Ventures, a division of the Southwest Virginia Higher Education Center Foundation, invests in early-stage companies in rural Southwestern and Southern Virginia. Its funding model differs from the Commission's traditional grant funding model; the Fund invests in companies using Commission monies with the aim of growing each company and receiving a financial return on the investment. The Fund has invested in renewables and conventional fuel technology companies, including OptaFuel, ReNew Fuels, and CavitroniX.

- The Southern **Virginia Product Advancement Center** serves as a business incubator and product development center. The Center operates a modeling and simulation center for virtual prototyping and testing and a leading-edge coating and finishing center.
- **CAER** has developed capabilities centered on the nuclear energy industry, in concert with the region's nuclear work. The Center also houses testing and analysis technologies and sensors and controls technologies for the energy industry.

Industry-based Energy R&D in Virginia

The survey uncovered an array of R&D, including focus areas in nuclear and increasingly in wind. R&D is performed by large companies, though small and start-up companies are seen as important sources of innovation. Energy technologies often have a longer development timeline, are capital-intensive, and R&D may require access to expensive equipment.

Several Virginia companies were interviewed to determine their general energy R&D interest areas. Table 10-2 summarizes energy-related R&D interests of these companies.

Table 10-2: Sampling of Energy R&D at Companies in Virginia

Sampling of Energy R&D at Companies in Virginia

COMPANY	Energy Generation / Sources & Technologies									Energy Trans-mission & Technologies	Energy Use / Impact & Technologies			Energy Policy
	Fossil Fuels	Nuclear	Fuel Cells / Hydrogen	Biofuels	Waste-to-Energy	Geothermal	Water / Hydroelectric	Solar / Photovoltaics	Wind	Electric Grid	Energy Storage	Efficiency / Conservation / Environment	Buildings / Construction	Energy Policy
Afton Chemical												•		
Alstom Power									•					
AREVA		•												
Babcock & Wilcox		•												
Dominion Virginia Power	•	•						•	•	•		•		•
GE Energy	•	•						•	•			•		
Newport News Shipbuilding	•	•		•			•		•		•	•	•	
Opower												•		
Siemens Energy												•		
Timmons Group	•								•			•	•	•
Verdant Power							•							
SBIR / STTR Companies			•	•			•		•		•			
GAP / CEF Portfolio	•		•	•	•							•		

Similar to statistics collected for academic R&D, NSF does not monitor the "energy" industry in its business-related R&D statistics. Energy R&D, instead, is incorporated in other sectors, including electrical equipment, appliances, and components, and in machinery (engine, turbine, and power transmission equipment).

The NSF's survey of industry R&D expenditures, *Business R&D and Innovation Survey: 2011*, reported that Virginia companies performed $5.56 billion in domestic R&D, of which $2.09 billion was paid for by the U.S. federal government. This report identifies select industries and classification codes; energy is not specifically called out.

Energy R&D at Selected Virginia Companies

Virginia's private sector companies researched and interviewed are working on efforts to further their commercial practices. When and if necessary, the firms seek partnerships with Virginia-based research universities. However, these partnerships are infrequent and are driven by their customer's needs. The companies provided limited information on their energy R&D expenditures.

Afton Chemical of Richmond is a global petroleum additives supplier. Afton Chemical sells a variety of lubricants (e.g., engine oil, fuel) to reduce wear in engine parts and improve fuel performance while reducing emissions. Afton Chemical's Ashland Technical Center is located 15 miles north of its headquarters and is researching clean-up levels of detergent additives, vehicle emission levels, and the benefits of fuels additives.

Alstom Power (Arlington), a global provider of power generation, power transmission, and rail infrastructure, maintains its turbine engineering, manufacturing, and service group in Midlothian and its Alstom's North American headquarters for wind energy in Richmond. Its wind energy activities include working with Dominion Virginia Power to install two Alstom wind turbines off the coast of Virginia as part of the Virginia Offshore Wind Technology Advancement Project supported by the DOE. In June 2014, GE purchased Alstom's gas and steam turbine business; the impact on Virginia R&D is not yet known.

AREVA (Lynchburg) has strengthened its R&D facility footprint extensively in Virginia since 2007. The AREVA Solutions Complex is home to world class labs and test facilities. In September 2012, AREVA opened its U.S. Technical Center as a major component of the Solutions Complex. The Technical Center contains a world-class seismic analysis laboratory, a chemistry lab featuring scanning electron microscopes for evaluating material properties, environmental chambers testing component and product performance, and chambers for thermal aging to support commercial grade dedication testing of safety-related components in the nuclear fleet.

AREVA maintains three principal locations in Lynchburg, including its Center of Excellence for U.S. Pressurized Water Reactors (PWR). AREVA is leading the development of its new PWR fuel design named GAIA for the U.S. nuclear fleet. The GAIA fuel design will provide utilities cost-savings through its high mechanical fretting resistance, better thermal performance, and increased tolerance to earthquakes. Moreover, the design features advanced cladding, which AREVA anticipates will meet new regulatory requirements in the United States.

AREVA is partnering with Virginia universities, in collaboration with the DOE, to develop a new fuel cladding that improves heat transfer characteristics. Moreover, AREVA partners with VCU, UVa and Virginia Tech. At VT, AREVA is on the College of Engineering Advisory Board as well as on the Nuclear Engineering Advisory Board. At UVa, AREVA has worked on wind energy development and on laser advanced manufacturing.

AREVA's fuel division spent more than $10 million in fuel design-oriented research and product development activities in 2013 in Virginia. Further, the company spent approximately $9 million on R&D in Virginia through its "Installed Base" business unit.

Babcock & Wilcox (B&W) maintains business operating units in Lynchburg, including mPower (development and deployment of small modular reactors), Nuclear Energy and Nuclear Operations (manufacturing and services for commercial nuclear applications and government applications, respectively) and Technical Services (nuclear operations and technical services for the government). The company partnered with CAER in Bedford County to develop and host the mPower Integrated Test Facility and, where a digital control room simulator is housed, the Center of Excellence for Safe and Secure Nuclear Energy. In Virginia, B&W conducts commercially-focused R&D in areas such as testing and evaluation of nuclear applications and materials and non-destructive evaluations.

Dominion Virginia Power's most public R&D effort pertains to the development of the offshore wind turbine demonstration project off the coast of Virginia. The $51 million project was funded by DOE to help with the construction of a 12-megawatt demonstration project, consisting of two 6-megawatt wind turbines. In addition, the company invested roughly $1.7 million in 12 renewable energy R&D grants to Virginia-based universities and colleges in areas such as wind turbine design, bio-mass, and green-roofing.

In June 2014, GE purchased Alstom's gas and steam turbine business. Prior to the acquisition, the foci of **GE Energy**'s Salem facility were expertise in controls and power electronics, and providing technology, software, and hardware needed for the reliable and efficient operation of GE's turbines, generators, compressors, and power conversion equipment for these and the wind, photovoltaic, and oil and gas markets.

Newport News Shipbuilding (a division of Huntington Ingalls Industries) is heavily involved in the development, manufacturing and construction of America's next-generation aircraft carriers and submarines. Its R&D of energy-related technologies directly relates to enhancing manufacturing, and construction of these core products. Areas of interest include improving energy efficiencies, small modular reactors, nuclear waste clean-up, transportation of nuclear waste, and wave energy. Newport News Shipbuilding also manages the Virginia Advanced Shipbuilding and Carrier Integration Center (VASCIC) established in 1998 by the Commonwealth. The purpose of VASCIC is to enhance and promote the quality and competitiveness of Virginia's shipbuilding industry and to promote the general welfare of Virginia citizens. At VASCIC, Newport News Shipbuilding, along with electronic system suppliers, software suppliers, U.S. Navy laboratories and program representatives, and Virginia institutions of higher learning, develop and integrate new technologies for aircraft carriers and advanced shipbuilding.

Opower (Arlington) is developing cloud-based solutions for utility companies to improve customer engagement and their energy use. Opower delivers a platform for utilities to engage their customers by using data mining techniques and behavioral sciences. Through its software, utilities are able to analyze their customers' energy usage and send targeted messages (alerts) indicating potential upcoming high usage patterns, thus enabling users to understand and manage their energy usage on an ongoing basis.

In 2013, **Siemens Energy** opened a manufacturing facility in Charlottesville for the commercial production of airfoil ceramic cores for gas turbine blades and vanes, utilizing technology developed by Mikro Systems, Inc. These developments are expected to improve cooling capabilities of gas turbine blades leading to higher efficiency levels.

Timmons Group, headquartered in Richmond, provides engineering services to clients on a custom basis. The company was awarded program management and site and regulatory work for the Virginia offshore wind power development project.

Verdant Power, one of three leading tidal turbine manufacturers, is headquartered in Arlington and is producing underwater turbines for deployment in a tidal stream demonstration project in New York City's East River.

SBIR / STTR Energy Research in Virginia

CIT identified 20 Virginia companies that have received federal energy-related SBIR or STTR awards in the last three years. These companies, and their research areas, are listed below:

- Aurora Flight Sciences Corporation, Manassas – high-efficiency propulsion
- Cell-Free Bioinnovations, Inc., Blacksburg – high-yield hydrogen production from biomass sugars by cell-free biosystems for mobile electricity generation (spin-off from Gate Fuels in November 2012)
- Columbia Power Technologies, LLC, Charlottesville – wave energy converter performance and cost optimization
- Craftell Power Sources, LLC, Fairfax Station – reserve cell technologies with fast initiation for power on demand
- Directed Vapor Technologies International, Charlottesville – processing methods for manufacturing multifunctional high-temperature coatings; coatings for turbine airfoils (based on UVa research)
- Edenspace Systems Corporation, Purcellville – poplar system for remediation of organic contaminants
- Gate Fuels, Inc., Blacksburg – production of formic acid powered by sugars; development of high-power and high-energy-density enzymatic fuel cells as a next-generation, environmentally friendly (micro-)power source
- GeneSiC Semiconductor, Inc., Dulles – silicon Carbide Quasi-Bipolar Junction Transistor (QBJT)-based boost converter platform for up-tower wind applications; advanced power modules for use in power electronics for energy storage in the medium-voltage range
- IRFLex Corporation, Danville – fiber delivery systems for ultrashort pulse lasers
- Luna Innovations, Inc., Roanoke – nanostructured carbon nanosheet electrode for enzymatic fuel cells; bio-responsive antifouling coatings for ship hull; battery management system for monitoring and diagnostics of energy storage modules; rechargeable batteries with advanced non-toxic and safe anode and cathode materials; embedded fiberoptic shape-sensing for aeroelastic wing components
- Materials Modification, Inc., Fairfax – next-generation processes for carbonate electrolytes for battery applications; new solvent system for CO_2 capture
- MicroXact, Inc., Christiansburg – real-time manufacturing diagnostic system for the photovoltaic industry; next-generation thermoelectric devices (based on VT research)
- Mikro Systems, Inc., Charlottesville – rapid manufacturing method for high-temperature turbine components
- Muplus, Inc., Newport News – muon collider cooling channel design and simulations
- NanoSonic Inc., Pembroke – encapsulation approaches for flexible solar panels, displays, and antennas; VOC-free, highly flame-resistant insulation coatings for next-generation thermal insulation and energy efficiency (based on VT research)
- Polymer Exploration Group, LLC, Midlothian – low-cost and durable ice-release coating to mitigate icing-related problems encountered by air transportation, power transmission, and wind energy industries (based on VCU research)

Energy R&D at CEF / GAP Portfolio Companies

Energy industry R&D performers include start-up companies with high-growth potential that have attracted external investment. Several of these companies are in the CIT investment portfolio and received investments from the CIT's Commonwealth Energy Fund (CEF) or the Growth Acceleration Program (GAP) Fund, accelerating the firms' pathways to significant growth through active partnership and company development. A sample cross section of portfolio companies appears below:

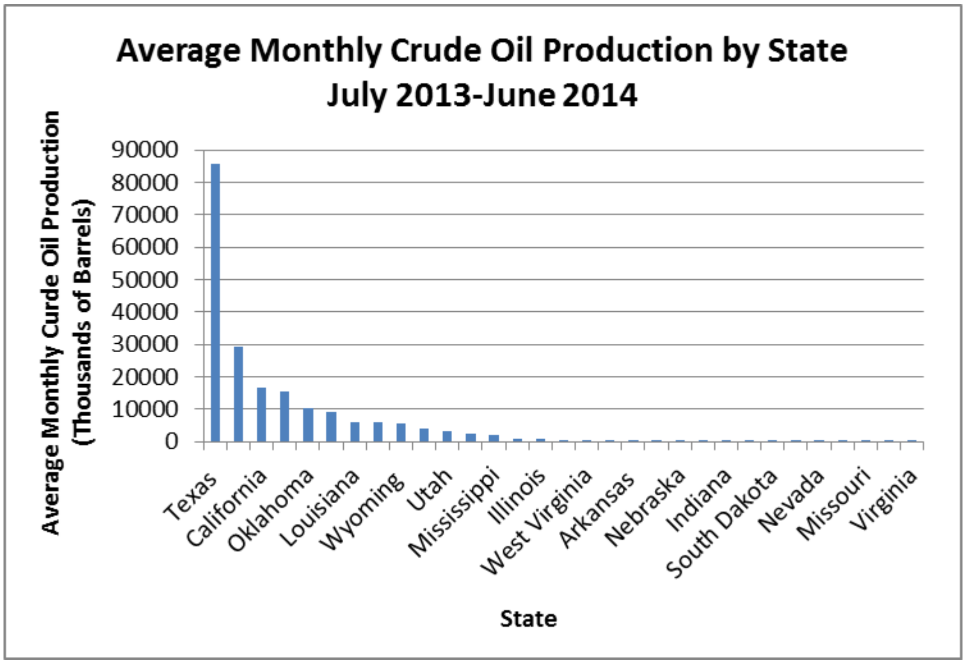
- Wiretough Cylinders, LLC, Bristol – developing and demonstrating a low-cost, high pressure hydrogen storage vessel using a steel wire overwrap with a $2 million grant from DOE
- Marz Industries, Glen Allen – focused on improving fuel efficiency through better hydrogen fuel cells, for ruggedized use in commercial short- and long-haul trucking applications
- Sunnovations, McLean – performing research to enable low-cost, smart-control of water heater energy usage; an emerging technology, enabled by development of an enthalpy sensor, allows for leak detection, water main shutoff, behavioral energy efficiency management, and utility demand response
- CavitroniX, Bristol – developing in-line technology and reducing greenhouse gas and soot emissions from oil fired boilers and furnaces, diesel generators, and marine diesel engines
- Piedmont Bioproducts, Gretna – uses renewable, farm-based feedstocks to generate clean biofuels through use of a thermo-chemical process

SECTION 11 – ADVANCED VEHICLE TECHNOLOGY AND ALTERNATIVE FUELS

Transportation Energy Alternatives Overview

Virginia is a state with almost no current petroleum production and with a near total dependence on oil for motor fuel imported from other states and countries, as shown in Figure 11-1. There are ample fuel alternatives available, and by considering alternative fuel vehicles, there are significant economic, environmental, and energy security opportunities for the Commonwealth.

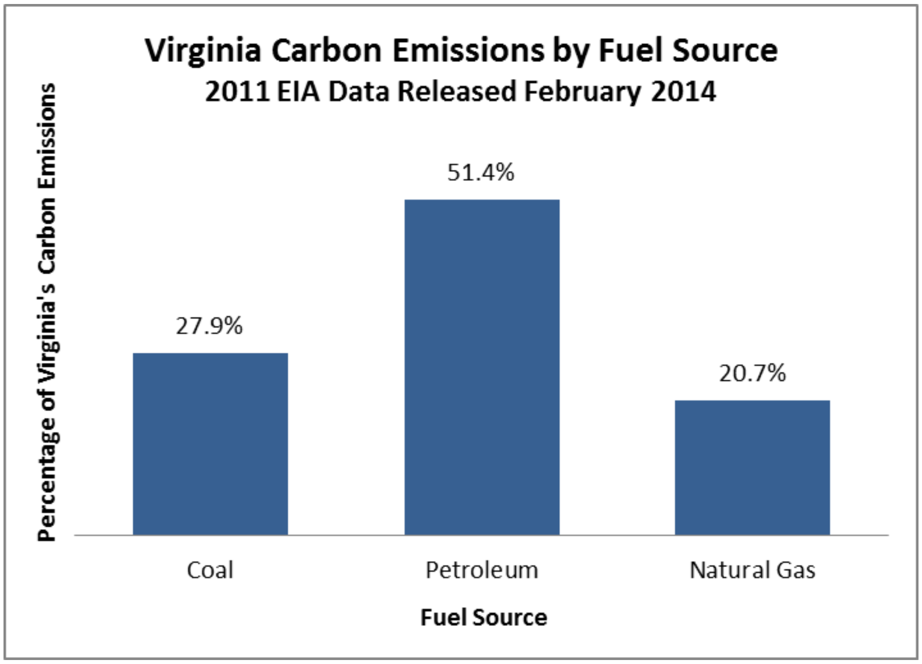
Figure 11-1: Average Monthly Crude Oil Production by State: July 2013-June 2014[1]



Oil use causes the majority of the State's emissions impact, as shown in Figure 11-2. This issue is important for climate change considerations. The Commonwealth has formed a U.S. Department of Energy-designated partnership called Virginia Clean Cities, hosted at James Madison University, which works to advance these energy, economic, and environmental opportunities for vehicle fleets and individual consumers in Virginia.

[1] Crude Oil Production, U.S. Energy Information Administration, Monthly Production Averaged for July 2013-June 2014, Data Released September 2, 2014. Data Accessed September 3, 2014. http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm Method: Follow link, Download Series History, Average July 2013-June 2014 Monthly Oil Production, Remove PADD averages, and create chart from highest to lowest production.

Figure 11-2: Virginia Carbon Emissions by Fuel Source[2]



Commonwealth's Alternative Fuel Vehicle Initiative

The Commonwealth of Virginia takes an "all-of-the-above" approach to achieving energy security and recognizes the need to replace imported fuels with cleaner domestic energy for vehicles. In 2011, the Virginia General Assembly unanimously approved legislation directing the establishment of a plan to replace state-owned vehicles that operate using gasoline or diesel fuel, with vehicles that operate using natural gas, electricity, or other alternative fuels[3]. Alternative fuels also include ethanol, propane, biodiesel, hydrogen, and others defined by alternative fuel providers or submitting entities.

In order to implement a successful and cost-effective strategy to replace state-owned vehicles, resources available in the private sector have been leveraged. In this effort, private sector natural gas and propane infrastructure and vehicle partners have been selected and approved on a state contract to deploy alternative fuel vehicles and stations that can service the state fleet. These partnerships help expand the alternative fuels and vehicles markets, support the expansion of private sector businesses, and create jobs in Virginia.

This initiative will continue to gain momentum as more public and private decision makers are brought together to discuss vehicle options for fleets across the state.

[2] Virginia State CO_2 Emissions, U.S. Energy Information Administration, Release Date: February 25, 2014, Data from: 2011, http://www.eia.gov/environment/emissions/state/state_emissions.cfm Method: Download Virginia Emissions data, Use Fuel Totals to create percentage shares of total carbon emissions.

[3] VA HB 2282, 2011, *Regular Session* (2011, April 06). Virginia Information System. Retrieved September 1, 2014, from http://leg1.state.va.us/cgi-bin/legp504.exe?111+sum+HB2282.

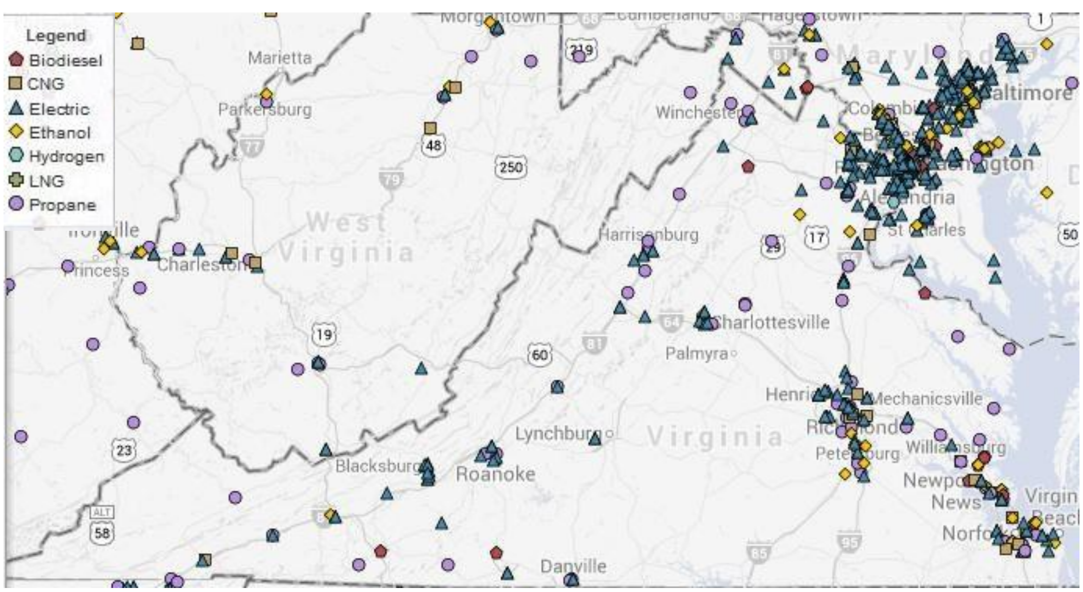
Transportation Infrastructure

Virginia's alternative fuel infrastructure is varied and growing. By the end of 2013[4], Virginia had 369 public and private alternate fuel stations throughout the Commonwealth. Virginia gained 83 new stations in 2013, mainly due to the large boost in electric vehicle charging stations. The most readily available of these fueling stations include electric, biodiesel, and propane (LPG). Table 11-1 shows the growth and changes in the total number of public and private alternative fuel stations in the Commonwealth, by individual fuels between 2005 and 2013 and Figure 11-3 shows a map of Virginia's Alternative Fuel Stations.

Table 11-1: Alternative Fuel Stations in Virginia[5]

	Biodiesel	CNG	E85	Hydrogen	LPG Propane	LNG	Electric	Total Alt Fuel Stations
2005	32	12	4	0	26	-	-	74
2006	39	12	4	1	26	-	-	82
2007	39	12	4	1	26	-	-	82
2008	40	12	4	1	26	-	-	83
2009	38	11	8	1	27	-	1	86
2010	44	14	11	1	49	-	4	123
2011	48	12	15	1	66	-	47	189
2012	36	17	19	2	70	2	140	286
2013	33	21	21	2	71	2	219	369
2014	33	24	20	2	82	2	247	410

Figure 11-3: Virginia Alternative Fuel Stations Map[6]



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[4] Virginia Clean Cities, Alternative Fuels Inventory Report, June 2014. Submitted to the Virginia Department of Mines, Minerals and Energy, Energy Division (2014, July 5).
[5] Virginia Clean Cities, Alternative Fuels Inventory Report, June 2014.
[6] Virginia Alternative Fueling Station Locator, Alternative Fuels Data Center, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy. Retrieved July 7, 2014 from http://www.afdc.energy.gov/afdc/locator/stations/state.

Market Trends

Production

Virginia's alternative fuel production is largely in natural gas, propane, (which is a byproduct of natural gas processing), biodiesel, and ethanol. In 2012, Virginia produced 146.4 trillion cubic feet of natural gas[7], of which the vast majority came from coal bed wells. In 2013, Virginia produced 3.3 million gallons of biodiesel at two active biodiesel refineries and 1 million gallons of ethanol from one active refinery, for a combined biofuel production of 4.3 million gallons[8]. This is the largest biofuels production output in the State over the past six years; and producers reported a potential production capacity of 17.5 million gallons[9]. Virginia's biofuels (biodiesel and ethanol) production from 2008 through 2013 is shown in Figure 11-4 and biofuels producing facilities located around the State are shown in Figure 11-5.

Figure 11-4: Gallons of Biofuel Produced in Virginia, 2008-2013[10]

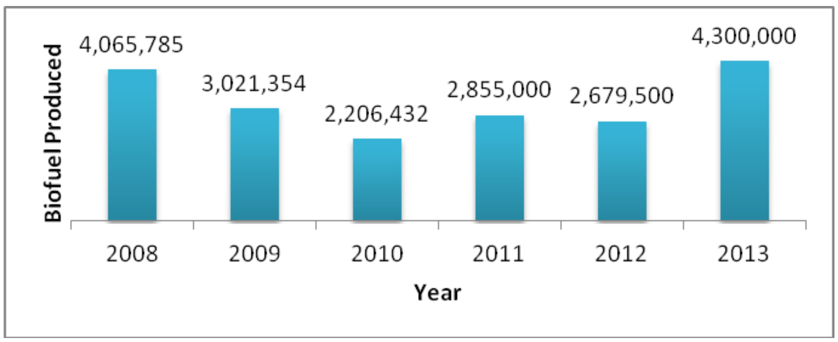
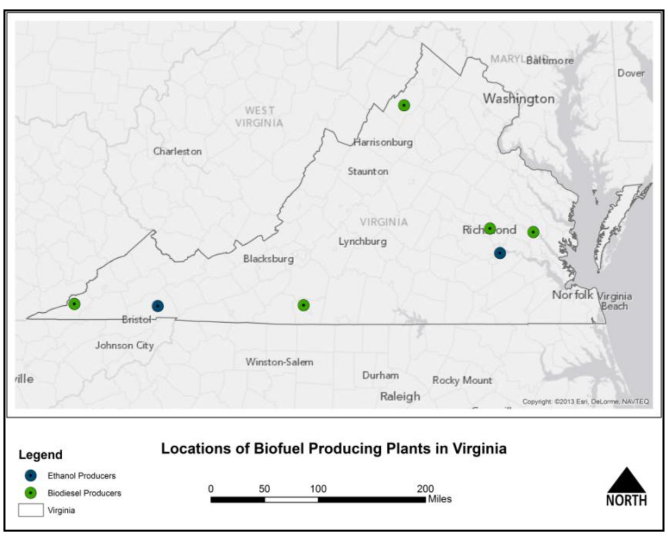


Figure 11-5: Biofuels Producing Plants in Virginia: January 2014[11]



[7] U.S. Energy Information Administration, Virginia Natural Gas Summary, http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_SVA_a.htm
[8] Virginia Clean Cities, Virginia Alternate Fuels Report, January 2014. http://www.vacleancities.org/wp-content/uploads/Alt-Fuels-Report-Q4-2013-Final.pdf
[9] Ibid.
[10] Ibid.
[11] Virginia Clean Cities, Virginia Alternate Fuels Report, January 2014. http://www.vacleancities.org/wp-content/uploads/Alt-Fuels-Report-Q4-2013-Final.pdf (Production plant location data was collected directly from production plants).

Consumption

Virginia has significant alternative fuel usage in government and private fleets. The growth of alternative fuel vehicles and conventional fuel vehicles in Virginia's green fleets are shown in Figure 11-6. Within these fleets, E85 and biodiesel represent the largest level of alternative fuel consumption in the Commonwealth, despite a recent decline in the use of biodiesel. In 2013, Virginia fleets reported using E85 in over 8,500 vehicles and biodiesel in over 4,300 vehicles[12].

Figure 11-6: Alternative Fuel Fleets and Vehicles in Virginia's Green Fleets

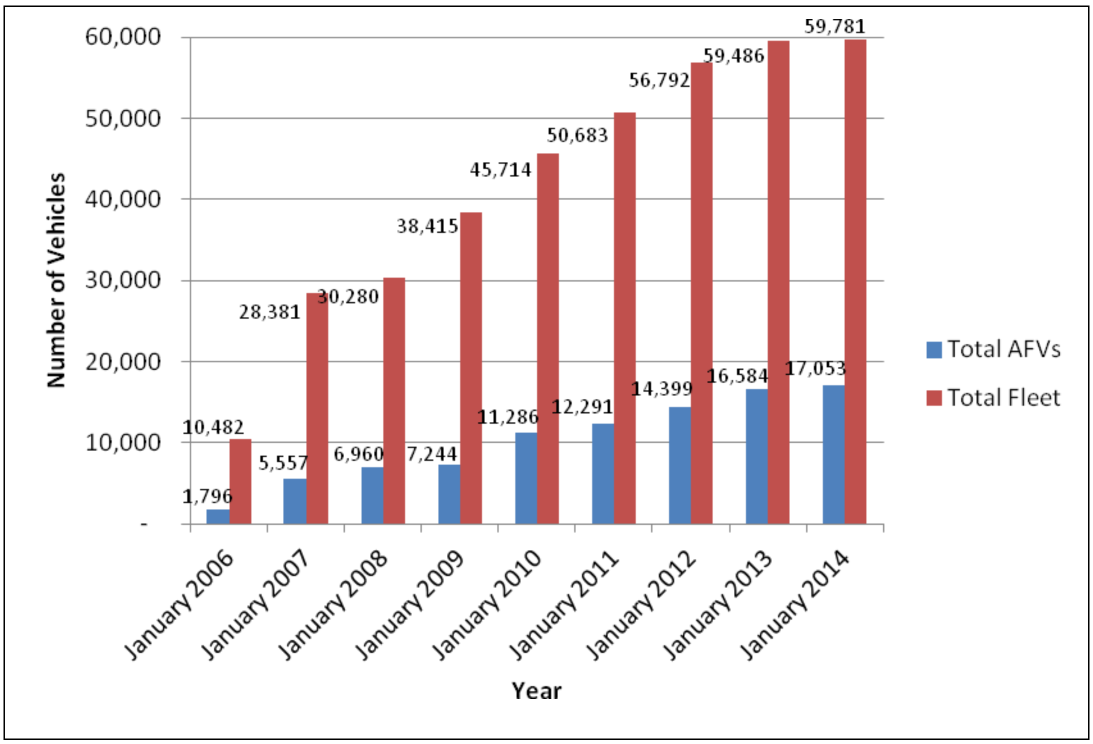
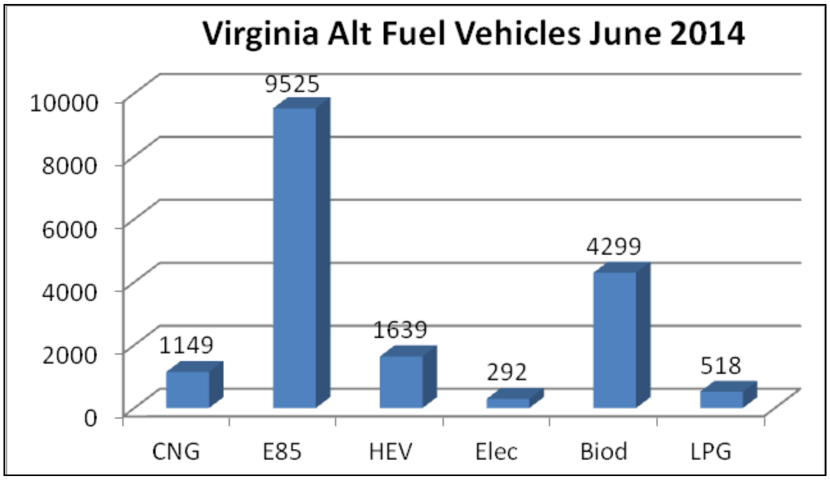


Figure 11-7 shows the total number of alternative fuel vehicles in fleets in the Commonwealth, as of June 2014. Natural gas has become a growing alternative for heavy duty vehicles, and in 2013, Virginia consumed 217 million cubic feet of natural gas for vehicle fuel[13]. Electric vehicles are also growing quickly in fleet use despite their low overall numbers.

[12] Ibid.

[13] Virginia Clean Cities, Alternative Fuels Inventory Report, June 2014.

Figure 11-7: 2014 Alternative Fuel Fleet Vehicles in Virginia[14]

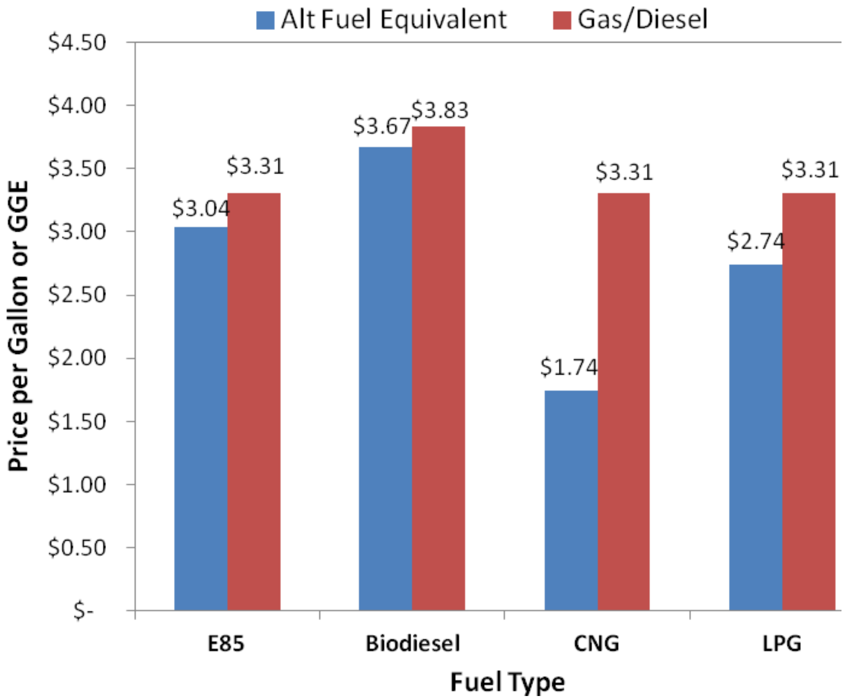


Fuel Prices

Figure 11-8 compares Virginia's average petroleum prices with alternative fuel equivalent prices collected in the Spring of 2014 by Virginia Clean Cities' alternative fuel price report[15]. Of note, several alternative fuel equivalents are often lower than their gasoline or diesel equivalent. Fleet pricing for alternative fuels is consistently and significantly lower than many public prices for gasoline and diesel in Virginia energy equivalents. Electricity is not included because Virginia electricity has no stable fuel retail price per kilowatt (KW), but at current utility rates electricity is available for less than $1.00 gallon equivalent at homes and workplaces.

[14] Ibid.
[15] Virginia Clean Cities, Alternative Fuel Price Report, April 2014. Submitted to the U.S. Department of Energy on 2014, April 15.

Figure 11-8: Virginia Alternative Fuel and Petroleum Prices: Spring 2014[16]



Alternative Fuels

Biodiesel

Biodiesel is a liquid fuel made up of fatty acid alkyl esters, fatty acid methyl esters, or long-chain mono alkyl esters. It is produced from renewable sources such as new and used vegetable oils, animal fats, and recycled restaurant grease (yellow grease). It is a nontoxic, biodegradable, and cleaner burning replacement for petroleum-based diesel fuel[17].

Biodiesel in Virginia is produced at several facilities, which collect waste grease or vegetable oils and process them into biodiesel fuel. In Virginia 3.5 million gallons of biodiesel are produced each year facilitating jobs and economic impact while reducing emissions[18].

Biodiesel is distributed from the point of production via truck, train, or barge. Pipeline distribution of biodiesel, which would be the most economical option, is still in the experimental phase. It is distributed to retail fueling stations and directly to end users such as large vehicle fleets, and can be easily dispensed through fueling equipment that is similar to regular diesel dispensers. Many stations throughout the Commonwealth offer biodiesel at the pump at various blend levels.

Biodiesel performs similarly to traditional diesel, though B100 (100 percent biodiesel) may result in minimal power loss and a slight reduction in fuel economy due to its having lower energy content than petroleum

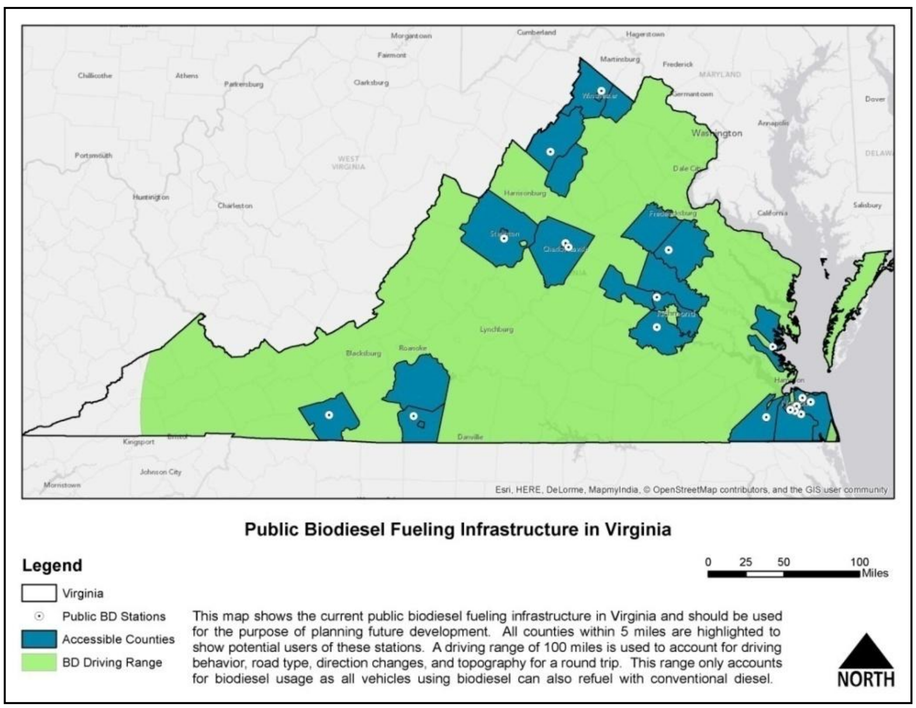
[16] Ibid.
[17] Biodiesel Fuel Basics, Alternative Fuels Data Center, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, http://www.afdc.energy.gov/fuels/biodiesel_basics.html
[18] Virginia Clean Cities, Alternative Fuel Production Inventory, January 2014.

diesel. Because biodiesel acts as a lubricant, it reduces wear and tear on the engine, reducing maintenance costs and extending engine life. Biodiesel also results in significantly lower emissions of particulate matter, carbon monoxide, toxic contaminants, sulfur dioxide, hydrocarbons, visible smoke, and noxious odors as compared to petroleum diesel emissions[19]. The production of biodiesel has a 1-to-5.54 energy balance ratio, which means that for every 1 unit of energy that goes into production, 5.54 units or energy are produced[20].

Numerous fleets in Virginia have used biodiesel including: school systems in Williamsburg-James City County, Gloucester County, and Virginia Beach; local government and school fleets in the Counties of Chesterfield, Arlington, Westmoreland, and Northumberland and the Cites of Newport News, Staunton, Blacksburg, Roanoke, and Waynesboro; U.S. military fleets for the Army, Navy, and Air Force; Woodfin Oil; SuperValu; the University of Virginia and Virginia Tech; and more.

Biodiesel can be used in almost any diesel vehicle without modification, except older vehicles that need rubber materials replaced because biodiesel is a powerful solvent. Figure 11-9[21] shows the locations of current public biodiesel fueling infrastructure in Virginia. Public stations are presented as white dots and all counties within 5 miles of the stations are highlighted in blue to show the potential users of these stations.

Figure 11-9: Public Biodiesel Fueling Infrastructure in Virginia: June 2014



[19] Biodiesel Vehicle Emissions, Alternative Fuels Data Center, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, http://www.afdc.energy.gov/vehicles/diesels_emissions.html.

[20] Pradham, A. et al. Energy Life-Cycle Assessment of Soybean Biodiesel Revisited, 2011 American Society of Agricultural and Biological Engineers: http://www.usda.gov/oce/reports/energy/EnergyLifeCycleSoybeanBiodiesel6-11.pdf.

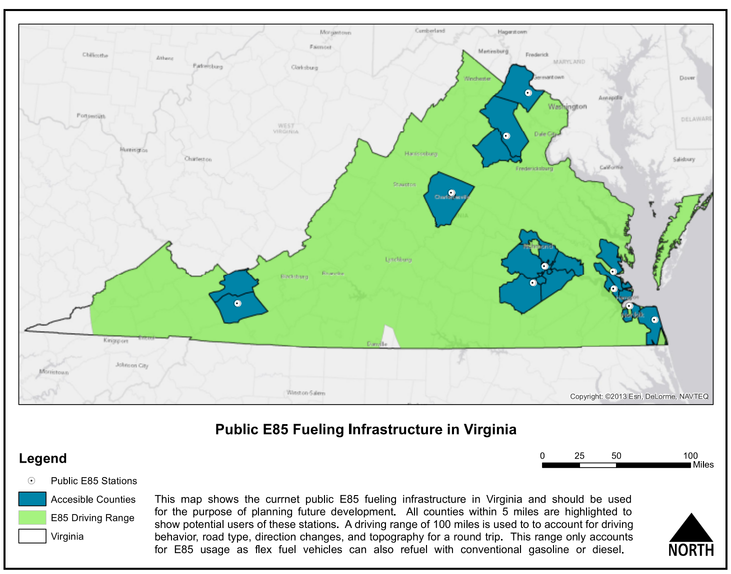
[21] Virginia Clean Cities, Virginia Alternative Fuel Maps: A GIS Based Analysis of Virginia's Alternative Fuel Infrastructure. June 2014. http://www.vacleancities.org/wp-content/uploads/Virginia-Alt-Fuel-Report.pdf.

Ethanol

Ethanol is a renewable fuel made from various plant materials, which collectively are called "biomass." This includes corn, barley, wheat, and cellulose feedstocks such as corn stalks, rice straw, sugar cane bagasse, pulpwood, switch grass, and municipal solid waste[22]. As a motor fuel, ethanol is produced is a similar process as alcohol, and it is blended with gasoline for use in vehicles.

There are currently several blends of ethanol fuel on the market. E10 is a blend of 10 percent ethanol and 90 percent gasoline[23]. More than 70 percent of American gas stations now sell E10, but as newer vehicles are manufactured, the industry may shift to raise the standard to more E15 use. E15 is a blend of 15 percent ethanol and 85 percent gasoline[24]. This is a new, higher octane blend that has been approved by the Environmental Protection Agency (EPA) for use in vehicles year 2001 and newer. The Mid-Level Blends, or E20, E30, and E40 are blended between 10 percent and 85 percent ethanol[25]. All flex-fuel vehicles (FFVs) on the road are manufactured to operate on gasoline and up to 85 percent ethanol, so mid-level blends can be dispensed at stations that have blender pump infrastructure. There are 300,000 FFV's in Virginia today[26]. The most common ethanol fuel mixture and standard fuel for FFVs is E85, a blend of 85 percent denatured ethanol and 15 percent gasoline[27]. Finally, E100 is pure ethanol fuel and is not commonly sold in the United States[28]. Figure 11-10[29] shows the locations of current public ethanol fueling infrastructure in Virginia.

Figure 11-10: Ethanol Fueling Infrastructure in Virginia: June 2014



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[22] Ethanol Fuel Basics, Alternative Fuels Data Center, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, http://www.afdc.energy.gov/fuels/ethanol_fuel_basics.html.
[23] Ethanol Blends, Alternative Fuels Data Center, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy http://www.afdc.energy.gov/fuels/ethanol_blends.html.
[24] Ibid.
[25] Ibid.
[26] Virginia Clean Cities, 2013 Transportation Technology Deployment Annual Report, March 2014. http://www.vacleancities.org/wp-content/uploads/Approved-Annual-Report.pdf.
[27] Ethanol Blends, Alternative Fuels Data Center, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, http://www.afdc.energy.gov/fuels/ethanol_blends.html.
[28] Ibid.
[29] Virginia Clean Cities, Virginia Alternative Fuel Maps: A GIS Based Analysis of Virginia's Alternative Fuel Infrastructure. June 2014. http://www.vacleancities.org/wp-content/uploads/Virginia-Alt-Fuel-Report.pdf.

Most ethanol is produced in the grain-growing states of the mid-western United States, but there are several producers within the Commonwealth. Vireol Ltd opened an ethanol plant in Hopewell, in 2014, that has a capacity to produce 62 million gallons of bioethanol a year[30]. The plant produces ethanol from corn, barley, and other small grains. One major byproduct of production is dried distiller grains, a high protein feed ingredient used in poultry and livestock industries. MXI Environment Services, LLC, is a leading national supplier of ethanol recycling. MXI has an Ethanol Recycling Facility in Abingdon, that takes in waste containing alcohol and recaptures the ethanol using distillation, then processes it into fuel grade ethanol with a molecular sieve[31]. Fiberight LLC has a pilot plant in Southern Virginia that turns garbage, corn stalks, and wheat straw into biofuel ethanol by pressure cooking materials into pulp composed of cellulose, which can be broken down into sugar and turned into ethanol in the right conditions[32]. Finally, at the time of this writing, Tyton BioEnergy Systems, a Virginia company, has announced plans to facilitate ethanol production in North Carolina using tobacco as a primary feedstock, which will create 79 jobs and will be a $36 million investment in the State[33].

Propane

Propane, also known as liquefied petroleum gas (LPG or LP-gas), or auto gas, is a three-carbon alkane gas (C_3H_8)[34]. Stored in puncture-resistant tanks at 300 psi, propane turns into a colorless, odorless liquid. As pressure is released, the liquid propane vaporizes and turns into gas that is used for combustion. An odorant, ethyl mercaptan, is added to all propane for leak detection. Propane has a high octane rating and excellent properties for spark-ignited internal combustion engines. It is also non-toxic and presents no threat to soil, surface water, or groundwater[35].

Propane, also known as liquefied petroleum gas (LPG or LP-gas), or auto gas, is a three-carbon alkane gas (C_3H_8)[1].

The interest in propane as an alternative transportation fuel stems mainly from its domestic availability, high energy density, clean-burning qualities, and low costs at the volumes used for motor fuel application. It is the most commonly used alternative transportation fuel and the third most used vehicle fuel, behind gasoline and diesel. Propane is considered an alternative fuel under the Energy Policy Act of 1992.

There are two types of propane vehicles: dedicated and bi-fuel. Dedicated propane vehicles are designed to run only on propane, while bi-fuel propane vehicles have two separate fueling systems that enable the vehicle to use either propane or gasoline. Currently, no light-duty propane vehicles are available for sale by automotive original equipment manufacturers (OEMs); however, other certified installers can economically and reliably retrofit many light-duty vehicles for propane operation. Light- and medium-duty options for vehicles powered by propane include the Ford F-250, F-350, E-450 cutaway, F-450, F-550, F-650, and cargo and passenger vans. Propane engines and fueling systems are readily available for medium- and

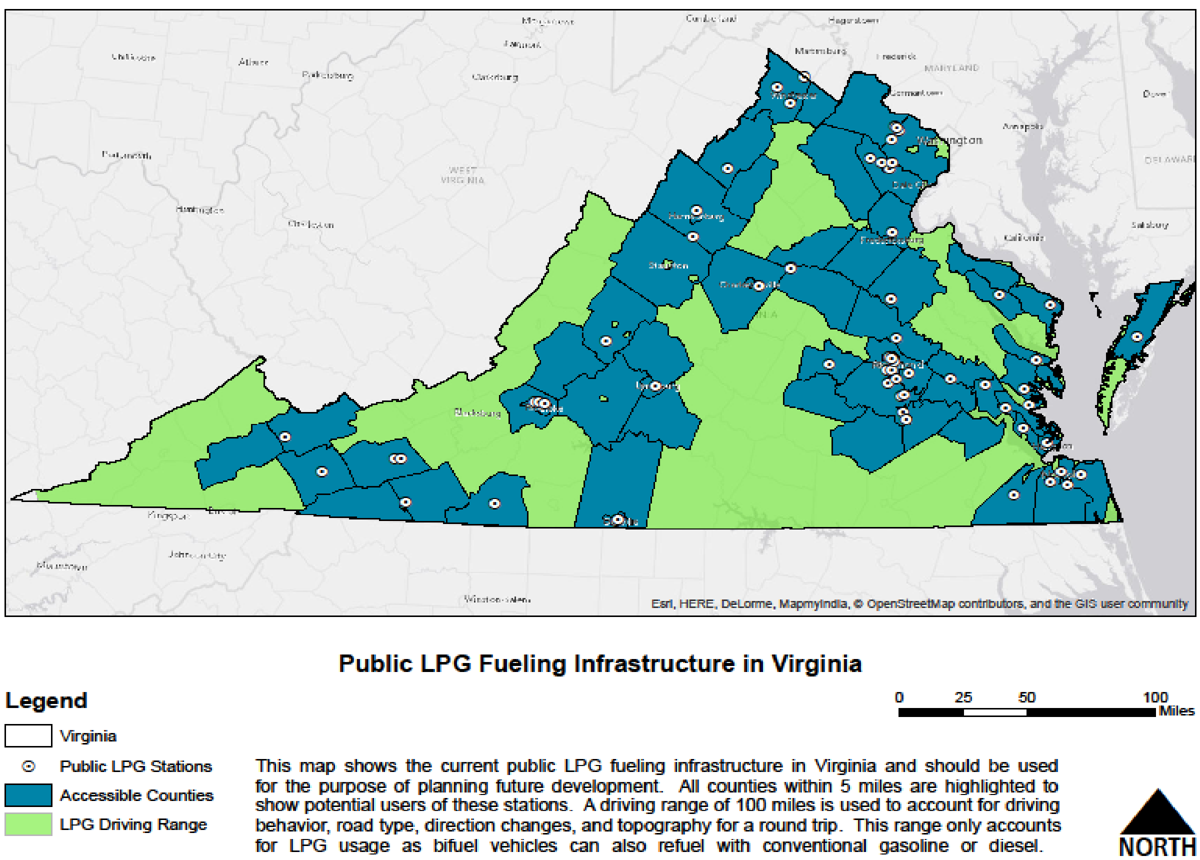
[30] British company plans to open Hopewell ethanol plant, WWBT-TV NBC 12, Richmond, VA, 2014, January 10, http://goo.gl/8IKJ6p.
[31] Ethanol Disposal & Recycling, MXI Envrionmental Services, LLC, http://www.ethanolrecycling.com/
[32] Business Overview, Fiberight, http://fiberight.com/investor-relations/
[33] $1.8 M Fed Grant Helps Bring $200M NC Biofuel Plant, North Carolina Biotechnology Center, 2014, June 18, http://www.ncbiotech.org/article/18m-fed-grant-helps-bring-nc-cellulosic-ethanol-plant/15636.
[34] Propane Fuel Basics, Alternative Fuels Data Center, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, http://www.afdc.energy.gov/fuels/propane_basics.html.
[35] Ibid.

heavy-duty vehicles such as school buses and street sweepers, including some from OEMs. Currently, over 500 vehicles are operating on this fuel in Virginia.[36]

Transportation vehicle conversions in the United States require U.S. Environmental Protection Agency (EPA) certification and a skilled propane conversion technician. The upfront costs to convert fleet vehicles to propane can be offset by lower fuel, operating, and maintenance costs over the lifespan of the vehicles. Conversion to a dedicated propane or bi-fuel propane vehicle can be attractive when fueling infrastructure is in place and volume fuel discounts are available. This fueling infrastructure is inexpensive and there are over 80 public and fleet stations in Virginia.[37] The payback period depends on the average distance traveled by these fleet vehicles. Fleet vehicles typically are high-mileage, high fuel consumption vehicles operating in a limited area, so the payback period on propane fleet vehicles can be very reasonable.

Figure 11-11[38] shows the locations of public propane fueling infrastructure in Virginia. Public stations are presented as white dots and all counties within 5 miles of the stations are highlighted in blue to show the potential users of these stations. A 100-mile driving radius was input for each station, accounting for driving behavior, road type, direction changes, and topography for a round trip. The driving range for Virginia public stations is highlighted in green.

Figure 11-11: Public LPG Fueling Infrastructure in Virginia: June 2014



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[36] Virginia Clean Cities, Virginia Alternate Fuels Report, January 2014. http://www.vacleancities.org/wp-content/uploads/Alt-Fuels-Report-Q4-2013-Final.pdf

[37] Virginia Clean Cities, Alternative Fuel Production Inventory, June 2014.

[38] Virginia Clean Cities, Virginia Alternative Fuel Maps: A GIS Based Analysis of Virginia's Alternative Fuel Infrastructure. June 2014. http://www.vacleancities.org/wp-content/uploads/Virginia-Alt-Fuel-Report.pdf.

Natural Gas

Natural gas is a mixture of hydrocarbons, predominantly methane, and also contains ethane, propane, and other gases such as nitrogen, helium, carbon dioxide, hydrogen sulfide, and water vapor[39]. It is one of the cleanest burning alternative fuels available and offers a number of advantages over gasoline.

Most natural gas used in the U.S. is produced domestically from gas wells or as a result of crude oil production. Natural gas can also be mined from subsurface porous rock reservoirs through extraction processes, such as hydraulic fracturing. In addition, natural gas can come from decaying organic materials, such as waste from plants, landfill gas and water/sewage, and livestock[40]. Processing is required to separate the gas from petroleum liquids and to remove contaminants.

The difference in tailpipe emissions between conventional and natural gas vehicles has narrowed because more stringent emissions regulations have been applied to conventional vehicles and modern emissions controls have been deployed[41]. In light duty applications, the emissions from natural gas vehicles are similar to conventional gasoline vehicles with modern emissions controls. However, CNG vehicles do see a reduction of 50 percent in evaporative volatile organic compounds and a 10 percent reduction in carbon monoxide[42]. Currently the primary applications for compressed natural gas vehicles are heavy haulers, public transit bus fleets, and waste hauling trucks, however, there are effective vehicle options as small as compact passenger vehicles.

Natural gas vehicles can be fueled at public stations or private, on-site stations. Currently there are 6 public and 18 private CNG stations and 2 LNG stations in Virginia[43]. Station development is an expensive and time-consuming process that requires working through local permitting agencies, acquiring land near an adequate pipeline, and obtaining long-term contracts and customers for the fuel. Growing worldwide demand for natural gas will also put pressure on suppliers and potentially increase the price per gallon, thereby reducing the financial incentive to invest in expensive refueling stations.

Natural gas vehicles can easily be fueled at public stations or take advantage of on-site refueling. Individual home compressors use a slow-fill system for overnight refueling. In heavy-duty applications, the cost of a high capacity fast-fill private or public station could be anywhere from $200,000 to as much as $3 million,

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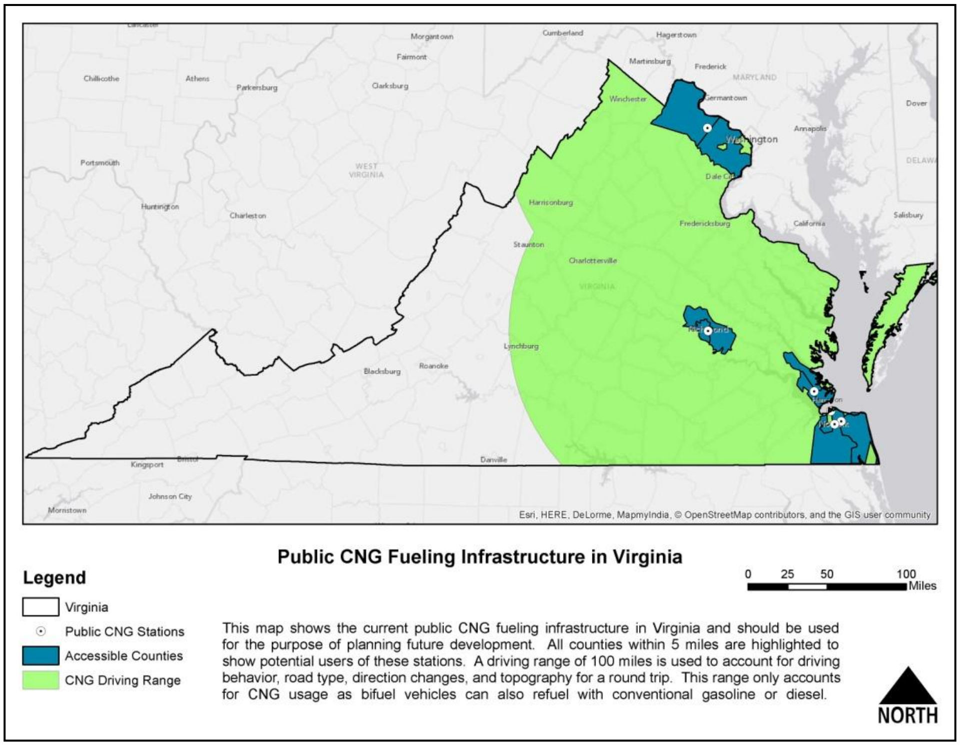
[39] Natural Gas Fuel Basics, Alternative Fuels Data Center, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, http://www.afdc.energy.gov/fuels/natural_gas_basics.html
[40] Ibid.
[41] Natural Gas Vehicle Emissions, Alternative Fuels Data Center, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, http://www.afdc.energy.gov/vehicles/natural_gas_emissions.html
[42] GREET Fleet Carbon and Petroleum Footprint Calculator, Argonne National Laboratory, 2012 https://greet.es.anl.gov/fleet_footprint_calculator
[43] Virginia Clean Cities, Alternative Fuels Inventory Report, June 2014.

but often range around $1 million. Wider availability of this inexpensive fuel could lead to much wider adoption. Figure 11-12[44] shows the locations of public CNG fueling infrastructure in Virginia.

Figure 11-12: Public CNG Fueling Infrastructure in Virginia: June 2014



Electric Vehicles

Adoption of electric vehicles (EVs) is becoming a reality in the Commonwealth of Virginia. Electricity represents a less expensive, cleaner, and locally generated energy source that also contributes to new economic advantages. The energy industry research group, PRTM Management Consultants, has estimated that vehicle electrification could represent more than $250 billion in economic development opportunities, worldwide, by 2020[45]. This estimate considers growth in electricity generation and distribution, grid and infrastructure investments, batteries and their components, vehicle sales, and associated advertising and marketing services.

Although electricity production may contribute to air pollution, EVs are considered zero-emission vehicles because their motors produce no exhaust or emissions. There are several types and models of electric vehicles that are on the market today from all auto manufactures. An all-electric vehicle runs solely on electricity with no internal combustion engine. Hybrid electric vehicles combine the benefits of high fuel economy and low emissions with the power and range of conventional gasoline fueling. Hybrid technologies also have potential to be combined with alternative fuels and fuel cells to provide additional

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[44] Virginia Clean Cities, Virginia Alternative Fuel Maps: A GIS Based Analysis of Virginia's Alternative Fuel Infrastructure. June 2014. http://www.vacleancities.org/wp-content/uploads/Virginia-Alt-Fuel-Report.pdf.

[45] Virginia Clean Cities, Richmond Electric Vehicle Initiative (REVI) Electric Vehicle Readiness Plan, March 2013, http://www.vacleancities.org/wp-content/uploads/Final-REVi-Plan-Email-low-res.pdf.

benefits. Plug-in hybrids are plug-in electric vehicles that carry a small conventional combustion engine. The combustion engine is engaged once the battery is exhausted at which point the car operates as a conventional hybrid. This combination allows for longer trips.

The Commonwealth of Virginia has seen extensive growth in electric vehicle deployment in recent years. Based on information from the Virginia Department of Motor Vehicles, there were 3,078 electric vehicles in Virginia as of May 2014.[46] This is an increase of over one thousand percent over 2012.

Electric Vehicle Charging

Electric vehicle recharging facilities are being installed at individual consumers' facilities and increasingly at multi-family, commercial, and government buildings across Virginia. Electric vehicles can be recharged from any outlet at home or at work, but Virginia drivers and owners often install a 240-volt charger similar in power use as a dryer, and as such are inexpensive or free to permit. A third level of charging is provided by Fast Chargers which are more like traditional gas station rapid charging. In Virginia, businesses and individuals can sell electricity for electric vehicle fuel use and not be considered a utility.

According to Virginia Clean Cities, there are currently 247 electric vehicle charging stations in Virginia. There are also current efforts across the Commonwealth to develop a network of DC Fast Chargers in key development areas. Figure 11-13[47] shows Virginia's current electric vehicle charging infrastructure.

Figure 11-13: Electric Vehicle Charging Infrastructure in Virginia: June 2014

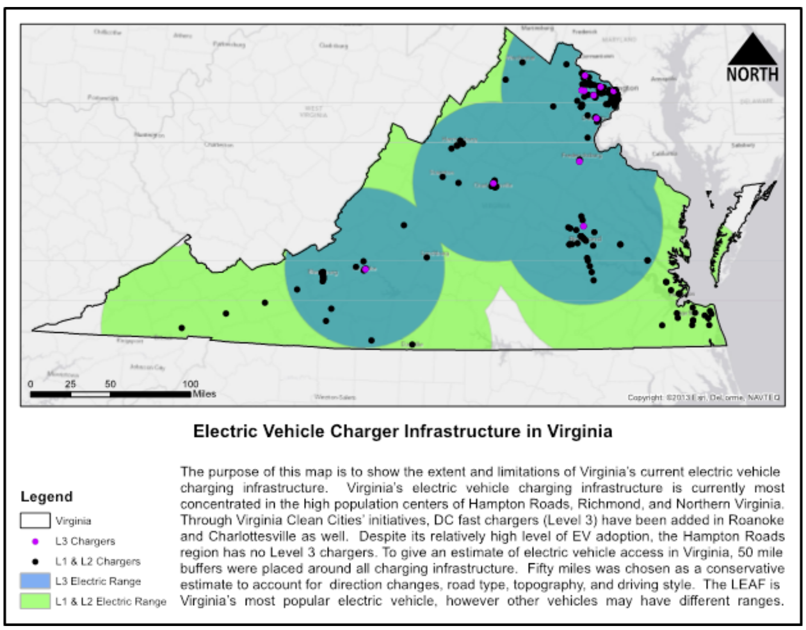
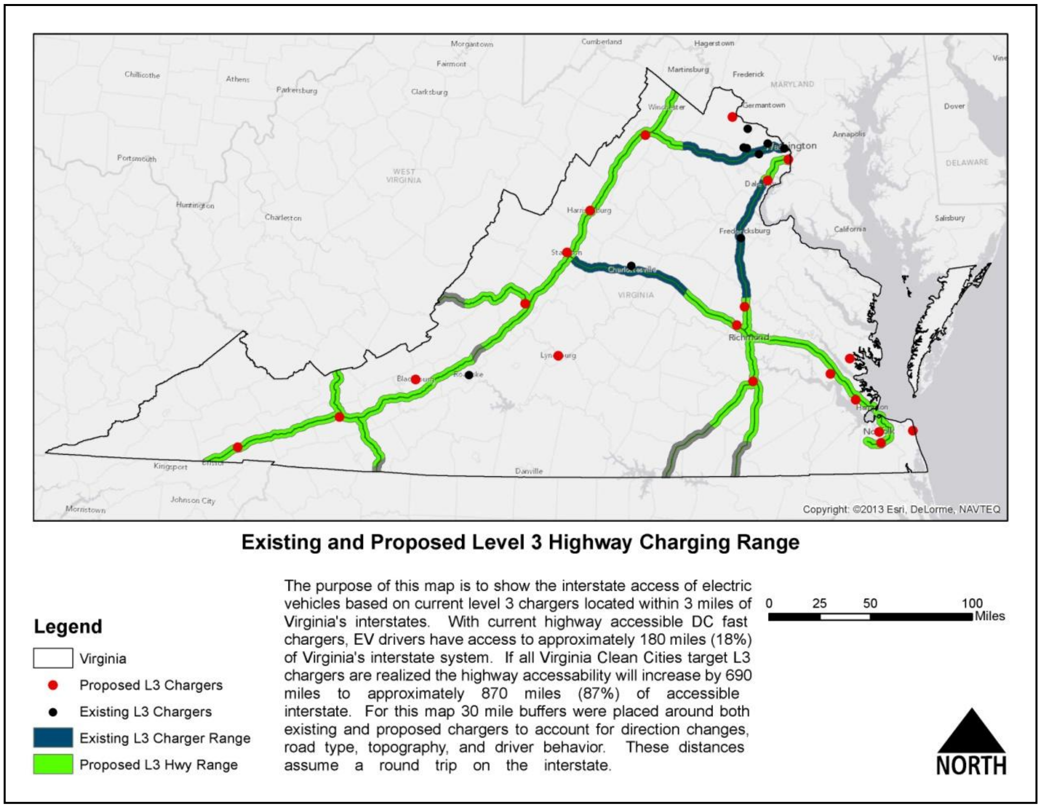


Figure 11-14[48] shows the current interstate access for electric vehicles based on current Level 3 chargers, within 3 miles of Virginia's major interstates. The map's black dots represent existing chargers and the blue

[46] Virginia Department of Motor Vehicles, proprietary information request, 2014.
[47] Virginia Clean Cities, Virginia Alternative Fuel Maps: A GIS Based Analysis of Virginia's Alternative Fuel Infrastructure. June 2014. http://www.vacleancities.org/wp-content/uploads/Virginia-Alt-Fuel-Report.pdf
[48] Virginia Clean Cities, Virginia Alternative Fuel Maps: A GIS Based Analysis of Virginia's Alternative Fuel Infrastructure. June 2014. http://www.vacleancities.org/wp-content/uploads/Virginia-Alt-Fuel-Report.pdf

lines represent the existing range. With the existing infrastructure, EV drivers can only access 18 percent of Virginia's interstate system.

Figure 11-14: Existing and Proposed Level 3 Highway Charging Range: June 2014



Hydrogen Fuel Cells

Hydrogen has been recognized as an alternative fuel under the Energy Policy Act[49] (EPAct 1992) since 1992 and currently qualifies for several federal motor vehicle and fuel tax credits, as well as infrastructure incentives[50]. Fuel cell electric vehicles powered by hydrogen are two to three time more efficient than conventional vehicles and produce no harmful tail pipe emissions. Numerous vehicle manufacturers have tested hydrogen fuel cell technology, and in 2015, several different platforms will become available in the American market. As of 2014, the market trend is to offer hydrogen fuel cell vehicles under a 3-year leasing program where the cost of the fuel is included in the lease price. The majority of hydrogen vehicles are expected in California where infrastructure and state incentives are available, but with technology and range advancement, additional states like Virginia will begin to adopt this technology for transportation.

Like battery electric vehicles, fuel cell electric vehicles use electricity to power a motor located near the vehicle's wheels. In contrast to other electric vehicles, fuel cell vehicles produce their primary electricity using a fuel cell powered by hydrogen, rather than a battery. Hydrogen is stored at 10,000 psi or in a

[49] Energy Policy Act of 1992. Public Law 102-486. Enacted October 24, 2002 by 102nd Congress. http://www.afdc.energy.gov/laws/key_legislation#epact92

[50] Federal Laws and Incentives for Hydrogen, Alternative Fuels Data Center, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, http://www.afdc.energy.gov/fuels/laws/HY/US

cryogenic liquid tank and is passed through a proton exchange membrane in the presence of oxygen. This creates the electric current that powers the vehicle, along with water vapor as waste product. During the vehicle design process, the vehicle manufacturer controls the power of the vehicle by changing the fuel cell size and controls the amount of energy stored on board by changing the fuel tank size. This is different than a battery electric vehicle where the amount of power and energy available are both closely tied to the battery size.

Hydrogen can be produced using diverse, domestic resources including fossil fuels, such as natural gas and coal (with carbon sequestration), nuclear, and biomass as well as other renewable energy technologies, such as wind, solar, geothermal, or hydro-electric power. One common way to produce hydrogen is through electrolysis, which separates water into hydrogen and oxygen; and hydrogen is also a waste product of certain nuclear power industry activities.

State Incentives

Notable incentives and regulations for Virginia from the Alternative Fuels and Advanced Vehicles Data Center (AFDC) are listed below:[51]

Biodiesel Production Tax Credit

Qualified biodiesel and green diesel producers are eligible for a tax credit of $0.01 per gallon of biodiesel or green diesel fuels produced. This credit is available for producers who generate up to two million gallons of biodiesel or green diesel fuel per year. The annual credit may not exceed $5,000, and producers are only eligible for the credit for the first three years of production. The Virginia Department of Mines, Minerals and Energy must certify qualified producers.

Biofuels Production Grants

The Biofuels Production Incentive Grant Program provides grants to producers of neat advanced biofuels, which include fuels derived from any cellulose, hemicelluloses, or lignin from renewable biomass or algae, and producers of neat biofuels, which include biofuels derived from cereal grains. The grant for neat advanced biofuels or neat biofuels produced in the Commonwealth is as follows: 2014 Calendar Year - $0.04 per gallon, 2015 Calendar Year - $0.03 per gallon, and Calendar Year 2016 through June 2017 - $0.025 per gallon. To qualify, a producer must have begun selling neat biofuels on or after January 1, 2014. A qualified producer must produce a minimum of one million gallons of biofuels, annually, in the Commonwealth, with feedstocks originating in the United States. Beginning January 1, 2016, grants will not be awarded for corn-derived biofuels. The Virginia Department of Mines, Minerals and Energy may not approve more than $1.5 million in grants for each fiscal year between 2014 and 2017. This program expires June 30, 2017.

Clean Energy Manufacturing Grants

The Clean Energy Manufacturing Incentive Grant Program provides financial incentives to clean energy manufacturers, including biofuel producers. A producer is eligible for a grant if it commences or expands operations in Virginia on or after July 1, 2011. Producers must make a capital investment greater than $50 million and create at least 200 full-time jobs that pay at least the prevailing wage.

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[51] Virginia Laws and Incentives. Alternative Fuels and Advanced Vehicles Data Center. http://www.afdc.energy.gov/laws/laws/VA.

Agriculture and Forestry Biofuel Production Grants

The Agriculture and Forestry Industries Development (AFID) Fund provides grants to promote and develop the agriculture and forestry industry in Virginia and create or expand value-add facilities, including qualified biofuel production facilities. Individual grants may not exceed $250,000 or 25 percent of qualified capital expenditures, and are awarded at the Governor's discretion. The grants are awarded to local governments and other Virginia political subdivisions working with qualified businesses. Terms and conditions apply, including the use of a minimum percentage of Virginia grown products, matching funds, and performance requirements.

Clean Transportation Technology Investment Funding

The Commonwealth Energy Fund (CEF), administered through the Center for Innovative Technology, provides early-stage investment funds for Virginia-based companies that provide clean energy products or services. Eligible clean transportation technologies may include vehicles, components, batteries, and fuel cells, in addition to biofuels.

Alternative Fuels Grants and Loans

The Alternative Fuels Revolving Fund is used to distribute loans and grants to municipal, county, and Commonwealth government agencies to support alternative fuel vehicle (AFV) programs; pay for AFV maintenance, operation, evaluation, or testing; pay for vehicle conversions; or improve alternative fuel infrastructure. Eligible alternative fuels include electricity, hydrogen, and natural gas. Projects with a funding match are given priority in the evaluation process.

High-Occupancy Vehicle (HOV) Lane Exemption

Alternative fuel vehicles (AFVs) displaying the Virginia Clean Special Fuel license plate may use Virginia HOV lanes, regardless of the number of occupants. For HOV lanes serving the I-95/I-395 corridor, only registered vehicles displaying Clean Special Fuel license plates issued before July 1, 2006, are exempt from HOV lane requirements. For HOV lanes serving the I-66 corridor, only registered vehicles displaying Clean Special Fuel license plates issued before July 1, 2011, are exempt from HOV lane requirements. Eligible vehicles include dedicated AFVs and some hybrid electric vehicles. The annual fee for Clean Special Fuel license plates is $25 in addition to the prescribed fee for the Commonwealth's license plates.

Alternative Fuel Job Creation Tax Credit

Businesses involved in alternative fuel vehicle (AFV) and component manufacturing, alternative fueling equipment component manufacturing, AFV conversions, and advanced biofuels production are eligible for a job creation tax credit of up to $700 per full-time employee. The credit is allowed in the taxable year in which the job is created and in each of the two succeeding years in which the job is continued. Qualified AFVs include vehicles that operate using natural gas, propane, hydrogen, electricity, or advanced biofuels. This credit is effective for taxable years through December 31, 2014.

Green Jobs Tax Credit

Qualified employers are eligible for a $500 tax credit for each new green job created that offers a salary of at least $50,000, for up to 350 jobs per employer. The credit is allowed for the first five years that the job is continuously filled. For the purposes of this tax credit, a green job is defined as employment in industries relating to renewable or alternative energy, including hydrogen and fuel cell technology, landfill gas, and biofuels. The tax credit expires on January 1, 2015.

Alternative Fuel Vehicle (AFV) and Fueling Infrastructure Loans

The Virginia Board of Education may use funding from the Literary Fund to provide loans to school boards that convert school buses to operate on alternative fuels or construct alternative fueling stations.

Ethanol Production Equipment Tax Exemption

A county, city, or town may exempt, partially exempt, or set a lower tax rate for qualified equipment used by farmers or farm cooperatives to produce ethanol, provided that the ethanol feedstock consists primarily of farm products.

Biofuel Feedstock Registration Exemption

Individuals that transport waste kitchen grease for conversion to biofuel are exempt from both the Virginia Department of Health registration and the associated annual application fee. This exemption only applies if the individual transports the waste kitchen grease in a container with a capacity of less than 275 gallons and possesses no more than 1,320 gallons of waste kitchen grease, biofuel feedstock derived from kitchen grease, or biofuel at any one time, excluding biofuel contained in vehicle fuel tanks. Other restrictions apply.

Alternative Fuel and Hybrid Electric Vehicle (HEV) Emissions Testing Exemption

The Virginia emissions inspection program, which requires biennial inspections of motor vehicles, does not apply to vehicles exclusively powered by compressed or liquefied natural gas, liquefied petroleum gas (propane), hydrogen, a combination of compressed natural gas and hydrogen, or electricity. Qualified HEVs with U.S. Environmental Protection Agency fuel economy ratings of at least 50 miles per gallon (city) are also exempt from the emissions inspection program unless remote sensing devices indicate the HEV may not meet current emissions standards.

Idle Reduction and Natural Gas Vehicle (NGV) Weight Exemption

Any motor vehicle equipped with an auxiliary power unit or other idle reduction technology may exceed the gross, single axle, tandem axle, or bridge formula weight limits by up to 550 pounds to compensate for the added weight of the idle reduction technology. Furthermore, any NGV may exceed the limits by up to 2,000 pounds.

Alternative Fuel Tax Exemption

Alternative fuel is exempt from taxes if it is sold to a government entity for its exclusive use, sold to a nonprofit charitable organization for the purpose of providing charitable services for low-income medical patients, or produced by an agricultural operator and used exclusively for farm use or vehicles of that operator.

Plug-In Electric Vehicle (PEV) Charging Rate Reduction - Virginia Dominion Power

Virginia Dominion Power offers two rates for residential customers who own qualified PEVs, the Electric Vehicle Pricing Plan and the Electric Vehicle + Home Pricing Plan. The Electric Vehicle Pricing plan allows PEV owners to take advantage of lower rates during off-peak hours. Under this plan, customers must install an additional meter specifically for their electric vehicle supply equipment (EVSE); and Dominion will provide this meter at no charge. The Electric Vehicle + Home Pricing Plan is a whole-house pricing plan in which the customer's EVSE is treated as another appliance. Dominion will provide a new meter at no charge, to record energy usage in 30-minute intervals. This allows Dominion to apply pricing based on time-of-day and encourages customers to charge their PEV during off-peak hours, as hours much as possible. PEV pricing plans are expected to expire on November 30, 2014.

SECTION 12 - RECOMMENDATIONS

STRATEGIC GROWTH IN THE ENERGY SECTOR

1. **Accelerate the Development of Renewable Energy Sources in the Commonwealth to Ensure a Diverse Fuel Mix and Promote Long-Term Economic Health**

   A. *Work to ensure the diversity of the Commonwealth's generation fuel mix.*

   - Virginia must not become over-reliant on a select number of fuel sources. Diversity in fuel mix will provide a hedge against volatility and spread the risk among varied sources of generation. This diversity must include an increase in the development of zero-emitting renewable sources, as well as on the largely untapped potential of energy efficiency. This path will lead to economic prosperity through increased jobs and environmental health through lower harmful emissions.

   B. *Establish the Virginia Solar Energy Development Authority based on the model of the Virginia Offshore Wind Development Authority.*

   - Facilitate partnerships between Virginia's electric utilities, government and private generation developers to install 15MW of solar energy generation at state and local government facilities by June 30, 2017. Additionally, the Authority should facilitate the installation of an additional 15MW of solar energy generation at commercial, industrial and residential facilities by the same target date of June 30, 2017.

   C. *Create an environment that welcomes significant growth in renewable generation in the Commonwealth, from small-scale distributed generation to commercial and utility–scale deployment.*

   - Increase the rated generating capacity for renewable that can be owned and operated by customer-generators from 1% to 3% of an electric distribution company's adjusted Virginia peak-load forecast for the previous year.

   - Increase the caps for residential and non-residential generating systems from 20 kilowatts for residential and 500 kilowatts for commercial with standby charges for systems over 10 kilowatts, to 40 kilowatts and 1megawatt, respectively, with standby charges for systems over 20 kilowatts.

   - Develop rules to permit neighborhood and office park sized distributed solar generation. These facilities could be treated as a single customer for the purposes of standby charges, but said charges could be spread evenly among contributors.

   - Make third-party Power Purchase Agreements (PPA) available throughout all utility service territories in Virginia. Double the current cap on total megawatt installation through PPA's from 50 MW to 100 MW, as well as the installation-specific cap from 1MW to 2MW.

D. Allow subscription participation in community solar programs.

- Develop a mechanism to allow individuals to pool resources to have their utility build an off-site solar installation on the group's behalf. The utility will provide a mechanism for on-bill financing to allow the group to pay for the development of the solar installation.

E. Strongly encourage and aggressively support the timely development of offshore wind in Virginia.

- The Administration is committed to the full and swift development of the current Virginia Wind Energy Area. Both the General Assembly and the Governor stressed that the planning and development of any and all offshore wind energy generating facilities is in the public interest of the citizens of the Commonwealth. DMME and DEQ should use their full authorities to facilitate the build out of the 113,000 acre Virginia Wind Energy Area. Furthermore, additional opportunities to gain federal permission to develop offshore wind beyond the Virginia Wind Energy Area should be pursued with vigor.

F. Establish Virginia as the ideal manufacturing, operational and supply chain hub for offshore wind development in the mid-Atlantic region and provide support and resources to accelerate development of Virginia's offshore wind resources.

- Assess the industry's needs for manufacturing, operational logistics, environmental and regulatory support; identify and address any gaps; and publicize the asset strengths and other unique advantages that differentiate the Commonwealth as the best location for a mid-Atlantic offshore wind hub. The Virginia Offshore Wind Development Authority should lead and accomplish this strategy by June 30, 2015.

2. Make Virginia a Leader in Energy Efficiency to Reduce Consumption and Spur Economic Growth

A. Establish the Virginia Board on Energy Efficiency.

- The 2007 Virginia Energy Plan established a voluntary goal of reducing energy consumption at the retail level by 10% by 2022, based on a 2006 baseline. The State Corporation Commission analyzed this goal and determined that it was feasible. While there is anecdotal evidence that work toward achieving this goal is underway, there is a lack of a comprehensive understanding, along with easily identifiable data, as to where the Commonwealth currently stands in meeting the 10% goal.

  Establish the Board on Energy Efficiency to develop a strategic plan to achieve the voluntary goal of reducing energy consumption by 10% by 2020, accelerating the 2007 Virginia Energy Plan goal by two years. The Board will be appointed by the Governor and will be comprised of a cross-section of energy efficiency industry stakeholders. The Board will be convened within 90 days of the release of the

Energy Plan. The Board will oversee the implementation of the strategic plan and provide guidance to accomplish plan goals. The Board will publish progress reports on implementation on a bi-annual basis.

Specific duties of the Board will be to develop a strategic plan that includes:

- Develop, within 12 months, a measurement and verification method to compile and track energy consumption at the retail, residential, and commercial levels to determine where Virginia currently sits in achieving the 10% voluntary goal.
- Identification of market, regulatory and policy barriers and opportunities to help both the private sector and regulated utilities work together to meet the 10% goal.
- A review of best practices in cost recovery and shared-savings mechanisms that may help accelerate utility adoption of energy efficiency.
- Recommendations to address market, regulatory and policy barriers and opportunities.
- Develop a plan to coordinate outreach efforts throughout all regions of the state and with all necessary stakeholders to ensure a consistent communications and messaging strategy focused on increasing energy efficiency education and participation.
- Identify creative financing tools that can be used at both the generation and demand side levels and make recommendations for their implementation.
- Recommend any new programs or policy changes that would support energy efficiency building upgrades for low income Virginians – particularly in Southside and Southwest Virginia.
- Review existing Virginia-specific energy efficiency studies to determine if a comprehensive report on Virginia efficiency potential is necessary.

The Board will also create a grant response team from its members to work with private and public sector entities to develop grant proposals to respond quickly to potential funding opportunities that further the work of the Board or state energy office.

B. Aggressively implement energy efficiency in state government.

- Create, within the administration, a Chief Energy Efficiency Officer to oversee the aggressive implementation of energy efficiency measures in state agencies, including Energy Performance Contracting (EPC).

- Streamline and standardize the EPC process by developing a master packet that agencies can use to guide them through the process and ensure no unnecessary barriers slow down the project.

- Accomplish the goal of reducing electricity consumption in state facilities by 15% through EPC by 2017.

- Reinstitute a commissioning/re-commissioning pilot program in state facilities.

C. *Develop a marketing, outreach and preliminary assistance program to engage local municipalities in Energy Performance Contracting (EPC).*

- In the Commonwealth, municipalities and counties are permitted to do EPC, and are not bound by the same set of regulations attending to state agencies. There are scores of local governments—small, medium, and large, town, city and county—that are good candidates for EPC.

  There are four broad tasks valuable to offer local governments and consistent with the scope of this contract:

  - Education about the pros and cons of energy performance contracting.
  - Assistance in prequalifying governments initially interested in the concept.
  - Assistance in getting prequalified governments out to bid and in selecting qualified Energy Service Companies (ESCOs).
  - Preliminary owner's agent assistance, through the investment audit stage.

  The Commonwealth should develop an initiative to promote increased adoption of EPC in local governments. Through DMME, the Commonwealth should work with local and regional stakeholders, as well as organizations focused on energy efficiency, to execute this program.

  The Governor could highlight this initiative through an energy efficiency tour to regions of the state that are centers of best practices, as well as localities that would benefit most from EPC.

D. *Create a central state facility energy data registry and dashboard to track energy consumption at all state agencies.*

- Energy Management Systems (EMS) and their associated cost savings and sustainability opportunities are increasingly vital to enterprise cost control and competitive strategies. The emergence of relatively inexpensive computing, data storage, and cloud deployment options have already transformed many industries, and are now poised to do the same for enterprise energy management. Applying technological advances to create smart buildings offers the opportunity to utilize data-driven energy management solutions on a cost-effective basis, which will provide predictable and unprecedented energy, operational, and capital expenditure savings.

E. *Engage social entrepreneurs in exploring and implementing innovative models, such as pay for performance, in order to test new and innovative ways to cut energy bills and to finance energy efficiency upgrades in existing multi-family residential properties.*

- Social entrepreneurship is uniquely positioned to aid government in addressing energy efficiency in two primary ways:

  - Better leveraging public and private resources
  - Testing and developing impact-making solutions

In partnership with government, social entrepreneurs can augment their ability to generate and implement transformative, cost-effective solutions to the most challenging societal challenges facing the Commonwealth, our nation and the world

3. Go Global with Coal Technology

A. *Build a proactive outreach program focused on coal-related companies to inform and educate about possible opportunities for their products in international markets.*

- As the coal industry in Virginia continues to face challenges domestically, it is important for companies in the coal supply chain to explore potential markets for their products that have not traditionally been exploited. Many companies are unaware of the international market potential for their products or that the Commonwealth has developed programs to assist in the marketing of Virginia businesses to international markets.

- The Commonwealth should develop a robust outreach program that proactively seeks out coal supply chain companies that may have potential for success in international markets. The program should be crafted similar to the "Going Global Defense Initiative" and work to:

    - Identify businesses that may have export potential and are unaware of existing programs in the Commonwealth to assist in tapping international markets.
    - Conduct educational seminars to introduce these companies to international trade and the export market. The seminars will also include a review of programs run by Virginia that can assist in tapping export markets.
    - Provide a forum for businesses to think creatively about how their products may be valuable to industries in other markets that are not specifically coal-related.
    - Bring in experts from markets that are targets for coal and mining supply chain products. These experts will provide an overview of market potential and give Virginia businesses personalized exposure to the technical expertise of a potentially attractive market.
    - Provide a forum for businesses that have successfully utilized Virginia programs to tap international markets to relay experiences, lessons learned, and best practices.

B. *Conduct an "export tour" in Southwest Virginia to highlight the importance and potential of international trade for the coal supply chain.*

- The Administration will hold roundtable discussions in various parts of Southwest Virginia to place an emphasis on the need to tap into international markets to diversify the client base. This tour will place a spotlight on expertise and products sold by industries and companies to supply the coal mining industry in Virginia

C. *Conduct coal supply chain specific trade missions to the most high-potential international markets for mining-related products*

- The Commonwealth should identify international markets that are specifically attractive for Virginia businesses in the coal industry supply chain

D. *Increase technical assistance provided to businesses that are committed to growing their international presence.*

- Many small businesses in the coal supply chain do not have the resources to appropriately market themselves or conduct the necessary research to understand their potential clients. Virginia's current support in these areas is limited for coal supply chain companies. This support should be expanded to provide more robust assistance to give these businesses the most favorable environment in which to succeed.

E. *Support continued funding of research and development to enable the deployment of clean coal technologies on a commercial scale.*

4. Pursue the Development of Virginia's offshore Gas and Oil Resources

A. Current Virginia statute on offshore energy development favors permitting the production of offshore oil and natural gas resources 50 miles or more off of the coastline. It is critical that the development of these resources be conducted in a safe manner that is protective of Virginia's coastal environment and its broad economic and ecologic base.

B. Fully support the development of oil and natural gas resources off of Virginia's coast, contingent upon a revenue sharing agreement being reached between the federal government and the Commonwealth of Virginia.

C. Advocate for the inclusion of Virginia's portion of the Mid-Atlantic Planning Area in the U.S. Department of the Interior's 2017-2022 Five-Year Outer Continental Shelf Oil and Gas Leasing Program.

D. Conduct a readiness study to determine Virginia's ability to sustain any potential offshore gas and oil exploration and development industry.

- Virginia should evaluate the adequacy of port infrastructure to ensure that the Commonwealth is fully prepared and capable of supporting this industry, can provide a timely and comprehensive response to oil spills, and can address the concerns raised by fishing and tourism interest. In addition, address the concerns raised by the military about conflicting uses to ensure that the portion of the Mid-Atlantic Planning Area south of the Virginia-Maryland border and beyond 50 miles from Virginia's coastline is included in the U.S. Department of the Interior's 2017-2022 Five Year Outer Continental Shelf Oil and Gas Leasing Program.

- The Department of Mines, Minerals and Energy will conduct a study on Virginia's readiness for offshore drilling, including spill preparedness, and report the findings of this study to the Governor, the Secretary of Commerce and Trade, and the Secretary of Natural Resources by April 15, 2015.

E. Support efforts at the federal level to ensure that revenue-sharing between the federal government and Virginia will be a component of any future potential gas and oil development off the Virginia coast.

- In the alternative, advocate for regional revenue sharing among participating Mid-Atlantic States' offshore energy development lease.

EXPAND BEST-IN-CLASS INFRASTRUCTURE

1. Expand, Improve, and Increase the Reliability of Virginia's Energy Infrastructure

A. Support legislative and regulatory policy, such as special utility rates, to allow Virginia's natural gas utilities to more proactively approach expansion of intrastate infrastructure into unserved and underserved areas; and support improvements and expansion of interstate natural gas pipeline infrastructure to increase capacity in currently restricted market areas, such as Central and Tidewater Virginia to improve the ability to attract new businesses and stimulate economic development in these regions.

- Facilitate regional discussions among economic development agencies, utilities, interstate pipelines and other key stakeholders to reach consensus on long-term plans for the strategic development of the appropriate energy infrastructure to support economic growth and business development.

- Encourage and facilitate increased interaction between compressed natural gas fueling station operators, fleet owners and natural gas suppliers to identify the most strategic locations for facilities that offer adequate pressure for compression and access for vehicles.

- Study the strategic location of pipeline, bunker, and an LNG fueling station within or near the Port of Virginia footprint to allow the servicing of terrestrial LNG and CNG vehicles as well as container ships that operate on LNG fuel. This facility would not be designed with specifications of sufficient scope to allow its use for export of LNG, only onsite fueling.

B. Support nuclear energy generation, research, education and workforce development and recognize nuclear energy's important role in the Commonwealth's diverse electricity generation portfolio.

- Recognize and support the Virginia Nuclear Energy Consortium efforts to make the Commonwealth a national and global leader in nuclear energy and serving as an interdisciplinary study, research, and information resource for the Commonwealth on nuclear energy issues.

- Regulatory certainty is important given the long-lead decisions required for the continued safe and efficient operation of existing nuclear assets and the substantial capital commitments associated with constructing new nuclear units. Virginia's energy policy should view nuclear assets in light of their capacity to deliver reliability, availability and source diversity for a general portfolio that achieves emission reductions required by pending federal regulations.

- Leverage Virginia international corporate outreach and intergovernmental efforts to support the Virginia-based nuclear design, repair, and installation industries. Virginia is home to global leaders in the nuclear energy sector, such as AREVA, Babcock and Wilcox, Bechtel and Newport News Shipbuilding. In addition, dozens of other companies, located all across Virginia, provide services, supplies and support to nuclear facilities inside the Commonwealth and globally. The nuclear energy sector drives Virginia's economy in every region, creating high-skilled jobs, supporting research and generating revenues at the state and local level.

- Virginia is home to two of only 31 nuclear engineering programs in the U.S. (VCU and Virginia Tech.) The Commonwealth should strengthen Virginia's existing nuclear science engineering and research programs to provide the pipeline of highly-educated and highly-skilled workers necessary to continue creating high-paying jobs for Virginians and to sustain our nuclear industry in the long term.

C. Create flexible financing mechanisms to help to put in place key additional energy assets and support priority energy programs.

- Objectives of the funding mechanism would include: provide low-cost financing for energy program delivery and projects to expand or improve energy infrastructure, including renewable energy systems, energy conservation and efficiency and alternative fuels; increase local economic activity and create jobs; and leverage private funding and markets.

    - Use of Virginia's Qualified Energy Conservation Bond (QECB) allocation and other funding sources could provide low-cost financing options for: energy Performance Contracting (EPC) to improve building energy efficiency; deployment of energy efficiency measures and programs, and renewable energy systems; and for alternative transportation refueling infrastructure.

D. In collaboration with Secure Commonwealth and the Climate Change and Resiliency Commission, refine and focus the Commonwealth's Energy Assurance Plan; and implement a pilot demonstration of affordable virtual hardening of critical infrastructure.

- The vulnerability of the electric, communication, and water infrastructure to natural disaster has recently been tragically demonstrated, and its susceptibility to malicious attack is well known. This susceptibility is both physical and electronic, requiring practical means of cyber security as well as hardening assets. A substantial study of resilience and security preparedness was made in 2012 by SAIC for DMME,[1] analyzing the Commonwealth's vulnerability and risks, and laying out options for preparing and responding to both physical and cyber security threats.

[1] *Energy Assurance Plan,* 21 September 2012, VA Dept. of Mines, Minerals, and Energy

ADVANCED VEHICLE TECHNOLOGY & ALTERNATIVE FUELS

1. Accelerate the Development of Advanced Vehicle Technology and the Use of Alternative Fuels for Vehicles in the Commonwealth

A. *State agencies and localities should purchase vehicles that use non-traditional sources to meet the transportation needs of the Commonwealth's public sector.*

- The state will facilitate this through the expansion of the Commonwealth Alternative Fuel Program. This program, began in 2012, facilitates the purchasing or converting of vehicles for fueling with natural gas or propane. The goal is to advance the first 100 vehicles within by October 1, 2015 and deploy at least 300 vehicles by the end of the Administration. This goal will be accomplished by DMME and DGS utilizing Federal Congestion Mitigation and Air Quality (CMAQ) funding to support the incremental cost of appropriate alternative fuel vehicles, and engaging agencies and localities in this effort.

B. *The Commonwealth will work to create and promote additional public private partnerships to double the total deployment of all types of alternative fuel refueling infrastructure for state fleet and public motoring use.*

- Virginia is a national leader in effective and mutually beneficial public-private partnerships. Using this expertise, the Administration will proactively communicate and collaborate with private partners to advance a greater availability of alternative fueling stations. This could involve leveraging state vehicle fleets to provide the volume of vehicles needed for the financial viability of building new fueling infrastructure. Virginia now has around 400 alternative fuel stations for biodiesel, natural gas, ethanol, electricity, and hydrogen, including nearly 250 electric vehicle-charging stations. The Commonwealth should work to double the number of alternative fuel stations to reach 800 by the close of the Administration.

C. *Virginia should work to publicly recognize high-impact alternative fuel vehicle fleets for their emissions reductions and fuel savings by creating a Governor's Green Fleet Award.*

- This annual award and recognition will showcase state agencies that are public sector leaders in shifting their fleets to alternative fuel vehicles.

D. *Virginia should facilitate consumer and business adoption of efficient alternative fuel vehicle technologies by making incentives available for the purchase of low or zero emissions vehicles to bolster pace of transition.*

- Purchasers of alternative fuel, zero emission vehicles will be eligible for a $1,000-$2,500 tax credit or grant. The tax credit will be available for up to 2,000 alternative fuel, low- or zero-emission vehicles per year and will expire after 10,000 of these vehicles have been purchased in the Commonwealth. Incentives for alternative fuels, zero-emission vehicles at this level is an effective tool used to increase deployment of these vehicles while allowing citizens to leverage and take benefit from the ongoing federal $7,500 incentive.

E. Virginia should identify state resources to fund alternative fuel education and deployment programs.

- A modest funding allocation for alternative fuel educational outreach and deployment programs can be effectively leveraged with private sector and federal dollars to create significant education and deployment penetration in Virginia. By participating with targeted state investments in the areas of outreach, education, and deployment, Virginia can contribute and lead a path forward that reflects the priorities of the Commonwealth.

F. The Commonwealth should support the continued use of Gas Gallon Equivalent (GGE) for Compressed Natural Gas when it is used as an on-road vehicle motor fuel.

- This standard unit of measure is used nationwide and gives consumers an understandable and useful comparison and provides equity in taxing and dispensing.

TALENT DEVELOPMENT IN THE ENERGY SECTOR

1. Expand and Foster an Educational Environment to Prepare the Next Generation of Virginia's Energy Workforce

A. Expand and accelerate participation in the Troops to Energy program, training veterans to work in the energy industry.

B. Collaborate with community colleges and four year institutions to train the next generation of STEM workers in the energy sector.

C. Establish annual goals and identify opportunities to increase statewide attainment rates of credentials that align with employer needs.

D. Align energy workforce supply to current and anticipated employer demands by constructing career pathways and training solutions for future workers.

Appendix A

Appendix B

Appendix A Introduction

The 2014 Virginia General Assembly modified Chapter 2 of Title 67 of the Code of Virginia to include the following:

"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;"

The analysis identified in the above language was required to be released on October 1, 2014 as part of the 2014 Virginia Energy Plan. Appendix A contains studies that comprise the mandated analysis.

The Environmental Protection Agency released a proposed regulation under section 111(d) of the federal Clean Air Act On June 2, 2014. This release triggered the statutory requirement that an analysis be conducted.

The EPA's proposed rule is a 674 page document, not including the technical supporting data used in developing the proposed rule. The complexity of the proposed rule persuaded the EPA to provide states and the general public with a virtually unprecedented 120-day public comment period, which was scheduled to close on October 16, 2014. On September 16, 2014, the EPA announced an extension of the public comment period an additional 45 days.

The publishing of the Energy Plan, including the statutorily mandated analysis of a non-final, proposed federal rule, comes two-months prior to the closing of the proposed rule's public comment period and seven months prior to the EPA's announcement of the final rule.

This level of uncertainty made it difficult to design an accurate study and makes it very difficult to draw meaningful and accurate conclusions from the studies included in this Appendix. The studies conducted are based on assumptions made about costs and benefits of a proposed rule, portions of which could very well change substantially based on public input received by the EPA. This uncertainty is evident in the varying and disparate conclusions provided in these studies. All conclusions reached in the studies should be viewed by the legislature and all interested parties as preliminary and speculative. Until there is a final rule and a state compliance strategy, there is no reliable way to estimate costs or benefits of the new regulations.

The groups conducting these studies should be commended for their efforts. They worked diligently to complete these studies in an extremely truncated time-frame to ensure publication by the deadline. The Commonwealth is grateful for the dedication and commitment shown by all of those involved.

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

September 26, 2014

VIRGINIA CENTER FOR COAL AND ENERGY RESEARCH

http://www.energy.vt.edu

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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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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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).

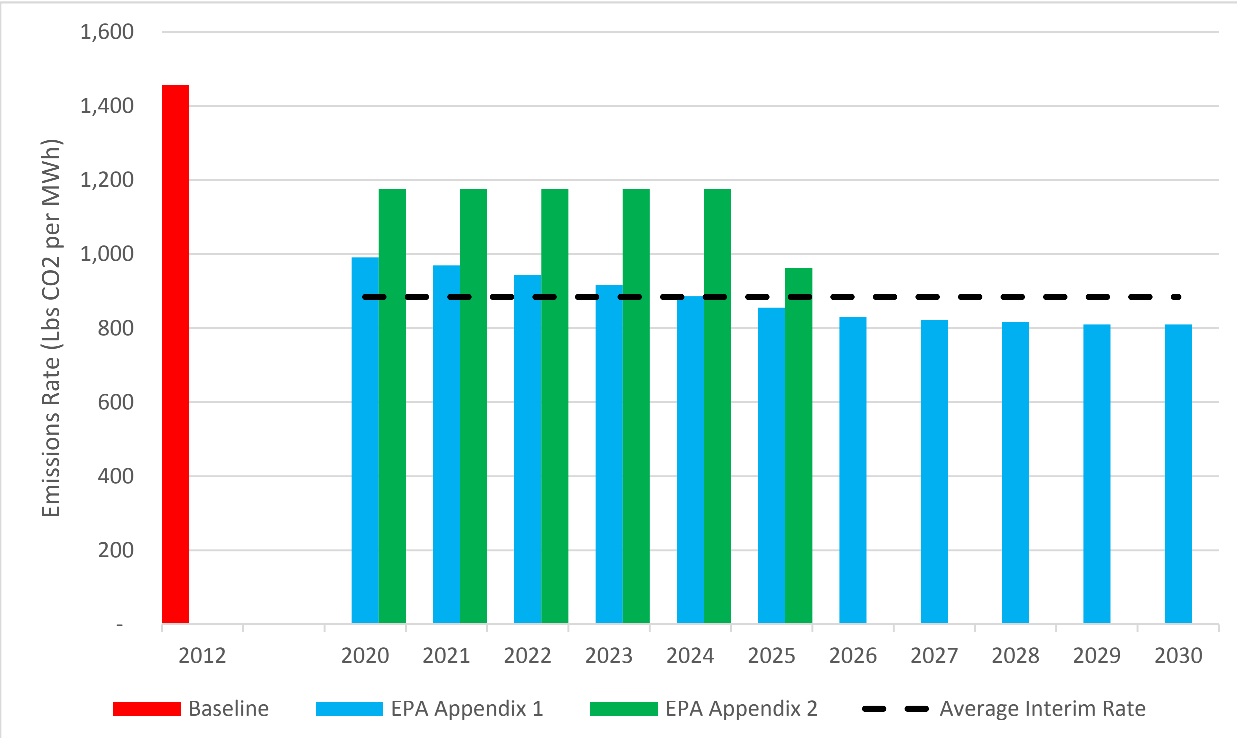
To implement the plan, EPA developed carbon emissions standards for ***new*** power plants by issuing proposed regulations to align with section 111(b) of the Clean Air Act on January 8, 2014, (EPA, 2014a). The EPA also released a proposal for additional carbon emissions regulations based on section 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



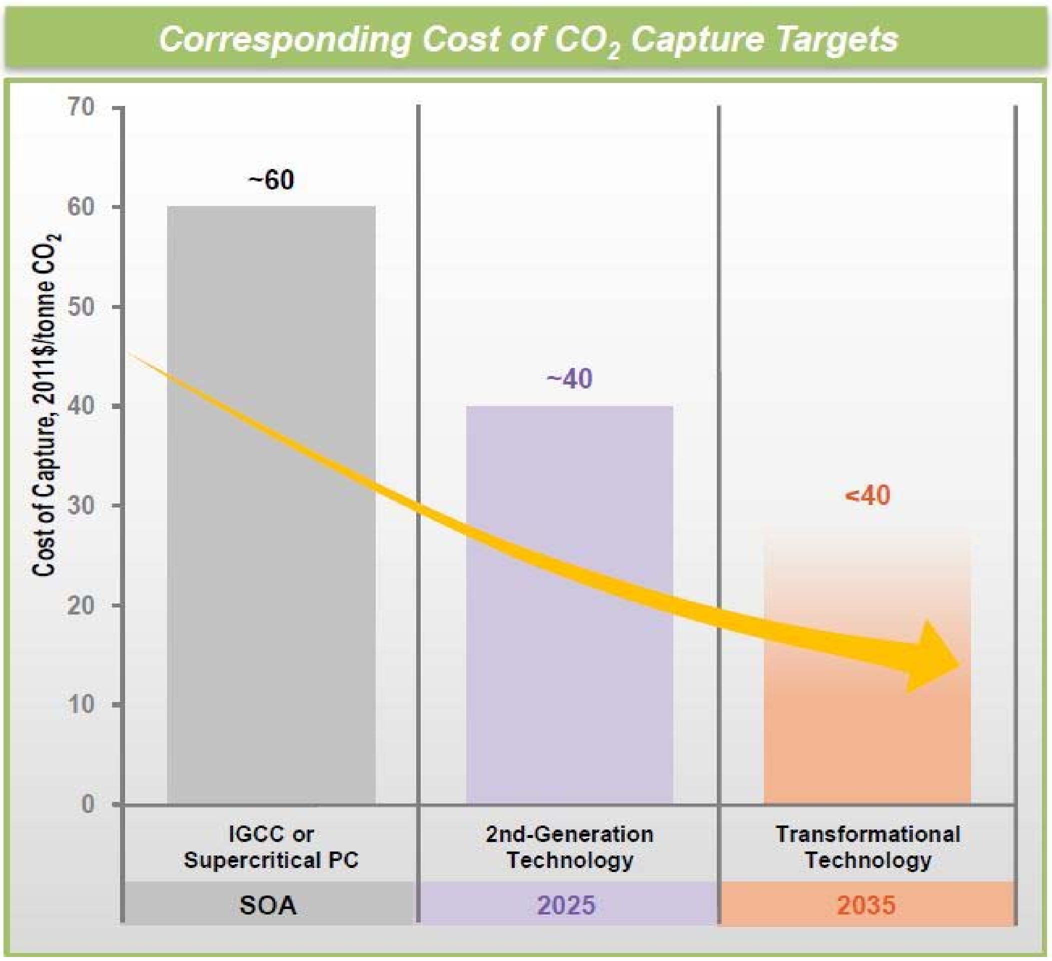
Changes in the power industry have been ongoing for decades. The US utility industry and its dependency on coal have undergone a series of abrupt changes during the past four decades. Virginia utilities responded quickly to meet environmental standards and fulfill their obligation to provide customers 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)

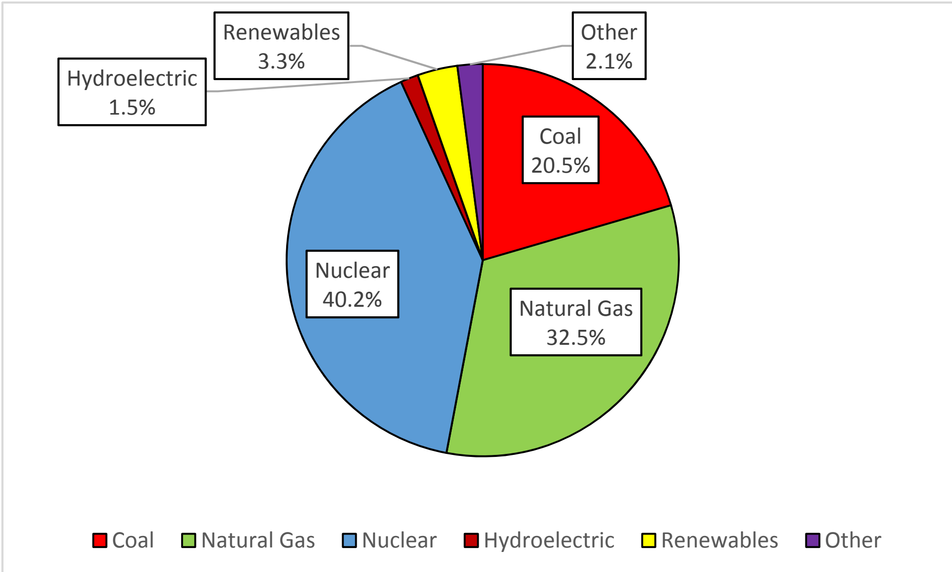


To ensure full implementation of CCUS, large field demonstration projects are necessary, requiring significant federal funding and state participation, including addressing significant legal issues. Based on the ongoing research conducted by the VCCER, Virginia is well-positioned to host and benefit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

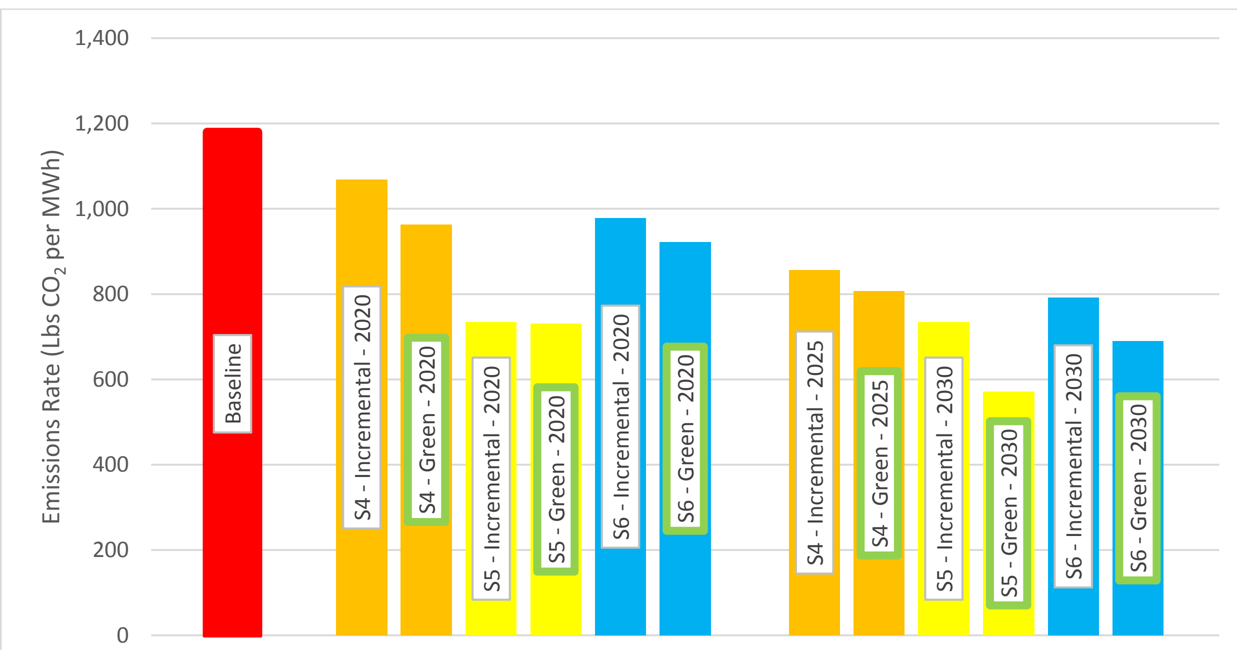
Scenarios represent possible alternative compliance approaches. Six unique operating or compliance scenarios were developed with the input of the Virginia Department of Environmental Quality, the Virginia Department of Mines, Minerals and Energy, the State Corporation Commission, and the report team 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

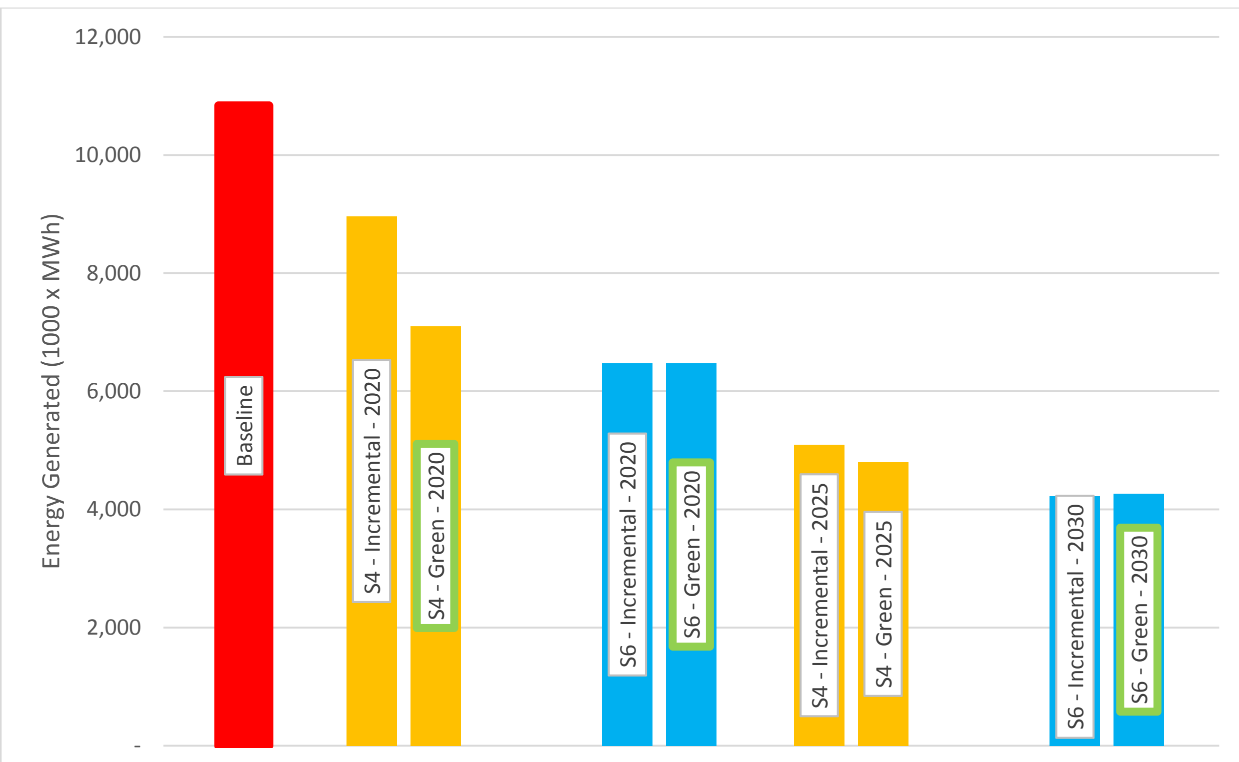


Figure ES-6: Natural Gas Generation by Scenario

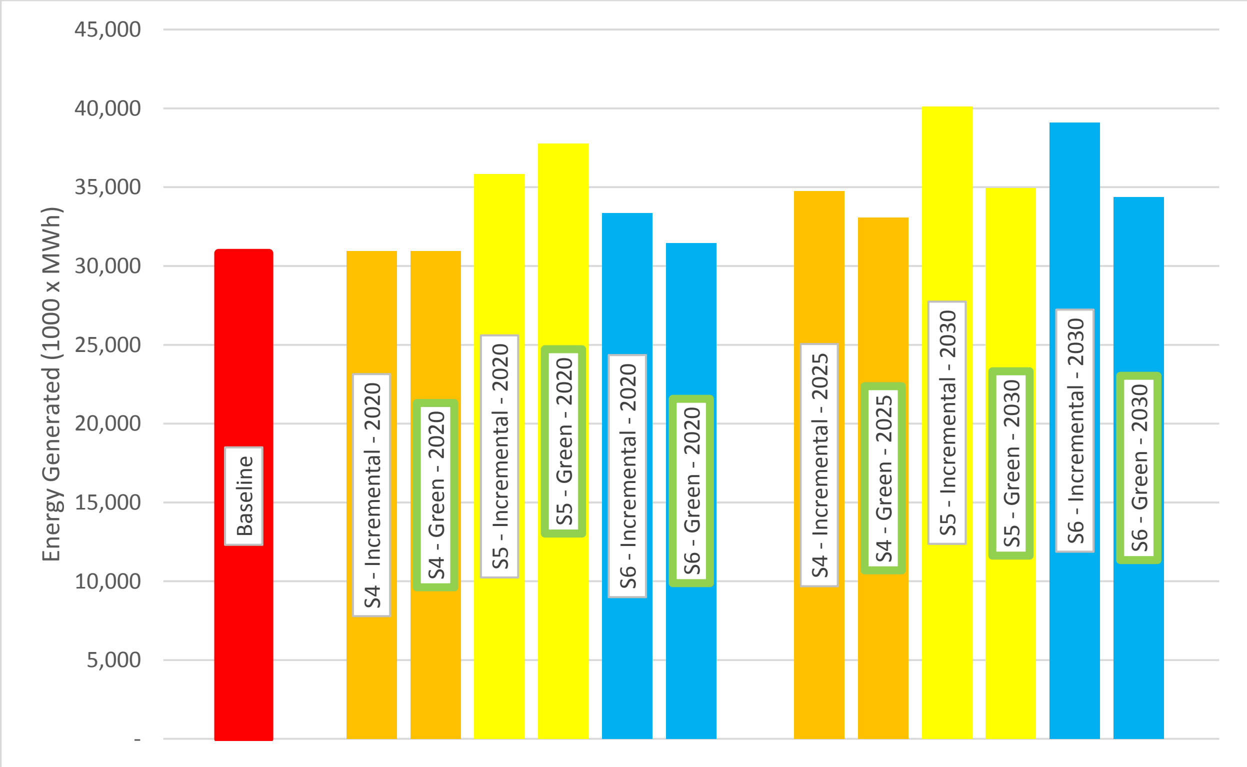
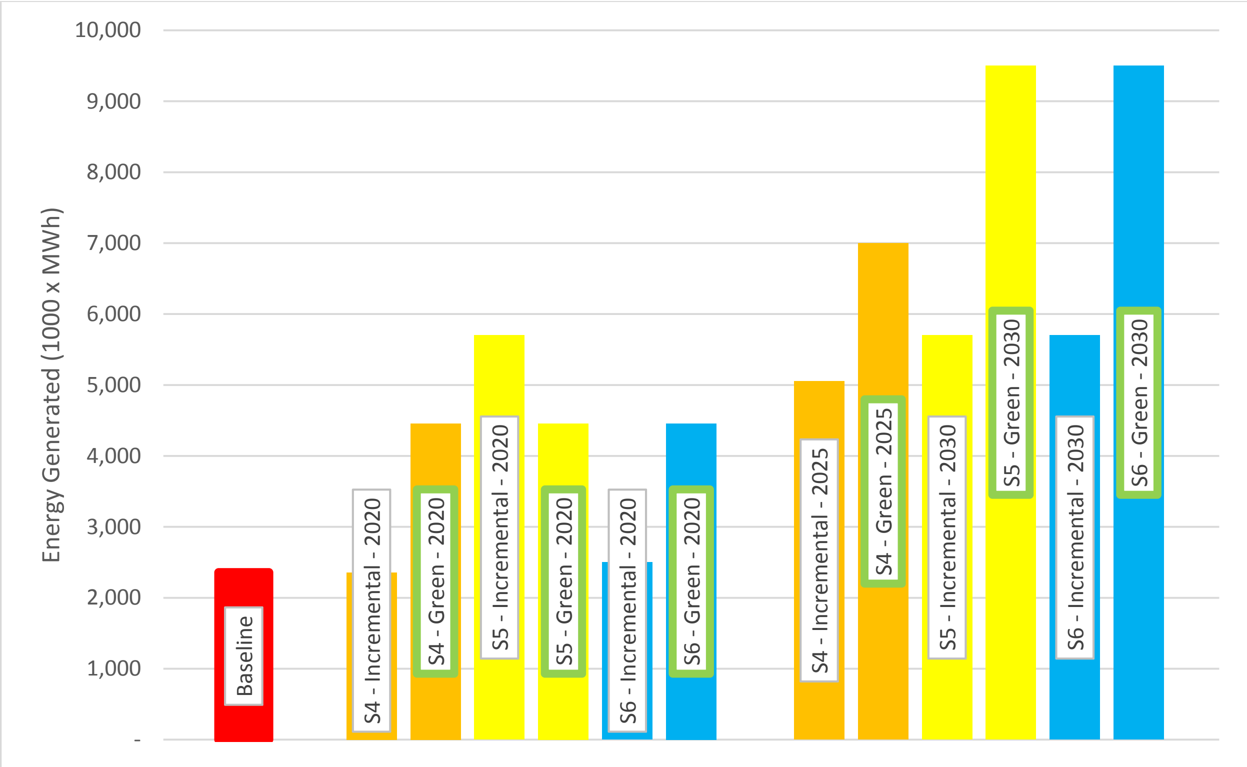


Figure ES-7: Renewable Energy Generation by Scenario



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

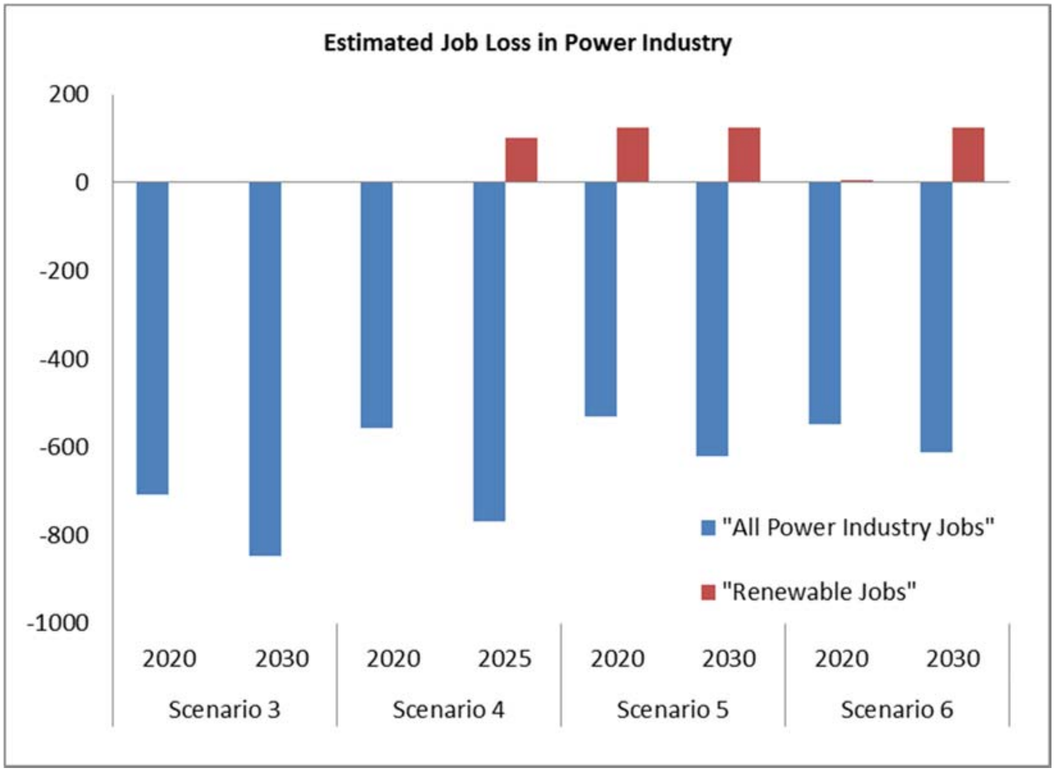


Table ES-4: Employment in the Coal, Oil and Gas, and Energy Efficiency Industries

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.

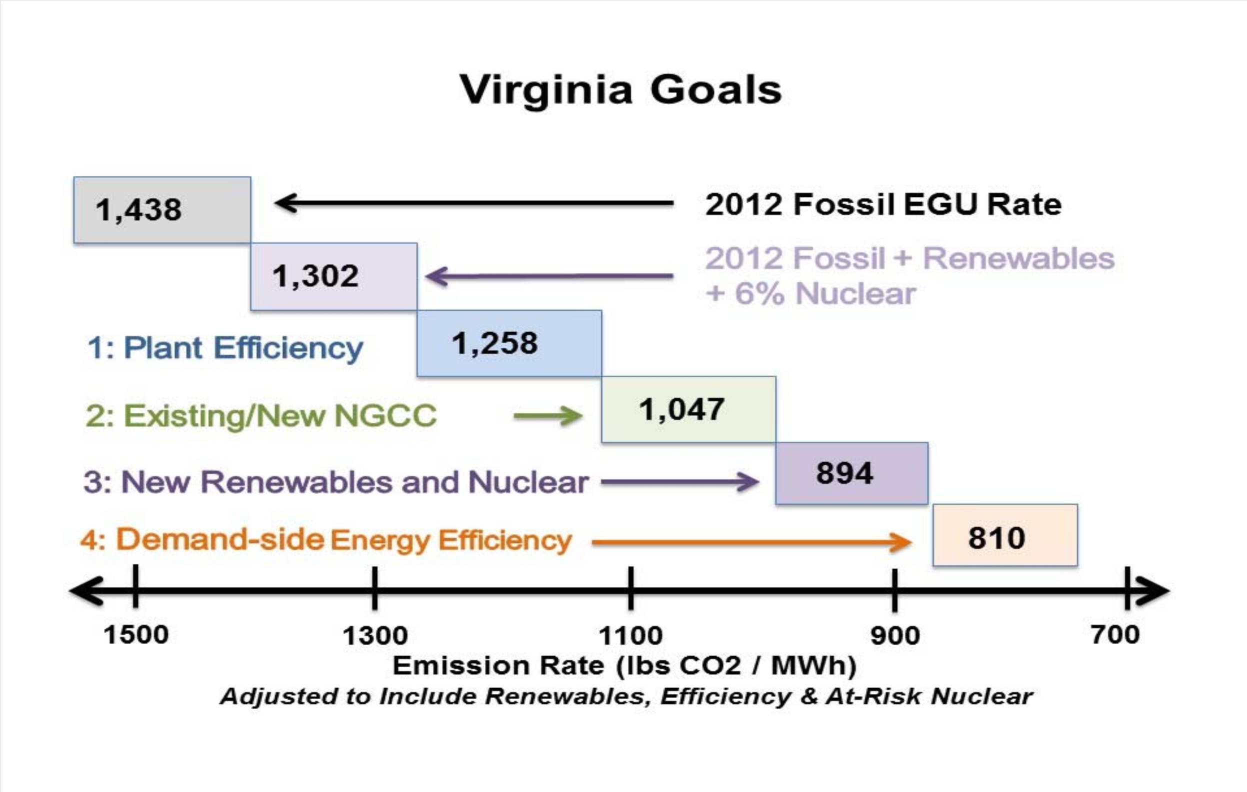
Discussion

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:

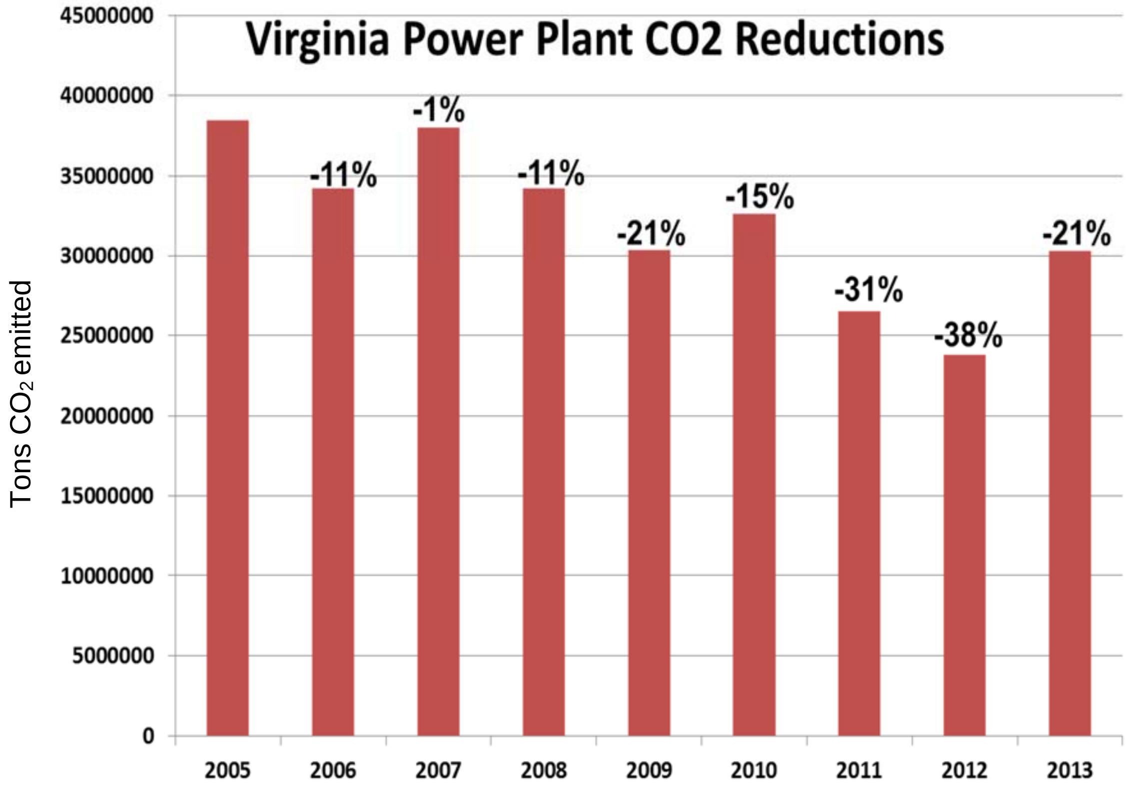
- CO_2 emissions from the coal-fired fleet have been decreasing in recent years due to both utilization and efficiency improvements. Between 2005 and 2012, many of the existing fossil fuel plants made a number of efficiency improvements which in addition to causing them to operate at lower capacity factors, 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

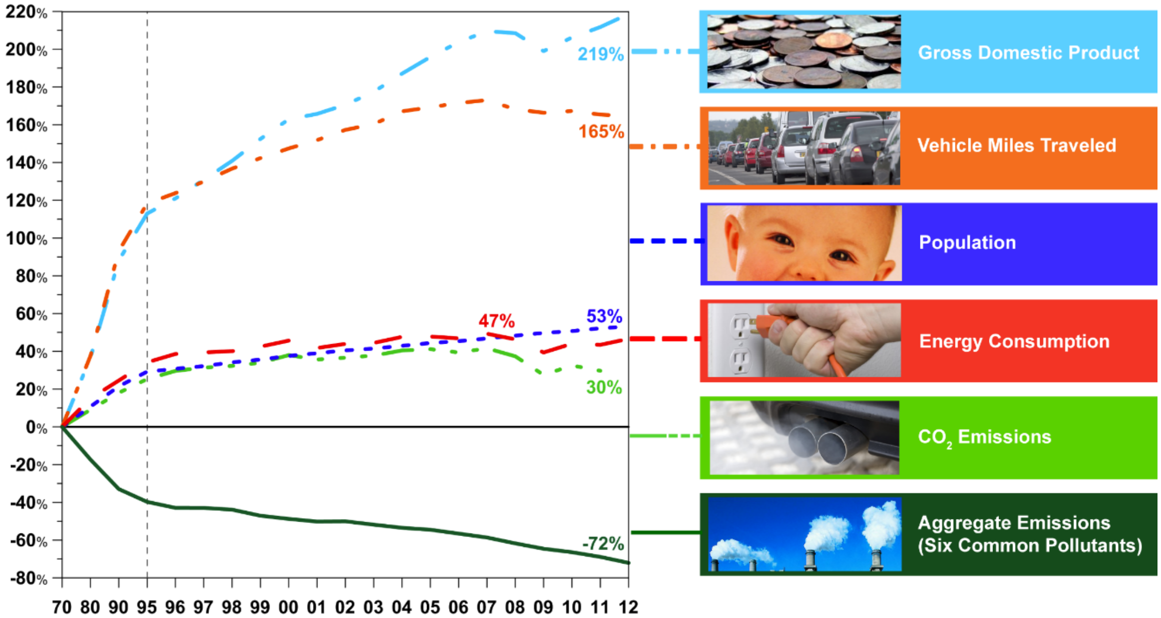
The power industry has developed and deployed environmental control technologies for a wide variety of emissions since the mid-1970s. As a result, emissions of major pollutants are significantly below historical levels even as power generation has grown to satisfy increased industrial, commercial, and 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.

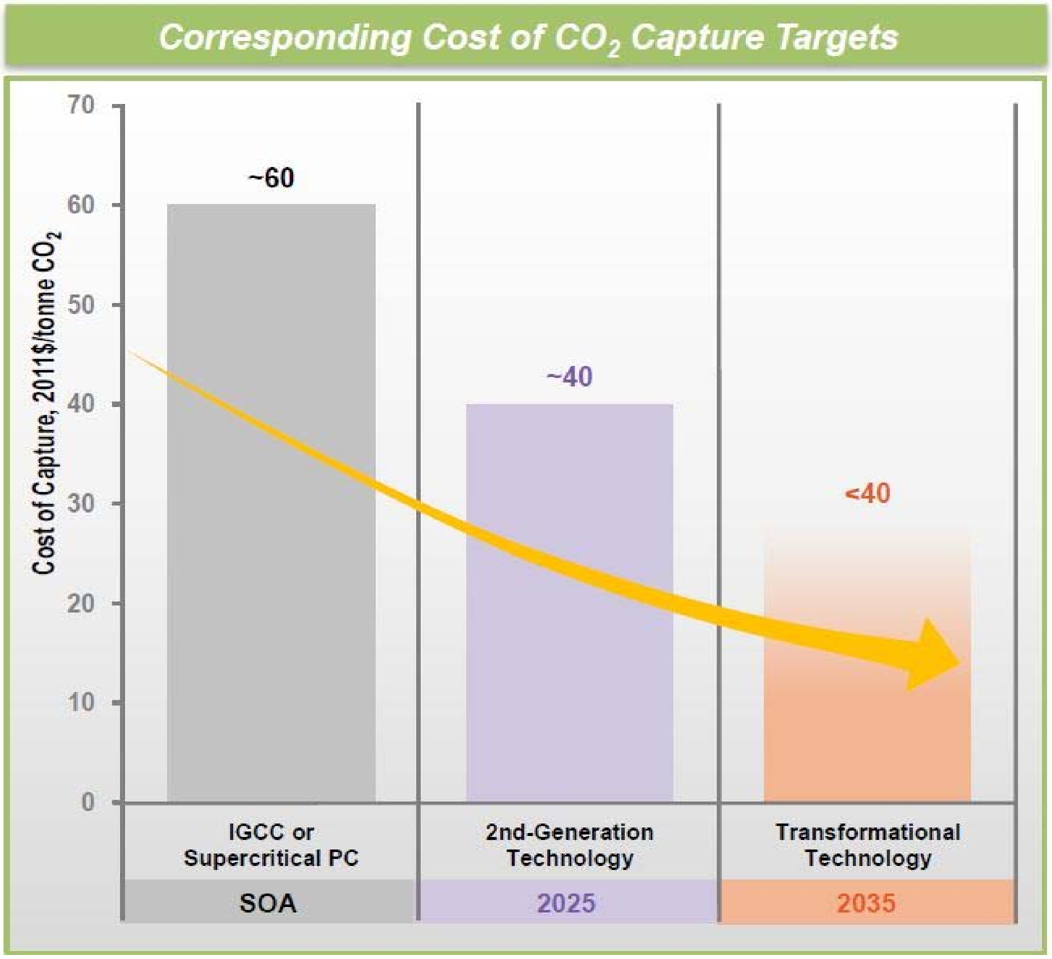
The main approaches pursued for separating CO_2 can be organized into three categories.

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).

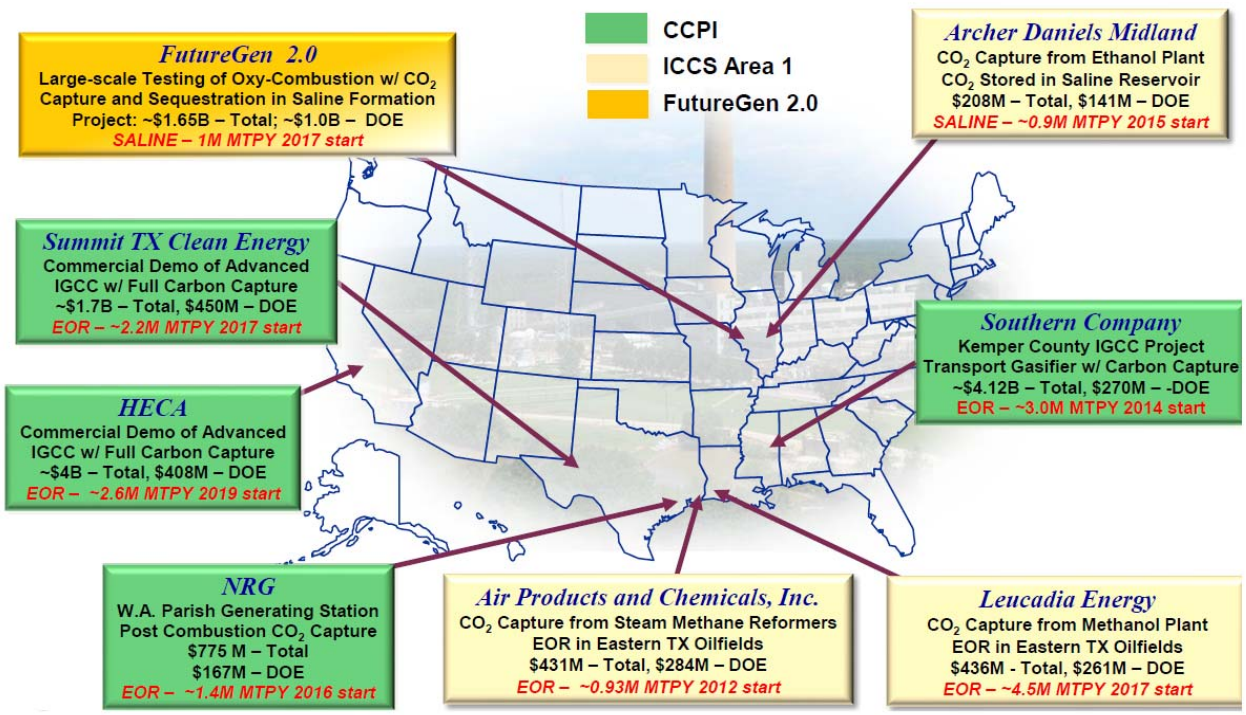
CCUS Demonstration and Pilot Tests

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)



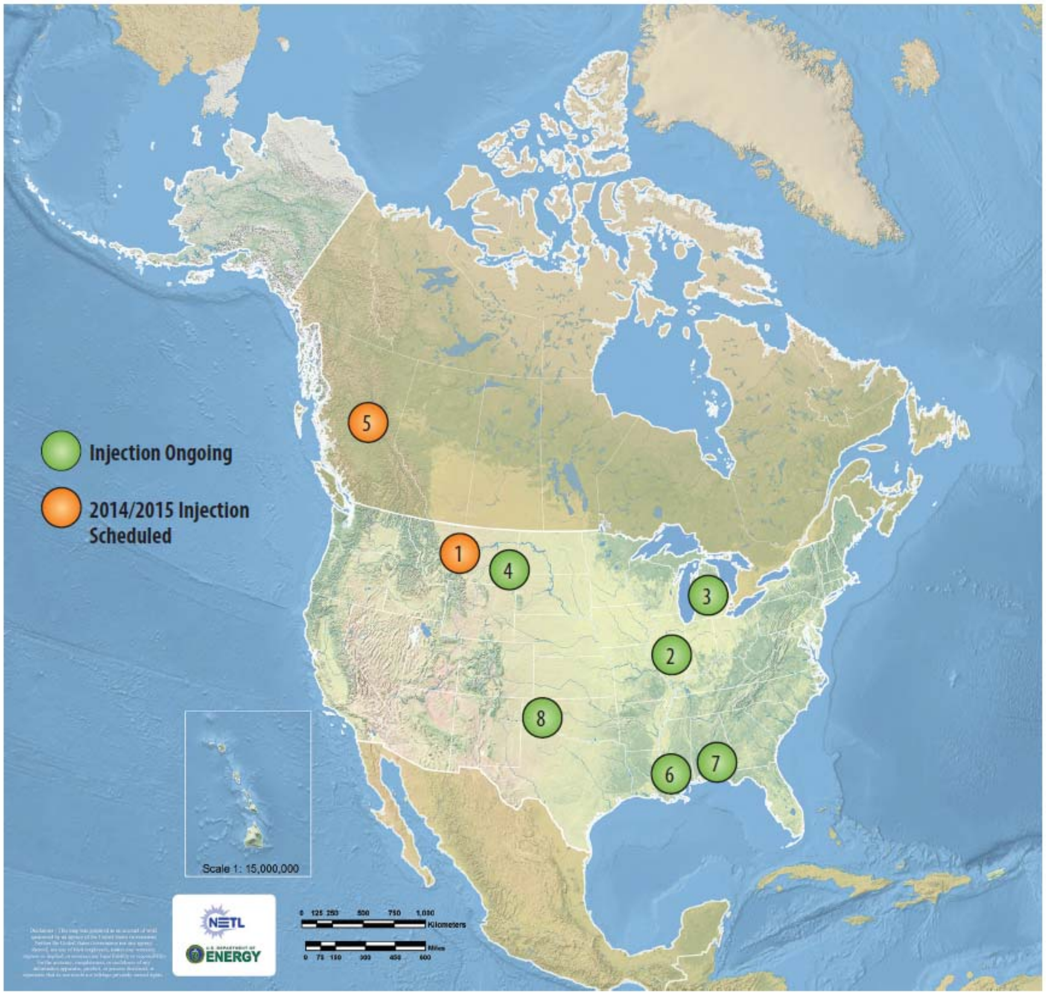
Two North American CCUS projects nearing operation are particularly important because they are the first such projects to be developed at large-scale in the power sector:

- 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.

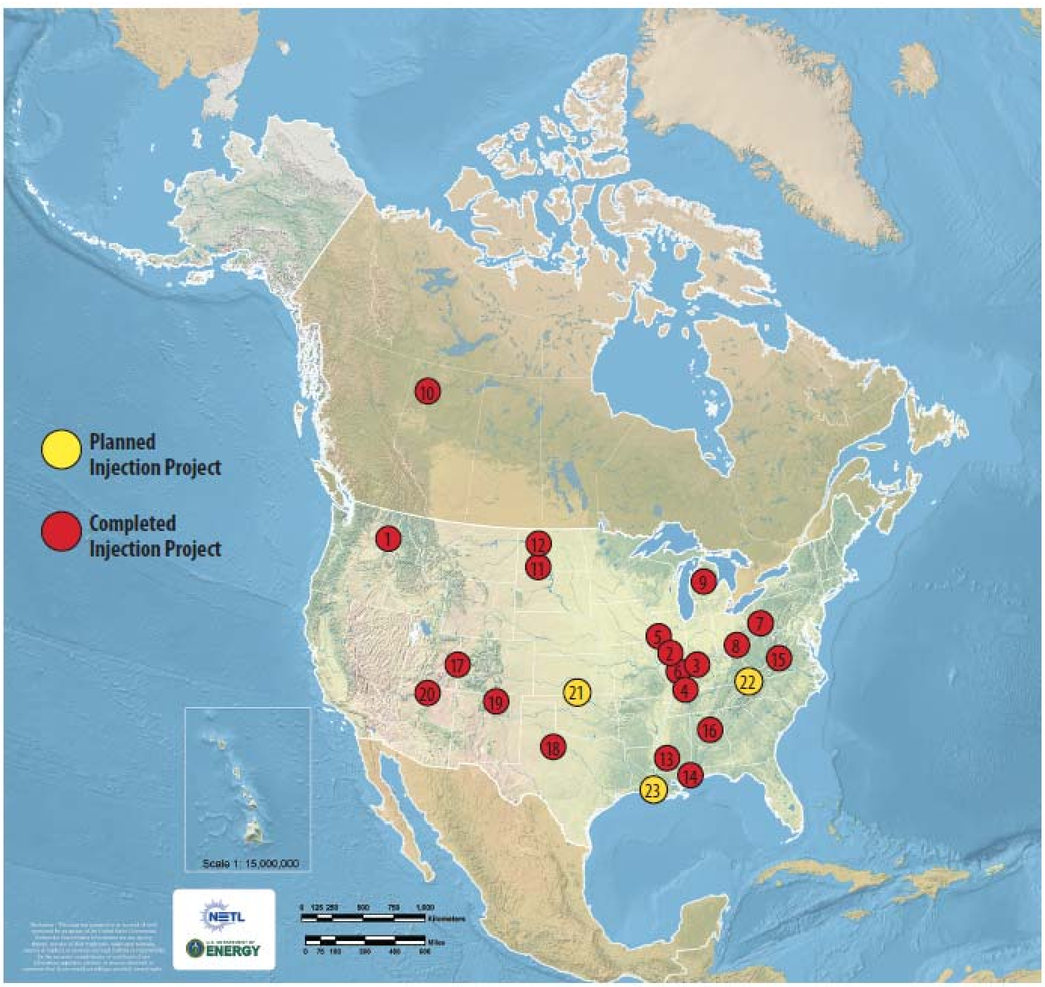
Figure 3-4: Large-Scale CO_2 Storage Tests in the US (Source: NETL)



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

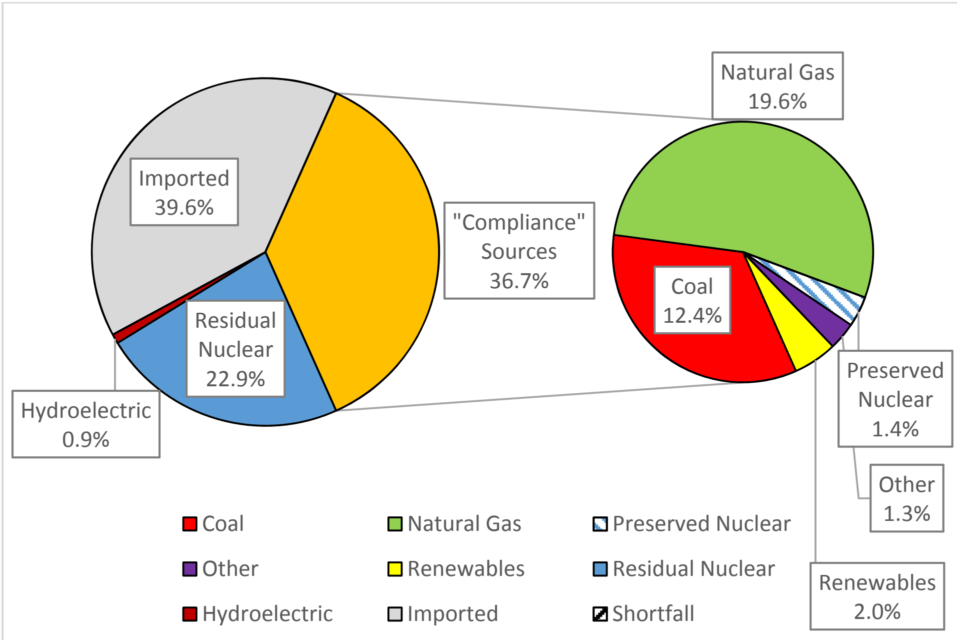
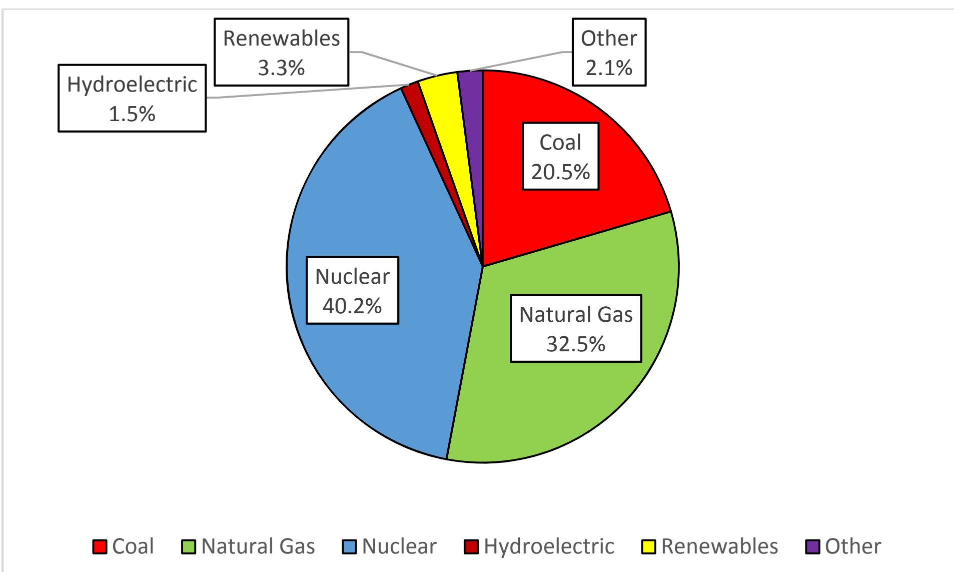
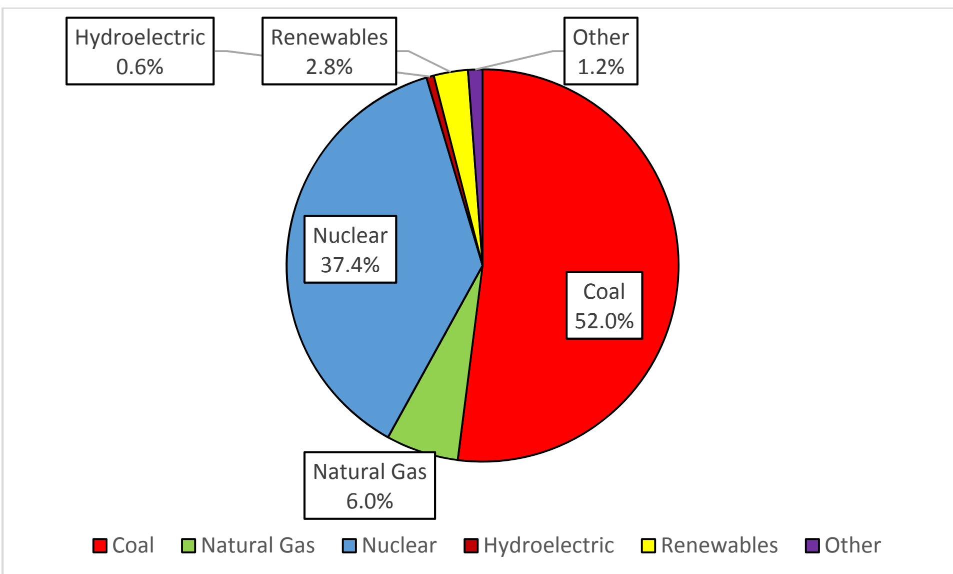


Figure 4-2: Virginia 2012 In-State Generation by Source (Source: EIA, 2014)



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

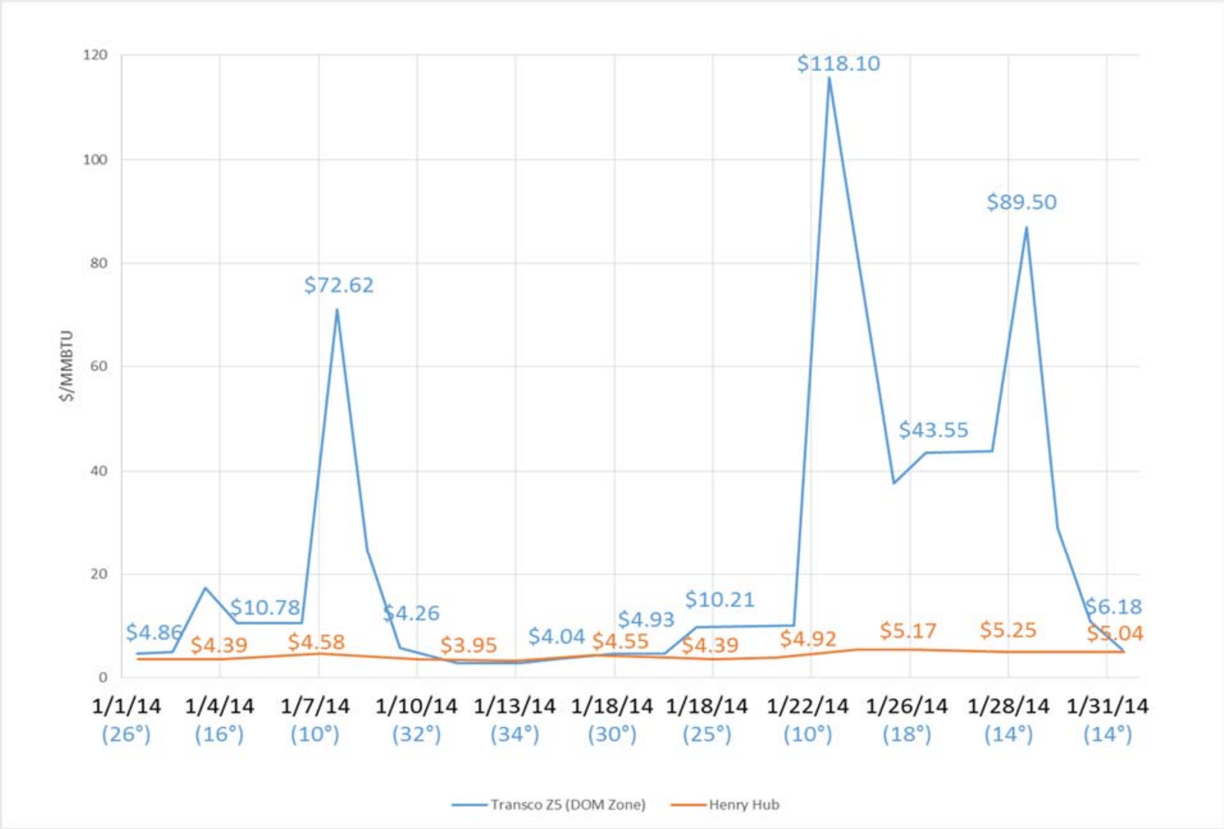
Approximately 2,700 MW of coal-fired generation in Virginia is scheduled for retirement and will be replaced primarily by new natural gas combined cycle units. The 2012 generation mix shows natural gas accounting for 35 percent of Virginia's power generation. Additionally, the various CO_2 compliance 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*

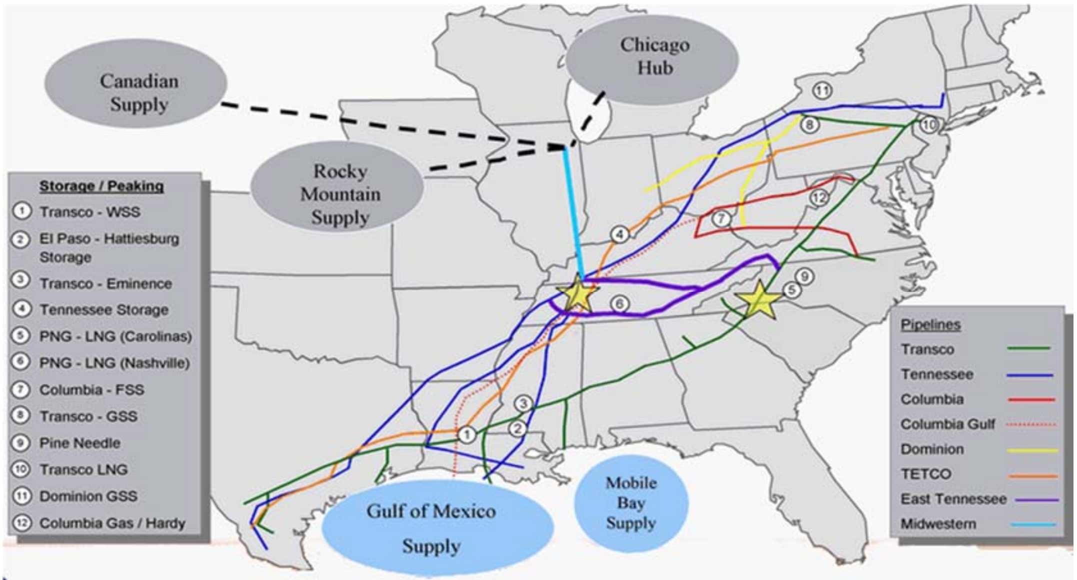
predictable environment where private capital will invest in an expanded pipeline network to move the unprecedented supplies of gas to our population and power load centers.

Figure 4-4: Winter 2014 Natural Gas Markets Stressed



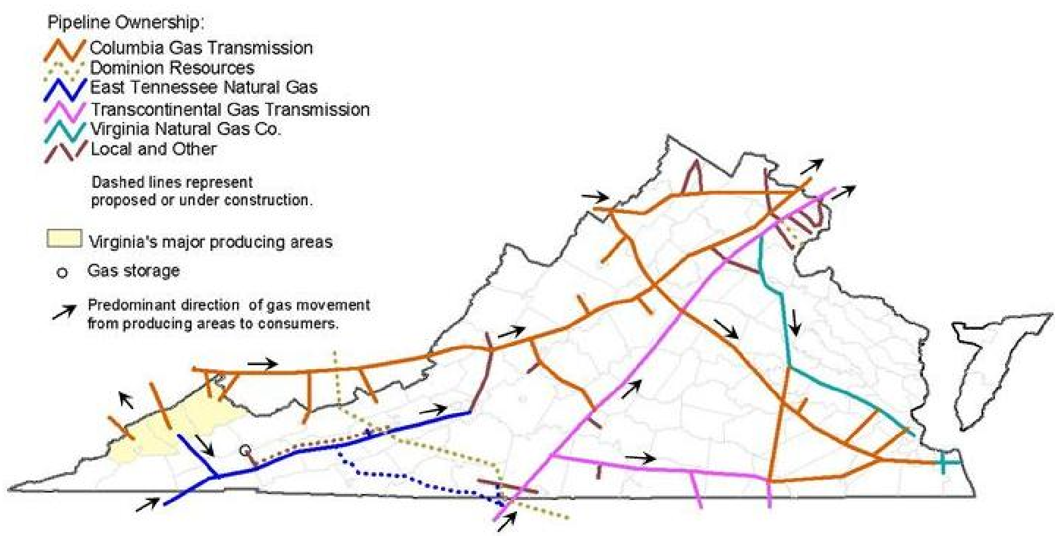
The 2010 Virginia Energy Plan addresses the natural gas pipeline system in the State, as shown in Figure 4-6 which depicts existing routes within Virginia, and Figure 4-5, which shows the state infrastructure in relation to the southeast and mid-Atlantic regions.

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

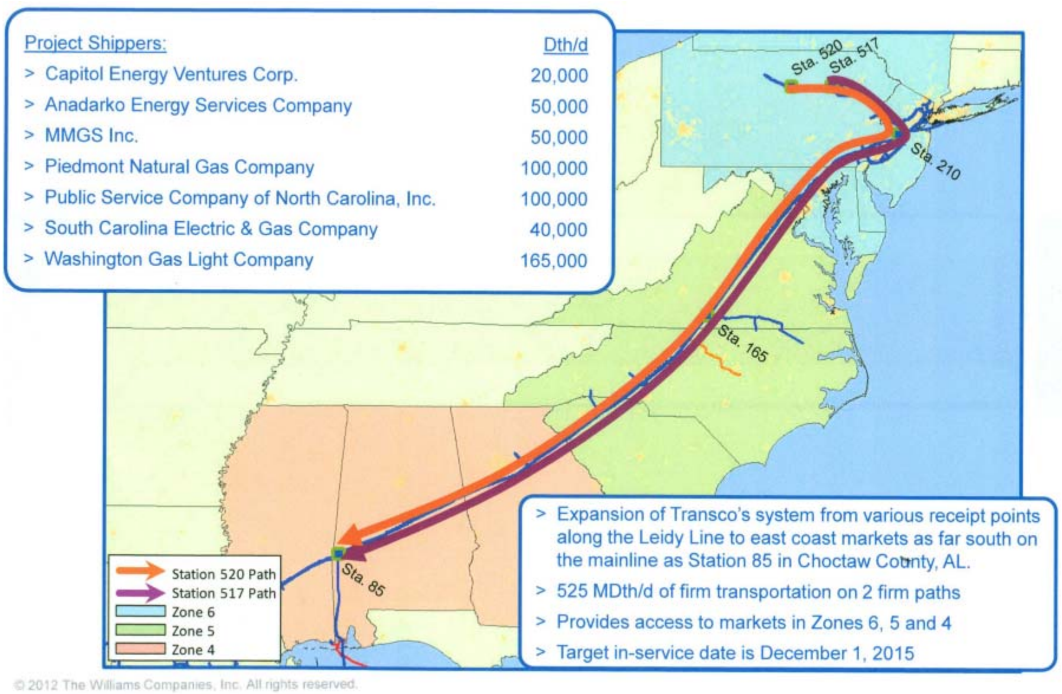


Figure 4-8: Atlantic Sunrise Pipeline Expansion Project

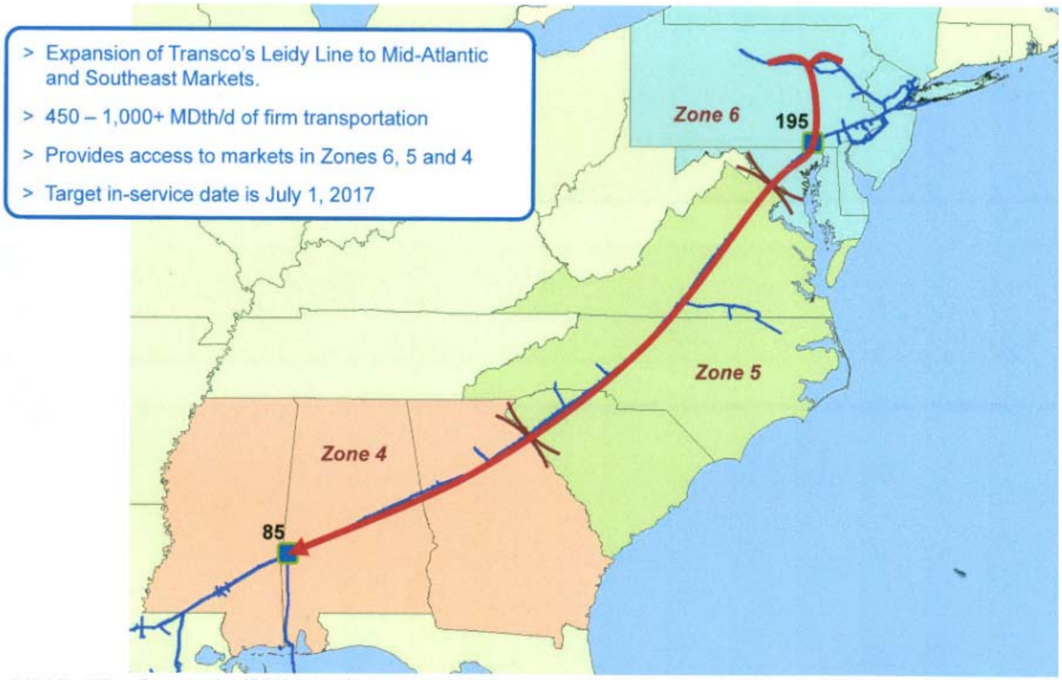


Figure 4-9: Virginia Southside Pipeline Expansion Project

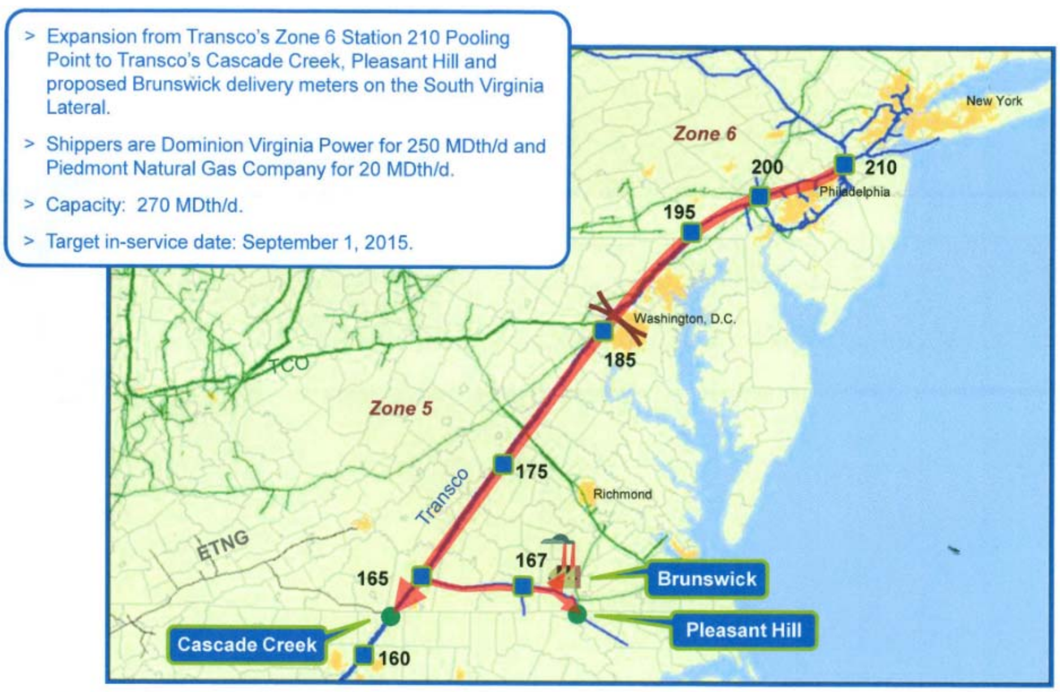
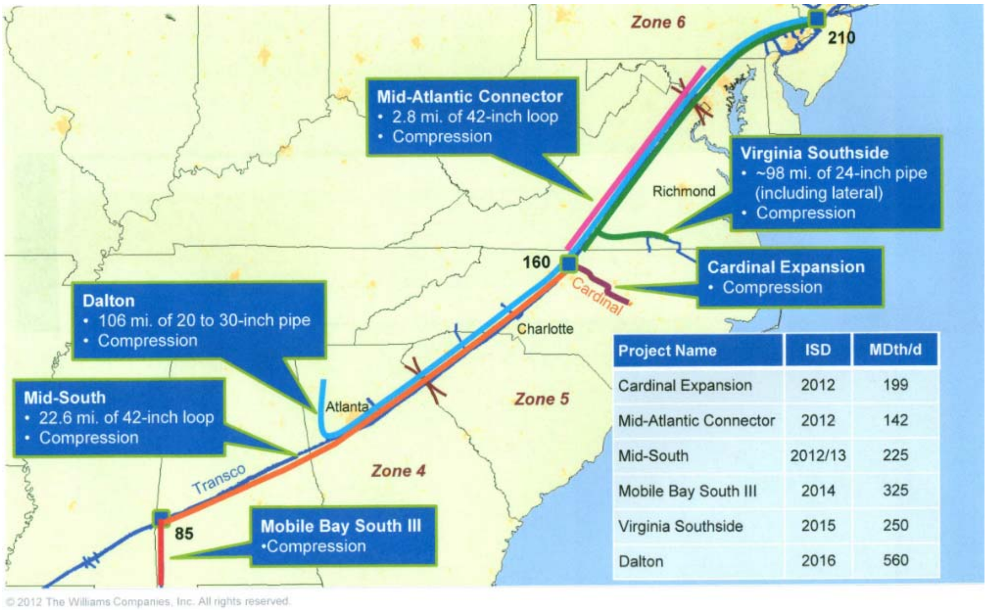


Figure 4-10: Southern Market Area Projects, including Mid-Atlantic Connector



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 14th 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)

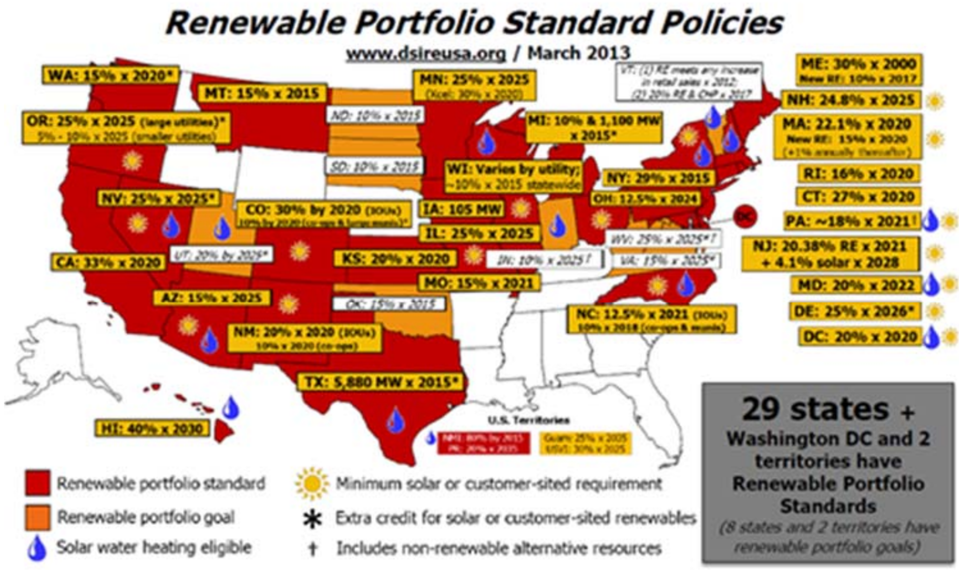
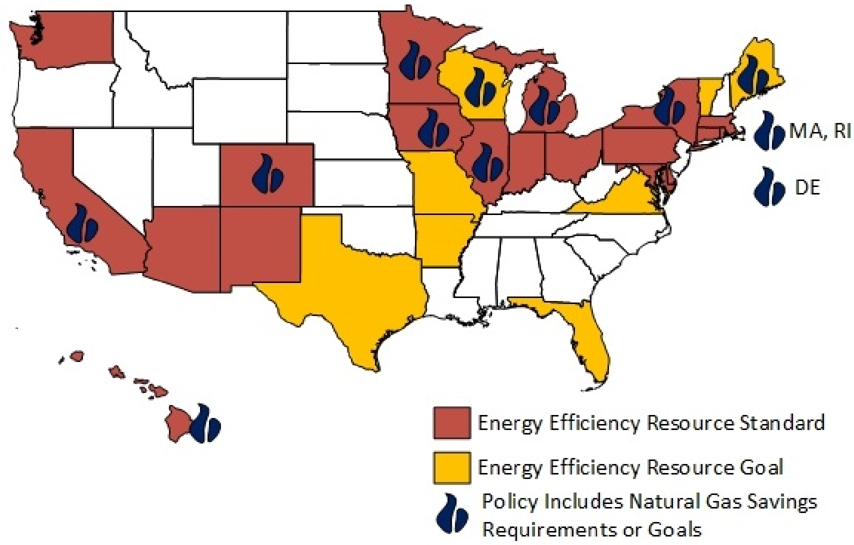


Figure 4-12: Energy Efficiency Resource Standards (Source: www.dsireusa.org)



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.

<u>Heat Rate and CO_2 Emissions</u>. 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.

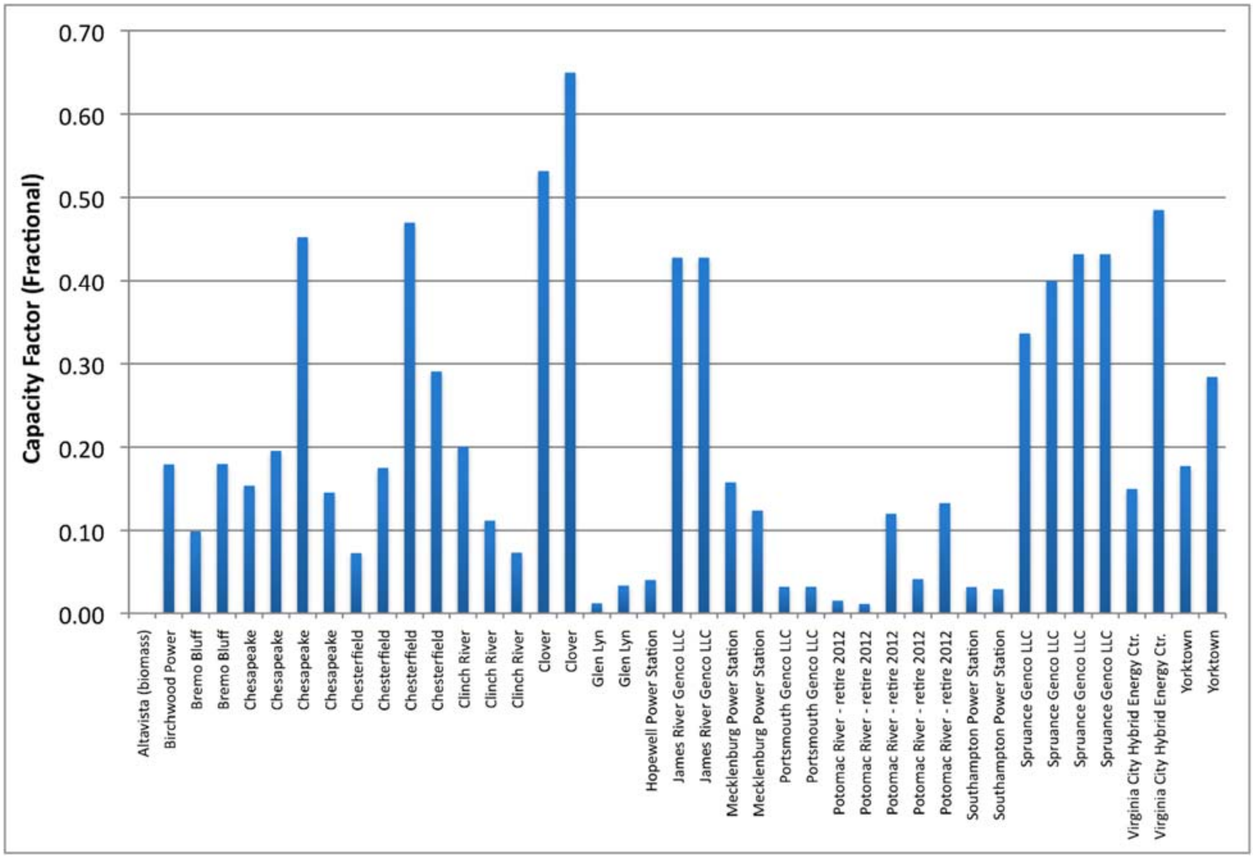
Consistent with EPA assumptions, preserved nuclear generation is not included in the 2012 baseline. Generation derived from renewable sources remains at 2012 levels. Conservation or energy efficiency is not included.

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.

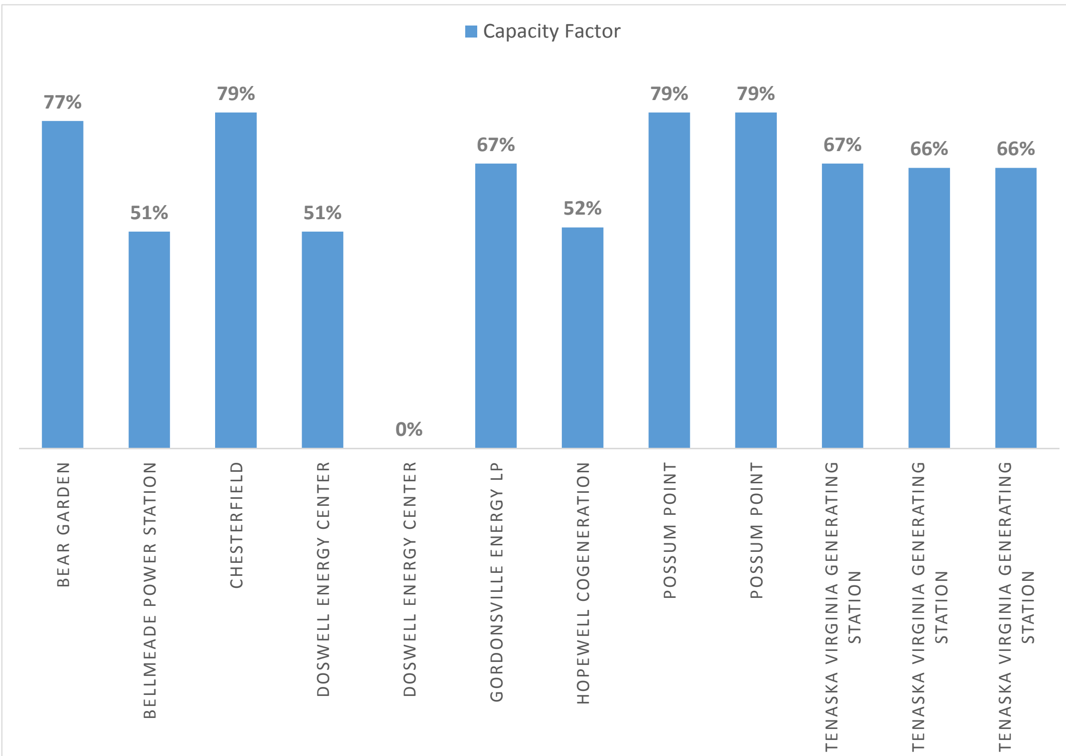
Numerous units have been designated for retirement by 2020. These include all units at the Bremo Bluff, Chesapeake, Clinch River, Glen Lyn, Potomac River, and Yorktown stations. Cumulatively, this will remove a total of 2,793 MW of generating capacity from the coal-fired inventory.

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.

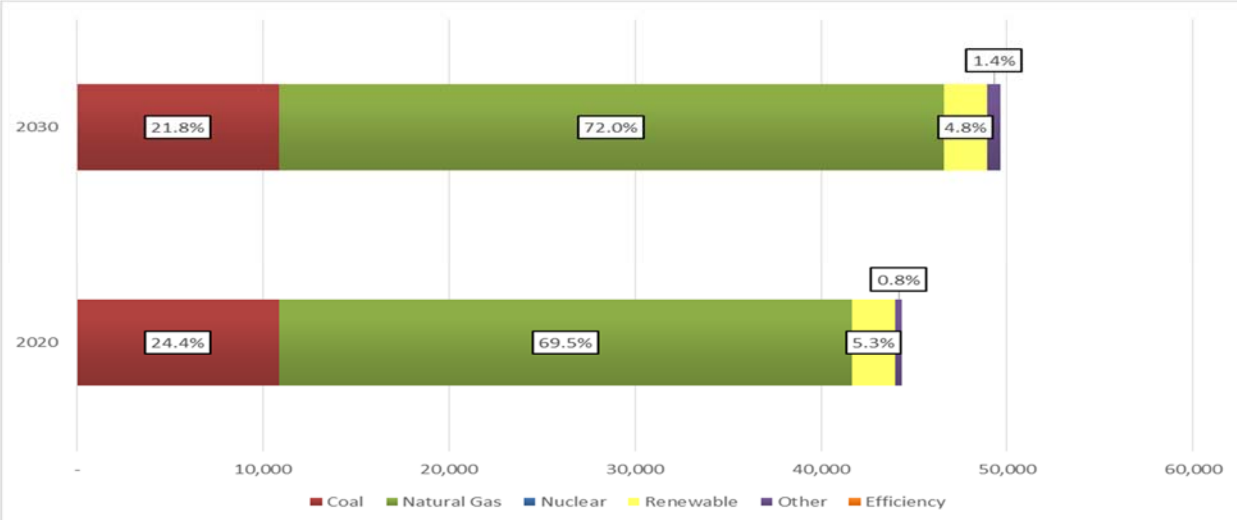
Table 6-3 presents a summary of the results for Scenario 1, which are reflected in Figure 6-3.

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.

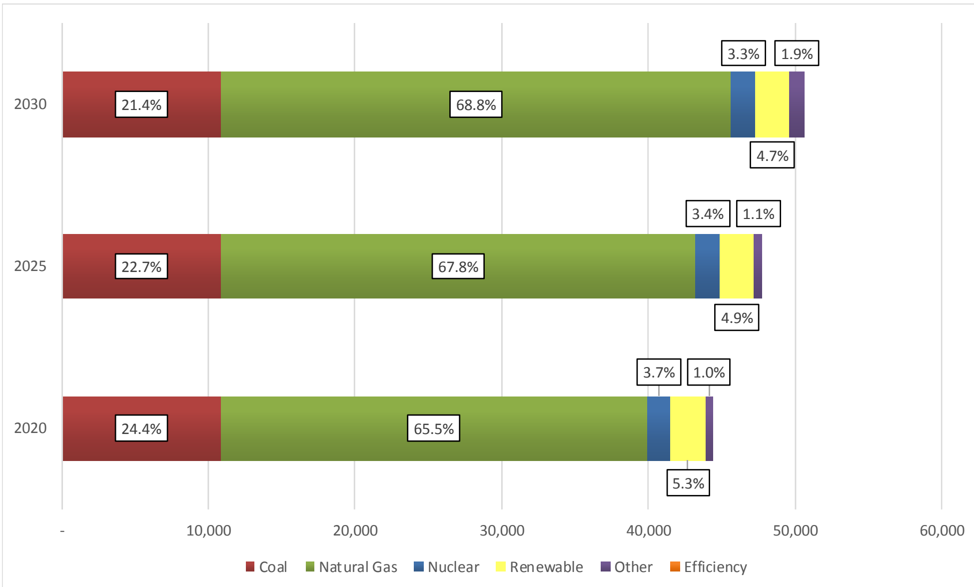
Scenario 2. Role of Preserved Nuclear

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.

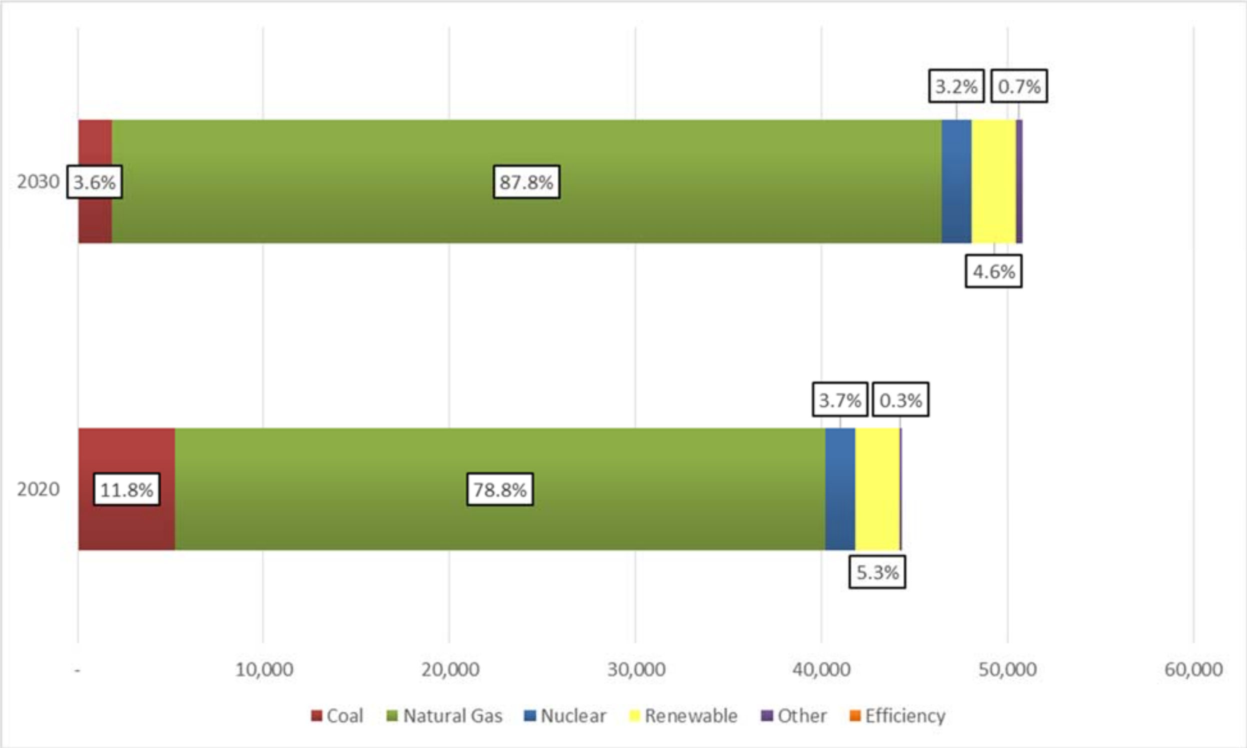
Scenario 3: Role of New Capacity

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:

Coal-fired Units. 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

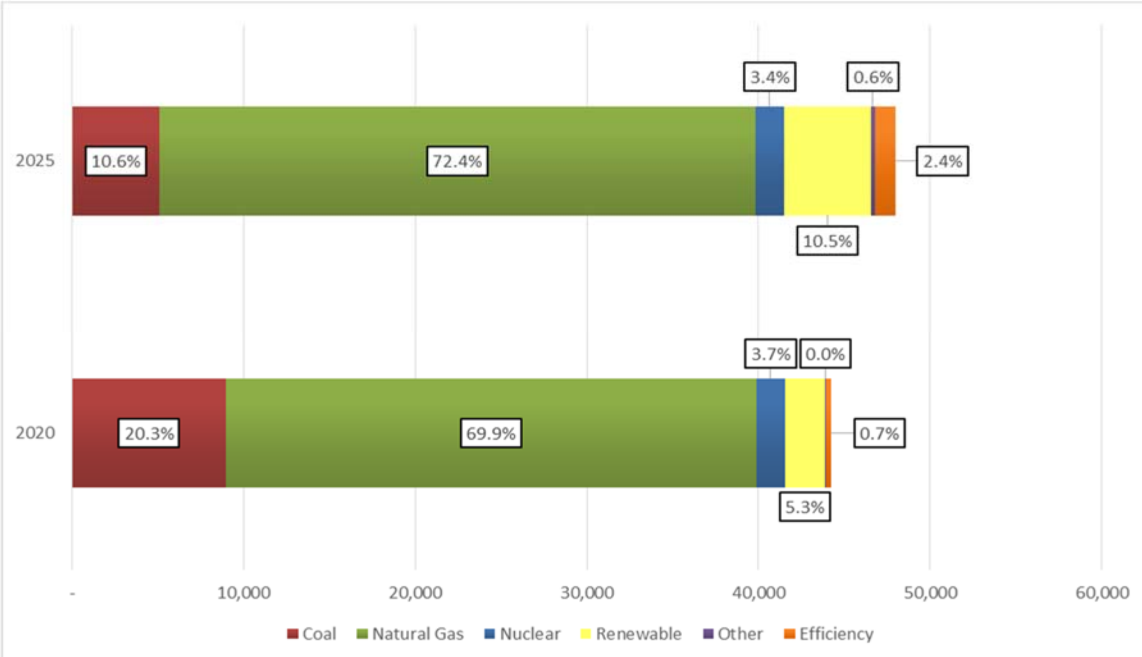
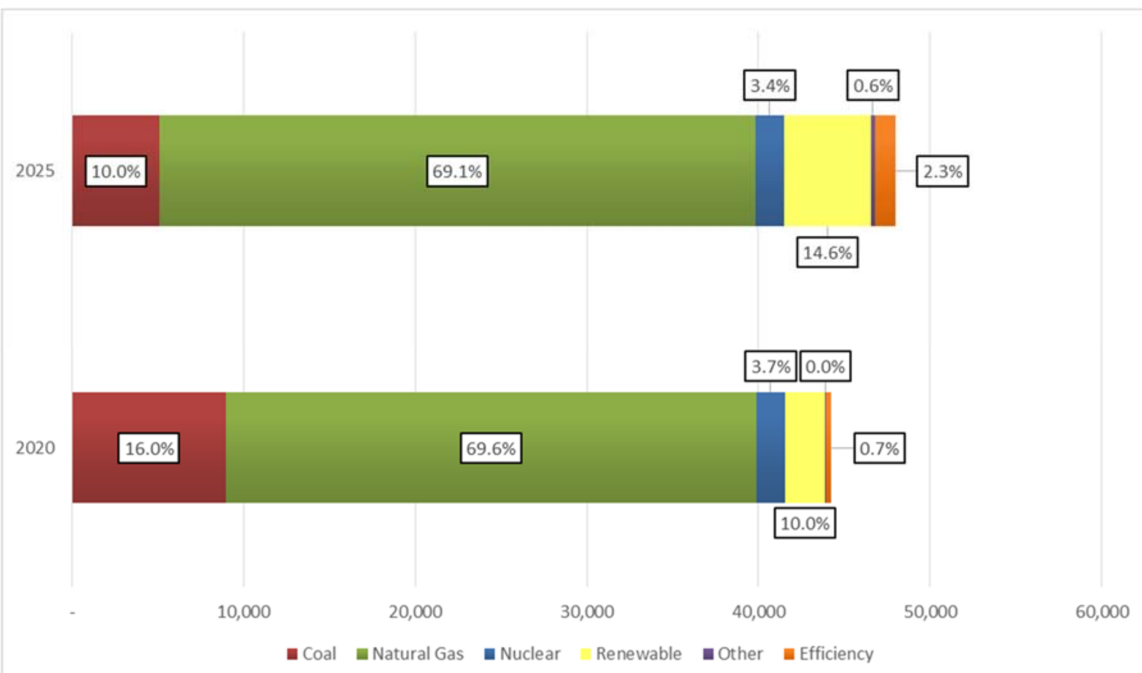


Figure 6-7: Scenario 4 (Green Dispatch) – Energy Generation Portfolio



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

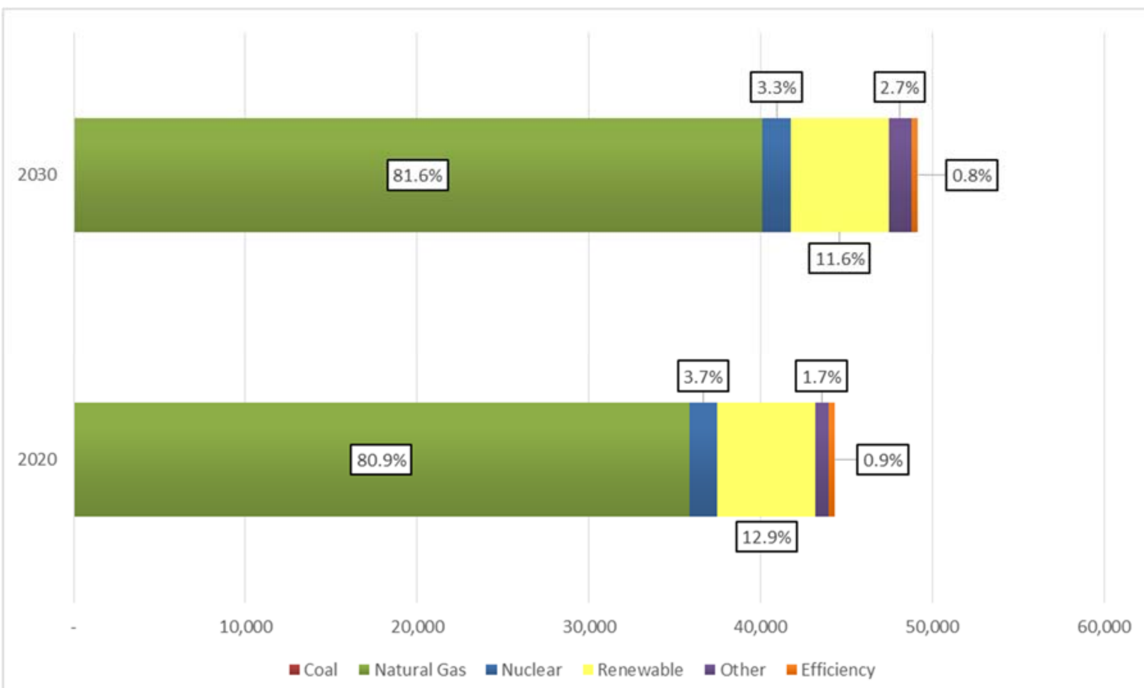
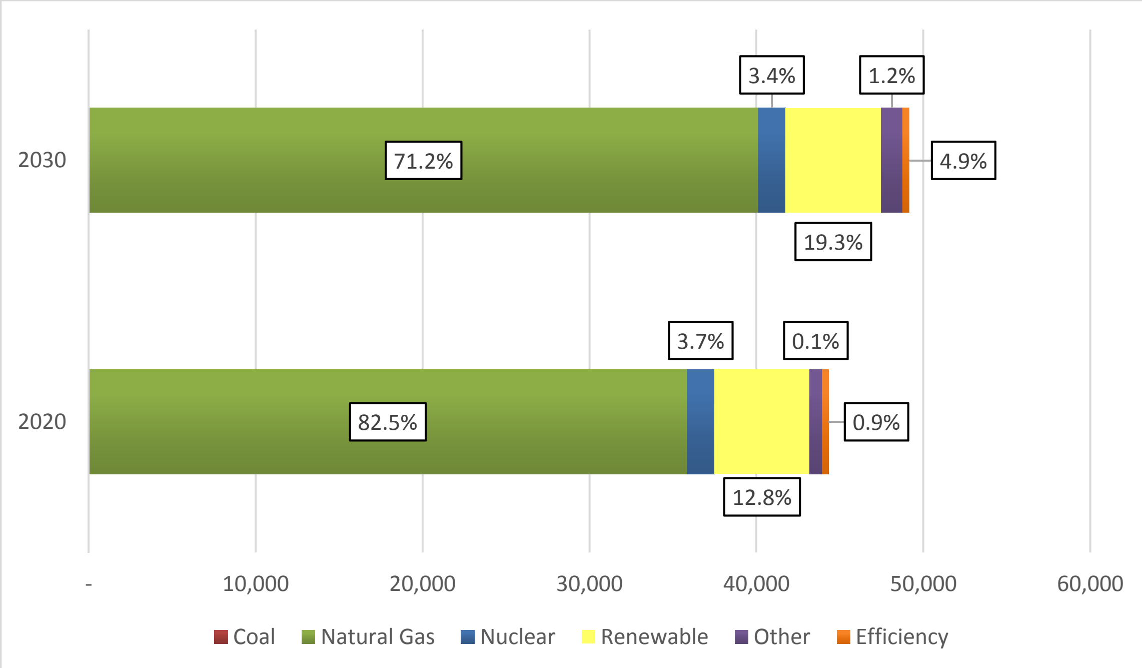


Figure 6-9: Scenario 5 (Green Dispatch) – Energy Generation Portfolio



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

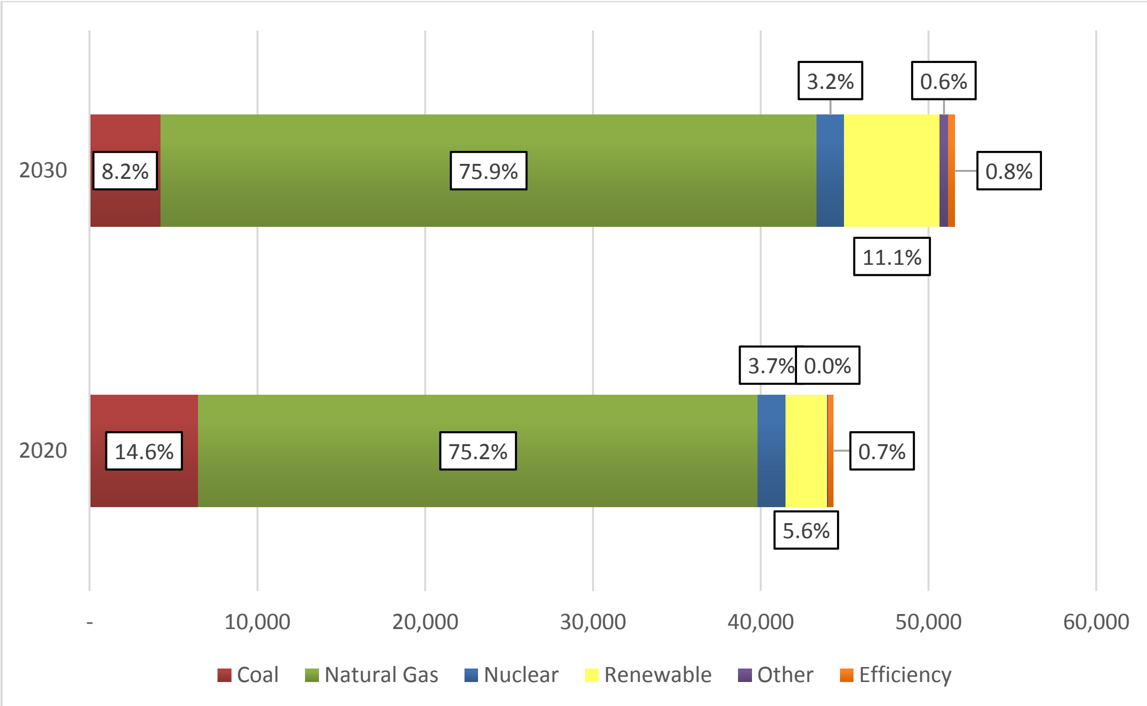
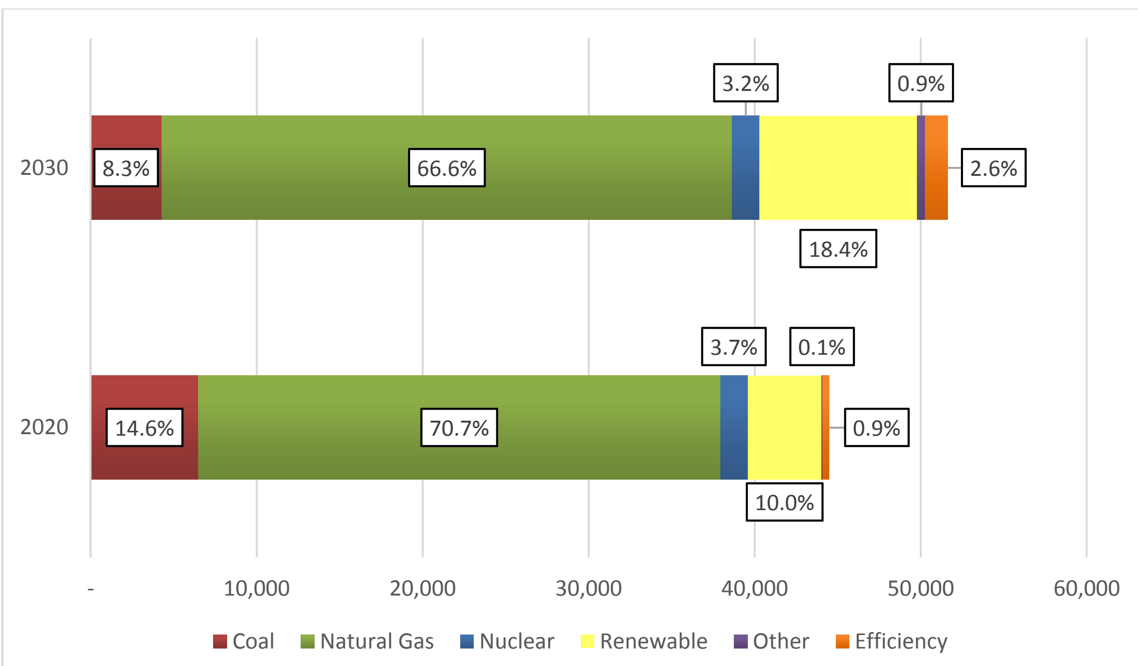


Figure 6-11: Scenario 6 (Green Dispatch) – Energy Generation Portfolio



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:

<u>Coal-fired units</u>. 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.

<u>Existing NGCC</u> 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.

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

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

<u>Other</u>. 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)

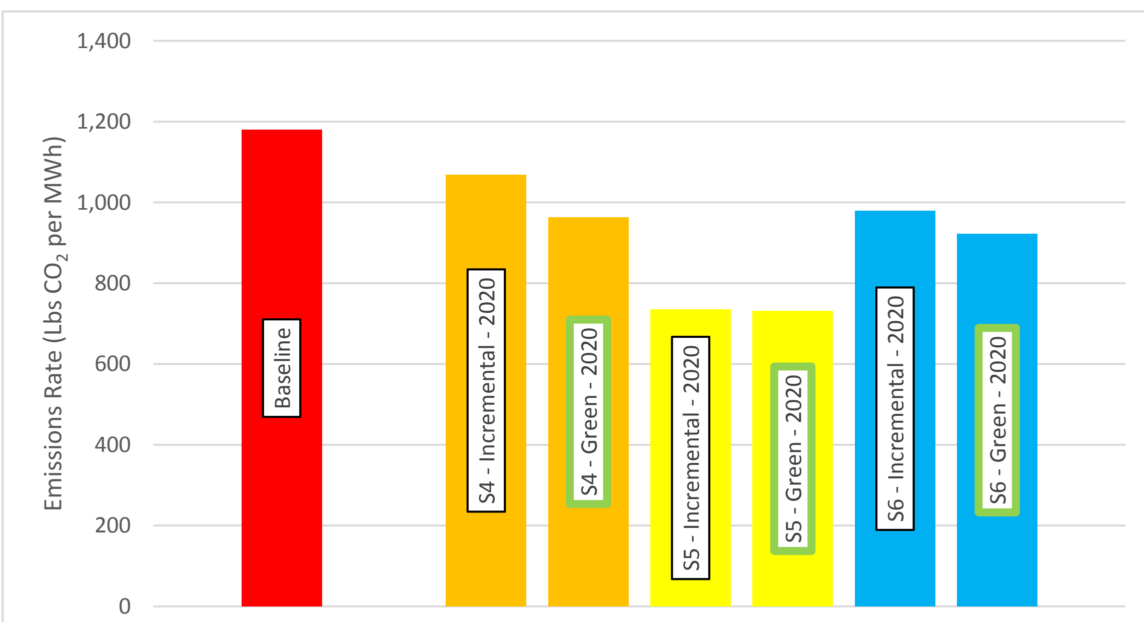
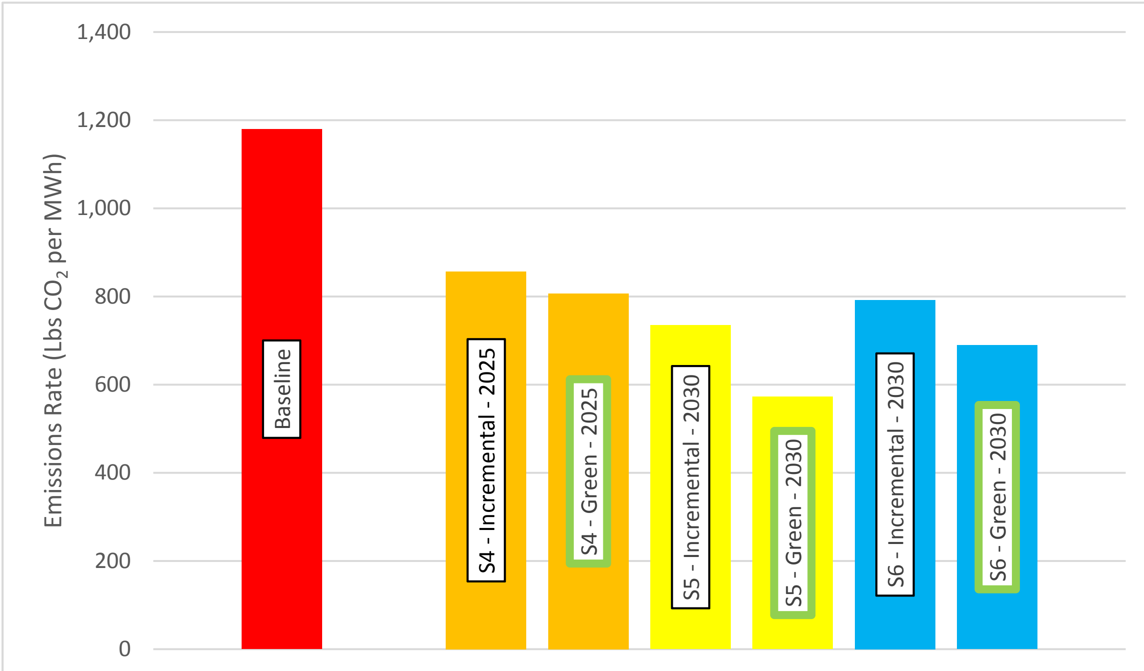
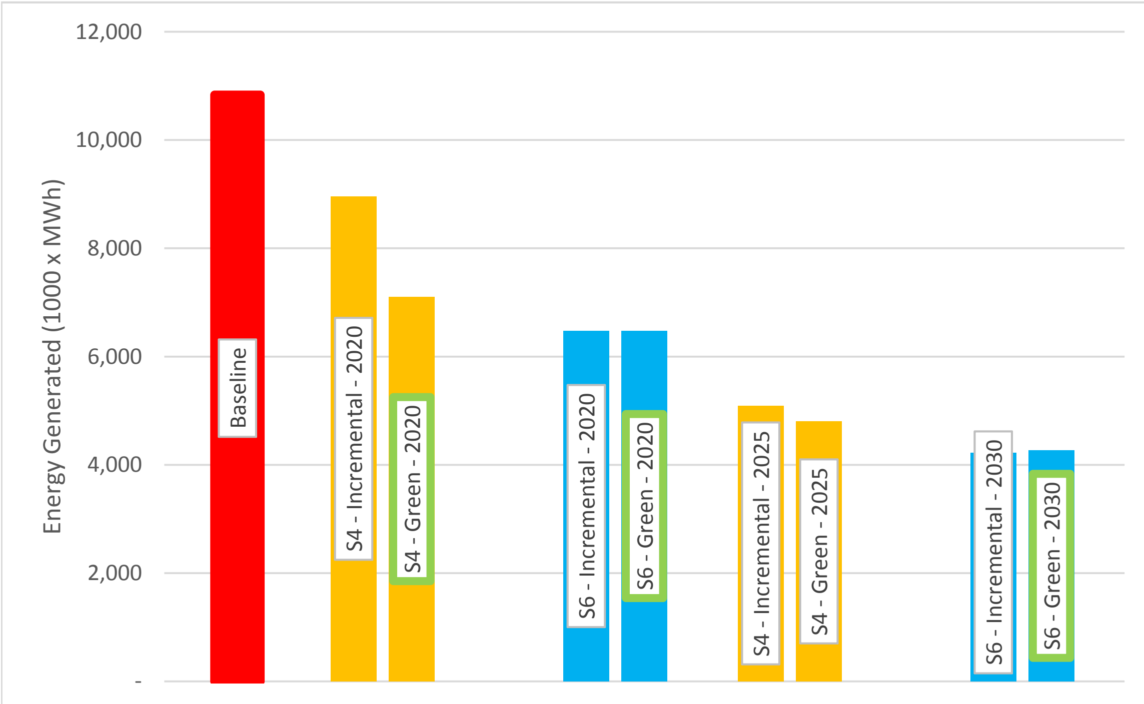


Figure 6-13: Virginia's Projected 2030 CO_2 Rate by Scenario vs EPA Target CO_2 Rate (in lbs of CO_2/MWh)



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)

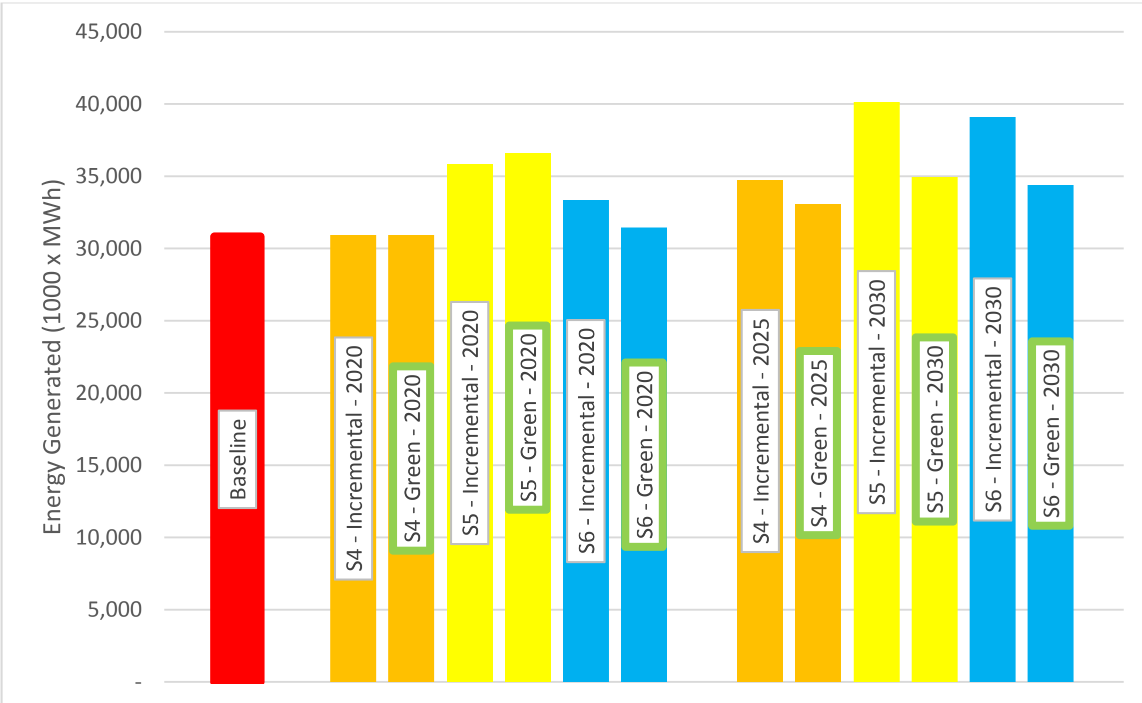
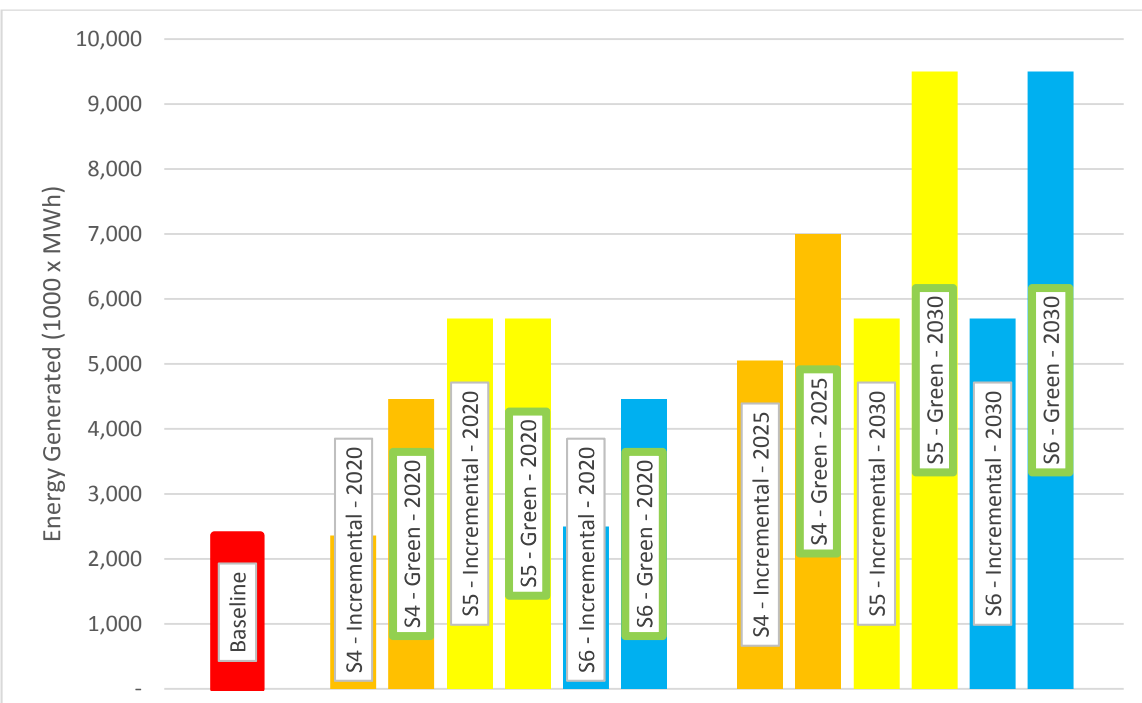


Figure 6-16: MWh of Renewable Generation Units in each Scenario (in million MWh)



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,

[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

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

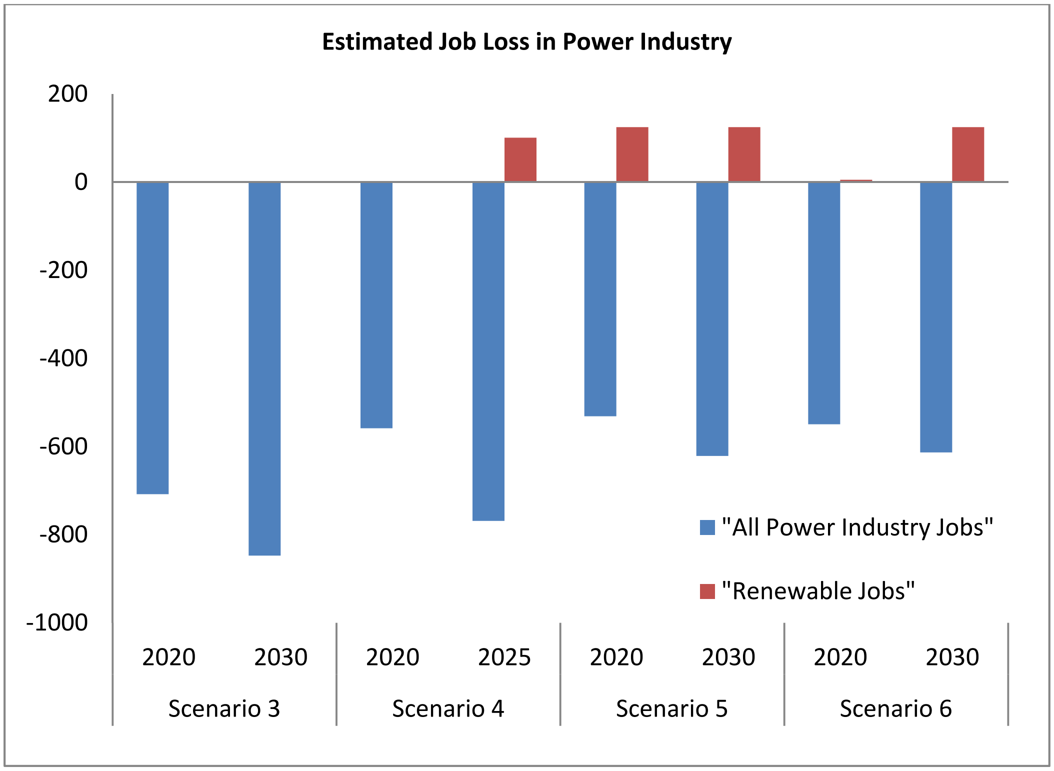
measured as total sales (revenue) will reach $59.4 million in 2020. An additional annual indirect impact of $11.7 million jobs will benefit other Virginia businesses that support power generation. Since the induced impact results from household spending, with anticipated jobs losses in the power industry, 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

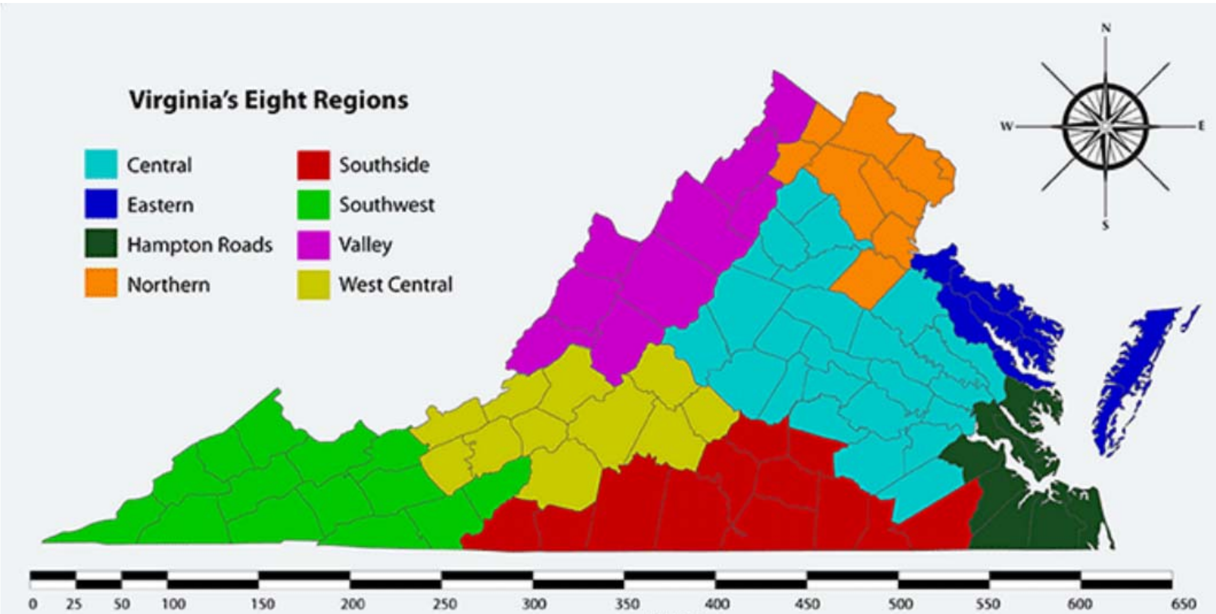


To estimate the number of those jobs, we first evaluate the current renewable generation and number of renewable jobs in Virginia in 2012 (BLS, 2014). We then estimate the jobs proportionally based on the output of electricity from renewable sources. From Figure 8-1, it can be concluded that addition 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

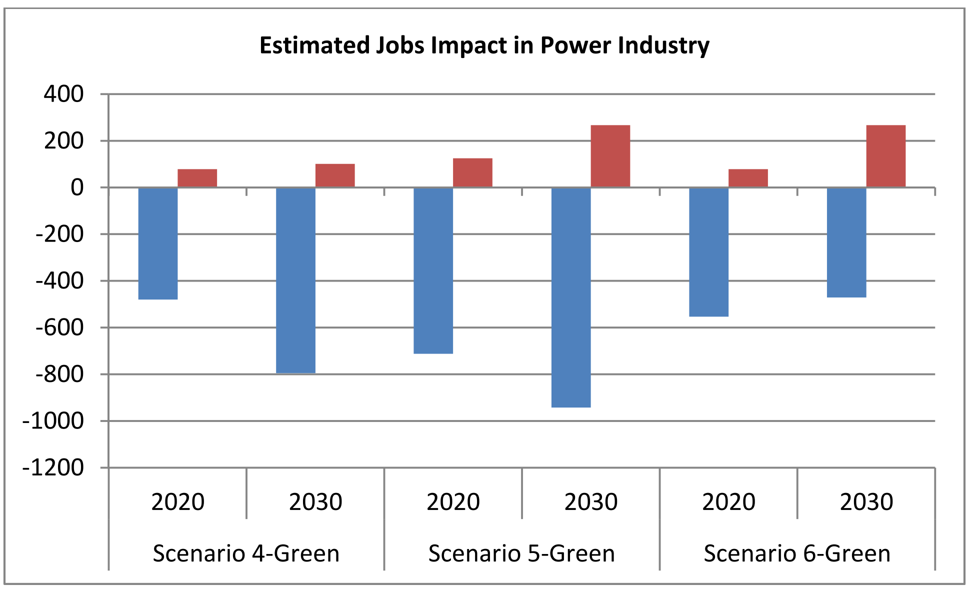
Green Dispatch Scenario-Increased Cost per Household						
	Scenario 4 (Green)		Scenario 5 (Green)		Scenario 6 (Green)	
	2020	2025	2020	2030	2020	2030
Lowest 20%	$71.8	$123.8	$100.0	$113.3	$75.1	$105.4
Second 20%	$88.7	$150.1	$123.4	$134.8	$92.7	$125.5
Third 20%	$101.3	$172.8	$141.0	$156.5	$105.9	$145.6
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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Clean Power Plan Impact Analysis Support

Southern Environmental Law Center

September 4, 2014

ICF was contracted by the Southern Environmental Law Foundation to compile and process data primarily published by the US EPA in conjunction with EPA's Proposed Clean Power Plan, formally published in the Federal Register as *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*. Specifically ICF compiled the data used in this *Clean Power Plan Impact Analysis Support* document from the following public sources:

- Power Sector Modeling of the Clean Power Plan proposed rule (http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html)
- Regulatory Impact Analysis: Clean Power Plan Proposed Rule (http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html)
- Other documents available in the Clean Power Plan Proposed Rule Technical Documents webpage (http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html)
- Other third party sources for the determination of changes in CO_2 reduction and other gases from power plants, which are noted explicitly in the report

The views, conclusions, and recommendations presented in this *Clean Power Plan Impact Analysis Support* document, however, are SELC's alone.

Contents

Introduction

ICF International (ICF) was contracted by Southern Environmental Law Center (SELC) to compile and process data primarily published by the US EPA in conjunction with EPA's proposed Clean Power Plan (CPP) to illustrate and quantify potential impacts the proposed rule that would control CO_2 emission rates from existing power plants. More specifically, ICF is assisting SELC in understanding the impacts of the CPP as it relates to the Commonwealth of Virginia. This report summarizes that data analysis. ICF has also separately provided SELC with a more detailed set of results associated with the scope of this analysis in spreadsheet format.

This analysis is wholly based on data collected from EPA's modeling results[1] and the Regulatory Impact Assessment (RIA)[2] of the CPP, as posted on EPA's website. Wherever applicable, we have noted any assumptions made.

This report discusses impacts due to the Option 1 standard, implemented both at the state level (Option 1—State Case) and regional level (Option 1—Regional Case). In both these cases, EPA modeled the CPP as a rate-based standard in which conventional generating resources, renewable resources and energy efficiency resources contribute to meeting the Best System of Emission Reductions (BSER) rate as proposed by EPA.

The next section of the report summarizes EPA's reported costs and benefits associated with the CPP. Following that, we briefly summarize the impacts of the CPP on power markets, both wholesale and retail, and also on employment. As mentioned earlier, the scope of this analysis is limited to impacts on Virginia only.

Costs and Benefits

The RIA provides detailed discussion of the cost and benefit associated with the implementation of the CPP. However, the approaches of determining these cost and benefit components vary significantly from component to component. For instance, while EPA provided a detailed spreadsheet on the calculation of energy efficiency (EE) implementation costs, as they are an integral component of the proposed rule, it only provided a qualitative discussion of some of the benefits associated with reduced emissions of SO_2 and NO_X, which EPA describes as ancillary benefits to the rule. Therefore, while these costs and benefits provide a benchmark, they are not directly comparable, and not necessarily exhaustive. Limitations associated with each of these approaches are detailed in the RIA, and we have highlighted some of those limitations below.

Compliance Cost

In EPA's analysis framework, compliance costs are defined as the difference between total system costs in a modeling run with the CPP (a policy case scenario) and a modeling run without it (a base case scenario). This difference therefore reflects the cost impacts attributable solely to the CPP. System costs

[1] EPA's modeling of the wholesale electric system was conducted using the Integrated Planning Model (IPM). Modeling results for the Clean Power Plan can be downloaded here: http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html

[2] Regulatory Impact Assessment for the Clean Power Plan Proposed Rule can be downloaded here: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

in this analysis were observed only for Virginia[3], and were taken as the sum of the following cost components for each run year[4]:

- Capital costs for the construction of new plants,
- Capital costs for the construction of new retrofits due to Heat Rate Improvements (HRI),
- Fixed operation and maintenance costs (FOM) and variable operations and maintenance (VOM) costs,
- Fuel costs for new and existing plants,
- Transportation and storage costs for fuel, and
- Costs associated with energy efficiency implementation.

Each of these cost components (except for energy efficiency costs) are reported separately for each generating unit in IPM (either new or existing). ICF aggregated these costs for generating units that were determined to be in Virginia. Energy efficiency (EE) was modeled exogenously in EPA's analysis, and costs associated with EE were reported separately by state. EE costs for Virginia were taken directly from EPA's GHG Abatement Measures TSD[5].

Tables 1 and 2 below show compliance costs, with wholesale market costs (system costs taken from IPM) separated from EE costs. We note that the implementation of the CPP leads to lower wholesale market costs, owing primarily to the fact that fewer new builds are required. However, accounting for EE costs shows that there is a net positive compliance costs associated with the implementation of CPP for the state of Virginia.

Table 1: Virginia Compliance Costs Associated with CPP (Option 1--State Level)

(in Millions of 2011$)	2016	2018	2020	2025	2030
Wholesale Market Costs	(31)	(266)	(81)	(175)	(64)
EE Total Annual Costs	-	19	103	647	1,171
Total Compliance Costs	***(31)***	***(247)***	***22***	***472***	***1,107***

[3] Capacity additions of conventional generators in EPA's analysis are classified at the model region level. Region definitions within EPA's analysis do not necessarily align with state borders. In that regard, there are four regions that cover Virginia in EPA analysis: PJM Dominion, PJM AP, PJM West, and PJM_EMAAC. Moreover, some of these regions also overlap with other states. EPA does not directly provide what percent of each state corresponds to each modeling region. ICF has calculated this breakdown by observing what portion of a state's existing generation is classified under each modeling region. This breakdown was then used to translate other results that were provided by IPM modeling region to results by state.

[4] EPA's analysis does not model every year in the forecast horizon. Instead, it only models specific years of interest, called run years. In EPA's modeling runs, the run years chosen were 2016, 2018, 2020, 2025, 2030, 2040, and 2050.

[5] Report available in Excel spreadsheet format here: http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-ghg-abatement-measures-scenario1.xlsx

Table 2: Virginia Compliance Costs Associated with CPP (Option 1--Regional Level)

(in Millions of 2011$)	2016	2018	2020	2025	2030
Wholesale Market Costs	(15)	(269)	(161)	(219)	(166)
EE Total Annual Costs	-	19	103	647	1,171
Total System Costs	***(15)***	***(251)***	***(58)***	***429***	***1,005***

Carbon Reduction Benefits

Given the global nature of CO_2 impacts, it is inherently difficult to ascertain the benefits of CO_2 reductions only to Virginia. EPA's RIA uses the Social Cost of Carbon (SCC) to determine carbon reduction benefits, and notes in their RIA that "the SCC estimates represent global measures because of the distinctive nature of the climate change problem"[6]. Consequently, it is impossible to conceptualize and quantify CO_2 reduction benefits only to Virginia, and accordingly EPA measured these benefits on a global, rather than state-specific scale.

For this analysis, ICF has taken reductions in Virginia's CO_2 emissions and quantified its impact using the Social Cost of Carbon (SCC) values quoted in the study. The SCC value chosen here is the one that assumes an average discount rate of 3%[7]. Because CO_2 emissions have global impacts, the SCC represents assumed benefits worldwide, and not just to Virginia. Figure 1 shows the reduction in CO_2 emissions in Virginia's power sector as a result of the CPP, and Figure 2 shows the

[6] See page 4-8 of the RIA.

[7] Other SCC estimates provided in the RIA assumed an average discount rate of 2.5% and 5%. These SCC estimates are averages from three other models. In addition, a fourth SCC estimate assumed a discount rate of 3%, but the 95th percentile value from these models was used instead of the average. More details on this approach are provided in pages4-7 through 4-11 of the RIA.

Figure 1: CO_2 Emission Changes in Virginia Due to the CPP

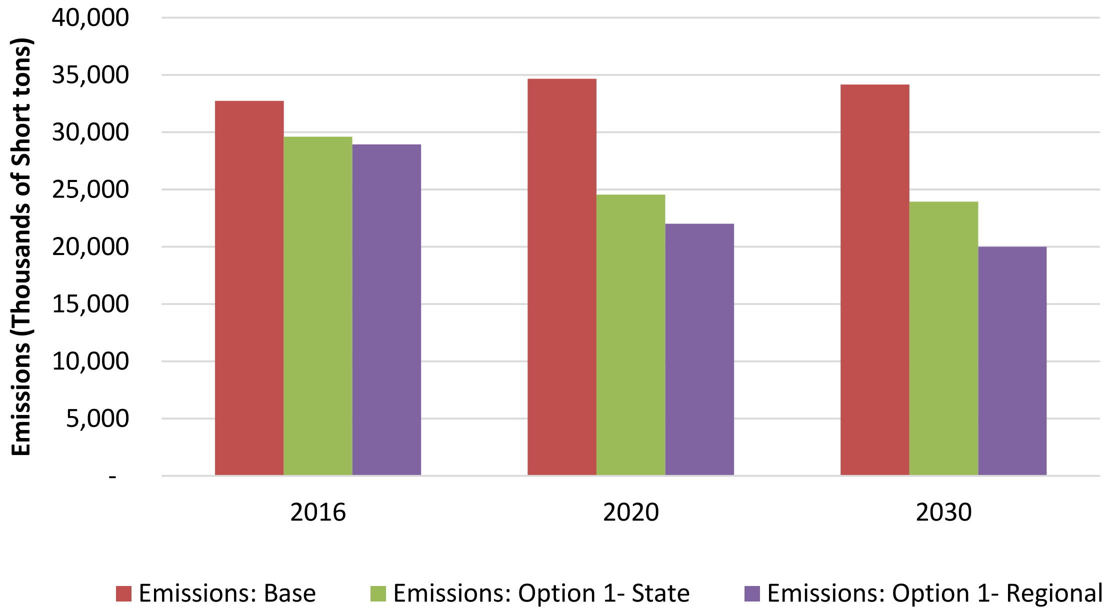
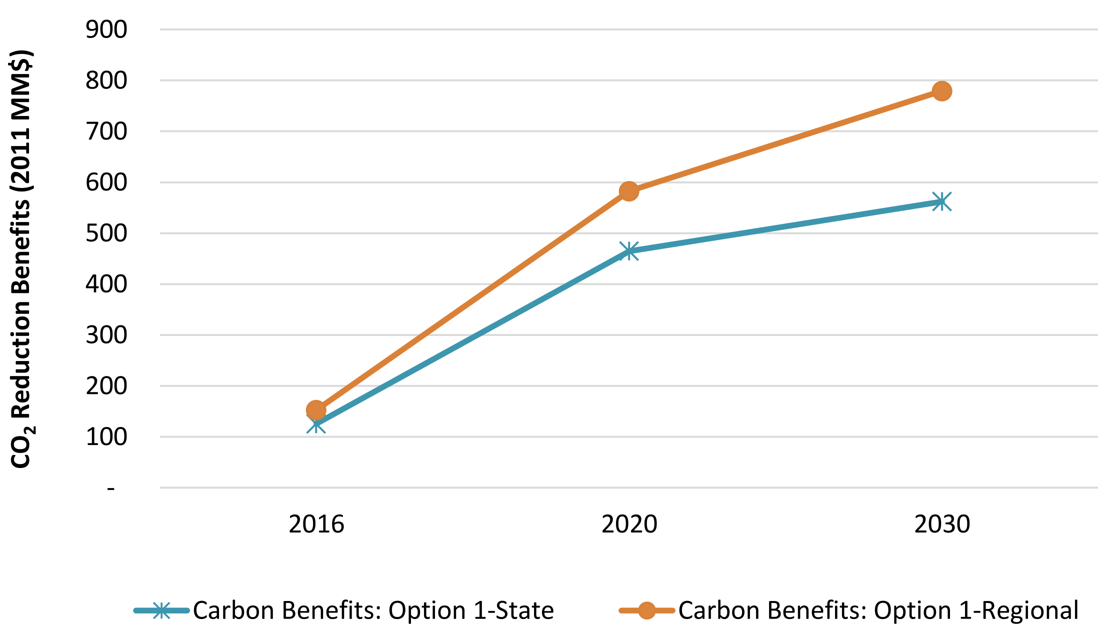


Figure 2: Carbon Benefits (Global) as a result of Virginia's Lower CO2 emissions due to the CPP



Ancillary emission reduction benefits

As the CPP is aimed towards CO_2 emissions reductions, benefits associated with other pollutants are seen as "co-benefits". In the RIA, EPA quantifies reduction benefits associated with $PM_{2.5}$ and ozone only (the RIA identified a number of benefits associated with these reductions, but did not quantify all of them). Reductions due to other pollutants such as HAPs (including mercury and hydrogen chloride), SO_2 and NO_x are not quantified in the RIA.

EPA evaluated the health co-benefits associated with $PM_{2.5}$ by calculating total monetized human health co-benefits of reducing one ton of $PM_{2.5}$, or one of its precursors (NO_x and SO_2). Similarly, EPA calculated health co-benefits of reducing one ton of NO_x in order to estimate ozone co-benefits, as NO_x is a precursor for ozone. In general, we did not find adequate data provided by the EPA in order for us to derive state-level impacts. Moreover, we also note that the RIA acknowledges that their own attempted analysis for a state-level impact was unreliable[8]. Therefore, this analysis only discusses the benefits associated with ancillary emission reductions in qualitative terms. ICF has also listed a few studies that show an indirect link between CO_2 emission reductions, and reductions of other gases in power plants.

Table 2 below shows non-CO_2 emission changes in Virginia due to the CPP. Even though Tables 3 through 5 show benefit-per-ton estimates and emissions for the East region, it would not be accurate to use the same relationship to monetize benefits to Virginia due to lower emissions shown in Table 2. In reality, as these pollutants can travel significant distances after being emitted, their effects (or reduction benefits) are not necessarily experienced in the same state as where they were emitted. Given the complexity in determining state-specific benefits of these reductions, EPA measured the benefits of such emission reductions on a regional scale.

[8] "When we evaluated the state-level estimates in the same manner as the national and regional estimates, we found that the state-level estimates performed similarly, in general, to the regional estimates for estimating total national benefits but were unreliable in estimating the benefits that would accrue to each state." (Page 4A-25 of the RIA).

Table 2: Non-CO_2 Emission Changes from Sources in Virginia Due to the CPP

	Emissions (thousands of tons)		
	Option 1 - State		
	2020	2025	2030
SO2	-3	-4	-3
Ozone Season NOx	-2	-3	-2
Annual NOx	-6	-9	-6
Hg	0	0	0
HCL	0	0	0
	Option 1 - Regional		
	2020	2025	2030
SO2	-3	-4	-4
Ozone Season NOx	-2	-5	-5
Annual NOx	-9	-13	-11
Hg	0	0	0
HCL	0	0	0

Benefits Associated with Lower $PM_{2.5}$ and Ozone

There are numerous health effects associated with exposure to $PM_{2.5}$ and ozone. A reduction in these two pollutants will reduce the incidence of these health effects. Negative health effects of exposure to $PM_{2.5}$, include: adult premature mortality, acute bronchitis, asthma exacerbation, cerebrovascular disease, and reproductive and developmental effects. Negative health effects of exposure to ozone, include: premature mortality, premature aging of lungs, cardiovascular effects, and reproductive and developmental effects.

In addition to health risks associated with exposure to $PM_{2.5}$ and ozone; there are additional health risks associated with direct NO_x and SO_s exposure. The EPA's NO_x *Integrated Science Assessment* found that there was a likely causal relationship between respiratory health effects and short-term NO_2 exposure.[9] There also exists a causal relationship between short-term SO_2 exposure and respiratory health effects.[10]

Benefit-per-ton estimates show the total monetized human health co-benefits of reducing one ton of the specified pollutant. Table 3 below shows the regional benefit-per-ton Estimate for the East[11]. Also, Table 4 and Table 5 show the corresponding emissions and monetized health co-benefits for the East.

[9] RIA 4-57
[10] RIA 4-58
[11] The "East" Region in this analysis is comprised of the following 37 states: Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina,

Table 3: Benefit-per-ton (2011$ per short ton) by Pollutant

	Benefit-per-ton (2011$ per short ton)					
	2020		2025		2030	
Pollutant	Min	Max	Min	Max	Min	Max
SO2	$40,000	$90,000	$44,000	$98,000	$47,000	$110,000
Directly Emitted PM2.5 (EC+OC)	$140,000	$320,000	$150,000	$340,000	$160,000	$370,000
Direct emitted PM2.5 (Crustal)	$18,000	$41,000	$18,000	$40,000	$19,000	$43,000
NOx (as PM2.5)	$6,700	$15,000	$7,200	$16,000	$7,600	$17,000
NOx (as Ozone)	$4,600	$19,000	$5,900	$25,000	$6,300	$27,000

Table 4: National Non-CO_2 Emissions in the East Region Due to the CPP

	Emissions (thousands of tons)					
	Option 1 - State			Option 1 - Regional		
	2020	2025	2030	2020	2025	2030
Pollutant						
SO2	311	395	441	279	376	406
Directly Emitted PM2.5 (EC+OC)	5	6	5	5	5	5
Direct emitted PM2.5 (Crustal)	41	44	39	31	42	39
NOx (as PM2.5)	315	378	376	305	372	366
NOx (as Ozone)	135	164	163	130	160	158

North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin.

Table 5: Monetized Health Co-benefits in the East Region Due to the CPP

	Estimated Monetized Health Co-benefits (millions of 2011$)					
	Option 1 - State					
	2020		2025		2030	
Pollutant	Min	Max	Min	Max	Min	Max
SO2	$13,000	$29,000	$18,000	$40,000	$21,000	$47,000
Directly Emitted PM2.5 (EC+OC)	$760	$1,700	$900	$2,000	$870	$2,000
Direct emitted PM2.5 (Crustal)	$790	$1,800	$830	$1,900	$800	$1,800
NOx (as PM2.5)	$2,200	$4,900	$2,900	$6,500	$2,900	$6,600
NOx (as Ozone)	$640	$2,700	$1,000	$4,000	$1,100	$4,600
Total	***$17,390***	***$ 40,100***	***$23,630***	***$54,400***	***$26,670***	***$62,000***
	Option 1 - Regional					
	2020		2025		2030	
Pollutant	Min	Max	Min	Max	Min	Max
SO2	$12,000	$26,000	$17,000	$38,000	$20,000	$44,000
Directly Emitted PM2.5 (EC+OC)	$750	$1,700	$850	$1,900	$840	$1,900
Direct emitted PM2.5 (Crustal)	$770	$1,700	$780	$1,800	$770	$1,700
NOx (as PM2.5)	$2,200	$5,000	$3,000	$6,800	$3,000	$6,700
NOx (as Ozone)	$630	$2,700	$1,000	$4,300	$1,100	$4,500
Total	***$16,350***	***$37,100***	***$22,630***	***$52,800***	***$25,710***	***$58,800***

Since regional benefit-per-ton estimates assume a constant percentage of emission reductions across the region, they do not fully reflect the spatial differences in emission reductions and health impacts across the proposed compliance scenarios[12]. Furthermore, it is difficult to use the regional benefit-per-ton estimate to derive state-level estimates, since the regional benefit-per-ton estimates do not reflect the state level variability in emission reductions, population density, air quality response, interstate pollution transport, and base case heath incidence rates.[13] While the EPA tested different methods for creating state-level benefit-per-ton estimates, it could not find a reliable approach.[14]

Studies about changes in CO_2 and other pollutants

Numerous studies show a link between emission reduction strategies and reduced emissions of CO_2, SO_2, and NO_x. We highlight some of these studies below. The 2001 study *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide,*

[12] RIA 4A-24
[13] RIA 4A-24
[14] RIA 4A-24- 4A-25

and Mercury and a Renewable Portfolio Standard done by the EIA, modeled the impacts of imposing caps on power sector emissions of NO_x, SO_2, Hg, and CO_2. In the case of the CO_2 cap "the model chooses among investments in lower emitting technologies (mainly new natural gas and renewables), changes in operations and retirement decisions for existing and new electric power plants (using lower emitting resources more intensively than higher emitting resources and maintaining low emitting resources such as nuclear), and conservation activities by consumers (induced by higher prices)."[15] The modeled case had a CO_2 emissions cap at 7% below the 1990 level; the 1990 level had to be met by 2008, 7% below the 1990 level had to be maintained from 2008-2012, and the emission cap remained at the 1990-7% level from 2012 through 2020. The model projected that in 2020 the CO_2 emission cap would lead to (compared to the reference case) 18% lower So_2 emissions, 52% lower NO_x emissions and 43% lower CO_2 emissions.

The article *Reduced emissions of CO2, NOx, and SO2 from U.S. power plants owing to switch from coal to natural gas with combined cycle technology* also shows a link between CO_2 and SO_2 and NO_x reduction. This study used historical data to look at how the switch from coal to natural gas with combined cycle technology affected US emission rates. The study found that "as a result of the increased use of natural gas, CO_2 emissions from U.S. fossil-fuel power plants were 23% lower in 2012 than they would have been if coal had continued to provide the same fraction of electric power as in 1997".[16] Additionally (compared to if coal had continued to provide the same fraction of electric power as in 1997), the increased use of natural gas resulted in emission reductions of 40% for NO_x and 44% for SO_2 in 2012.

A recent study, *A Systems Approach to Evaluating the Air Quality Co-benefits of U.S. Carbon Policies*, presents a systems approach to quantifying air quality co-benefits of U.S. policies to reduce GHG emissions. The study concluded that monetized human health benefits associated with air quality improvements could offset 26-1050% of the cost of U.S. carbon policies. It also found that flexible policies, such as cap-and-trade, had larger net co-benefits than policies that targeted specific sectors (such as electricity and transportation). Another key finding from the study suggested that net co-benefit is driven by costs, rather than benefits, for a number of carbon policy choices, including policies that offer subsidies influencing the cost of renewables. Finally, the study notes that potential co-benefits associated with carbon policies diminish rapidly as these policies became more stringent—the benefit-cost ratio decreases as lower cost controls are exhausted.

Wholesale Electricity Market Impacts

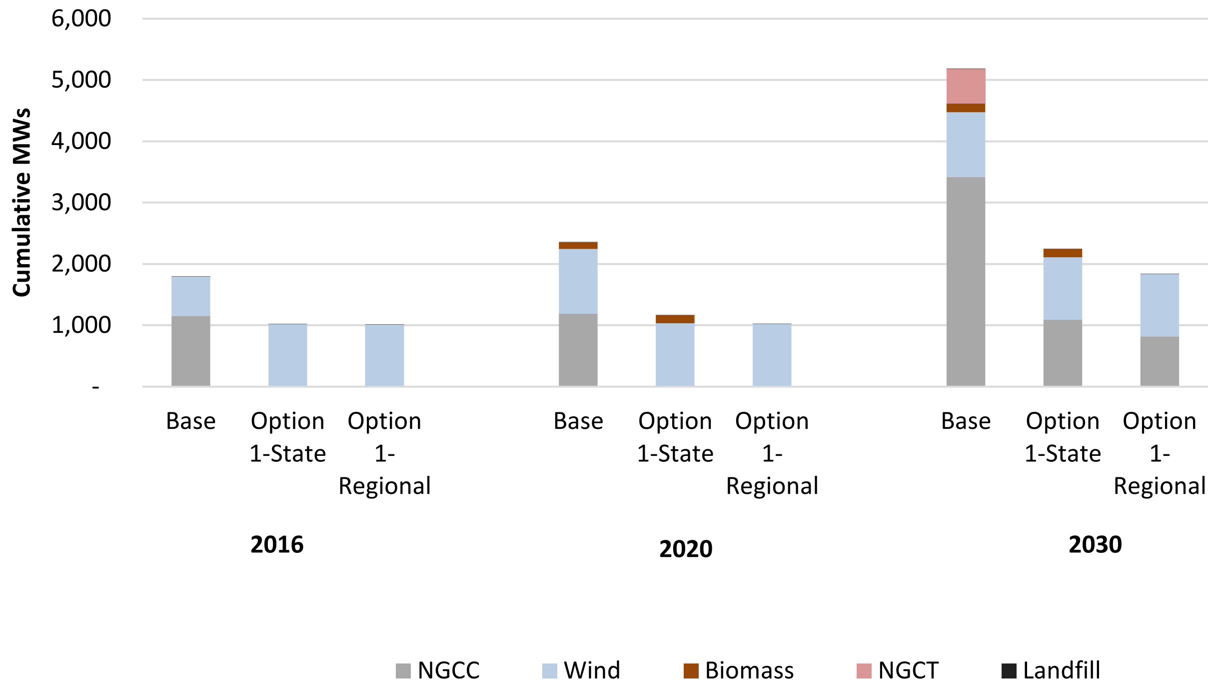
The implementation of the CPP will inevitably lead to changes in the power generation mix, as new capacity is added, and some existing capacity is retired or dispatched differently. Since, IPM directly reports new capacity builds, retirements, and the generation mix, ICF was able to parse these reports to determine impacts of the CPP on Virginia's power sector.

As shown in Figure 3, the amount of new capacity, particularly Natural Gas Combined Cycle (NGCC), required with the CPP is significantly lower in both the Option 1—State Case and the Option 1—Regional

[15] Pg. 14
[16] Pg. 75 of the study

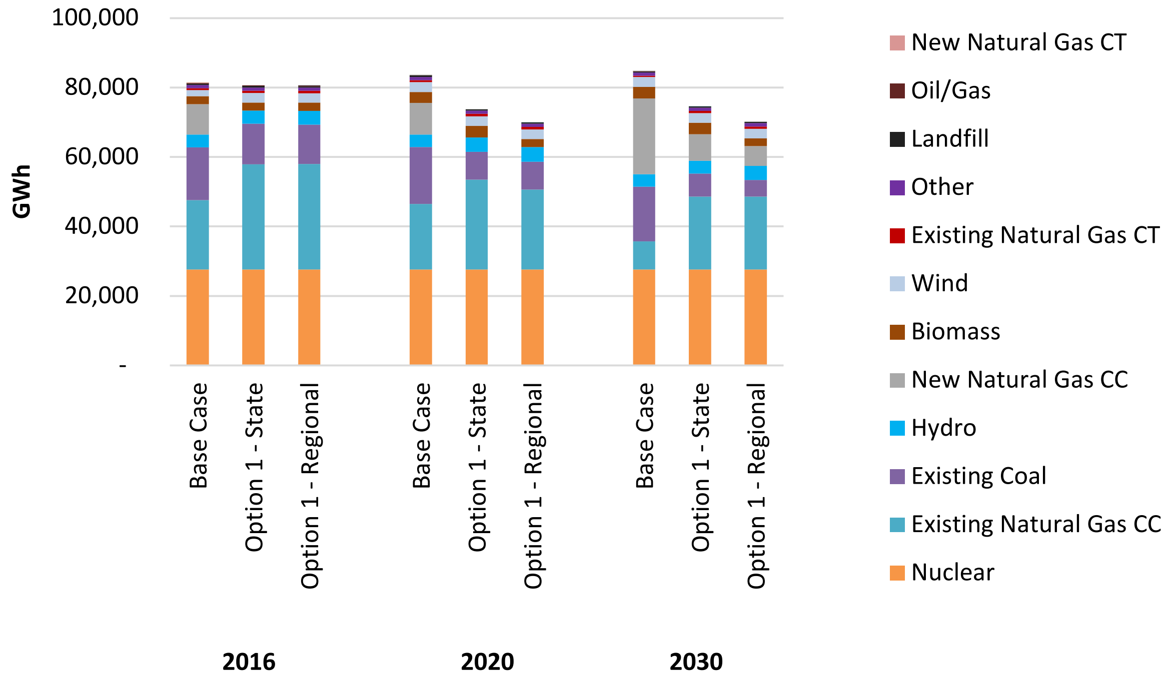
Case. These lower builds are primarily due to EE measures, which lower energy demand. Figure 4 illustrates this behavior even more clearly, where we notice that overall generation in Virginia is lower in the two CPP cases, than in the Base Case.

Figure 1: Virginia New Capacity Build Impacts Due to the CPP



The CPP results in new wind builds occurring earlier relative to the Base Case—wind builds in 2016 are over 60% higher in each of the CPP cases than in the Base case. However, in the long term, the difference in wind builds between the CPP cases and the Base case is negligible. There is also a small amount of landfill gas capacity that is built in each of the cases. No other renewable type is built in any scenario.

Figure 2: Virginia Generation Mix Impacts Due to CPP



Changes in retrofits due to the CPP are relatively modest, as shown in Table 6—Heat Rate Improvement (HRI) technology is implemented in 401 MWs of existing coal in 2020 in the Option 1—State Case, and no such implementation occurs in the Option 1—Regional Case.

Table 6: Impacts of the CPP on Retrofit Decisions in Virginia

	Option 1--State Case					Option 1--Regional Case				
	2016	2018	2020	2025	2030	2016	2018	2020	2025	2030
CCS	-	-	-	-	-	-	-	-	-	-
HRI	-	-	401	-	-	-	-	-	-	-
ACI	-	-	-	-	-	-	-	-	-	-
FGD	-	-	-	-	-	-	-	-	-	-
DSI	-	-	-	-	-	-	-	-	-	-
SCR	-	-	-	-	-	-	-	-	-	-
SNCR	-	-	-	-	-	(103)	-	-	-	-
C2G	-	-	-	-	-	-	-	-	-	-
CCG	-	-	-	-	-	-	-	-	-	-

Retirements of existing coal units, however, increase by about 50% in the Option 1—State Case and 58% in the Option 1—Regional Case. Table 7 shows the changes in retirements due to the CPP.

Table 7: Impacts of the CPP on Retirement Decisions in Virginia

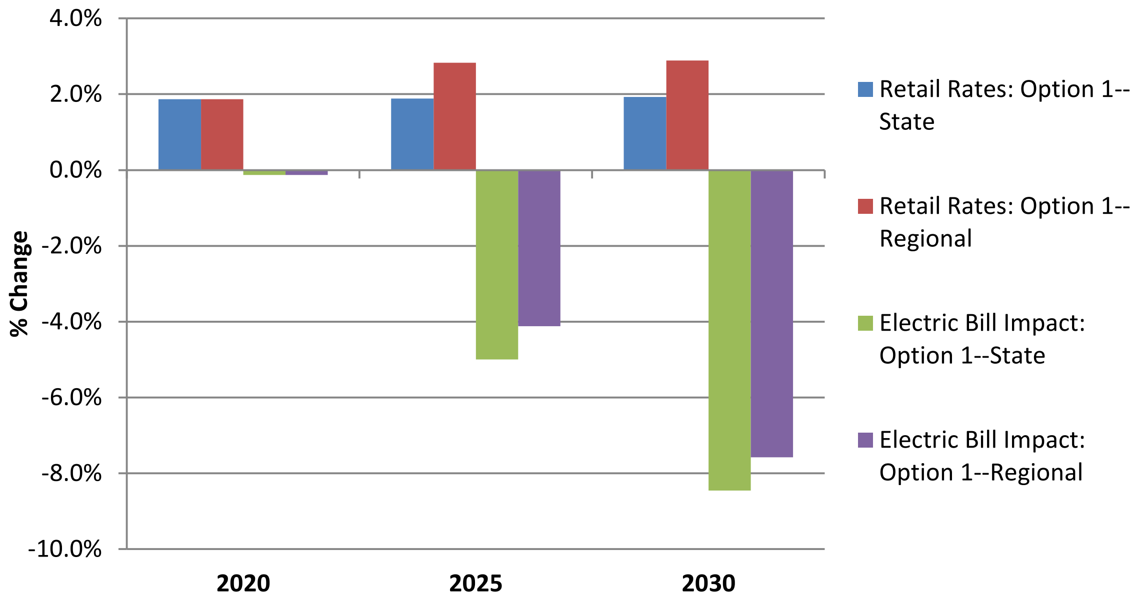
	Option 1—State Case					Option 1—Regional Case				
	2016	2018	2020	2025	2030	2016	2018	2020	2025	2030
CC Retirement	-	-	-	-	-	-	-	-	-	-
CT Retirement	-	-	-	-	-	-	-	-	-	-
Non-Fossil Retirement	-	-	-	-	-	-	-	-	-	-
Coal Retirement	884	-	-	-	-	1,055	-	-	-	-
O/G Retirement	-	-	-	-	-	-	-	-	-	-
Nuke Retirement	-	-	-	-	-	-	-	-	-	-
IGCC Retirement	-	-	-	-	-	-	-	-	-	-

Retail Rate Impacts

Impacts on retail rates were provided by EPA at the regional level. Note that these are not the same broad regions used for reporting elsewhere (i.e. East, West, and California regions), but are more granular, so that they reflect impacts on Virginia more closely[17]. Based on this classification, Virginia is part of the SRVC region, along with North Carolina and South Carolina. Figure 5 shows the impact of the CPP on retail rates in this region.

[17] Retail rate impacts were provided by the EPA at sub-RTO region level, in which Virginia is part of the broader "Virginia-Carolina" region. ICF will assume that retail rate impacts experienced at the state-level will be the same as that at the regional-level.

Figure 3: Retail Rate and Electric Bill Impacts in Virginia due to the CPP



The implementation of the CPP will also result in lower household electric consumption, due to EE technologies. Therefore, while retail rates are higher as a result of the CPP, the lower household consumption counters that effect on the overall household bill. Figure 5 above shows the impact on bills, after accounting for both these effects[18].

[18] The percent change in electric bill is based on the decreases in Net Energy for Load, as modeled in IPM. We used the Net Energy for Load differences in the SERC-VACAR (which includes the Carolinas) and PJM-Dominion regions in this case, since the retail rate differences were reported by EPA collectively for these regions.

Economic and employment impacts:

EPA's approach for determining employment impacts mostly looks at "first-order" jobs associated within the power sector, such as jobs for construction and maintenance of new units, jobs for heat-rate improvement upgrades, etc. The only "second-order" job impacts discussed are jobs in the coal mining and gas extraction sectors.

In order to derive these impacts for Virginia, ICF has followed the approach described by EPA in its RIA. In order to verify that our approach was consistent with that of EPA's, we first used the approach to derive job impacts at the national level, and compared that against what was reported by EPA (see Table 6-4 and Table 6-5 in the RIA). After determining that the values derived by our approach for national impacts were reasonably close to that reported by EPA, we adopted the same approach to calculate job impacts in Virginia.

Table 8 summarizes job impacts resulting from each of the two Option 1 cases. We also provide further detail below on each of the categories listed in the Table. The values shown in this table are in job-years, which represents the amount of work performed by one full time equivalent (FTE) employee in one year. For instance, 10 job-years in 2015 may represent 10 full-time jobs or 20 half-time jobs in the same year, or a combination of full- and part-time workers that would result in 10 FTEs.

However, jobs created in the energy efficiency sector represent both full-time and part-time jobs, and cannot be compared with other FTEs. Therefore jobs created in this sector are not shown in Table 8. Please refer to the section below on Jobs Gained due to Energy Efficiency for more details.

Table 8: Job Impacts in Virginia due to the CPP

Construction-related (One-time) Changes	Option 1--State			Option 1--Regional		
	2017-2020	2021-2025	2026-2030	2017-2020	2021-2025	2026-2030
Heat Rate Improvement: Total	**75**	**-**	**-**	**-**	**-**	**-**
Boilermakers and General Construction	51	-	-	-	-	-
Engineering and Management	14	-	-	-	-	-
Equipment-related	7	-	-	-	-	-
Material-related	2	-	-	-	-	-
New Capacity Construction: Total	**(743)**	**(1,133)**	**(64)**	**(985)**	**(1,114)**	**(310)**
Renewables	(743)	-	(132)	(985)	-	(126)
Natural Gas	-	(1,133)	68	-	(1,114)	(184)
Recurring Changes	**2020**	**2025**	**2030**	**2020**	**2025**	**2030**
Operations and Maintenance: Total	**(568)**	**(641)**	**(573)**	**(652)**	**(718)**	**(663)**
Changes in Gas	(134)	(246)	(224)	(135)	(247)	(247)
Retired Coal	(433)	(395)	(349)	(517)	(471)	(417)
Retired Oil and Gas	-	-	-	-	-	-
Fuel Extraction: Total	**(78)**	**(77)**	**(44)**	**(72)**	**(75)**	**(31)**
Coal	(78)	(77)	(44)	(72)	(75)	(31)
Natural Gas	-	-	-	-	-	-
Supply-Side Employment Impacts	**(571)**	**(717)**	**(617)**	**(725)**	**(793)**	**(694)**

Notes:
1. The format for Table 4 above is the same as that for Table 6-4 and Table 6-5 of the RIA, which show job impact results at the national level
2. Job-year estimates shown above are Full-Time equivalent (FTE), and do not include impacts on energy efficiency jobs (which include both part-time and full-time jobs).
3. From the RIA: “Construction-related job-year changes are one-time impacts, occurring during each year of the 2 to 4 year period during which HRI installation activities occur.”
4. From the RIA: “Recurring Changes are job-years associated with annual recurring jobs including operating and maintenance activities and fuel extraction jobs…In addition, there are recurring jobs prior to 2020 to fuel and operate new generating capacity brought online before 2020; the recurring jobs prior to 2020 are not estimated.”
5. Job estimates for New Capacity Construction are estimated by extrapolating national job impacts shown in Table 6-5 and Table 6-4 of the RIA. This approach is different than what is described in the RIA. ICF was unable to reasonably reproduce EPA's estimates using the methodology described in the RIA, and thus implemented a simpler extrapolation to estimate job impacts in Virginia.

Jobs due to Heat Rate Improvements

The EPA assumes that all construction jobs created owing to heat rate improvements (HRI) in coal plants will occur between 2017 and 2020. Construction jobs for HRI are further divided into the following four categories:

- Boilermakers and General Construction
- Engineering and Management
- Equipment-related
- Material-related

Jobs Due to Construction of New Capacity

The implementation of the CPP results in accelerated deployment of new renewable capacity, and consequently results in more renewable construction jobs being created in the near term, relative to the Base case. The corollary to that is that there are fewer jobs in the long-term when compared to the Base case. Similarly, because there are fewer megawatts of new gas in the Option 1 cases, the implementation of the CPP results in fewer construction jobs in that sector.

Construction job impacts were calculated based on total capital costs spent in the construction of new capacity, as reported in the IPM results. These amounts were used in conjunction with labor productivity estimates. In that regard, EPA looked at the following labor categories:

- General power plant construction
- Engineering and management
- Material use (steel)
- Equipment Use (Machinery)

Jobs Lost due to Retirement: Plant Operations

The retirement of fossil plants will lead to the elimination of operations and maintenance (O&M) jobs in such plants. EPA assumed an average fixed O&M cost for coal plants and for oil/gas plants, and also looked at labor productivity values for plant operators. These values were then taken in conjunction with total capacity retired, resulting in total jobs lost in power plants.

Jobs Lost due to Retirement: Coal Extraction

The loss of coal plants will also lower demand for coal (both inside and outside Virginia), and will lead to job losses in the coal mining. EPA assumes labor productivities in the coal extraction sector for different coal supply regions. In that regard, in order to estimate job impacts in Virginia, we chose the labor productivity value provided for Appalachian coal.

As mentioned earlier, job impacts in the gas extraction sector are not examined here, as Virginia does not have any significant gas extraction activities.

Jobs Gained due to Energy Efficiency

As energy efficiency (EE) is expected to play an important role in the implementation of the CPP, there is a significant potential for job creation in this sector. However, note that the CPP does not obligate states to pursue any EE activities, and consequently job creation in this sector is highly dependent on how states choose to develop their State Plans. EPA estimates jobs created in this sector by assuming a standard factor that translates dollars expended in EE implementation to jobs created in this field. EPA acknowledges that this approach has several limitations, which are noted in the RIA.

The RIA also notes that jobs estimated for other sectors (shown in Table 8 above) are all full-time equivalent jobs. However, EE jobs are either full-time or part-time jobs, and should not be lumped together with other jobs. Thus, in order to maintain consistency with EPA's recommendation, we list jobs created due to EE separately below.

Table 9: Energy Efficiency Jobs Created in Virginia Due to the CPP

	Jobs Created in both Option 1--State and Option 1--Regional		
	2020	2025	2030
Additional jobs per additional million dollars spent on EE	265	1,657	2,998

Note: These figures are not comparable with other FTE jobs shown in the previous table, since EE jobs shown here represent number of employees (full-time or part-time).

Other Job Impacts

The RIA does not detail job impacts associated with the CPP on an economy-wide basis. More specifically, the CPP only evaluates first-order jobs and some second-order jobs (which are discussed above). Some of these job impacts could be derived by using specialized modeling tools such as REMI and JEDI. For instance, the National Renewable Energy Laboratory's (NREL) Jobs and Economic Development Impact (JEDI) Models[19] estimate jobs created due to the construction of new renewables such as wind and solar. These models calculate impacts on direct jobs, indirect jobs, and induced jobs. Although, these models are not able to calculate jobs lost in the power sector, and therefore the job impacts estimated are gross impacts, not net impacts. Even though the specific definition of direct, indirect, and induced impacts can vary, we provide potential examples of such impacts, as illustrated in a 2012 NREL study[20]:

1. Direct Impacts: These impacts are related to project development and onsite labor, and are included in the CPP RIA. For instance, direct impacts can include jobs, earnings, and outputs related to specialty contractors, construction workers, clean-up crews, truck drivers, management and support staff, and other specialists hired to permit, design, and install the system.
2. Indirect Impacts: These impacts account for jobs, earnings, and outputs associated with manufacturing of equipment and materials used in the facility, the supply chain that provides raw materials to these manufacturers, and the finance and banking sectors that provide services

[19] More information on JEDI available here: http://www.nrel.gov/analysis/jedi/

[20] Preliminary Analysis of the Jobs and Economic Impacts of Renewable Energy Projects Supported by the Section 1603 Treasury Grant Program (http://www.nrel.gov/docs/fy12osti/52739.pdf)

for the construction and operation of these facilities. For instance, these jobs could include jobs at a wind turbine manufacturing plant, jobs at other facilities that fabricate structural hardware, foundations, and electrical components for the wind facility's systems. These jobs would also include bankers who finance construction contractors, accountants who keep track of the contractors' books, and jobs at steel mills that provide raw materials to manufacturing facilities.

3. Induced Impacts: The impacts refer to jobs, earnings, and outputs that occur through spending of earnings by persons directly or indirectly employed by new projects (i.e. jobs described in the first two categories). For instance, jobs are induced when workers hired for construction spend their earnings to purchase food at grocery stores and restaurants, when they pay rent or mortgages in their homes, and purchase clothes or other goods to meet their needs.

In addition to indirect and induced jobs, other job impacts not captured in EPA's analysis include impacts due to price changes. For instance, the implementation of the CPP could lead to increased energy prices in some regions, which may increase the cost of doing business and hence have a negative impact on jobs, all else being equal. A potential countervailing impact on jobs may come from companies with sustainability goals that are looking to do business in states with lower-emissions intensive power and/or ready access to renewables. This level of analysis would require a more sophisticated platform such as The REMI model. Hence, the CPP RIA only analyzes a portion of the potential economy-wide job impacts due to the proposed rule.

Members of the Virginia Energy Council:

- Cynthia Adams of Charlottesville, Executive Director, LEAP Virginia
- Kristen Hughes Evans of Richmond, Founder, Sustainable Chesapeake
- Alleyn Harned of Harrisonburg, Executive Director, Virginia Clean Cities
- Chelsea Harnish of Richmond, Energy Policy Lead, Virginia Conservation Network
- Francis Hodsoll of Reston, Founder, Virginia Advanced Energy Industries Association
- Steven Jumper of the District of Columbia, Director, Corporate Public Policy, WGL Holdings, Inc.
- Irene Kowalczyk of New York City, Director, Global Energy Sourcing & Policy, MeadWestVaco
- Bernard Lamoureux of Boydton, Data Center Operations Manager, Microsoft
- David Lawson of Norfolk, Vice President, Coal, Norfolk Southern
- Vishwa Link of Richmond, Partner, McGuire Woods
- Robert Matthias of Virginia Beach, Assistant to the City Manager, City of Virginia Beach
- Ann Blair Miller of Roanoke, Director, Project Management, Roanoke Regional Partnership
- Laurie Moran of Danville, President, Danville Pittsylvania Chamber of Commerce
- Dr. Ganapati Myneni of Yorktown, Senior Scientist, Jefferson Labs
- Dr. Kenneth Newbold of Harrisonburg, Associate Vice Provost, James Madison University
- Archie Pugh of Roanoke, Managing Director, Transmission, Appalachian Power
- Donald Ratliff of Big Stone Gap, Vice President, States – Government Affairs, Alpha Natural Resources
- Jack Reasor of Glen Allen, President & CEO, Old Dominion Electric Cooperative
- Sandy Reisky of Charlottesville, CEO, Apex Clean Energy
- Stephen Walz of Fairfax, Director, Environmental Programs, Metro Washington Council of Governments
- Mike Ward of Richmond, Executive Director, Virginia Petroleum Council
- Molly Ward of Richmond , Secretary of Natural Resources
- Dan Weekley of Richmond, Vice President, Government Affairs, Dominion

Commonwealth of Virginia
Office of the Governor

Executive Order

NUMBER SIXTEEN (2014)

ESTABLISHING THE VIRGINIA ENERGY COUNCIL

Importance of the Issue

The Commonwealth of Virginia's energy industry is a source of great pride, prosperity, and potential. Historically, Virginia has ensured reliable and affordable energy, helping businesses and consumers thrive. The Commonwealth boasts tens of thousands of energy-related jobs, including miners, gas well crews, manufacturing workers, engineers, mechanics, computer programmers, accountants, and managers. Virginians can and should be proud of the energy industry, but a changing market and energy environment requires decisive action to position the Commonwealth to be a national leader in innovative energy generation and utilization. Virginia must continue to leverage its business-friendly climate, high-quality research and educational institutions, and varied energy resources to attract businesses and create jobs. This requires Virginia to develop and implement a cohesive, comprehensive, and aggressive strategy for energy policy.

The Commonwealth will update the Virginia Energy Plan ("Plan") to be submitted to the General Assembly by October 1, 2014. The Plan will address the objectives of the Commonwealth Energy Policy set forth in the *Code of Virginia.*

These objectives include:

- Accelerating the development and use of renewable energy sources – Virginia can become a hub of innovative and alternative energy research and development by focusing on expanding the use of the Commonwealth's underutilized renewable assets, such as solar and offshore wind.
- Increasing energy productivity through greater efficiency – Virginia can become a national leader in energy efficiency practices that will increase the productivity of the energy used by citizens and businesses throughout the Commonwealth, while not imposing a disproportionate adverse impact on economically disadvantaged or minority communities.

- Promoting a diverse energy mix – Virginia should continue to increase the diversity of sources used to generate energy in the Commonwealth to ensure that we are not overly-reliant on particular sources.
- Growing jobs in the energy sector – Virginia's quality higher education institutions and world-class community college system are well-positioned to educate and prepare the next generation of energy workers. A trained and skilled energy workforce will attract new businesses and help expand existing businesses.

To achieve these objectives, it is critical that the Commonwealth engage the private sector, localities, and other interested stakeholders to develop significant and meaningful energy policies.

Establishment of the Council

The Governor shall create The Virginia Energy Council ("Council"), an advisory group comprised of members representing all areas of the Commonwealth's energy industry. The Council shall work to formulate a comprehensive and innovative energy plan.

All members of the Council will be appointed by the Governor and shall serve at his pleasure.

Responsibilities and Duties of the Council

The 20-25 person Council is charged with working to update the Virginia Energy Plan. Duties of the Virginia Energy Council include:

- Receiving, reviewing, and evaluating input offered by Virginia's residents and businesses related to the Plan;
- Developing strategies to make Virginia a national leader in energy efficiency and ensure that the cost of energy for Virginia consumers remains highly competitive;
- Developing strategies to increase the diversity of energy used to power Virginia, while ensuring a commitment to the most efficient use of existing energy sources;
- Developing strategies to increase Virginia's renewable energy economy and grow the entire energy industry in Virginia by retaining, expanding, and attracting businesses in the energy sector;
- Developing strategies to increase the international export of Virginia's coal;
- Identifying opportunities to expand Virginia's needed energy infrastructure and to increase the reliability of the Commonwealth's existing energy infrastructure;
- Reviewing an analysis of 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);
- Providing expertise and advice on other policy strategies deemed appropriate during the drafting of the Plan to grow the energy industry in the Commonwealth; and,
- Monitoring the implementation of the Plan, providing strategic guidance to ensure successful achievement of Plan goals, and reviewing the interim update of the Plan required to be presented by October 1, 2017.

Council Staffing and Funding

Staff support for the Council shall be furnished by the Secretary of Commerce and Trade, Secretary of Natural Resources, the Department of Mines, Minerals, and Energy, and such other agencies and offices as designated by the Governor. Necessary funding to support the Council and its staff shall be $5000. All executive branch agencies shall cooperate fully with the Council and provide any assistance necessary, upon request of the Council or its staff.

The Council shall meet at the call of the Chairman.

Effective Date of the Executive Order

This Executive Order shall be effective upon signing and shall remain in force and effect from its signing unless amended or rescinded by further executive order.

Given under my hand and under the Seal of the Commonwealth of Virginia, this 4th day of June, 2014.

Terence R. McAuliffe, Governor

Attest:

Secretary of the Commonwealth